

GEOExPro 5²⁰²⁶

BRAZIL'S PRE-SALT CARBONATES – A UNIQUE RESERVOIR

Exploration Opportunities

Odysseus of the Philippines

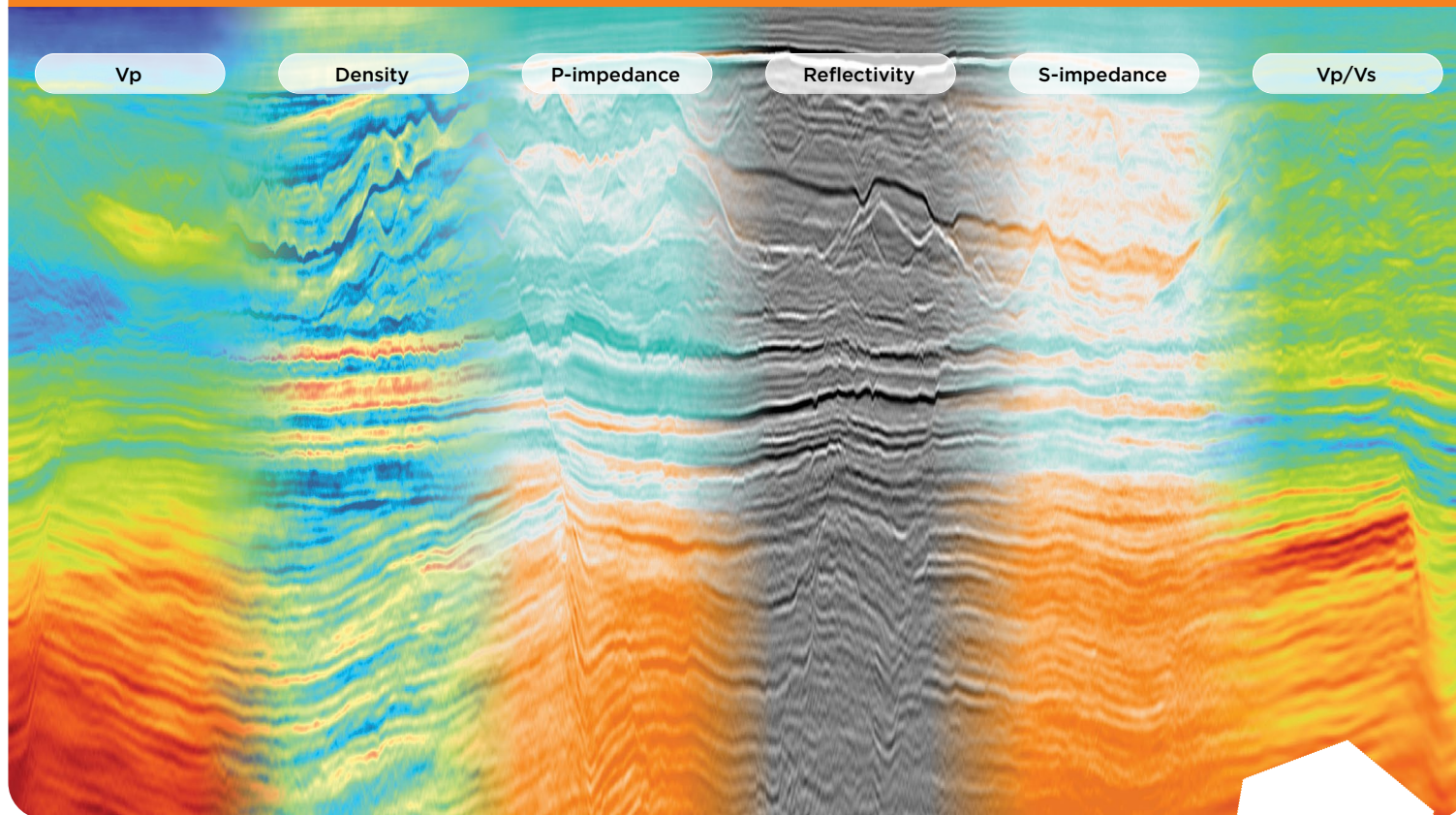
Equatorial Guinea: Douala and
Rio Muni risk reduction

Côte d'Ivoire: Modern reimaging –
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SOURCE: DE ROS & OLIVEIRA (2023) – JOURNAL OF SEDIMENTARY RESEARCH

Content is king

WITH THE DRAMATIC rise in the use of AI, everybody can be a proficient writer. Where we occasionally received poorly written content when an author really struggled to put a consistent and well-thought-through narrative on paper, today we often see the total opposite. Articles are slick, buzzing, and have a natural flow with strong beginnings and clear-cut ends.

But has that made it easier to accept content for publication? Not necessarily. There still has to be substance behind the carefully crafted sentences.

“What remains invisible is the effort it takes to source the story”

Writing should not be done for the sake of writing. Writing should be done because there is a message to convey. That message preferably needs to be something new for readers to enjoy or learn from, not a story that is a regurgitation of something that has already seen the light before. That is where more than half of the work lies: Collecting material, reading, performing analyses, and talking to people with experience on the matter. Our contributors are all aware of that too.

The very last article in this issue – around cutting a core that is subsequent-



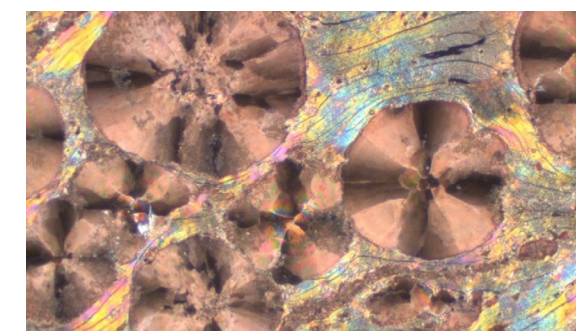
ly stolen – is an example of that. I didn’t write it myself, but it took considerable effort to make the authors write it for the magazine. Because many people have to be told that they carry plenty of great stories, and they may not be inclined to put these on paper and submit them to us on their own initiative.

Asking AI to blend a nice story together takes seconds. What remains invisible is the effort it takes to source the story. That work still needs to be done. Content that we are proud to present in this magazine and that we stand by. It is one of the main reasons why we travel to so many conferences around the world and stay connected with our audience. It is still a very important way to ultimately provide you with the interesting content that we hope you will appreciate. Simply by having random conversations. Face to face.

Henk Kombrink

BEHIND THE COVER

It was twenty years ago that the Tupi field was discovered offshore Brazil. It happened at a moment in time when the industry as a whole was starting to wonder where the next frontier would emerge, with some people being fairly open about the possibility that this would not happen at all. And then, bang, there was the success in the pre-salt carbonates. In the cover story, we go back to the years around 2006 through conversations with two people who were there when it happened. They both share with us their insights and learnings on these very odd carbonates,



and how they gradually learned how they formed. The photo shows calcite spherulites in a magnesian clay matrix, a combination that not many people had seen before.

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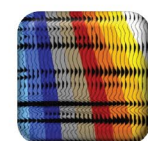
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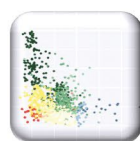
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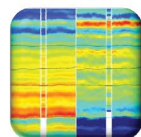
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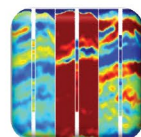
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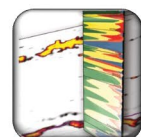
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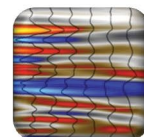
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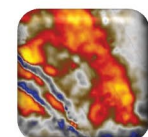
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FIRSTS

"It takes more energy to extract energy
than it did before"

Rodney Garrard

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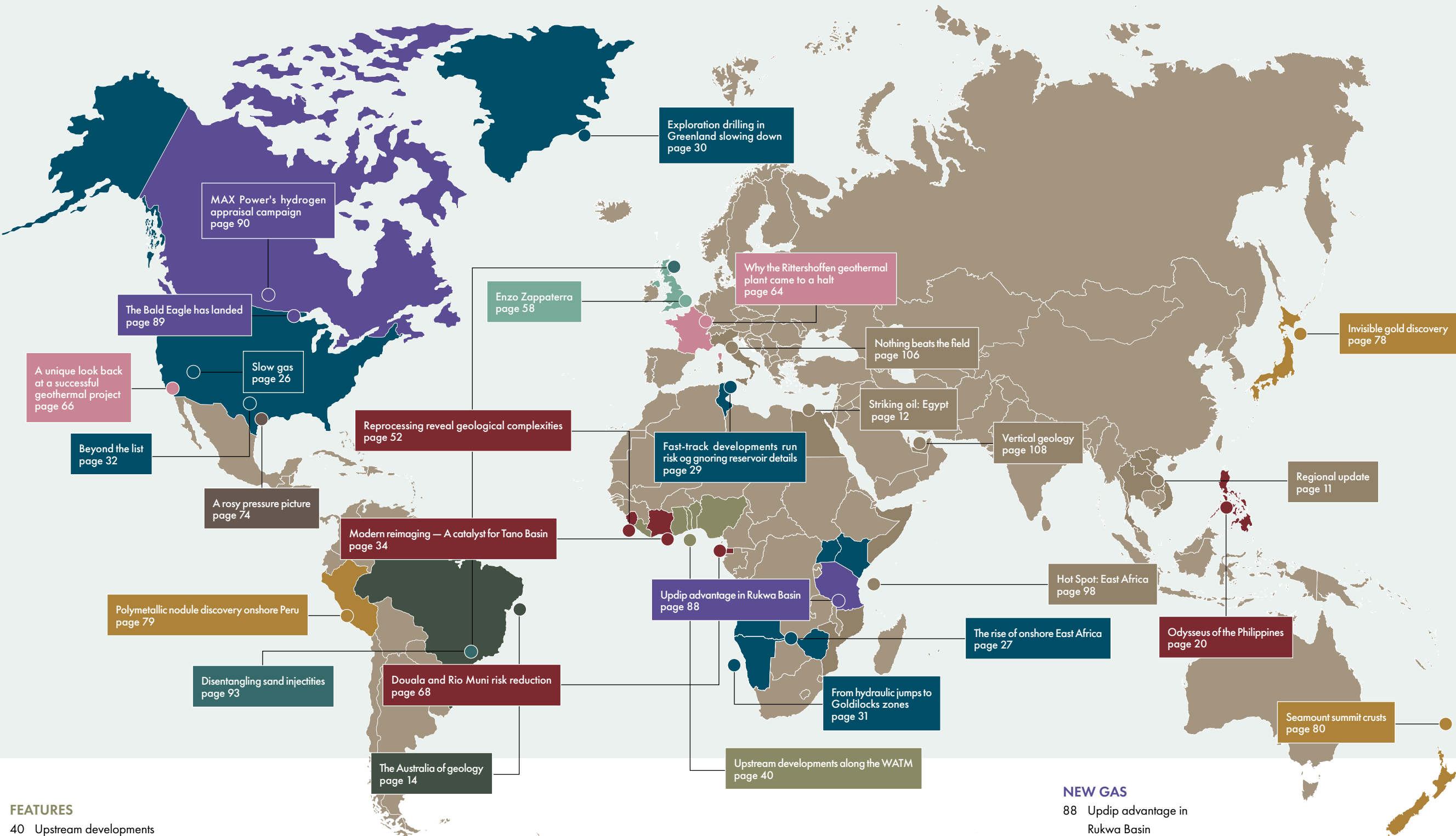
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TWO SEPARATE BASINS OR JUST ONE?

Before offshore exploration drilling took off, many people – including geologists – saw the present-day coastline as an important geological boundary. During his recent presentation at the Discovery Thinking Forum at the IMAGE Conference in Houston, Kevin McMichael from Claymore Oil & Gas said something that reminded me of that observation. He said that the onshore Gulf has always been the domain of geologists looking at logs, where the offshore is seismic territory. Until he had the realisation that it is just one and the same basin, and you could indeed look at seismic onshore too. It led to the discovery of a big gas field...

JAMES HUTTON IS STILL VERY MUCH AN ACTIVE GEOLOGIST

During an open day in Aberdeen, I visited the James Hutton Institute, which takes its name from one of the founders of modern geology. It was James Hutton who arrived at the concept of deep time following the identification of a major unconformity along the coast of east Scotland during the late 18th century. And in a way, James Hutton continues to be associated with geoscience, as someone from the institute I spoke to told me that they are analysing clay mineral samples from all over the world, including the shale gas sector. It goes to show that James Hutton is still very much involved in geology.

THE COST SIDE OF FWI

"We're working on the cost side of FWI," said Kevin McLaughan during the opening panel session at IMAGE in Houston. This comment shows the current challenges Full Waveform Inversion faces. Everybody knows that FWI is the holy grail; some even go as far as saying it is the end point of subsurface imaging, but as a geophysicist told me during lunch in Houston – "it is always a race between hardware and technology. And now it is down to the hardware to overtake." All this probably means that there are a lot of imaging projects waiting until the price drops. And that will ultimately happen.

THE AUSTRALIA OF GEOLOGY

Luiz Fernando de Ros from the University of Rio Grande do Sul in Porto Alegre called the Brazilian pre-salt carbonates "The Australia of geology" given their very particular nature. Taking that expression to Australia itself, it is interesting to note that the continent is celebrating two recent field start-ups that have their own particularities. Woodside's Scarborough field, which started production in July, is apparently full of sand injectite structures. This is not unique, but still, it adds spice. Similarly, the Beetaloo Basin is also reporting first commercial gas production by Formentera Partners and Daly Waters Energy. This is just fascinating, as this gas is generated by 1.3 billion-year-old algae.

IS THE HYDROGEN BUBBLE BURSTING?

I very recently caught the news of a natural hydrogen start-up company deciding to call it a day. The reason? Lack of confidence in the commerciality of exploration results so far, and the associated difficulty of raising money. This obviously triggers the question: Is the hydrogen bubble bursting? I personally think it is.

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

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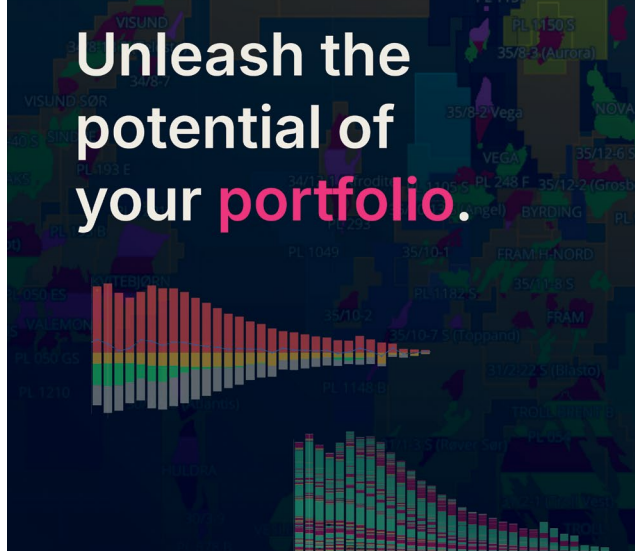
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The energy that never arrives

It's not what we produce, it's what we keep

IN THE PREVIOUS issue – GEO EXPRO Vol. 23, Issue 4, 2026 – we talked about geology being the ultimate scorekeeper and that what exists is not the same as what we can use. This time, I want to take that a step further. Because between what exists, what gets claimed, and what is actually delivered, there is a gap, and it is larger than most people appreciate. That gap is created by physics. We've become used to systems improving almost frictionlessly; just look at the iPhone. But the energy system doesn't behave like software; it cannot be compressed or scaled without loss. It must be physically worked for, at every step.

We tend to start energy conversations with endowment. The world is rich in hydrocarbons, sunlight, wind, heat, and minerals. On paper, there is no shortage of energy. But systems do not run on what exists. They run on what arrives. And what arrives is always less. Every unit of energy must pass through a chain: Extraction, processing, transport, and conversion.

Each step consumes energy itself. Not as an accounting detail, but as a physical necessity. The system feeds on its own output to keep moving, and the losses accumulate.

Let's start at the subsurface. The best resources come first. What follows is deeper, tighter, leaner, and more complex and more capital intensive. More wells, more water, more intervention. It takes more energy to extract energy than it did before. That is the first erosion. Then processing. Refining, separation, upgrading, each governed by thermodynamics. Heat, pressure, and chemistry impose their own cost. These stages cannot be bypassed, only managed even if more efficient processes are devised.

Transport adds the next layer. Molecules move through pipelines and tankers; electrons through grids that must be balanced continuously. Both systems incur losses. Both depend on infrastructure that expands slowly and resists compression. Then comes conversion. Combustion, stor-

age, electrolysis, inversion, each step trades energy for usability. Each layer reduces what remains.

Because as the chain lengthens and complexity increases, more of the system's output is required just to sustain itself. What appears abundant at the source becomes constrained at the point of use. This is why energy systems can feel tight even when supply appears to grow. Why surplus and scarcity can coexist. Why adding capacity does not always translate into more usable energy. It is also where the idea of energy return on energy invested (EROI) quietly becomes critical. Not all energy is equal. Some arrives with much of its value intact. Some arrives diluted, delayed, or diminished by the system required to deliver it. And that difference matters more than we often admit.

Because energy systems do not fail on annual averages or theoretical supply. They fail at the margin, when demand meets whatever energy actually arrives, in the hour that matters. This is not a failure of markets or policy. It is the accumulation of physical limits, decline, conversion losses, and infrastructure constraints asserting themselves through the system.

So the question is not simply how much energy we have. It is how much survives the journey. The harder we work to make it arrive, the more the geology reminds us who is setting the terms.

Rodney Garrard

Adapted from Rodney's forthcoming book – Rock Hard Truths: Energy, Risk, and the Limits of Narrative; Physics and geology don't negotiate; the consulting class does.



The core of Khorat

The onshore Khorat Plateau has a poor exploration reputation, but with two proven finds that continue to deliver, and a hungry gas market, there should be an appetite to look further

SURROUNDED by the Phetchabun and Annamitic fold-belts in Thailand and Laos / Vietnam respectively sits the only mildly deformed Khorat Plateau. The region has seen a long history of exploration. Union Oil was the first company granted exploration rights on the Khorat Plateau as far back as 1962, followed by drilling the first well, Kuchinarai-1, in 1971. It was unsuccessful and may have been drilled without seismic coverage. In 1982, Esso, which did the majority of exploration in the 1980s, made the Nam Phong gas discovery on what was at the time considered an oil play. This was followed by the Phu Horm (later renamed Sinphuhorm) success the following year. Both dis-

coveries were made in Permian-aged, fractured carbonate reservoirs often referred to as the Ratburi Limestone. Esso brought Nam Phong on stream in 1991, and production peaked at over 100 MMcf/d. Sinphuhorm was a late starter, and after successfully being appraised by the new operator, Amerada Hess, in 2002, following a farm-in, it was brought on stream in 2006.

With a combined ultimate recoverable resource estimated at over 1.5 TCF, the Nam Phong and Sinphuhorm fields continue to deliver today. In August, Horizon Oil announced first gas from its Pad D Facility Sinphuhorm project. There was more good news in early September when MH Energy Thailand, the Horizon

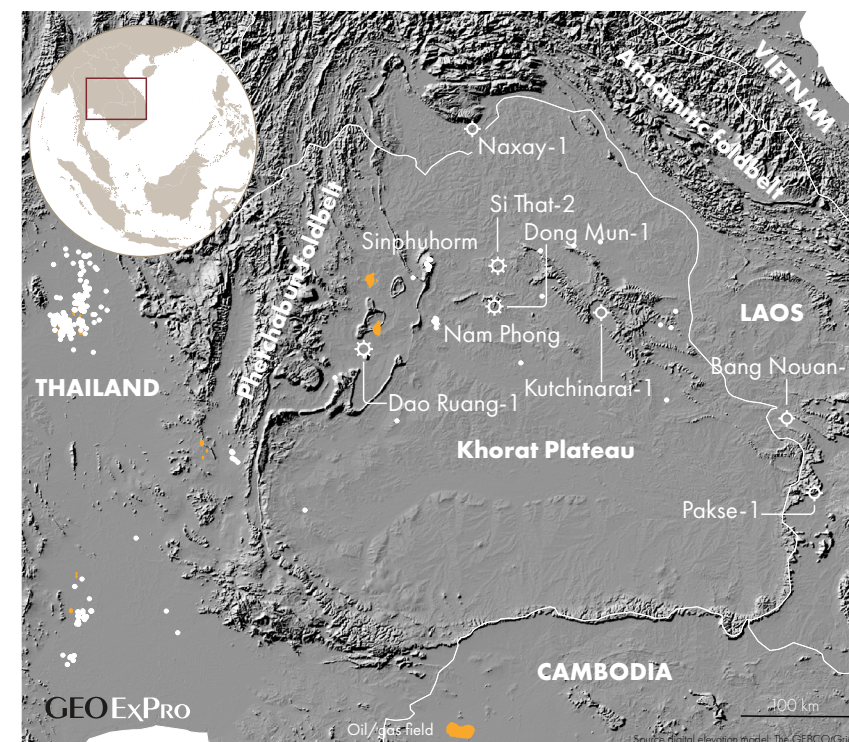
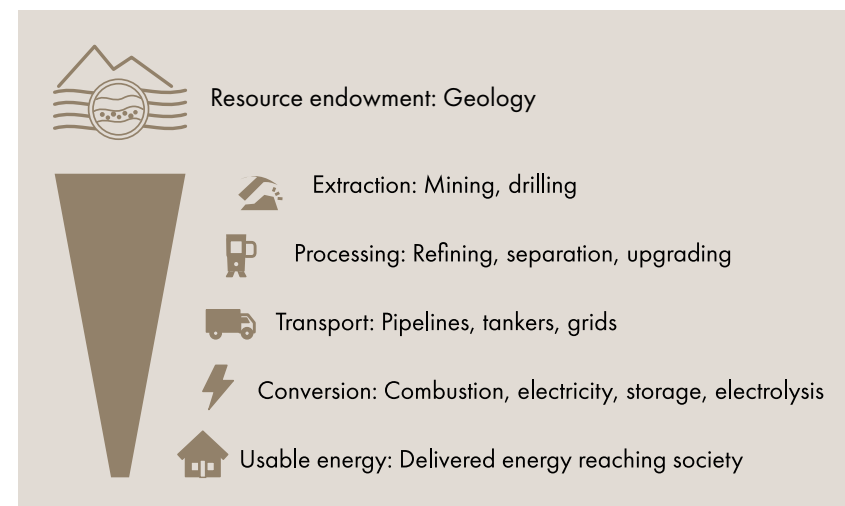
Oil-Matahio Energy joint venture, announced a large boost in gas production from its Nam Phong Field.

All in all, over 50 wells have now been drilled on the Thai portion of the Khorat Plateau, most targeting the Permian carbonate. Besides the two commercial discoveries, gas flows have been reported at Esso's Dong Mun-1, Texaco's Dao Ruang-1 and Cairn Energy's Si That-2 wells.

Meanwhile, northern and eastern slithers of the Khorat Plateau basins are present in Laos and, following the two Esso successes in Thailand, this caught industry's attention. As a result, in 1989 Enterprise Oil was awarded the Savannakhet PSC and the following year Hunt Oil was awarded the Pakse PSC. Hunt drilled the unsuccessful Pakse-1 well in 1997, and the objective proved to be volcanic basement as opposed to the targeted Permian carbonate reefal buildup. In 1998, Monument Oil drilled Naxay-1(ST), and it is understood the wildcat did not reach its objective. However, there was encouragement in Laos for Salamander at Bang Nouan-1, which encountered gas shows in Triassic sandstones in 2010.

A 1998 paper by John Booth at the SEAPEX Exploration Conference gives an excellent summary of early activities on the Khorat Plateau. Booth concludes that much of the exploration drilling on the Khorat Plateau has been wasted with a poor understanding of the geology and play concepts, with many invalid tests, and added that another phase of exploration is needed, applying the lessons learnt. Maybe that phase is now?

Ian Cross - Moyes & Co



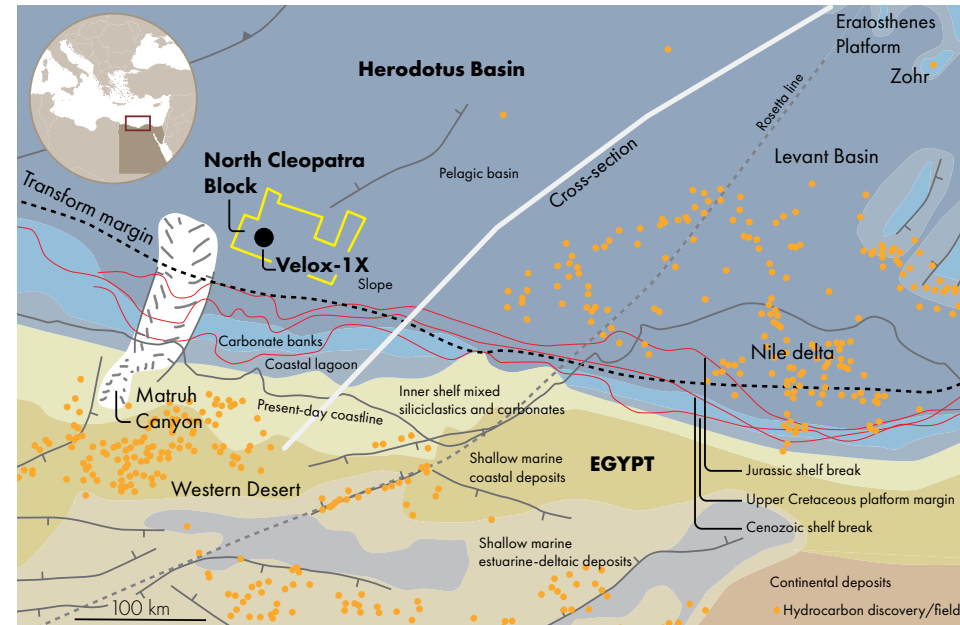
The geological context of Velox-1

Shell recently announced the discovery of oil in the North Cleopatra block, offshore deepwater Egypt. Here, we take a look at the depositional setting of the main reservoir targets

THE NORTH Cleopatra Block is situated in a poorly-known crustal setting within the Herodotus Basin. The basin came into existence during Triassic-Early Jurassic rifting, which opened along a NW-SE trending axis. As such, the region just north of the present-day Egyptian coastline developed as a narrow transform margin.

In line with this basin history, the oldest sediments that can be expected in the area where the well was drilled are Triassic to Lower Jurassic sediments, possibly deposited in the hanging walls of tilted fault blocks. These sediments might also constitute the oldest source rock interval, which is likely to be a gas-prone at present levels of thermal maturity. Speculative deep exploration targets could include Triassic to Lower Jurassic shallow water carbonates developed on footwall highs.

The rapid subsidence of the Herodotus Basin dur-



Early Cretaceous gross depositional environment map for Egypt's Western Desert and the offshore area to the north where Shell's Velox-1X well was drilled. The map is based on work from Strata GeoResearch, which is again a compilation of published material.

ing the Mesozoic meant that the Middle Jurassic to Cretaceous platform margin shows a back-stepping character, with the North Cleopatra Block clearly in a deepwater setting.

A prominent feature in the area is the so-called Matruh Canyon, which is likely to have been a sediment

corridor into the basin since Late Jurassic or Lowermost Cretaceous times. An Upper Jurassic or Cretaceous target could therefore be into deepwater sands shed off the margin via the Matruh Canyon.

The second source rock interval that is likely to be present in the area of the North Cleopatra Block is a series of Cretaceous black shales, deposited during worldwide anoxic events.

The Cenozoic, which constitutes a thick succession in the area, is probably mostly sourced from the paleo-Nile, at least during the Oligocene and Middle

Miocene when the Levant Basin to the east experienced a predominantly fine-grained sediment input.

Knowing that the target of Velox-1X was a Lower Cretaceous reservoir, now looking at the regional geological setting, the well probably targeted a series of deepwater sands sourced from nearby Lower Cretaceous anoxic mudstones. Any Oligocene or Lower Miocene targets are likely to be deepwater sands sourced from the Nile when it had a more westerly direction of flow. ■

Henk Kombrink

ILLUSTRATION: MODIFIED AFTER TASSY ET AL. (2015)

COVER STORY

"The pre-salt had determined my professional life to an extent that my wife called it the third person in our marriage"

Paul Wright – Carbonate sedimentologist

This story has benefited from a conversation with Peter Shiner, who has done a lot of work in the Eastern Mediterranean, as well as input from Strata GeoResearch, who kindly provided an Early Cretaceous gross depositional facies map that was used as a basis for the illustration shown here.

THE AUSTRALIA OF GEOLOGY

Once the first cores from the pre-salt carbonate discoveries came to surface in the Santos and Campos basins in Brazil, it became obvious that they represented a facies that was not very well-known, leading to a debate about its origin that can still be felt today. As it is now twenty years since the first discovery in 2006, we take a look back at those years through conversations with two geologists who were very close to the fire

HENK KOMBRINK

Oil exploration platform anchored in Guanabara Bay, Rio de Janeiro.

IN A PRESENTATION from 2005, the year before the Tupi field was discovered, Andrew Latham from Wood Mackenzie gave a talk at the AAPG Annual Convention & Exhibition in Calgary. He spoke about the exploration landscape of the ten preceding years, which is interesting to look at with the benefit of knowing what happened post-2005.

A few things stand out. First of all, plotting the discovered oil per year between 1994 and 2003, he noted a drop in commercial oil as a percentage of the total volume of oil discovered since 2001. He suggested that the world was starting to run low on big fields to discover, even though he admitted that more data were needed to confirm this. He then showed a graph that demonstrated that the investment in acquiring deepwater acreage had peaked in 1999, suggesting that there were only limited opportunities left. Brazil was included in that statistic. He also quoted a few titles of published reports in those years, leaving the impression that oil and gas exploration was in terminal decline. Against this backdrop, it may not be a surprise that even people high up in some of the majors thought there was nothing left to explore.

But then the year 2006 came round. The year that the first pre-salt oil discovery was made in the Santos Basin in Brazil, causing quite the consternation in the exploration community. For this article, I spoke to two geologists who became heavily involved in the research that followed when the first cores and other data from the oddly looking carbonates came to surface; Luiz Fernando de Ros and Paul Wright. They describe how the initial depositional model that was carried for the Barra Velha carbonates quickly broke down as they started to make their first observations of these fascinating rocks, but they also note how opinions remain divided. It is a fascinating story not only of the opening of a new petroleum province, but also of the discovery of a new carbonate facies system altogether that still sparks debate today. ►

A CALL FROM SYLVIA ANJOS

"My early professional years, of which I spent nine years with Petrobras, were mostly in siliciclastics," says Professor Luiz Fernando De Ros from the Federal University of Rio Grande do Sul in Brazil. But that was about to change. "I remember having lunch in the late 1990s with a Petrobras geologist, Jefferson Dias, at the university," Luiz recalls. "He was telling us that it was only a matter of time before a deep well was going to be drilled below the thick salt in Santos Basin, where the level of diagenesis is probably limited and the porosity still good."

Then, at some point in 2008, Luiz got a call from Sylvia Anjos, who was managing an exploration team working on the pre-salt. Anjos is now the global exploration manager of Petrobras, a position she took up after she initially retired from the company. She invited Luiz to look at some cores and thin sections from pre-salt rocks that had recently been cut in the Campos Basin. It was a special moment, because by accepting the invitation, he would become the first person outside Petrobras to do so.

"I was not a microbial carbonate expert," Luiz says, "but of course I had seen some. For instance, the beautiful

Precambrian and Cretaceous stromatolites we have here in Brazil." But when he looked at the thin sections, he realised that the pre-salt reservoirs represented something different. The reservoirs he saw were made of calcite with fibrous, fascicular and spherulitic textures. He did not see the usual microbial clotted textures that he was used to.

The Petrobras geologist who was with him was shocked, and she called her boss straight away. People were waiting in anticipation of what Luiz would say, knowing that many at Petrobras' Research Centre were of the opinion that the cores represented microbial carbonates. He caught the response at the other end of the line: "What?" It seemed like some people in Petrobras already had made up their minds about what these carbonates represented.

But even though Luiz did not support the microbial nature of the carbonates he had seen from the Campos Basin, he was still invited by Sylvia Anjos to come over to Rio de Janeiro a while later and have a look at the cores and thin sections that had now arrived from the Tupi discovery in the Santos Basin. The game was on.

It led to an agreement that he would further study the nature of the

carbonates and produce a series of reports. Luiz wrote ten of them. One of the most important things he did was to delve into the literature to find analogues to what he saw in the thin sections. And he ended up finding Archean and Paleo-Proterozoic stromatolites that were described and interpreted by John Grotzinger as being abiotic in nature, meaning that they were chemically precipitated without a substrate by microbial colonies. Another option he postulated was the possibility that some of these carbonates represented some sort of travertines, also interpreted to be abiotic, or the product of chemical interactions in a hyper-alkaline lake.

The reports Luiz wrote were not met with great enthusiasm. In fact, he experienced resistance, because a number of people were totally convinced that the carbonates were microbial, mostly based on the macroscopic features they observed such as the irregular stratification that is characteristic for both microbial and abiotic stromatolites. So, by the time he had finished his extensive series of reports, and after attending many meetings during which he was met with fierce criticism, he was told that his services were no longer needed, and for a few years he was no longer working with Petrobras.

STEVENSITE AND GELS

A geologist who worked with and for BG for a long time is Paul Wright. Initially, he provided part-time consultancy and advisory services while serving as a professor at the University of Cardiff. Following the discovery of Tupi, however, he quickly joined the company as a full-time employee. He travelled to the country around 30 times in the years between 2007 and 2011. His carbonate expertise came in very handy, even though he soon discovered that he had to start from scratch when it came to understanding these types of rocks. They were clearly something else.

In line with what Luiz experienced, Paul was also of the initial impression that the Aptian carbonates of the Barra Velha Fm were mostly of microbial ori-

gin when he started working on these rocks. "The first cores I saw from the Tupi pre-salt reservoirs in August 2007 were ambiguous," Paul says. "They were only short cores, and in the absence of thin sections, which were still in the process of being made, my conclusion was that these were strange microbial bioherms."

However, spherulites in microbial limestones are normally deposited in thin sheets, but in this core, they were domed, which is unusual. Also, once the BG team received the thin sections a few months later, the hypothesis of these rocks being microbial carbonates was quickly abandoned. "We concluded that the domes were related to an isopachous growth around an irregular feature, possibly a pipe that had fallen over," explains Paul. "But the thing is," he emphasises, "only after seeing 1.3 km of pre-salt core in subsequent years, I could conclude that the struc-

tures I saw in these first two cores were unique. When you don't have that context, you can easily get sidetracked."

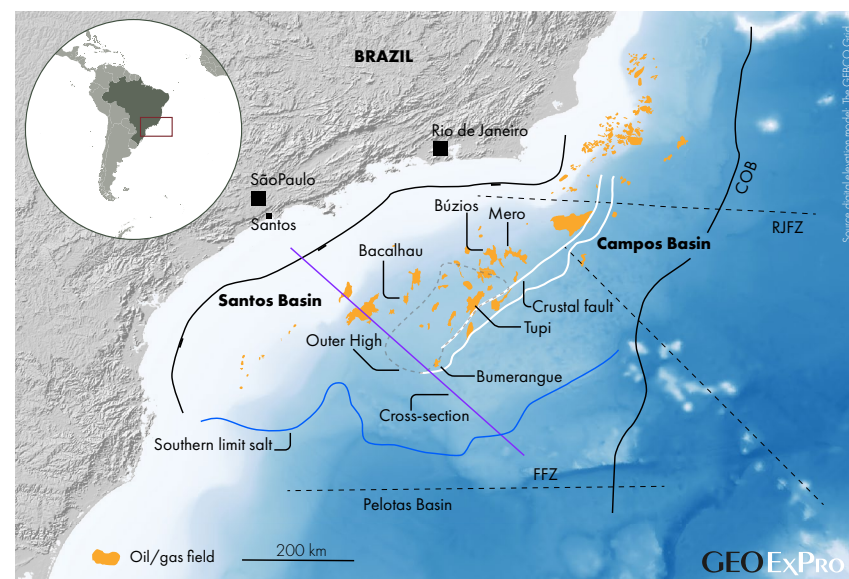
That's not to say that the microbial nature of the pre-salt reservoirs was refuted completely. "I do remember ExxonMobil cutting core in the play and returning what was clearly a microbial limestone," says Paul. "Again, it was only after seeing long core intervals that we realised that the microbial element was about 1 % of what we had seen."

Despite the signs that the rocks were of a non-biotic origin, for some geologists it was the ability to interpret platform-type of structures in the seismic that made them conclude that the pre-salt carbonates were deposited on (microbial) platforms. However, Paul came to the conclusion that the seismic data could not be taken at face value. "Post- and syn-depositional faulting can equally explain the structures we see,"

he says. "I spent many hours in data rooms addressing this very question."

But the most important clues that argued against a microbial origin of the carbonates came from the rocks themselves, and not only through the identification of the spherulites and shrubs. Initially, he also thought about hot springs, as Luiz also did. "But we were soon coming to the conclusion that the scales didn't match; you can't have hot springs across an area as wide as the entire Santos and Campos Basins," he says.

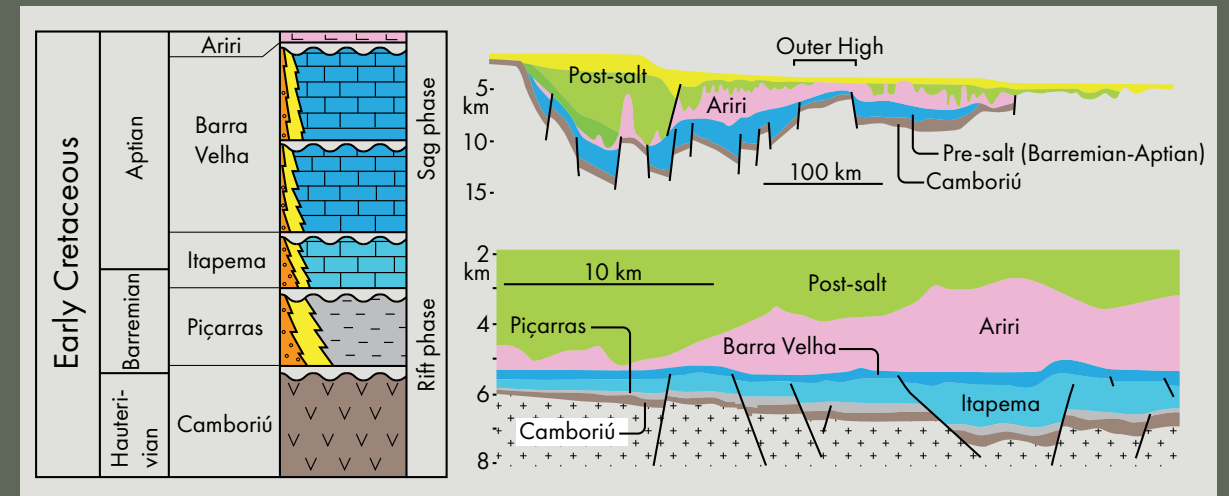
The intra-particle cement in the form of a specific type of clay minerals also formed a challenge. "We didn't understand what this clay mineral was," says Paul. "I wasn't even used to seeing clay minerals associated with carbonates." So he asked people in the Petrobras labs, and they said that it was stevensite in association with its altered equivalent, talc. ▶



The Santos Basin is the most important basin for the pre-salt play; most of the fields shown around the Outer High are in pre-salt reservoirs. Please note that, especially in the Campos Basin further north, most fields on the map are in post-salt reservoirs. The cross-section indicated by the purple line is the top-right cross-section shown in the geological setting.

THE PRE-SALT GEOLOGICAL SETTING

The Santos and adjacent basins formed during the break-up of the South Atlantic in Early Cretaceous times. It is the widest marginal basin across the Southern Atlantic, partly because the final spreading axis shifted eastwards. The typical stratigraphic succession encountered in the Santos Basin is the presence of a thick layer of flood basalts of the Camboriú Formation on top of the rifted basement, emplaced during the Hauterivian. This was followed by what most people interpret as a syn-rift succession of alluvial, deltaic and lacustrine deposits of the Piçarras Formation. The overlying Itapema Formation is characterised by a combination of alluvial fan deposits on the margins, but in more basinal positions this formation is particularly well-known for its lacustrine coquina beds, which are extensive deposits purely consisting of mollusc remains, even forming large prograding structures. The Aptian restricted lacustrine carbonate deposits of the Barra Velha form the last phase of the pre-salt succession, and it is in this formation where most of the oil in Brazil's pre-salt has been found.



Stratigraphic diagram showing pre-salt formations in the Santos Basin. The top cross-section nicely illustrates the large-scale structure of the Santos Basin, including the Outer High where many pre-salt fields have been found. The lower cross-section is a more zoomed-in illustration of the pre-salt succession, showing that the Barra Velha formation is only the topmost part of the entire pre-salt succession, also showing only moderate thickness changes when compared to the syn-rift deposits deeper down.

PHOTOGRAPHY PREVIOUS PAGE: @RENATOPMEIRELES VIA ADOBE STOCK

ILLUSTRATION: REDRAFTED AFTER NEPOMUCENO ET AL. (2026) (LEFT) / REDRAFTED AFTER BAPTISTA ET AL. (2023) (RIGHT)

Paul had never heard of stevensite before, and neither had his colleagues. “So, my next mission was to understand the distribution of stevensite,” says Paul. Through his contacts in Spain, he then found a quarry in Miocene evaporitic lake deposits in the Madrid Basin that was supposed to produce stevensite for the pet litter industry. “We’d better go there then,” Paul said, “and he made a bit of a team-building event out of it by inviting the licence partners along, including some geologists from Petrobras.”

Sometime later, the group of geologists arrived and were welcomed with open arms, including presentations and an elaborate lunch. Until Paul asked the quarry manager if they could see the stevensite in outcrop. “No, we don’t have any,” he said, “but we have some in the lab because we use it in different mixes.” Paul subsequently heard from a contact at the Universidad Complutense in Madrid about some work done on stevensite in an oasis in the Nevada desert, halfway between Death Valley and Las Vegas. “So I decided to pay a visit to the area when I was in the USA anyway,” he says. Once he arrived at the site, just a few hundreds of meters from the road, they found a stream coming off the basaltic terrane. “It’s like a paradise in the desert,” says Paul. “It’s green, and there is running water.” The samples he obtained were brown and greasy-looking.

Paul gave some of this stevensite to geologist Nick Tosca from Cambridge

University, who carried out lab experiments to reproduce the clay mineral. It was Nick who provided Paul with some really good insight into the formation of stevensite. “It initially forms like a gel,” Nick told him. It was the penny dropping for Paul. “Until that point, I could not very well explain why some of the pores in the pre-salt reservoirs are so open. Now I realised that some of the spherulites were actually growing within the gel, which is the explanation as to why you get a very open texture. Before I became aware of the gel, it had seemed that the carbonates had grown in empty space, but now I had an explanation.”

“People have since also found stevensite in microbial carbonates,” continues Paul, “and sometimes made the case that it is microbial instead. But the amounts of stevensite in microbial carbonates are minute. We saw intervals of meters thick over regional areas, which is absolutely impossible to explain using a microbial model and clearly points to an abiotic origin.”

Most of the porosity in the pre-salt carbonates develops because of the dissolution of the stevensite clays. “Again, that is quite extraordinary,” says Paul, “because clay minerals usually transform, but don’t dissolve. The ‘normal’ clays we find in the subsurface such as smectite, illite and kaolinite precipitate, but they don’t dissolve.” The very reason for this to happen is that stevensite is a mineral that doesn’t have aluminium in its lattices to hold the plates togeth-

er better, as well as the weak bonds between magnesium and oxygen. So, they easily break down.

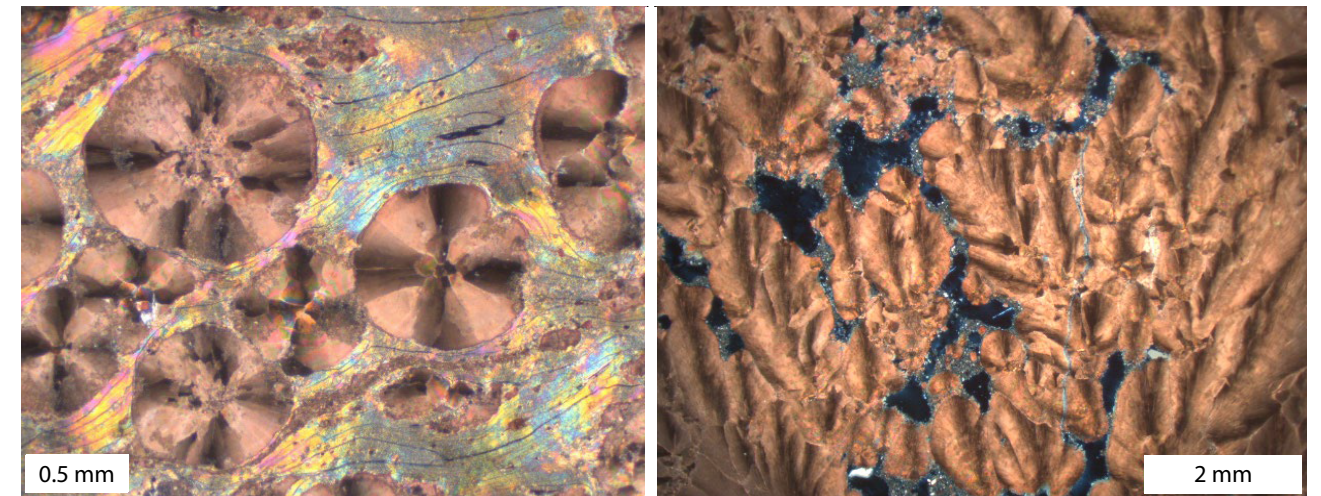
Yet, despite the evidence building that the Aptian carbonates were of a different nature than what the initial assessments seemed to suggest, the model of microbial carbonates persisted. “During my years,” says Paul, “it was like a meme that was difficult to challenge. He also remembers conference talks from the same operator where one presenter argued for these carbonates as being microbial and another as abiotic. There were obviously different camps within these companies that didn’t agree with each other,” he recalls.

Paul left his pre-salt research behind in the early 2020s. “It had determined professional life to an extent that my wife called it the third person in our marriage,” he laughs. He also still gets requests to review scientific papers on pre-salt all the time, which he mostly politely declines. “One has to stop at some point.” But while Paul has started doing other things, Luiz has returned to pre-salt research.

BACK TO THE PRE-SALT

And as Shell came back to the Santos Basin through the acquisition of BG in 2015, Luiz came back to the pre-salt through academia, by supervising people from Petrobras who were carrying out their master’s or PhD projects. “I’ve been working on the pre-salt ever since, which is quite some years now,” he says. Something that he is currently researching is the reworking and redepositing of intraclasts of the shrubs and spherulites for Petrobras, in addition to studies on the Bacalhau field for Equinor, and also as part of a project for the Libra consortium that includes Petrobras, Shell, TotalEnergies, CNOOC and CNPC, working on the Mero field.

But with the passing of time, has the view on what these carbonates represent changed at all? “There are still opposing views,” says Luiz, “and there are still people who don’t talk to each other because of this. Even when the textural evidence is fairly clear-cut, also



Calcite spherulites in magnesium clay matrix (right), and in-situ reservoir made of calcite fascicular aggregates (shrubs) with interstitial porosity (left).

because there is no microbial isotopic fractionation – the CO₂ isotopes show a mantle signal rather than an organically-driven one.”

“But is there no microbial activity at all?” I ask. “No, there are locally some deposits with characteristic microbial features,” says Luiz, “particularly in the interval just below the salt, as the environment was shifting from a large connected hyperalkaline lacustrine system to the establishment of smaller isolated lakes where conditions were improving for organisms to grow.”

The abiotic nature of the carbonates is also good news when it comes to the lateral connectivity of the reservoirs. The main reason for this is that these abiotic carbonates were precipitated everywhere across the lacustrine system, where a microbially-driven carbonate factory would rely on very specific environments to grow. As Andrew McBarrett described it to me: “If you start with a microbial platform model, the process of discovering that you were wrong is only full of pleasant surprises because the abiotic model gives you much better lateral reservoir connectivity.”

So, if we assume that the reservoir characteristics are very similar throughout the carbonate interval, why would there be no potential in the structural lows, where stratigraphic trapping might play a role in the formation of viable closures? “That’s a good question,”

says Luiz. “What we know from the flanks of these highs is that the proportion of carbonates decreases as you go deeper, whilst the magnesian clays, such as stevensite, that are commonly found associated with the carbonates, have a higher proportion and preservation potential in the structural lows.”

“That is what makes these deposits so unique,” he says. “In addition to the primary porosity that also exists among the fascicular shrubs, we see that secondary porosity from the dissolution of the clays is an important element in creating the high-quality reservoirs we find today.”

“The mechanism that we think is responsible for the complex deposition of the carbonates and the clays, and in turn the dissolution of the clays, is variations in the water composition due to stratification of the lacustrine water column,” says Luiz. “How else can one explain the rapid variation and intercalation of lithologies that we currently observe? The lacustrine system was too extensive for this high-frequency intercalation to be driven by variations in lake level, but rather by variations in the level of stratification, probably driven by changes in freshwater runoff, climatic variations or magmatic activity.”

TAKING A STEP BACK

On the basis of the conversations with Luiz and Paul, it has become

clear how spectacular the discovery of the pre-salt fields in Brazil was. Not only was a major new petroleum province unlocked, a new depositional carbonate model also emerged – the “Australia of geology” as it was called by Luiz. And it is still the focus of a lot of research today. This article only scratches the surface in that respect, as current work focuses on re-deposited intervals within the Barra Velha, the interaction with magmatism, its diagenesis, and, of course, the seismic identification of the intervals showing the best reservoir properties to assist exploration.

It is also important to be aware that different points of view still exist, not only between the abiotic and biotic camps. For instance, Paul argues for the formation of the spherulites to take place in a gel-like structure – the precursor of stevensite. However, Luiz argues in one of his papers that this is impossible because of the low settling of the particles. Paul explains the formation of some of the intra-Barra Velha highs as a result of structural inversion, whilst Luiz does invoke the presence of a system of highs and lows during deposition. But one thing is for sure: When Andrew Latham gave his presentation in Calgary in 2005, it all seemed a bit gloomy on the frontier exploration front. A year later, this picture was turned upside down. ■

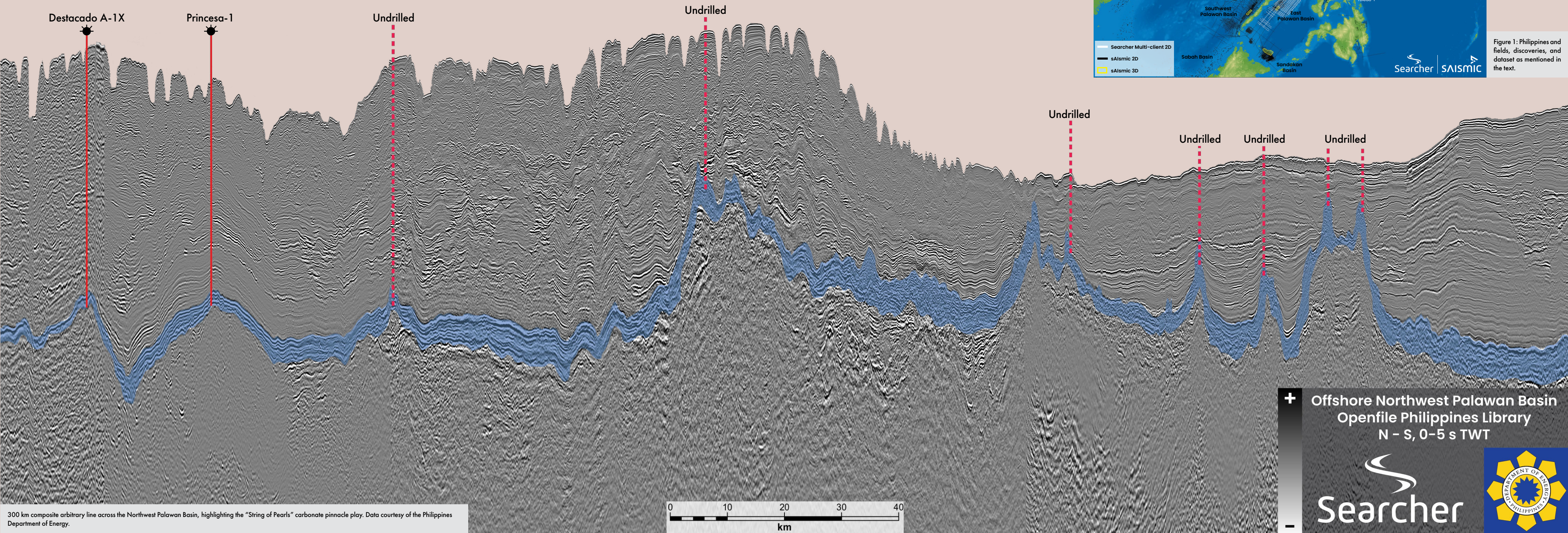
SHELL AND BG

When Shell bought BG in 2015, access to BG’s Brazilian assets was one of the reasons for the transaction. BG had a 25 % stake in the licence that saw Tupi discovered, alongside Petrobras (65 %) and Galp (10 %). All the while, Shell had been looking at the pre-salt play even before the Tupi discovery was made. A source with knowledge of the matter shared that internally, Shell had indeed identified that multi-billion-barrel fields could indeed be found in the Santos Basins, but the probability of success was deemed to be too low. And the interesting thing is that the reservoir was identified as being the main risk, which in hindsight is probably correct. Source rocks, mostly based on Shell’s long history in Gabon, were not considered a problem. It was the poor imaging and the reservoir that were thought to be the biggest uncertainties. Ten years later, the reservoir had proven to be of very decent quality, and the seismic imaging had been partly solved. BG had become a too attractive opportunity to surpass.

Using new data to unlock prospectivity in the Philippines

LAUREN FOUND, NEIL HODGSON AND KARYNA RODRIGUEZ, SEARCHER

The keys to play success in the Philippine basins have already been found and include the newly available and improved datasets. An epic journey awaits; to locate the doors behind which lies the astonishing potential remains and unlock them



Odysseus of the Philippines

“SING, O MUSE, of the basins hidden beneath the seas of the Philippines, of oil and gas-soaked reefs that rise as towers beneath the subsurface, of the heroic explorers who, having seen nearby analogues work repeatedly, would return to further targets with sharp eyes, and of the new opportunity to access data that will guide us through our journey of exploration around the islands.”

This is undoubtedly how Homer would have begun to describe the underexplored prospectivity of the Philippines after the government announced the easing of the dissemination of the open-file seismic database. A critical moment in the Philippines exploration journey, the revelation that comes from the availability and close inspection of such a database is to marvel at how much low-risk exploration there is still to be done in the Philippines following proven trends and using solid analogues.

Exploration in the Philippines, like The Odyssey itself, is one of the greatest stories ever told. The scene is laid in the late 1890s as clever and resourceful explorers find active oil seeps onshore the beautiful island of Cebu (Figure 1). This leads to the first onshore exploration well in 1896 (Toledo-1). Eighty years later, the successful discovery of oil in large quantities by Cities Service, drilling offshore Northwest Palawan with Nido No. 1 (1976), proved the carbonate pinnacle reef hydrocarbon system, leading to a plethora of similar targets being drilled in shallow water.

This story, though, is about what happened next. In Homeric terms, after the initial success, it is on the journey home that things get really exciting. With the West Linapacan oil field (1990) and the huge Malampaya gas (Figure 1) and condensate discovery (1992), West Palawan proved to be a prolific basin. And indeed, it’s still delivering – Prime Energy resources announced the Malampaya East discovery in 2026. This proves that new data and new ideas can bring success in even well-explored areas, and the Philippines has many more carbonate buildup / pinnacle reefs still to be explored (Foldout). For today’s exploring Odysseus, new data brings new islands of prospectivity to explore.

Specifically established to make data more accessible to explorers, in a collaboration between the Philippines Department of Energy (DOE) and Searcher, the DOE seismic archives have been collated, standardised and rigorously quality controlled to create a contiguous database of open-file seismic data across the sedimentary basins of the country (Figure 1). At the time

of publishing, 94,000 km² of 2D and 19,500 km² of 3D seismic across 130+ surveys have been hosted on the sAlsmic platform, allowing rapid screening and exploration of proven and frontier basins. New explorers now need not sail blindfolded, strapped to a mast of hope, avoiding the siren calls of sparse and poorly imaged prospectivity.

Perhaps the most recognisable play in the Philippines is the Northwest Palawan Basin’s “String of Pearls”, a series of Miocene-aged pinnacle reefs that include the country’s largest oil and gas fields, including the Nido, Malampaya and Galoc complexes (Foldout and Figure 1). Since the first of these treasures was discovered, advances in seismic technology have been extraordinary, as seismic processing and imaging are so much faster and clearer in 2026; it has been the area of greatest advance for our industry in the 21st century. Sometimes the dreams of an aspiring explorer, an Odysseus of our time, are not new

but simply newly imaged. Indeed, many carbonate buildups of a variety of ages remain undrilled (Foldout), with more being revealed and mapped as an infilled seismic grid is made available for the first time.

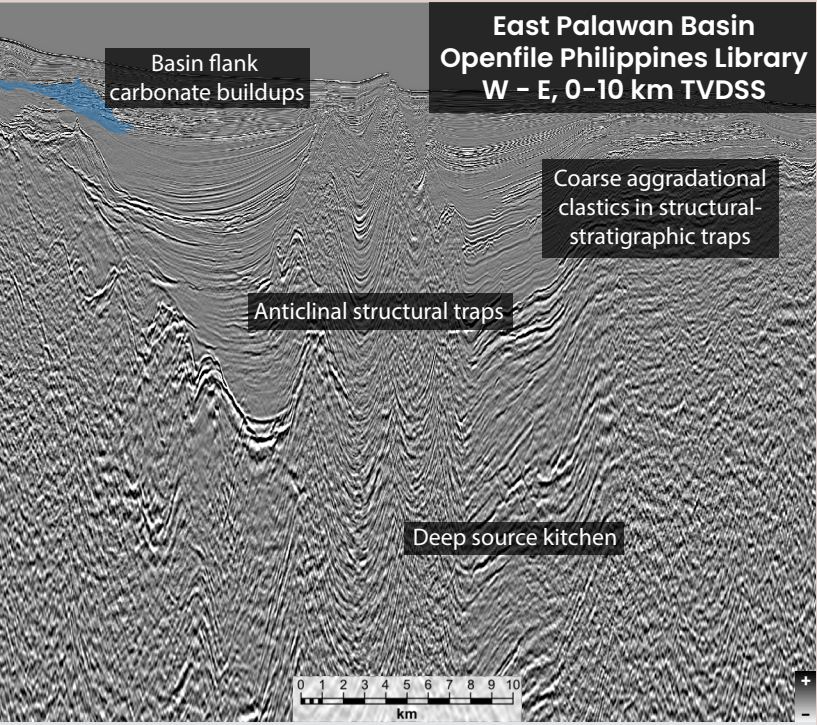
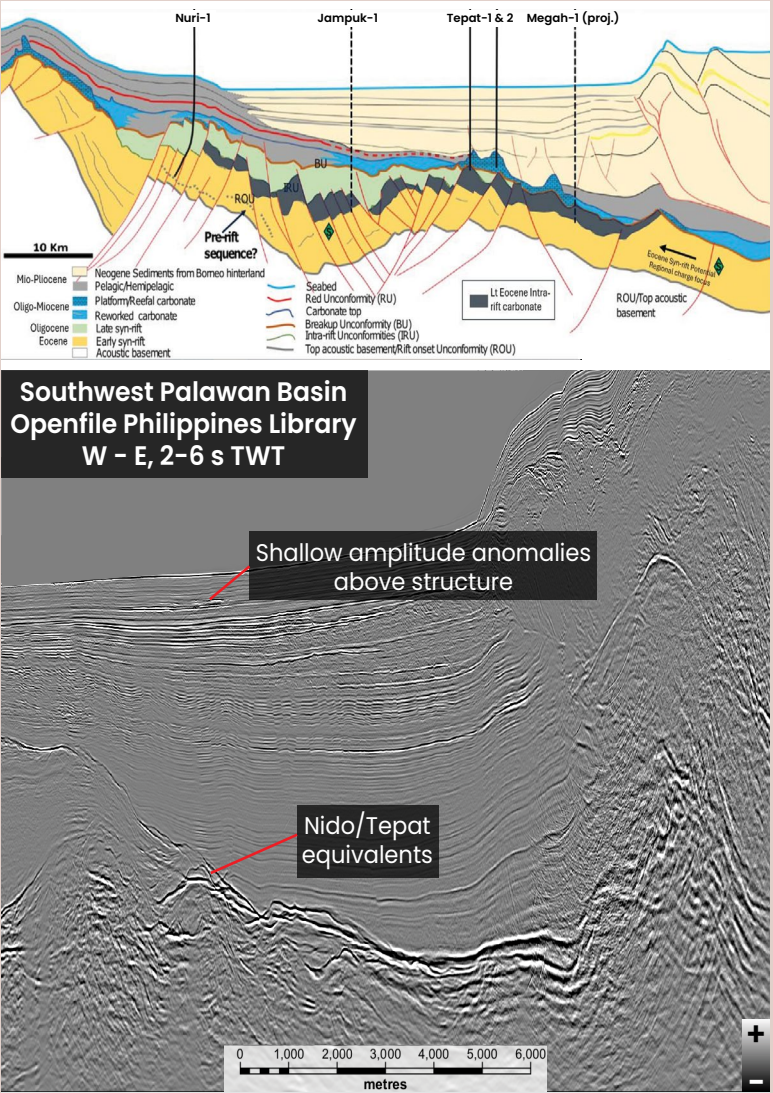
The Nido play dives into deeper water to the south, which would have been rendered too difficult to pursue in the past. Though the sea has changed little, the explorer’s mindset has changed dramatically as drilling technology advanced – the other greatest advance in our industry in the 21st Century! So much has it advanced that water depth is no longer a deterrent – if the prize is big enough – with carbonate buildups now located in deep water becoming one of the most intriguing and strongly pursued plays across Southeast Asia.

In what is turning out to be a hot trend, TotalEnergies’ planned wild-cat Jampuk-1 is targeting a similar carbonate play in the neighbouring Sabah Basin, which is proven with the Tepat discovery in 2017/18 (Figure 2). The Tepat and Nido plays

meet in the Southwest Palawan Basin, with a string of carbonate buildups which are in deeper water until they dive underneath the fold and thrust belts in the east. An important risk reduction in this play is the recognition of shallow hydrocarbon-bearing anomalies located above the deeper buildups, which are telltale signs that the hydrocarbon system is working.

In the East Palawan and northern Sandakan basins (Figure 1), continent-continent collision in the Early to Middle Miocene initiated foreland loading and clastic sedimentation, later than the deposition of the western Nido Limestone and its equivalent. Clastic plays, of drape and stratigraphic trapping styles, are abundant in the East Palawan Basin, located on the flanks and over the top of source rock-bearing synrift grabens and offer large and repeatable prospectivity. The continued subsidence and decreased sedimentation rates resulted in some later carbonate development along the basin edges, remaining prospective where top seal is intact (Figure 3). Only five wells have been drilled in the East Palawan Basin (GEO EXPRO Vol. 21, Issue 3, 2024), where the thick sedimentary succession and strong hydrocarbon indicators leave the frontier basin primed to yield the success of its western and southern cousins.

In a world where national energy security has proven to be a key driver for governments, the rejuvenation of exploration activities in basins previously considered mature and overlooked is a welcome initiative. Having a reliable and readily available open-file seismic library, such as the one now available for the Philippines, is but one of many tools that can give a wily explorer a fair wind on their adventures. Working with the DOE and Searcher on that dataset will surely inspire any aspiring Odysseus to shortcut through years of wandering and rapidly take a pinnacle-shaped journey to exploration success.



OIL & GAS

“In the Rotliegend, architecture inherited from an ancient desert continues to control how gas moves millions of years after the dunes themselves disappeared”

James Mullins

When fast gas becomes slow gas

How ancient dunes control gas production

JAMES MULLINS

PERMIAN Rotliegend sandstones form one of north-west Europe's most important gas reservoirs. Yet, despite decades of mature field production and apparently excellent reservoir properties, something has never quite added up. On paper, these reservoirs look excellent. Core measurements often show high permeability and good reservoir quality. Once taken into production, however, they can behave very differently, with effective flowing permeability sometimes 100 to 1,000 times lower than the values measured from core.

A well can begin life producing strongly at high rates, only for pressure and production rates to fall rapidly. Yet, the well does not die. Instead, gas continues to arrive at much lower rates for years, sometimes decades. Individual wells exhibiting this characteristic "slow-gas effect" can remain in production for 30 – 40 years.

At first glance, there is an obvious explanation: Compartmentalisation. Perhaps faults are breaking an otherwise good reservoir into poorly connected pieces. But what if the problem is not structural at all? What if the answer lies within the dunes themselves?

To find out, we went to the deserts of Arizona and Utah. Here, spectacular exposures of the Entrada, Navajo and Page Sandstones reveal outstanding 3D outcrops of aeolian sedimentary systems. From a distance, these sandstones look like giant bodies of homogeneous sand, but when looking in more detail, they are separated and bounded by low-permeability wind-ripple deposits and a hierarchy of erosional surfaces. We used these analogues to reconstruct 3D reservoir models, pop-

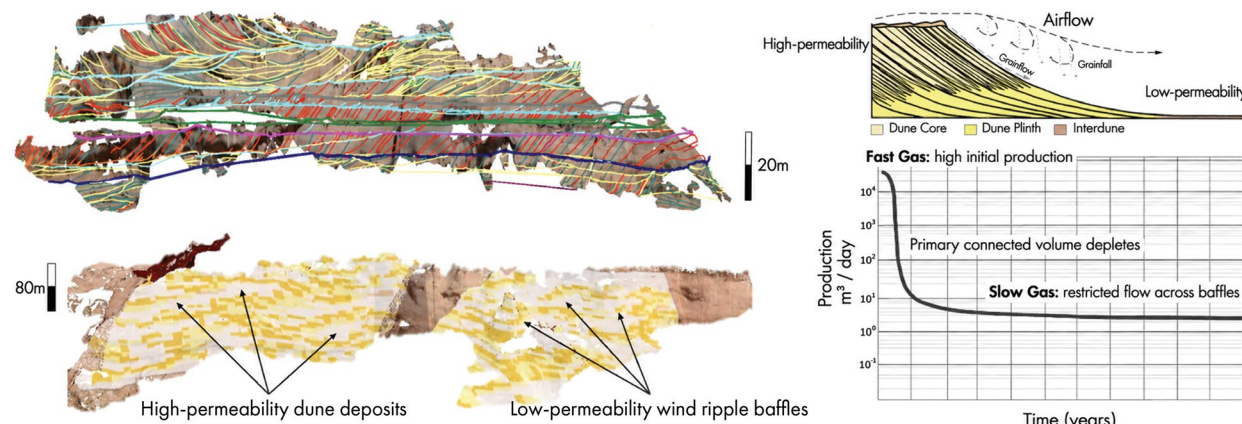
ulated them with properties representative of producing Rotliegend reservoirs, and simulated 20 years of gas production. The resulting models reproduced the same distinctive production behaviour without requiring faults to compartmentalise the reservoir.

At the start of production, the well has easy access to gas stored within the high-permeability dunes immediately around it. This connected volume provides the "fast gas", supporting the high initial production rates. The larger the primary connected volume, the longer those high rates can be sustained. Eventually, however, the easy gas runs out.

The remaining gas is not necessarily trapped behind sealed compartments. Instead, it has to find an increasingly tortuous pathway across low-permeability wind-ripple deposits separating individual dune bodies. These layers act as baffles rather than seals: they restrict flow without stopping it. Driven by pressure difference, gas continues to migrate from the surrounding reservoir back towards the depleted near-well volume. It arrives too slowly to restore the initial production rate, but it can sustain production for years. This is "slow gas".

Understanding this reservoir architecture has practical consequences. If the volume of readily accessible "fast gas" depends on the number and size of dunes connected to a well, then well trajectory and spacing become part of the depletion strategy. Periods of shut-in may even allow the depleted near-well volume to recharge as gas slowly migrates across the surrounding baffles. In the Rotliegend, architecture inherited from an ancient desert continues to control how gas moves millions of years after the dunes themselves disappeared. ■

ILLUSTRATIONS: MULLINS ET AL. (2021) / WINTERSHALL DEA (RIGHT)



From dune architecture to slow gas. Virtual outcrop analogues reveal the complex internal architecture of aeolian reservoirs. High-permeability dune deposits provide readily accessible "fast gas", while lower-permeability wind-ripple deposits form baffles that restrict flow between dune bodies. As the primary volume connected to the well depletes, increasingly restricted migration across these baffles sustains the characteristic long tail of "slow gas" production.

The rise of the onshore

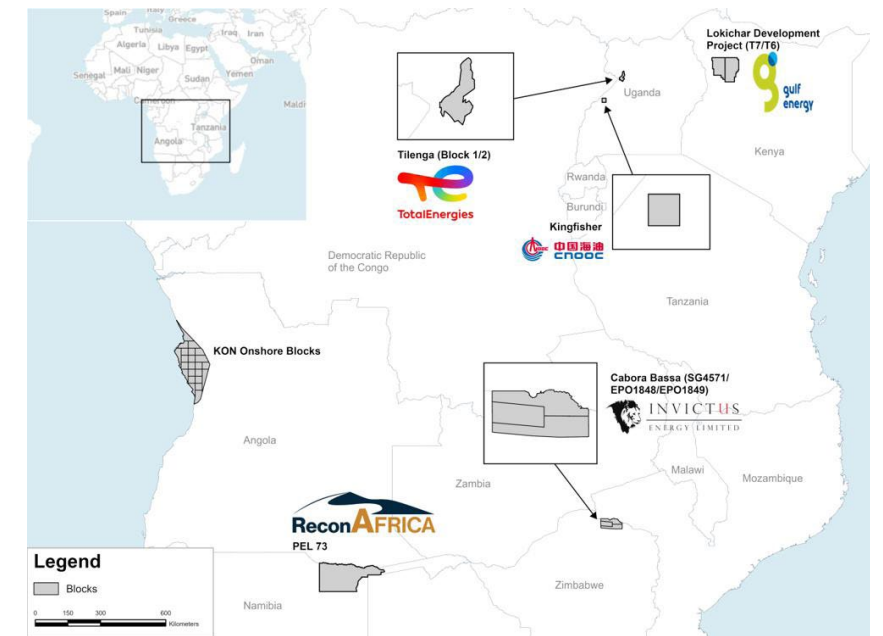
Onshore activity across Sub-Saharan Africa continues to gain momentum, with opportunities ranging from under-development projects to pre-sanction and exploration plays

LAUREN HUNTER AND DAVID THOMSON, WELLIGENCE ENERGY ANALYTICS

WITH MOST attention going to the big discoveries offshore Namibia, or what is shaping up in the Rovuma Basin, it's easy to miss that onshore activity across Sub-Saharan Africa continues to gain momentum. In Uganda, Tilenga and Kingfisher remain on course to establish the country as a producer before the end of 2026. Combined, the projects hold ~1 Bbbl of reserves. First production is tracking for September 2026. The East African Crude Oil Pipeline is nearing completion, currently at ~90 %. One note of caution is that delays at Tilenga will constrain Kingfisher, given that first oil must be synchronised across both projects to fully support the pipeline.

In Kenya, Gulf Energy, operator of the Lokichar development, is making progress and targeting first oil by the end of 2026. But funding has remained uncertain. While the operator has moved to address this, committing to invest \$6 B, in June 2026, the National Treasury removed the \$76 M development allocation from the State budget. First oil now depends on Gulf Energy delivering its financing commitments and the Treasury reversing its decision. Until there is clarity on how any funding gap will be bridged, the December 2026 target remains aspirational.

ReconAfrica has been active throughout 2026. The company raised \$22.5 M at the start of the year, earmarking the proceeds to advance several projects, including production testing at the Kavango West-IX well onshore Namibia. The first testing phase concluded in August, and while it failed to



Onshore hotspots across Sub-Saharan Africa.

deliver oil, flowing hydrocarbons to surface marked a first for onshore Namibia. Subsequent testing and the Kavango-2A well will follow and have an important bearing as to whether Namibia's onshore will produce oil.

In Zimbabwe, Invictus has advanced towards a commercial development at its Cabora Bassa project. The company signed a Petroleum Production Sharing Agreement (PPSA) on June 1. The Environmental Impact Assessment was also extended, clearing the way for the Musuma-1 campaign, a new-play exploration well in the eastern basin, expected to spud in November 2026. Invictus funds itself largely through the issue of new shares. The signing of the PPSA will have buoyed investor confidence, but a disappointing Musuma-1 result will risk appetite.

Angola's onshore Kwanza Basin is at a different stage of its hydrocar-

bon history. It offers exploration, discovered resource and re-development options. At Afentra's KON4 block, the operator plans to take FID on a redevelopment project focused on the shut-in Quenguela Norte field by late 2026 / early 2027. This is ambitious, as reactivation is never a given. The last reactivation project in the onshore Kwanza had similar plans but stalled as new wells were unsuccessful. However, the geology across the basin differs, and Afentra is confident it can fast-track the project.

In summary, while the onshore continues to garner interest across Sub-Saharan Africa, exploration results, financing constraints, and development complexities can hinder progress and push back first oil dates. Challenges remain as these predominantly frontier countries look to join the league of producing nations. ■

"I don't want dry holes, and I only want big prospects"

Or to put it differently; how to optimise serendipity

IT MAY sound odd to the exploration geoscientist, but some leaders in the oil and gas business still believe that they can demand only successful wells to be drilled, and only on big prospects. It goes to show that the concept of risk versus reward can still be a poorly known thing once you get outside your geoscience bubble, even when the whole idea underpins the very fabric of how the industry operates.

It's this "divine management intervention" that can cause significant upheaval. For instance, there is the story of a CEO who ordered the building of a gas plant even before the prospect that was supposed to deliver the gas to that very plant was drilled. The firing of geologists straight after the completion of a dry hole is another example that has never proven to be a great strategy.

At the same time, you can understand the bitter frustration when a bunch of poorly funded amateurs repeatedly deliver massive exploration successes in surprising locations, whereas the smartest and best funded new venture teams fail all the time. "But

that's why this industry is so fascinating," says Ian Longley from GIS-Pax in the video on which this article is based. Let's take a look at how to really try to optimise serendipity, especially from a management perspective.

Every oil and gas prospect portfolio consists of opportunities that ultimately plot in a diagram as shown here. "Once this basic concept is explained to management," says Ian, "what often happens is that the higher-risk opportunities are excluded because risk is bad and has to be avoided at any cost." And from their point of view, it even makes sense, as most of their business strategies are all around the belief that risk is a state of knowledge and that it can be reduced by working hard."

But that's obviously not how you achieve exploration success. Management therefore needs to embrace risk, and focus on how it is estimated. Calibration against previous drilling activity in the same region is one of the key elements in this process, as it enables people to set expectations. In other words, no cooking up in a vacuum, but in a consistent and traceable way, preferably



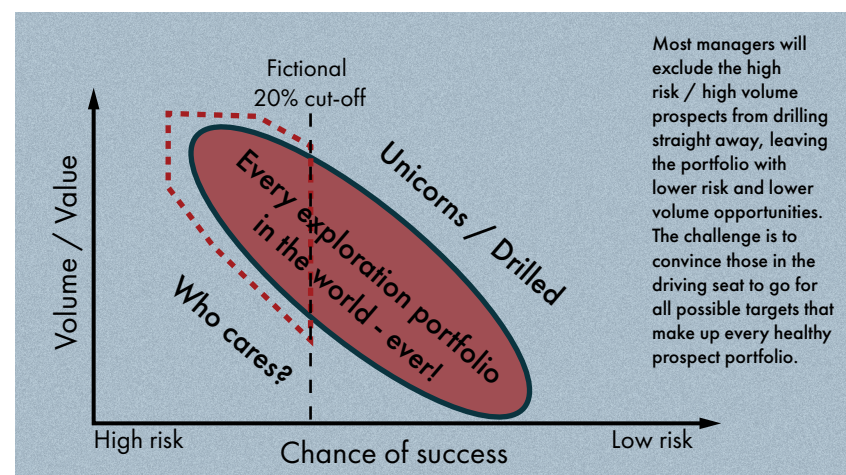
using software. That's why most companies have a portfolio of opportunities in the frontier side (10 %), play extensions (30 %) and proven plays or near-infrastructure (60 %).

What else do you need? Well, good people in your exploration department, and keeping them happy in their job. By the way, remember that the ideas-geos are often the ones that are a little "unconventional" and don't fit a large corporate company very well. Issuing a corporate manual on colour schemes, logos and fonts for a new corporate PowerPoint template is normally the trigger for most quality explorers to hand in their notice.

And as a last bit of advice, go to the more geologically complex areas, since by far most of the easy targets will have been drilled by now – except of course in the disputed areas. It is much more likely that the bigger remaining fields are hiding in a geologically complex setting than finding them in an easy-to-map structure that has been seen by many before. ■

Henk Kombrink

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



How fast-track field developments run the risk of ignoring key reservoir details

Whilst the oil industry is to thank for major advances in sedimentary facies classification, it may now be on course to "forget" about the lessons learned

THAT IS one of the thoughts Andrew McBarnett, Paul Wright and Haifa Khaldi voice in a paper they published in a carbonate sedimentology special issue last year. In the conclusion of the paper, they write:

"The last 75 years have witnessed significant advances in our understanding of modern and ancient carbonate depositional systems. Much of this scientific progress has been driven by a need to understand porosity and permeability distribution for both the exploration and development of hydrocarbon reservoirs. While the motivation for this research was clearly the optimisation of oil and gas extraction, it has contributed enormously to our understanding of Earth surface processes. It is somewhat ironic, therefore, that as the oil and gas industry arguably enters its final phase, the detailed reservoir description needed to leverage our accumulated knowledge of carbonate depositional systems and diagenesis is increasingly bypassed in the interest of fast-tracking projects. This problem is likely to get even more acute as, from a technical point of view, exploration prospects become increasingly risky, and field developments ever more complicated."

This is quite an interesting statement, especially when it comes from someone who works for Shell (Andrew McBarnett). The authors subsequently use an example from the Miskar field offshore Tunisia demonstrating why a detailed sedimentological description of the reservoir facies remains so important. They describe the Upper Cretaceous R1 Inférieur reservoir in the Miskar field that documents a shallowing upward carbonate shoreline system, which is capped by an anhydrite.

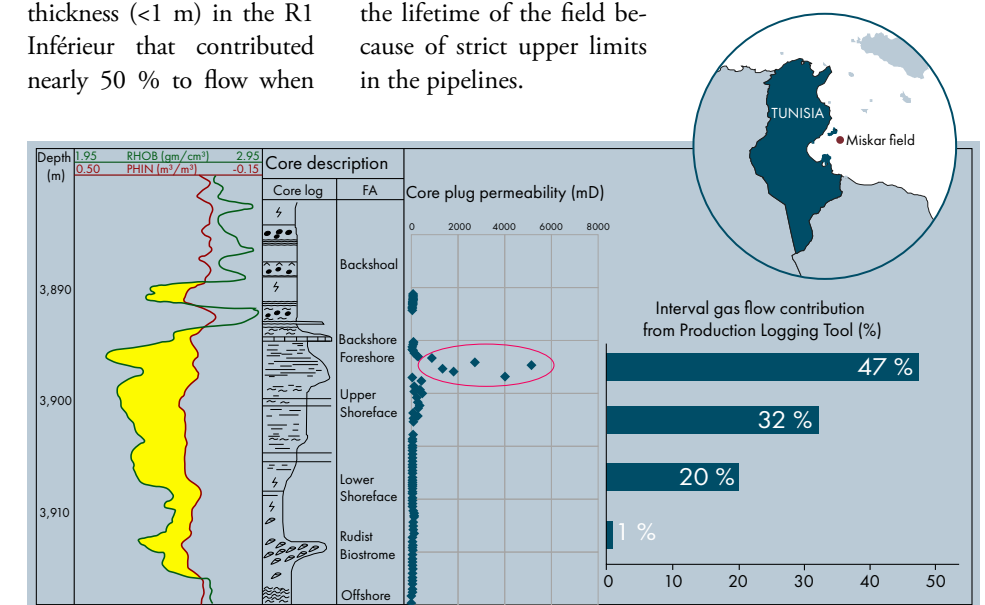
Detailed core interpretation carried out in 1996 identified one anomalously permeable interval of minor thickness (<1 m) in the R1 Inférieur that contributed nearly 50 % to flow when

subjected to a production logging test. This high-perm streak is a bed consisting of rudstones (rudist fragments) and very coarse-grained grainstones, thought to have formed in the foreshore to shoreface interface where advancing waves are confronted with the backwash from the preceding wave.

When the field was taken into production, this high-perm streak seemed to be of little importance because no water injection was planned at the time. However, after a few years of production, an issue gradually developed in the form of increasing levels of H₂S in the produced fluids. This led to concerns about the lifetime of the field because of strict upper limits in the pipelines.

This is where the detailed work on facies came in handy. First of all, the source of the H₂S was identified to be the anhydrites deposited on top of the R1 reservoir, generated through sulphate reduction. Secondly, it was soon realised that the high-permeability facies of the R1 Inférieur was likely to be the conduit for the H₂S to migrate from the "kitchen" into the main reservoir, forming a better starting point for mitigating the production problem, and clearly demonstrating how a detailed facies model can be very useful even when it may not seem to be the case at the start of production. ■

Henk Kombrink



Logs and core description / facies association of one of the wells drilled in the Miskar field, offshore Tunisia. Permeability measurements clearly show a thin high-perm streak that is associated with almost 50 % of gas inflow during a production logging test.

Exploration drilling programme in Greenland postponed and slimmed down

It turns out that necessary permits still need to be obtained before work can proceed

IN LATE 2025, we reported (GEO EXPRO Vol. 22, Issue 6, 2025) on a planned two-well onshore exploration campaign to be carried out by Greenland Energy on Jameson Land, in the east of Greenland. At the time, the expectation was to commence drilling this summer already, targeting prospects of Jurassic to Permian age. Finance for the two wells seemed to be in place, but now it appears that the permits were not.

The lack of permits came to light following a number of media publications in August when it was reported that 80 Mile, the company that holds the three exploration licences on Jameson Land, had only just started the first step in the permitting process by drafting up a project description. What will follow before any drilling can go ahead are a number of public hearings, the publication of several reports dealing with environmental assessments, and a large number of regulatory ap-

provals. In other words, the company isn't there yet.

In the meantime, the first shipment of material required for the exploration project has already arrived in Greenland, as shown in a photo that was taken from the area close to the airport of Nerlerit Inaat.

Greenland Energy has also decided to reduce the programme from two wells to one. We approached the company to ask which well they are now planning to drill, but we have not received a response. However, based on the ERCE Resource Evaluation Report produced for the company in 2025, and the associated prospective volumes related to each of the assessed well locations, it seems likely that OPW-1 is still the main candidate.

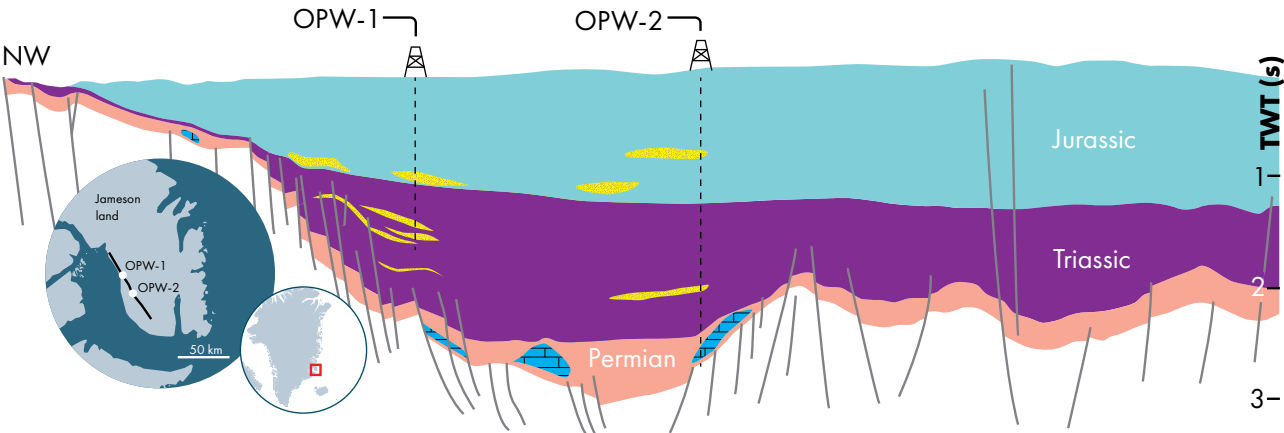
But the question now is, when will it be drilled? 80 Mile issued a press release on August 12th stating that "current guidance by the regulator is for winter 2027 drilling." The company also ac-

knowledges that it received a warning from the Government of Greenland concerning the landing of equipment because necessary permits were not in place when the material arrived.

The Jameson Land acreage consists of three licences that were initially awarded in 2015 and 2019. All three are now set to expire on December 31st 2028. With drilling now planned for the winter of 2027, there will not be much more room for delays in the drilling programme.

Based on conversations with people with knowledge of the matter, the chance of finding commercial quantities of oil is slim, because the Jameson Peninsula represents an uplifted petroleum system. For that reason, seals may have been breached, source rocks lifted out of the kitchen, and oil that has subsequently leaked from the reservoirs. Observed slicks at surface may point to that process still happening today. ■

Henk Kombrink



Schematic cross-section showing the position of the two wells that were initially planned to be drilled on the west coast of Jameson Land this year. In April, OPW-2 was subsequently dropped in favour of two other well locations. Now that it has been decided to only drill one well, we anticipate OPW-1 to be the main candidate for drilling. Redrawn after a cross-section by Greenland Energy Company.

SOURCE: REDRAWN AFTER A CROSS-SECTION BY GREENLAND ENERGY COMPANY

From hydraulic jumps to Goldilocks zones

New insights into the mechanisms behind deposition, compartmentalisation and reservoir quality of the Namibian deepwater reservoirs

THERE IS a reason why talks delivered by operators are often well attended at conferences; there is always the chance that something new is being presented. That was not only the case during a talk by Aurélie Tassy from TotalEnergies at the recent IMAGE Conference in Houston in August, but also during a few talks delivered at the AAPG "Finding New Elephants" workshop in Windhoek in June. Here are some highlights.

In contrast to the Lower Cretaceous Venus find, the Upper Cretaceous discoveries such as Graff and Mopane are often dissected by faults as a result of mass transport complexes that formed post-deposition. This is not a surprise if you look at the schematic cross-section shown here, which is based on high-quality seismic data, but it was still interesting to hear this so clearly

expressed by an operator. This message also corresponds to what we published earlier regarding the Saturn Complex north of Mopane (April 9th 2025, <https://geoexpro.com/this-may-be-a-reason-why-woodside-decided-not-to-farm-in-to-pel-87-in-namibia/>). Here, seismic time slices also suggest the presence of ridges that could be explained by internal slumps formed as a result of the shelf edge failing. In other words, the challenge for Mopane, Graff and any other Upper Cretaceous deepwater sand in the Orange Basin might be significantly compartmentalised and therefore more challenging to develop than the Venus discovery further outboard. This is probably the very reason why Venus is likely to be the first development that is getting the go-ahead.

Another interesting view on how the Cretaceous reservoirs found in the Orange Basin were deposited relates

to the suggested presence of a hydraulic jump. At the time the Venus-style sands were deposited during the Aptian, the idea is that a hydraulic jump existed across the Outer High. This hydraulic jump subsequently caused the deposition of sands basinward of the Outer High where Venus now is located. With ongoing sea-level rise, the hydraulic jump migrated further landward, and therefore sand deposition also shifted more landward, and in this case inboard of the Outer High where the Mopane and Graff discoveries are.

Then there is the reservoir quality issue that has been a concern for the deepwater Namibia discoveries. During the June conference mentioned above, an attendant shared information with us that was presented by Shell about the Jonker and Graff discoveries. Both discoveries apparently show thick and blocky sands in core logs and images, but overall permeability is poor, with some intercalated good permeability zones. Sandstones with reasonable 24 % porosity and pore-lining chlorite tend to be around 15 mD, whereas it drops to 15 % porosity and 1 mD where both pore-lining and filling chlorite are present. Sandstones where no pore-lining chlorite is present tend to be cemented up, leading to porosity values of around 9 % and less than 1 mD.

With TotalEnergies recently completing its entry into the Mopane discovery as an operator, it will be very interesting to see how the deepwater Namibia story unfolds, and how many snippets will be released during forthcoming talks. I keep my ears to the ground. ■

Henk Kombrink

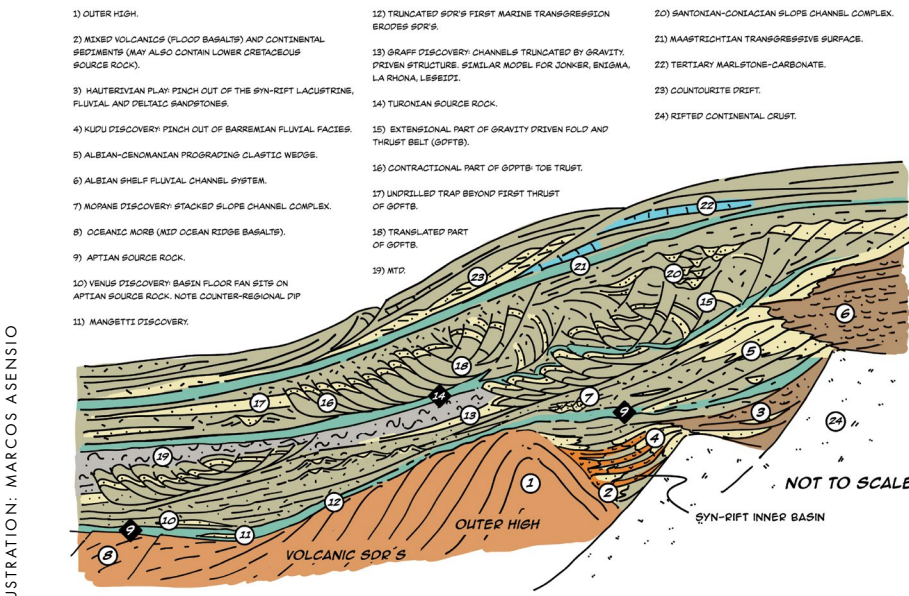


ILLUSTRATION: MARCOS ASENSIO

Schematic cross-section showing the main geological elements of the deepwater Orange Basin, Namibia.

Beyond the list

Which inactive wells are most at risk?

HANA KABAZI AND AMII ROZELL, SYNMAX

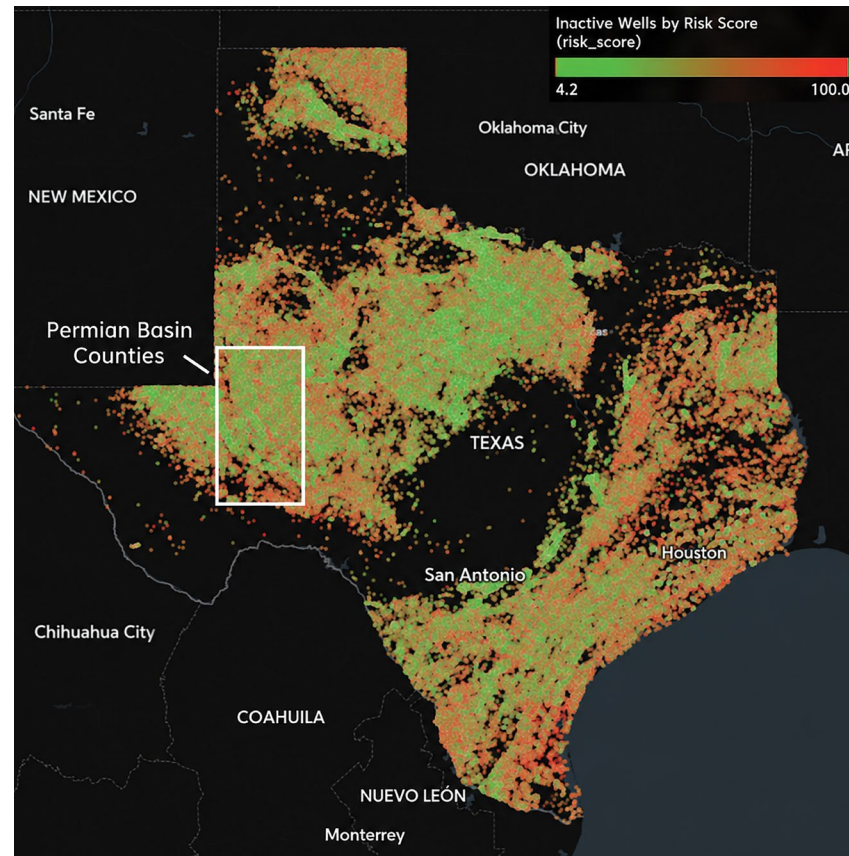
TEXAS HAS seen more than 1.2 M wells drilled throughout its history. The Railroad Commission (RRC), the oil and gas regulator in the Lone Star State, currently lists more than 12,000 wells as legally orphaned, a figure that has grown by more than a third in the past year. But the population of wells showing signs of long-term inactivity is much larger.

An analysis of 1.21 M Texas well records found approximately 183,000 that have gone idle. More than 125,000 have not produced in over a decade. These figures describe different things. Regulatory data identifies wells that have already crossed a defined threshold. The larger question is whether the data can also tell us which inactive wells may be moving toward it.

In Texas, an orphan designation follows a regulatory process. A well must be inactive and non-compliant, and the responsible operator's organizational filing must have remained delinquent for more than 12 months. Regulatory status can therefore delay changes in the circumstances surrounding a well. In other words, production history can provide an earlier signal, but it is not enough on its own.

Consider two wells that have both been idle for five years. The first is 4,000 ft deep and belongs to an operator active across dozens of leases. The second reaches 8,000 ft and is the sole remaining asset of an operator that has reported no production in three years.

Neither appears on the state's orphan list. But if the objective is to anticipate future plugging liabilities rather than simply catalog existing



Inactive Texas wells, colored by risk score.

ones, the distinction matters. The second well carries warning signs that can be identified years before its regulatory status changes.

Those differences become clearer when production data is linked with well engineering, operator history and location. A company carrying hundreds or thousands of inactive wells has a different liability profile from one with a small number of aging assets. Changes in ownership can also reveal wells that have moved repeatedly between operators as their economic value declined.

The patterns are visible at a larger scale. In the Permian Basin, the Andrews, Ector, Crane, Ward and Pecos counties contain significant concen-

trations of long-idle wells from decades of conventional development. Some operators are also responsible for thousands of inactive wells and substantial potential plugging liabilities.

No single variable tells the full story. The value comes from connecting production history, well characteristics, operator exposure and location at the individual-well level. Regulatory data shows which wells have already crossed a defined threshold; integrated data can help identify which ones may be moving toward it.

For an industry managing a large and aging well inventory, that creates a more useful question: not only which wells are liabilities today, but which are most likely to become liabilities next. ■

ILLUSTRATION: SYNMAX

The Discovery Thinking Forum

An inspiration for every explorer

IT ALWAYS takes time to realise that a recurring conference session is worth going to. The first time, you end up attending almost by accident. Then, the second time, you only vaguely remember being there before. The third time becomes a bit more concrete, with some familiar faces around. Then, when scanning the programme prior to going the fourth time, and seeing the session advertised, it finally lands that it is actually a must.

What am I talking about? The Discovery Thinking Forum, run by Charles Sternbach and Mike Forrest during the annual IMAGE Conference in Houston. Explorers share their stories of

how they proved a new play, discovered a new field, or developed a successful strategy. And they are allowed to speak a little longer, which means they can go into more detail than the regular speaking slots at the conference.

This year, it was Bill Armstrong who started the session that consisted of four talks. Entitled “The Hottest Conventional Play in the World”, it was obviously centred around Alaska’s North Slope discoveries in the Cretaceous Brookian delta-top play. A really interesting detail around the discovery of this play, which sits at a shallower level than some of the existing fields in the area, is how data from previously drilled wells were

systematically overlooked. Bill mentioned the Alpine field, which is located just west of the first Brookian play discovery, Pikka. The delta-top sands in Pikka also extend to where Alpine is, but due to the nature of delta-progradation, the sands are thinner at Alpine. Yet, the majority of the approximately 130 wells drilled on Alpine must have “seen” an oil-bearing horizon on their way to where their reservoir is. It is therefore surprising that the operator of Alpine – ConocoPhillips – never took up the Pikka acreage next door to test the thickness of this shallow pay zone. It shows how simple geological thinking – reservoirs increasing in thickness

– can lead to the recognition of a play that was hiding in plain sight.

Andrea Cozzi from ENI ran through ENI’s worldwide portfolio of discoveries announced over the previous fifteen years; from Perla in Venezuela (2009) to Geliga this year. What stood out was that the company drilled fewer exploration wells in this period compared to the years before. What determines the increase in success? “We never outsource our competencies,” Andrea said. “We also retain a large group of G&G specialists,” he added. Was that a pun towards his direct IOC competitors? It is tempting to believe so.

Kevin McMichael from Claymore Oil & Gas, who delivered the third talk, told the audience about the deepest gas well ever drilled in Louisiana, the Highlander-2 well. Another great story, not the least because this well, which proved 1.6 Tcf of gas in place at a depth of around 30,000 ft, and the people behind it, stood at the basis for the Landman drama series.

Eric Zimmermann from LLOG delivered the final talk of the session. The way he spoke about the many examples of near-misses that became a discovery was inspirational to everyone in the room. All in all, four talks that each deserve a full article on their own. ■

Henk Kombrink



The moderators (m) and presenters at the 2026 edition of the Discovery Thinking Forum. From left to right: Charles Sternbach (m), Eric Zimmermann, Andrea Cozzi, Kevin McMichael, Bill Armstrong and Mike Forrest (m).

PHOTOGRAPHY: AAPG

Côte d'Ivoire

Reimaged datasets provide new geological insights within an exploration hotspot

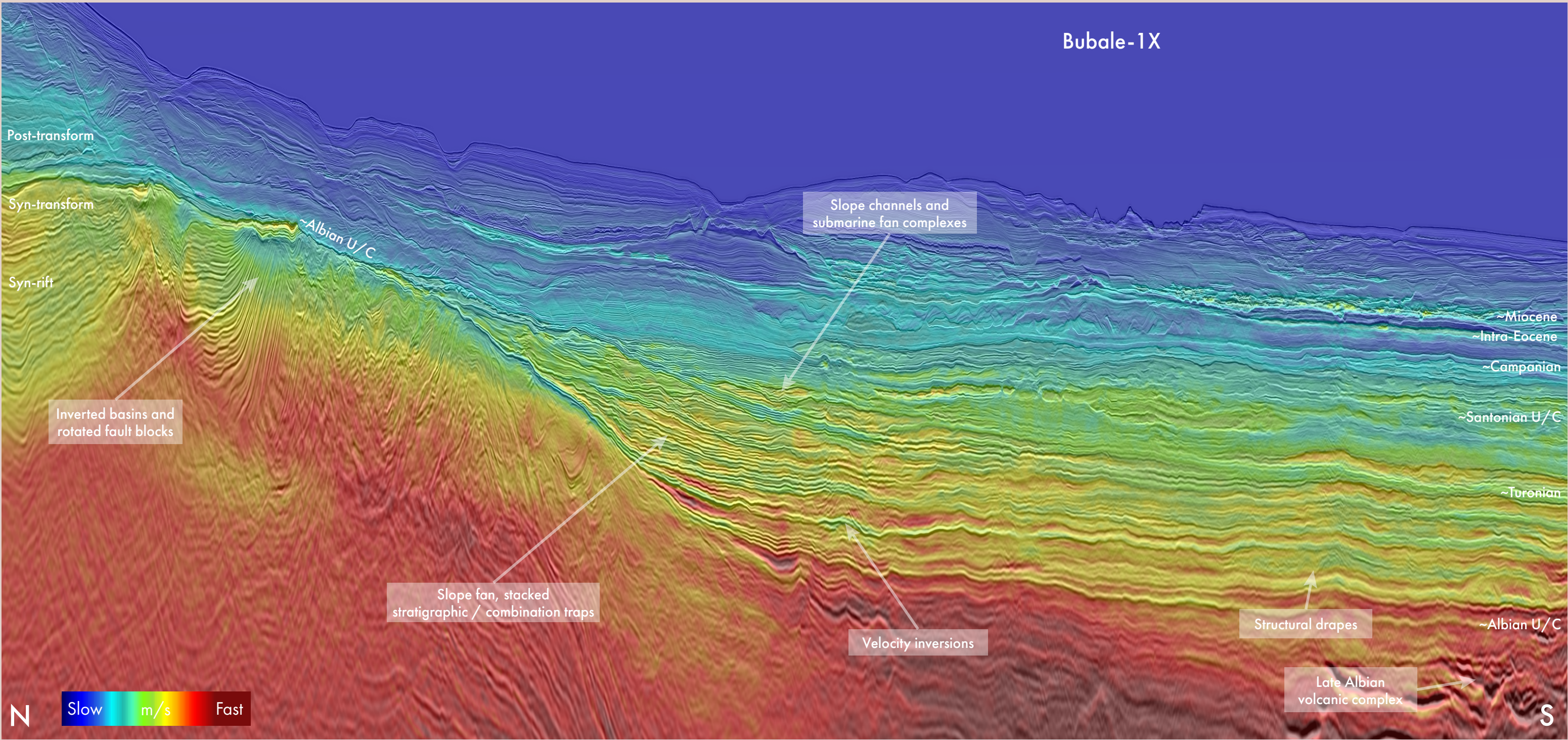
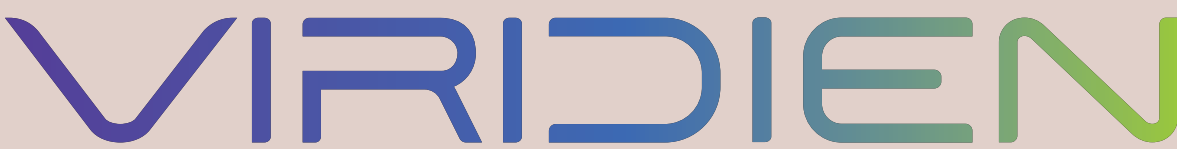


Figure 1: Arbitrary seismic line (final stack depth, with velocity co-blend) from the Tano Basin, highlighting key plays.

Côte d'Ivoire's Tano Basin offers significant exploration opportunity, with multiple recent discoveries including Bubale-1X, Murene-South-1X within Upper Cretaceous deepwater slope channels / fan systems, and Baleine, a shelf-edge carbonate discovery. The extensive play diversity and prospectivity is highlighted by a new 16,000 km² high-resolution reimaged dataset derived from 19 legacy surveys. The seamless dataset enables detailed structural, stratigraphic and petroleum system analysis at a regional scale, with stratal slicing enabling basin-scale analysis of the depositional fairways. The improved imaging, high-resolution velocity model, and robust Amplitude Versus Offset (AVO) response enhance the identification and maturation of a prospect portfolio. Figure 1 highlights the prolific Cretaceous syn- and post-transform plays, together with Bubale-1X, a discovery made on Viridien's CDI23 reimaged seismic (Figure 2).

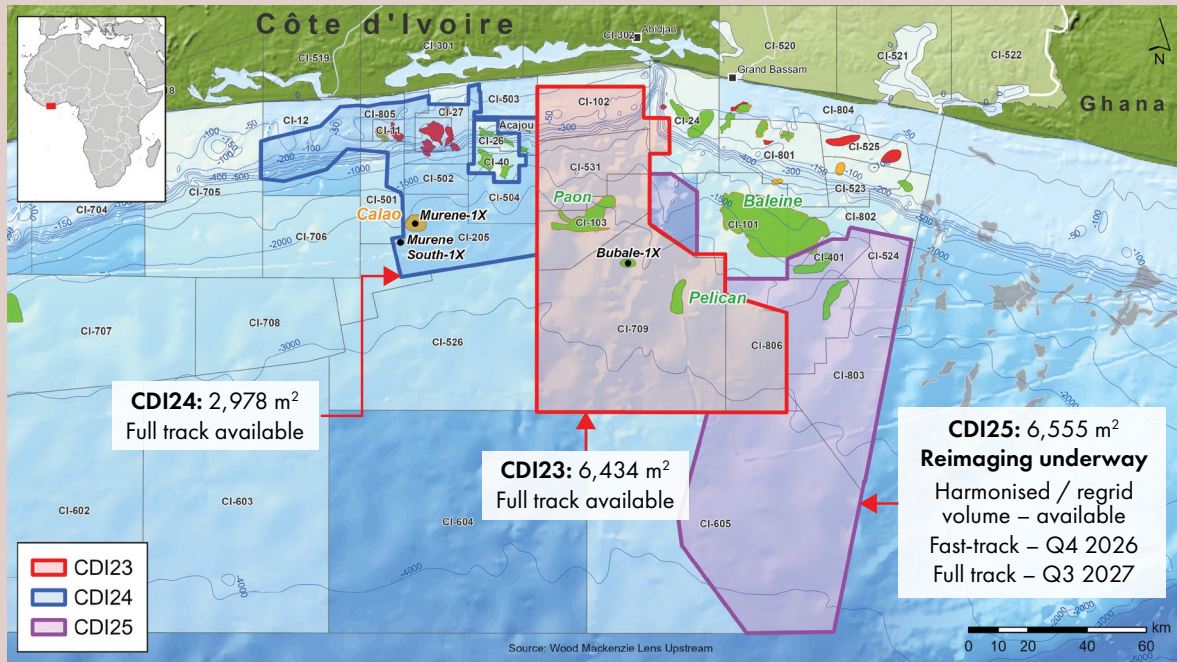


Figure 2: Location map showing Viridien's seismic coverage (CDI23: 6,434 km² / CDI24: 2,978 km² – reimaged datasets; and CDI25: 6,555 km² where reimaging is underway), together with selected wells, hydrocarbon fields and license blocks in the Tano Basin, Côte d'Ivoire.

Modern reimaging – A catalyst for exploration in the Tano Basin

GRAHAM COOKE AND PAOLO GABRIELLI, VIRIDIEN

REIMAGED DATA DRIVES DISCOVERIES

The Tano Basin, offshore Côte d’Ivoire continues to deliver significant discoveries, including Bubale-1X and Murene-South-1X (2026) within Upper Cretaceous deepwater slope channel / fan systems as well as the Baleine carbonate discovery (2021). These discoveries emphasise the region as one of the most prospective hydrocarbon provinces in West Africa and a global exploration hotspot.

In 2023, Viridien, in association with Direction Générale des Hydrocarbures (DGH) and PETROCI Holding, initiated a comprehensive reimaging program (Figure 2) over several key legacy surveys in the Tano Basin covering more than 9,400 km². This program is being extended to incorporate a total of 19 legacy datasets acquired between 1994 and 2017, with varying azimuth and streamer length, with reimaging from field tapes to create a seamless and contiguous high-resolution volume over a total 16,000 km² area.

This new basin-scale dataset is already revealing new geological insights into the depositional systems, structural framework and petroleum system of the Tano Basin, with the high-resolution velocity model, improved imaging, and robust Amplitude Versus Offset (AVO) response enhancing the identification and maturation of a prospect portfolio, as demonstrated with the discovery of Bubale-1X, drilled on the CDI23 dataset.

BUILDING THE FOUNDATION FOR RELIABLE INTERPRETATION

The processing sequence was designed to address the specific imaging challenges posed by the leg-

acy datasets, including merging multiple surveys. Amplitude fidelity was a primary consideration, with every step applied to preserve the relative amplitude relationships between offsets and angles, fundamental to AVO analysis.

Two technologies proved instrumental in delivering the imaging improvements shown.

The first is 3D Ghost Wavefield Elimination (GWE), performing simultaneous source- and receiver de-ghosting. By addressing both ghost components within a unified 3D framework, GWE removes offset-dependent wavelet distortions that could otherwise masquerade as genuine AVO effects, while harmonising datasets acquired with different configurations, broadening the effective bandwidth, and delivering a consistent amplitude response across surveys.

The second key technology is Time-Lag Full-Waveform Inversion (TLFWI), integrated with multi-layer tomography. By incorporating reflected energy alongside diving waves, TLFWI overcame the limitations imposed by streamer lengths of 4 to 8 km, resolving lateral and vertical velocity variations that conventional approaches could not capture. Operating at frequencies up to 15 Hz further increased model resolution, delivering substantial improvements in both structural and stratigraphic imaging (Figure 3) and, critically, producing flat gathers, an essential AVO prerequisite.

UNDEREXPLORED REGION WITH A WIDE PLAY DIVERSITY

The Lower Cretaceous syn-rift play (Figure 1) comprises rotated fault blocks and compactional drapes

of Apto-Albian terrestrial to shallow marine reservoir sands with associated source facies.

The Upper Cretaceous post-rift plays comprise laterally extensive and stacked slope channel and turbidite fan systems (Paon, Murene and Bubale discoveries), primarily within stratigraphic and combination traps (Figure 1), with shelf-edge carbonate deposition over crests of fault blocks as seen in the world-class Baleine Field. Primary source rocks include the Albian, Cenomanian and Turonian (ACT) deepwater marine shales, adjacent to the deepwater reservoir systems (Figure 1).

Stratal slicing was performed regionally, across the 16,000 km² volume, at multiple stratigraphic levels, enabling clear delineation of depositional architecture and associated reservoir distribution and underpinning the identification of prospects and leads including subtle stratigraphic and combination traps. Within the Upper Campanian interval, for example (Figure 4), clearly defined sediment entry points in the north supply multiple large-scale stacked slope channel systems.

Analysis at multiple stratigraphic levels, including the Murene, and Paon channel systems, highlights the highly variable deepwater sediment distribution systems, and significant stacked reservoir potential throughout the Turonian-Campanian, reflecting the complex evolution of the Late Cretaceous section.

Significant uplift in fault imaging has been achieved, improving structural framework evaluation and ultimately trap definition. The extensive stacked reservoir potential of the deepwater clastic systems and carbonates coupled with their proximity to the prolific ACT source rocks offers significant prospectivity potential, which is reinforced by the recent discoveries.

AVO ANALYSIS DRIVING PROSPECT IDENTIFICATION

AVO analysis is key for reducing uncertainty and refin-

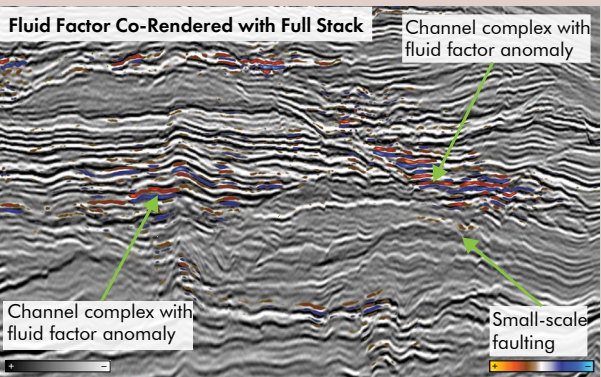


Figure 5: Full stack co-rendered with fluid factor. Highlighting deepwater channel complexes with angle-dependent behaviour and fluid factor anomalies, showing a variation in Vp/Vs ratio from the background trend.

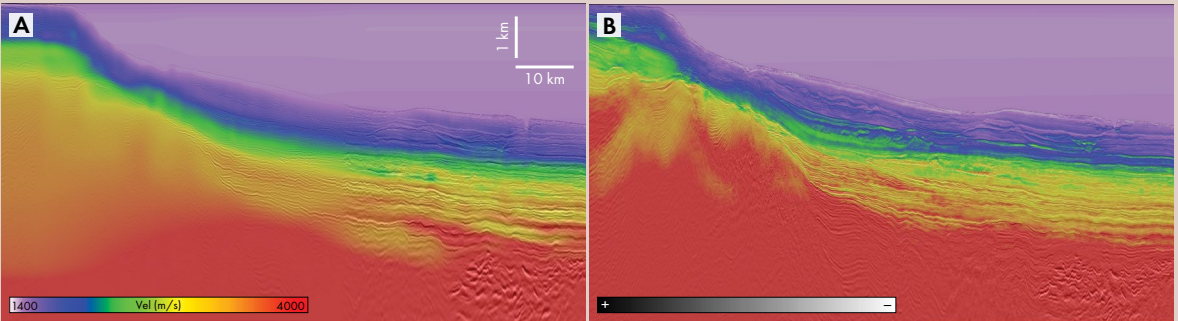


Figure 3: Legacy (A) and reimaged (B) stack sections with velocities overlay. New velocity model (B) shows details and high-frequency elements conformal with the geology. Newly reimaged data shows improved imaging, higher resolution and consistency between different surveys due to de-ghosting.

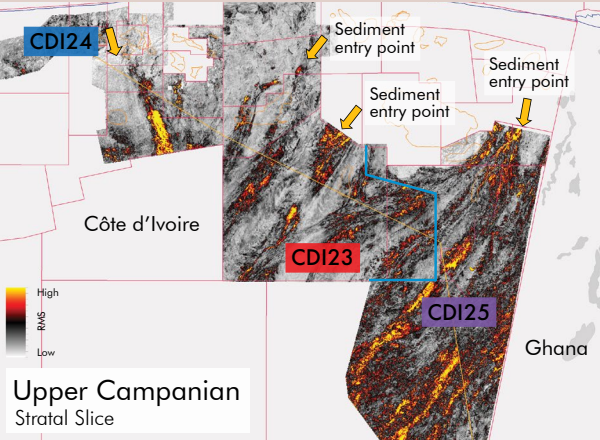


Figure 4: Upper Campanian – stratal slice, gated RMS amplitude extraction across the reimaged CDI23, CDI24 and legacy CDI25 volumes (reimaging underway).

ing exploration risk for prospects in the basin. The flat, low-noise gathers allow stable AVO diagnostics across the full region, leading to the identification of consistent Class II-p and Class III responses, improving the ability to differentiate fluid effects from lithology-driven amplitude variations.

In Figure 5 the fluid factor generated from the Shuey-derived intercept and gradient is co-rendered with the full angle stack, highlighting anomalies associated with potential hydrocarbon-bearing sands.

HIGH-RESOLUTION AND AVO-COMPLIANT PROCESSING EXPEDITING THE EXPLORATION PHASE

The project has delivered high-resolution and AVO-compliant regional seismic volumes from multi-vintage legacy datasets using Viridien’s technology. These datasets are utilised in active exploration programs, leading to discoveries, demonstrating a robust and cost-effective alternative to acquisition, and potentially expediting the exploration and appraisal phase.

The amplitude fidelity, together with the high resolution of the data, enhances the regional structural stratigraphic evaluation of the basin, with improved trap definition and AVO response, together revealing a more geologically coherent set of exploration opportunities and reaffirming the offshore Côte d’Ivoire margin as one of West Africa’s most prospective regions.

Looking ahead, higher-frequency FWI could further sharpen velocity resolution, improving definition of fine-scale stratigraphic features. Ocean Bottom Nodes (OBN), even with a cost-effective sparse node geometry, complementing existing streamer surveys, would allow a reliable simultaneous inversion of P- and S-waves, that would directly feed into seismic inversion workflows, delivering a robust platform for prospect evaluation.

FEATURES

“A complex chain of interpretations and assumptions has suddenly become a beautifully precise map. That precision can be misleading...”

Snorre Heimsund

Upstream developments along West Africa's Transform Margin

The West African Transform Margin (WATM) is receiving increased attention thanks to several large discoveries and a surge in frontier exploration activity. However, what is the WATM exactly, and what are the latest industry developments?

THE WEST African transform margin refers to the north coast of the Gulf of Guinea, stretching roughly east – west from western Nigeria, along Benin, Togo, Ghana and Côte d'Ivoire, to southern Liberia. The term WATM is sometimes also used to refer to a wider region, thereby including all of Liberia, as well as Sierra Leone to the north. Technically speaking, however, that part of the continental margin has a passive rather than transform origin, even though transform faulting did occur at a smaller scale in those basins due to variation in sea-floor spreading rates.

The transform margin initiated when the African and South American continents rifted apart during the breakup of Gondwana in Cretaceous times. Most of the future coastlines on both sides of the South Atlantic were parallel to the rift and formed passive margins. However, due to the orientation of the north coast of the Gulf of Guinea, perpendicular to the direction of rifting, it sheared along the edge of present-day northwest Brazil and French Guiana in a lateral fashion before the continents eventually broke free and new oceanic crust could be formed.

Of course, that is the large-scale picture. When we zoom in, we see two large transform fault zones, offset by a stretch of passive margin, creating a tectonically complex region with pull-apart basins, grabens and the presence of marginal plateaus.

The larger of the two fault zones is the Romanche transform fault or frac-

ture zone, stretching along the coast of Ghana. On the eastern end, it branches northwards into the West African craton, following pre-existing weaknesses in the basement, and creating an en-echelon pattern onshore Togo, Benin and western Nigeria.

This article will briefly discuss the individual sub-basins that can be found along the West Africa Transform Margin, covering a short geological overview as well as major discoveries and plans.

DAHOMÉY BASIN

The Dahomey Basin, which includes both onshore and offshore regions, is a large coastal basin that covers part of Togo, Benin and western Nigeria. The basin opened due to rift-related basement subsidence in the Early Cretaceous. However, much of the sedimentary infill was eroded during the Late Cretaceous uplift.

The discovery of the Sèmè field in Benin's shallow offshore has been the country's only economic find. Discovered in 1968 and produced between 1982 and 1998, it has lain dormant since. Now, after nearly three decades without production, Benin is redeveloping the historic field. Akrake Petroleum drilled a successful horizontal well earlier this year, and the start of production is now imminent. The shallow water well in the coastal basin of Benin penetrates the Cretaceous Abeokuta reservoir, penetrating approximately 950 m of oil saturated sandstone. Akrake has deployed a jack-up mobile offshore production unit and a floating storage and offloading unit for pro-

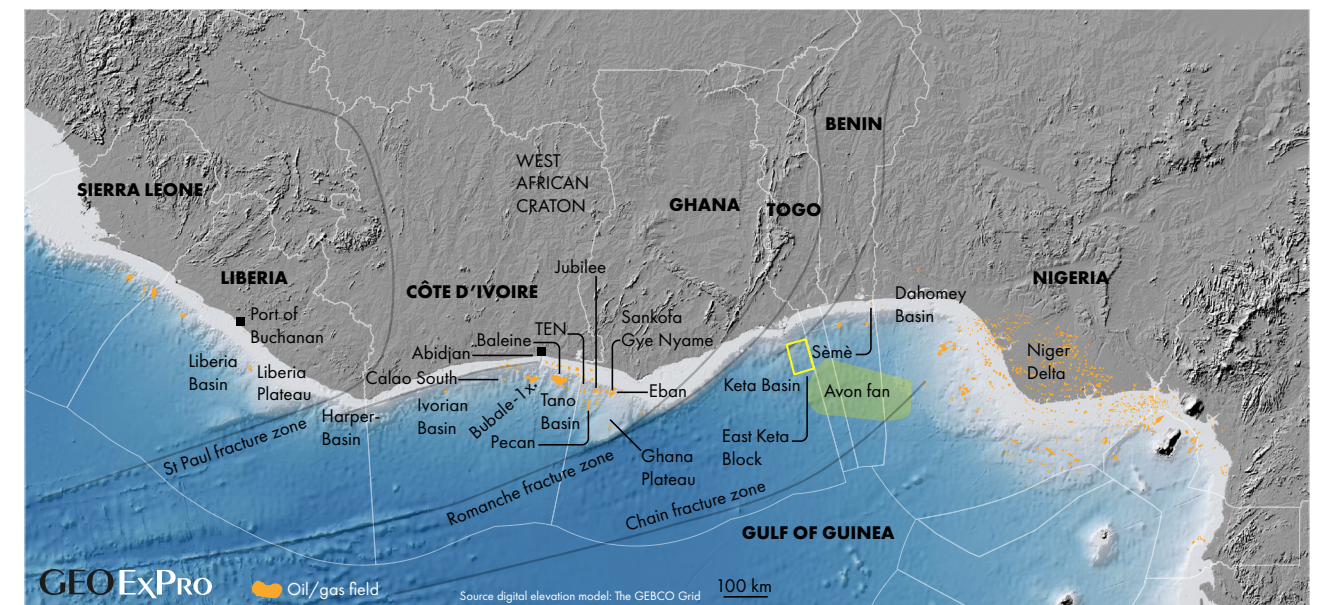
duction to start. While some technical challenges have arisen, SNH-Benin confirms that they are being resolved and that the project is progressing.

Further offshore, there is long-term potential. The Avon Fan, a deepwater continuation of the Niger Delta system, represents one of the most promising frontier plays. "When you combine that with the connection to the broader Dahomey basin, you begin to see a large, continuous petroleum system extending across borders," Blandise Biaou, Director of Exploration and Data Management at SNH-Benin, told us in an interview.

KETA BASIN

The Keta Basin is located in the eastern part of Ghana's offshore domain and has been largely unexplored. The sedimentary basin infill shares many similarities with the successful Tano Basin to the west. Syn-rift organic-rich rocks were deposited as the basin opened, followed by turbidites as the basin deepened. On seismic, both structural and stratigraphic trapping styles have been interpreted, and historic wells have confirmed the presence of the key petroleum system elements. However, none of these wells has made a commercial discovery.

While interest and geological understanding of the Keta Basin are growing, no drilling is planned for the near future. The only licensed acreage in the basin is currently held by the OPCO and Heritage Oil joint venture in the ultra-deepwater East Keta block and has so far focused on seismic acquisition and interpretation. Petrobras is currently negotiating with



Main geological features and hydrocarbon discoveries along the West African Transform Margin.

the Ghanaian government to obtain exploration contracts for four further blocks in the Keta Basin.

TANO BASIN

At the southernmost tip of Ghana, the Romanche transform fault stretches into the Atlantic. This was one of the last points of contact between the African and South American continents during break-up. At this location is a large, triangular-shaped submarine plateau to the north of the Romanche fault. Seismic data has shown it consists of stretched and thinned continental crust, rather than anomalously thick oceanic crust. This sliver of continental crust was sheared off the margin by the transform fault and marks the transition of the continental rift to drift phase.

The Tano Basin covers the Ghana Plateau and the deeper depocentre to the northwest. It is the most prolific hydrocarbon basin of the WATM, as it stretches across the maritime border into Côte d'Ivoire. Early Cretaceous rifting resulted in the opening of basins that filled first with lacustrine and subsequently marine organic-rich shales that currently form the regional source rock.

Around 84 Ma, during the Late Cretaceous, the small oceanic basins

had connected, and Africa and South America were drifting apart. Turbiditic sandstones filled the Tano Basin and now serve as the primary reservoir target. On the Ghanaian side, more than 25 discoveries have been made in the Mahogany and West Cape Three Points Cretaceous fan systems, including the Jubilee, TEN, and Sankofa-Gye Nyame fields.

Ghana's Petroleum Commission has projected a doubling in investments in the country's upstream industry in 2026, with the majority of activity concentrating in the Tano Basin. Multiple operators, including ENI, Tullow, Planet One, AMNI, and OPCO, have drilling campaigns scheduled for 2026 – 2027, while development activities for the Pecan field and the Eban-Akoma discovery are ongoing. There is also a drive to explore for hydrocarbons onshore Ghana.

In Côte d'Ivoire, the major Baleine field was discovered in the Deep Tano Basin in 2021. Both oil and gas are currently produced from the field, and ENI is investing in further development. The discovery has reinvigorated exploration in the country, with attention now also focusing on the Ivorian Basin to its west.

IVORIAN BASIN

The St Paul transform fault runs along the coast of Côte d'Ivoire from the city of Abidjan to the border with Liberia. The fault flanks the Ivorian Basin, where multiple discoveries have been made in its eastern half, including ENI's Calao discovery in 2024 and Calao South in 2026. Murphy Oil drilled a three-well exploration campaign this year and struck oil in the final well, Bubale-1X. It found 30 m of net pay across two reservoirs, with preliminary assessment indicating light oil.

Most of Côte d'Ivoire's acreage has now been taken up, with ENI covering the Tano basin and the mature part of the Ivorian Basin. Murphy Oil occupies the acreage in between. Eight blocks of deepwater frontier acreage have been signed by Petrobras this year. That is not surprising, given Petrobras' success in deepwater basins on the conjugate margin of Brazil.

HARPER BASIN

At the border between Côte d'Ivoire and Liberia, the main fault of the St Paul transform system offsets to the north, likely dictated by inherited weaknesses in the crust. The Harper Basin covers the area between the two main transform faults. The basin is yet ►

undrilled, but the identification of Cretaceous deepwater fan systems in seismic data is analogue to other transform margin discoveries. Other early exploratory work in the basin includes a seabed survey in search of hydrocarbon seep activity, conducted over the summer.

One of the largest exploration risks along the WATM is the presence of breached traps due to late-stage tectonism. In Côte d'Ivoire, this is a primary reason for deepwater well failures. This does not bode well for the adjacent Harper Basin, which is confined by major transform faults. Although the hope is that the deepwater fan systems contain sufficient stratigraphic traps that are less sensitive to tectonic reactivation.

LIBERIA BASIN

The Liberia Plateau, a transform marginal plateau, is located to the north of the main St Paul fault. Although less well studied than the Ghana Plateau, the interpretation is that this is also

thinned continental crust rather than a volcanic feature. The Liberia Basin is to the north of the plateau, and although drilling has confirmed the presence of a working petroleum system, an economic discovery is yet to be made.

There are parallels between the setting of the Liberia and Tano basins. Both are situated along a stretch of passive margin and shielded from the large transform faults by marginal plateaus. This quiet tectonic setting means the Liberia Basin could benefit from the presence of both stratigraphic and structural traps, just like the Tano Basin.

Blu Energies has secured reconnaissance exploration rights in the Harper Basin and TotalEnergies in the Liberia Basin. Liberia's Petroleum Regulatory Authority is launching the 2026 Offshore Direct Negotiation Licensing Round later this year. It will offer investors access to prospective deepwater and ultra-deepwater acreage across the Liberia and Harper Basins.

Meanwhile, the National Oil Company of Liberia (NOCAL) has started work on a logistics hub near the Port of Buchanan to support future offshore exploration and in preparation for the country's first commercial discovery.

NEXT DISCOVERY

Activity along the West African Transform Margin is on the rise. Although drilling focusses on the mature parts of the margin at the moment, there is plenty of deepwater frontier to unlock, and attention is shifting to those areas.

Will any frontier acreage be able to parallel the success of the Tano Basin? Possibly the Liberia Basin with its analogue tectonic setting? Or will prolific stratigraphic traps be found in the deepwater fan systems of the Harper and Dahomey basins? Or what about the tectonically quieter Keta Basin? Time and drilling will eventually tell. ■

Mariël Reitsma

Is the oil industry cannibalising itself in geoscience recruitment?

Despite the drop in the number of students embarking on a geoscience degree, those who manage to graduate are often looking for work for a long time. Based on several recent conversations, we're not hopeful that the tide is turning

DURING his opening address to the IMAGE conference delegates in August this year, AAPG's President John Casiano told the students in the room that this was the best time to join the industry, given the range of subsurface energy and storage roles there were to be filled. But is that really true?

"We advertised two graduate positions, and got around 400 applications," someone told me at the same event. This was in Norway, the country where the number of students choosing geosciences as a degree has plummeted. Yet, despite this decline, there are still many out there who are seemingly desperate to join the industry.

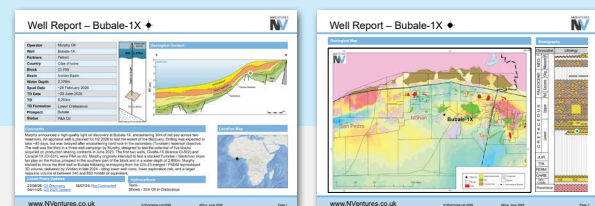
This example does not stand in isolation. I met a student in the USA who was very candid about the lack of job opportunities. "I am told that I need to do internships," he said. "But when I finally secure one, there is still absolutely no guarantee that there is a job waiting for me at the end. And the same is true when I do a second internship." Some people told him that he needs to do a PhD as well. "But what will the job market look like in three years?" he asked rhetorically. He then went on to say that out of 12 students who recently graduated from his university, only one found a position in oil and gas. It just shows the very sorry state of recruitment with the majors.

Of course, there are exceptions. But I feel it's very much like a lottery. A geologist who works for a major in Houston told me that during the years he has been there, he had not seen any graduates start in his department. So, it's not only the students who see this lack of recruitment; people in the companies are aware of it too.

The combination of no new graduate recruits, an ageing workforce, and redundancy rounds can have a detrimental effect on the number of geoscientists working in the energy industry. A short conversation with a business development manager of a service company is probably a testament to that. He told me that they are ►

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PHOTOGRAPHY: DARREN CLARK

Stacked rigs in Scotland's Moray Firth are another sign that the industry is experiencing a lull in activity, which ultimately translates into a lack of recruitment into geoscience roles.



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increasingly selling to engineers rather than geologists.

The increasing absence of operator stands on exhibition floors may also be a sign that there is hardly any recruitment going on. At the IMAGE conference, there was not a single operator with a prominent stand. The service sector has completely taken over. It's not to say that operators were always there for recruitment alone, but doesn't it make more sense to exhibit and show yourself when you are looking for new talent to join?

Maybe graduates are not being hired, but that doesn't mean that there is a complete hiring stop. As another geologist told me, there may even be an uptick in recruitment with some majors on the back of the increased interest in exploration. The "problem" is that the roles that are being filled are mostly going to those who have previous experience. And there are many of them around, given the numerous rounds of layoffs we have seen in the recent past.

It is this hiring of experienced people and leaving the graduates browsing the job market that creates a dangerous cycle. As another geoscientist told me: "It is partly the specialist jobs that we see a demand for now, for instance, our biostratigraphers. If someone with those skills is poached, where do we find a replacement? Because who graduates from a university with a biostratigraphy major these days?" This is where the title of the article comes from; there is a level of job cannibalisation happening that seems unsustainable in the long run.

Another indication that the majors are losing their internal specialists is yet another conversation I had. Someone who is part of a research consortium told me that one of the majors is now interested in potentially joining the consortium, after many years of showing no interest at all. This is yet another sign that the internal specialists within the company have moved on, which in turn results in more of a need to join a research

consortium dedicated to a niche aspect of reservoir geology.

And what about those who are currently in one of those sought-after jobs? I spoke to various people about this, who all worked for the majors, and no one was very upbeat about the daily realities of their jobs. In other words, these people are basically keeping their heads down while awaiting the next redundancy round. Because that is probably the thing that is the most certain; there will soon be another request to apply internally for a new role. "Job security does not exist anymore," someone said. People literally feel the threat of AI, or the threat of losing their position, as their role will now be done by a newly established centre in India. And just as we go to print, I see an announcement from TotalEnergies saying that they will further invest in AI to advance exploration.

Taking all this together, I am sometimes a little confused as to how it is possible that the world keeps on pumping 100 MMbbl of oil where the community of geoscientists making that happen seems to be in long-term decline. Of course, I have gradually learnt that geoscience is very much a niche sport even in the best of times, but let's not forget that it is ultimately the geoscience discipline that is responsible for finding new fields, as well as supporting the drilling of appraisal and development wells. It looks as if the industry is not only cannibalising its people, but it is also cannibalising its reserves.

So, coming back to John Casiano's statement during the IMAGE opening address; based on the conversations I've had recently, I still don't see a real pick-up in opportunities for graduates – to the extent that I'm truly interested in how this dynamic will unfold in the years to come. The concern voiced by so many industry leaders around the drop in students embarking on a geoscience degree may well be trumped by the lack of hiring from within their own ranks. ■

Henk Kombrink

Unlocking a century of subsurface intelligence

Digital transformation of Malaysia's drill cuttings archive

HAFIZ B. JALIL, SUZANA BT. ABDUL HADI AND HERRY MAULANA, MPM
AND GUY OLIVER, GEOLOG

DRILL CUTTINGS are an invaluable source of organic and inorganic geological data. Yet, they are often underutilised, with hundreds of thousands of cuttings stored in warehouses and repositories across the globe, spanning decades of drilling activity. In Malaysia alone, PETRONAS, through Malaysia Petroleum Management (MPM), is storing more than 6,000,000 cuttings and core samples from across Malaysia, covering some 100 years of exploration and development.

With the onset of new analytical technologies and AI-driven software applications, all these samples can generate high-quality, consistently generated digital datasets that will assist in our detailed understanding of subsurface plays at a fraction of the cost of drilling a new exploration well. Standard techniques are now available to correctly and accurately depth-match fresh and historic samples to wireline log suites.

Figure 1 outlines a cuttings sample digitisation workflow that is currently being utilised for the digitisation of the MPM cuttings data repository in Kuala Lumpur, Malaysia. The key to unlocking this digital data revolution from cuttings is to understand how to properly and consistently prepare each sample for analysis, and which types of analyses will yield valuable and correlatable data. Consistent sample preparation is key when trying to interpret and correlate data from samples of different vintages acquired by different vendors. Understanding mineralogy, potential organic richness and mud type are some of the important factors to consider when making sure a sam-

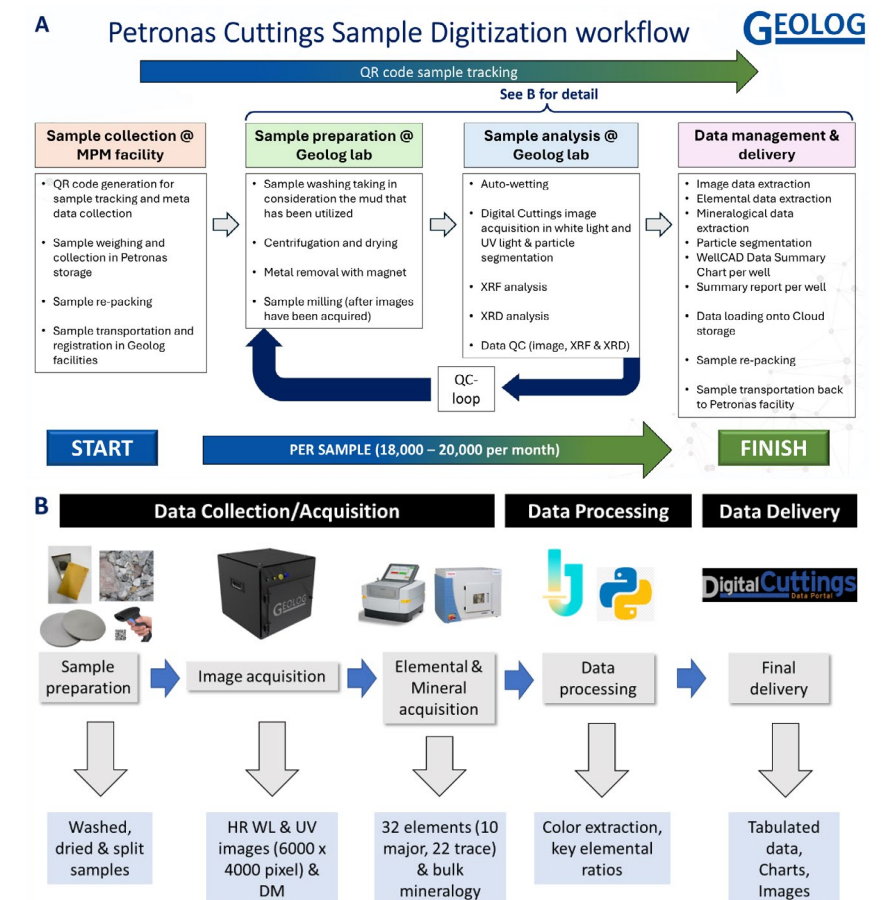


Figure 1 A and B: High-level cuttings sample digitization workflow (A) outlining key stages from sample collection to delivery of digital data, and (B) details associated with sample preparation through data delivery.

ple is properly prepared. In addition, correct washing and drying procedures are fundamental for preserving mineral species and evidence of hydrocarbons.

Once correctly washed and dried, a base analytical workflow should be undertaken to ensure that every sample is consistently measured, thus allowing for confident correlations sample to sample, well to well, and both vertically and laterally across the basin / play / asset. Typically, this base workflow should consist of white light (WL) and ultraviolet light

(UV) quantitative digital imaging, color extraction (Red-Green-Blue (RGB) and Brightness), particle size and shape segmentation and elemental data analysis. Beyond this base workflow, on a case-by-case basis, additional valuable data can be obtained, such as mineralogical content, organic richness and maturity and biostratigraphic data. All these collected digital data can then be used to help constrain rock physics models or as input to regional or field subsurface 3D models by creating accurate ▶

image analysis and elementally constrained lithofacies models.

THE SOTONG GAS FIELD CASE STUDY

The Sotong field lies to the NE of the Tenggol Arch, offshore east of Peninsular Malaysia in the South China Sea. It is located down-dip from other hydrocarbon-producing fields such as Tembakau and contains reservoir sections characterised by stacked fluvial channelised facies, tidal flats and shoreface complexes. Analysed cuttings data as part of the MPM-led digital transformation initiative were used to build a new lithofacies model for the field, thus offering a new and greater insight into the subsurface complexities.

Figure 2 cross plot shows an image analysis based on brightness derived from Red-Green-Blue colour parameters versus key elemental data (log Si/Al ratio) generated from Sotong field drill cuttings samples. This cross plot forms the basis of a new lithotype model with cut-offs defined as Brightness > or < 80 and log Si/Al > or < 3.8, leading to the creation of four newly defined and quantitative lithotype families:

- 1. Clean Sandstone: Brightness > 80; log Si/Al > 3.8
- 2. Heterolithic Sandstone: Brightness > 80; log Si/Al < 3.8
- 3. Clay-dominated Silt/Sandstone: Brightness < 80; log Si/Al < 3.8
- 4. Heterolithic Muddy Siltstone: Brightness < 80; log Si/Al > 3.8

As Brightness is a known facies indicator in clastic sediments, each of the four Lithotype Families was subdivided into Lithotype Associations based upon the individual cuttings sample Brightness readings, e.g. for the Clean Sandstone Family, Ss1, Ss2-Ss5 etc. and then further subdivided into individual lithotypes.

These interpretations were further cross-checked against log data (Gamma Ray (GR), Neutron / Density and Deep Resistivity) and other elemental and elemental ratio data such as Si%, Al%, Zr/Nb and Si/Ca for sedimentological

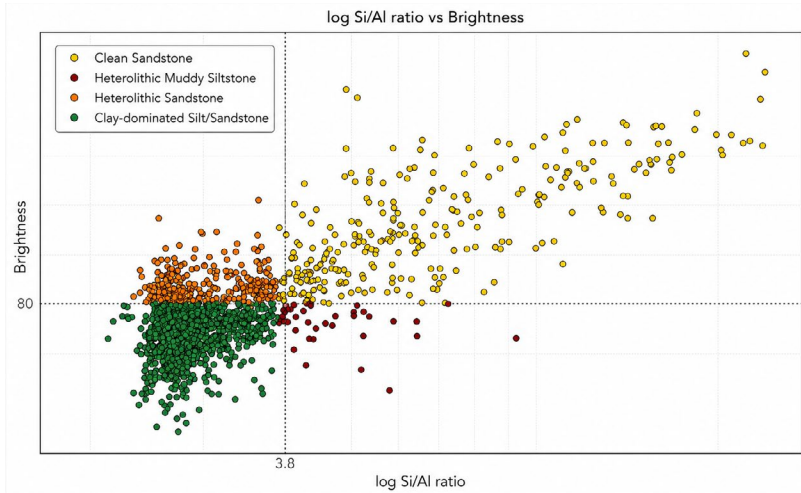


Figure 2: Lithotype model created from quantitative drill cutting analysis and adopted for the Sotong field, combining color extracted image analysis (Brightness) and elemental data (log Si/Al ratio).

context. Once complete, the newly developed Lithotype Scheme was used to identify small to medium-scale cyclicity in the form of darkening upwards and brightening upwards cycles, which stack to form a series of newly developed field-wide correlatable reservoir layers.

These models can then be used to define cuttings-based resolution downhole interpretations on a well-by-well basis. Figure 3 is an example of such a downhole interpretation for one well from the Sotong field. From the left-hand side, tracks 1 to 6 show depth (ft, MD) stratigraphy and log data, including the computed gamma ray calculated from the K (%) Th (ppm) and U (ppm) elemental data. Tracks 7 to 11, outlined in red, show the downhole detail associated with the lithotype model, including interpretation. Tracks 12 to 18 show the colour extraction metadata and interpreted brightness calculation from the image analysis data. Finally, tracks 19 to 36 show selected elemental and elemental ratio data extracted from the XRF analysis, including the Si/Al ratio (track 31) and other elemental data used to support the interpretation (e.g. U/Th ratio, Ti/Si ratio, Rb (ppm)).

The detail associated with the Lithotype interpretation (outlined in red in Figure 3) clearly shows cyclicity at different scales from small scale (10 – 20 ft) darkening upwards cycles shown in Track 7 (Lithotype Code) to medium scale (50 – 100 ft) generally darkening

upwards cycles shown in Track 10 (Gross Cyclicity) and finally to large scale cycles depicted as Reservoir Layers and shown in Track 11. Reservoir Layers C.1 to C.3 are dominated by the Clean Sandstone Lithotype Family (high brightness coupled with high log Si/Al ratio) with minor Heterolithic Muddy Siltstone and Clay-dominated Silt / Sandstone. These layers are associated with a dominantly fluvial depositional setting. Above this, Reservoir Layer D.1 probably represents a transition zone, grading upwards into a more Clay-dominated Silt / Sandstone facies with lower brightness and lower log Si/Al ratio. Associated with this layer is a decrease in U/Th ratio, an increase in Ti/Si ratio and an increase in Rb (ppm). The upper section of the well (upper Lower Miocene to lower Upper Miocene) is dominated by the Clay-dominated Silt / Sandstone facies with low brightness, low log Si/Al ratio, higher but stable Rb (ppm) and upwards increasing P (%) and probably represents a more quiescent marginal marine depositional environment.

Once applied to other Sotong field wells, this newly developed rock-based Lithotype Model will greatly assist with the updated, spatial subsurface understanding of this play and will create rock-constrained input into the updated 3D reservoir model for this field, which is due to be completed during 2027.

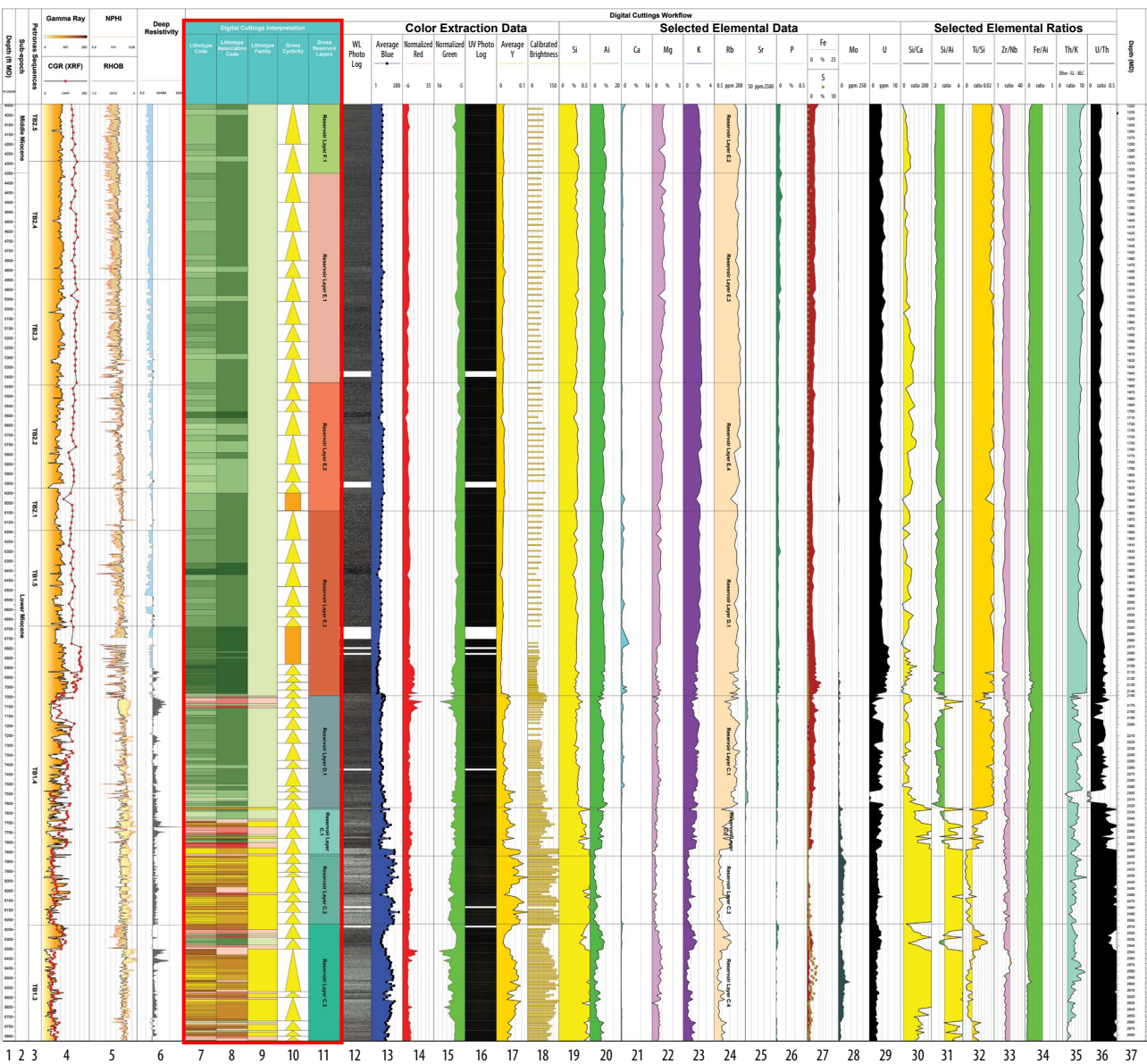


Figure 3: Data summary chart for Well A, Sotong field. For a detailed explanation, see text.

AN INEXPENSIVE BUT POWERFUL TOOL

Understanding subsurface plays typically requires a substantial initial investment (e.g. seismic and log data) and long analysis times at multiple labs. However, the datasets generated by the Digital Cuttings project, coupled with the added-value and consistently measured rock-based workflow presented here, offers increased efficiencies by providing a cost-effective and rapid method to collect, analyse, define, model and predict key reservoir drivers. The ability to identify elemental and image analyses specific lithotypes from routinely collected fresh and legacy drill cuttings

will allow operators to better predict across-field spatial reservoir definition and understanding, thus improving subsurface model-build and overall field development. The workflow example for the Sotong field presented here can easily be utilised for all other fields and plays within PETRONAS' current and future portfolio.

Drill cuttings can be a relatively inexpensive but incredibly valuable dataset that could help to unlock the future potential of our energy plays for years to come. As an industry, we need to make the most of these datasets by digitally unlocking their data potential and having the confidence to use these

data in our subsurface evaluations. Reliable, accurate and consistent data is the key to unlocking or confirming regional and field-specific reservoir / seal trends. With large data centers containing enormous compute power now readily available to all, having access to these vast 'integrated / AI-ready' consistently measured datasets will revolutionise the way we explore for, or appraise our energy assets.

The authors would like to thank and acknowledge Malaysia Petroleum Management (MPM), PETRONAS, and Geolog for granting permission to publish this work. In addition, the authors would like to thank all our colleagues who have worked tirelessly to generate the data for this publication. ■

When precision becomes a trap

Why more detailed models do not always mean greater geological certainty

SNORRE HEIMSUND

IN EXPLORATION, we spend a great deal of effort making our interpretations more precise. We improve seismic imaging and refine horizon picks. We build increasingly detailed depth maps. We calculate probabilistic volumes and assign geological probabilities to reservoir, charge, trap and seal.

However, there is a subtle danger: The precision of our outputs can begin to exceed the certainty justified by the underlying data.

A useful example comes from the Bauer Field in the Cooper Basin of South Australia. Before drilling in 2011, Bauer was mapped on 3D seismic as a low-relief anticlinal closure with only about 9 m of structural relief. The pre-drill mean recoverable resource was estimated at approximately 0.5 MMbbl of oil. The discovery well subsequently encountered a 14 m oil column, and by early 2015, the estimated ultimate recovery had increased to around 13 MMbbl.

Importantly, this was not simply a case of a poor pre-drill interpretation. Better-than-expected reservoir performance contributed significantly to the growth. At the same time, though, drilling consistently demonstrated an uncertainty of approximately ± 5 m at reservoir level. On a structure initially mapped with only 9 m of relief, that matters enormously. That is the essence of the false-precision problem.

A MAP CAN BE PRECISE AND STILL BE UNCERTAIN

A seismic interpretation may consist of thousands of carefully picked points. However, every mapped surface contains uncertainty associated with seismic resolution, interpretation, calibration and velocity modelling. This becomes particularly important in low-relief structures, where relative-

ly small depth errors may materially change the geometry or even the existence of a closure.

Work from the Cooper-Eromanga Basin has demonstrated that different depth-conversion approaches can produce materially different structural outcomes, including differences affecting low-relief oil-bearing closures. The map may therefore look definitive while the geological question remains open.

This is not a reason to distrust seismic interpretation. It is a reason to understand what the interpretation can – and cannot – resolve.

And the issue extends beyond one Australian field. A post-well review by TotalEnergies of 90 deep-water Gulf of Mexico exploration wells identified prospect geometry as the principal failure mode. Some wells were drilled outside closure, while other interpreted traps proved incompletely formed, with limitations in seismic imaging identified as an important underlying cause (Schoellhorn & Guerin, 2006). In other words, a detailed prospect geometry is not necessarily a well-constrained prospect geometry.

DEPTH CONVERSION IS AN INTERPRETATION TOO

We often talk about converting a seismic interpretation from time to depth as though it were simply a computational step. However, the relationship between seismic velocity and reflector depth is inherently non-unique. Different velocity-depth models may satisfy the seismic observations while producing different subsurface geometries, particularly where calibration is limited.

Once converted to depth, however, the result acquires considerable visual authority. A complex chain of interpretations and assumptions has suddenly become a beautifully precise map. That

precision can be misleading if the underlying velocity and depth uncertainty disappears from the discussion.

The challenge is therefore not simply to produce the best depth map. It is to understand how strongly the available data constrain that map – and which alternative geometries remain credible.

VOLUMETRICS CAN CREATE THE SAME ILLUSION

Modern probabilistic volumetrics are far superior to relying on a single deterministic case. But probabilistic calculations do not remove geological judgement. Area, thickness, net-to-gross, porosity, hydrocarbon saturation, contact depth and recovery parameters still have to be estimated. The ranges and distributions assigned to those parameters need to reflect the geological evidence and the uncertainty that actually exists.

A Monte Carlo simulation can generate thousands of outcomes with impressive numerical precision, but that does not make poorly constrained inputs more reliable. The important question is therefore not only what the P50 volume is, but also why we believe this distribution adequately represents the geological uncertainty. A probabilistic result is only as meaningful as the geological reasoning behind its inputs, ranges and dependencies.

GETTING ONE PREDICTION RIGHT DOES NOT VALIDATE THE WHOLE PROSPECT MODEL

A recent Norwegian Sea exploration well provides another useful perspective. The 6507/4-3 S well tested the Peder prospect on the Dønna Terrace in 2022. The prospect was associated with a Cretaceous amplitude anomaly, and the well location was positioned just inside a subtle four-way-dip closure. The pre-drill model also required a stratigraphic

DETAILED DEPTH MAP (HIGH PRECISION)

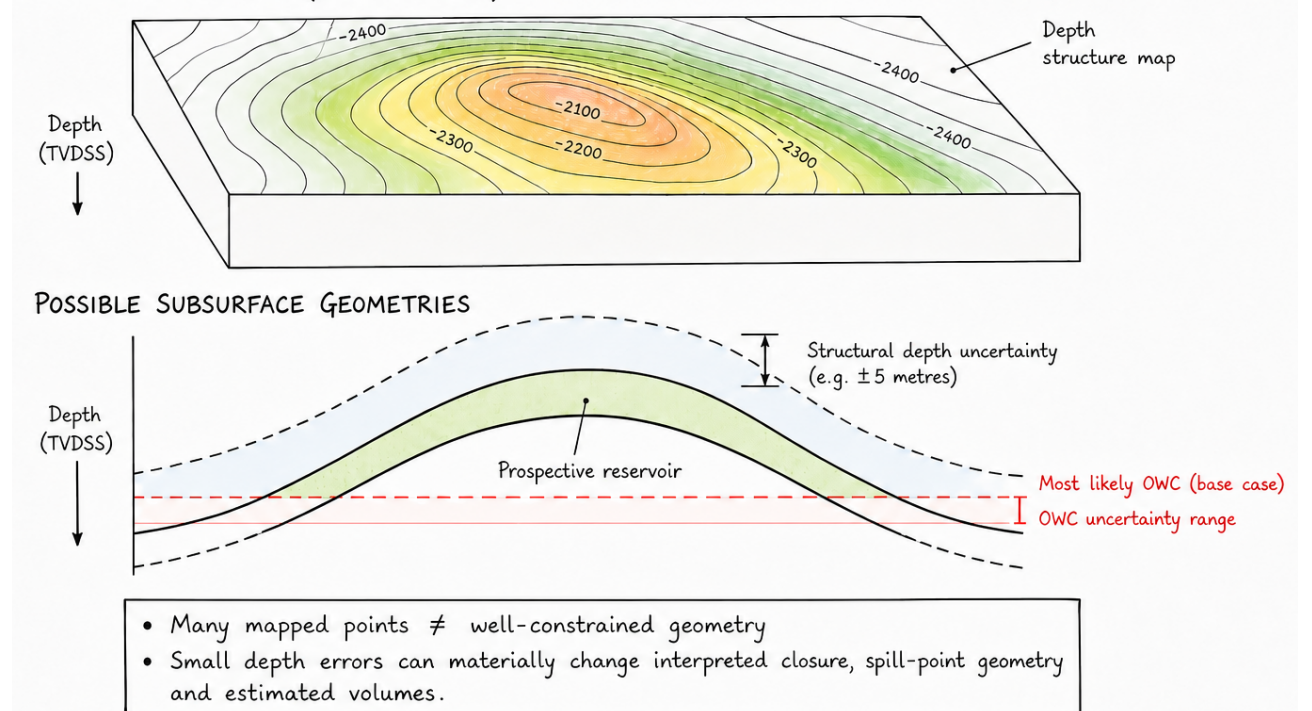


Figure 1: Precision vs. geological uncertainty. A more precise map does not necessarily mean a more certain subsurface.

trapping component to fill the wider amplitude-defined prospect.

The target itself arrived remarkably close to prognosis – approximately 2 m TVD shallow. Yet, the geological outcome was very different from the full pre-drill concept.

Only about 0.5 m of pay was encountered within the small four-way closure, while the remainder of the sandstone interval contained residual hydrocarbons. The Norwegian Offshore Directorate concluded that the result suggested the absence of an effective stratigraphic trap element. Reservoir quality was also poorer than predicted.

This is not an example of false precision in depth conversion. It illustrates that one part of a model can be accurate while another decision-critical assumption is wrong. Landing the reservoir close to predicted depth does not validate the trap model, just as correctly predicting reservoir presence does not necessarily validate charge, seal or commercial volume. That is why prospect uncertainty has to remain decomposed and visible.

GEOLOGICAL RISKING HAS THE SAME VULNERABILITY

An exploration team may assign probabilities to reservoir, charge, trap and seal and combine them into an overall geological chance of success. This calculation may be mathematically precise, but the inputs are not measurements. They are structured expressions of geological judgement based on evidence, analogues and experience.

Peter Rose explicitly warned explorationists against false precision in prospect-risk estimates and emphasised the need to challenge individual risk factors, compare assessments with analogous prospects and calibrate estimates against subsequent exploration outcomes. Two competent teams may therefore assign different probabilities to the same prospect without either necessarily being objectively “wrong”.

This is also where systematic post-well analysis becomes particularly valuable. A TGS study assessed Gulf of Mexico wells through an interdisciplinary workflow integrating geology, geophysics, petrophysics, seismic data

and basin modelling. Reservoir, trap, seal and charge were assessed individually, while confidence ratings were applied not only to the geological interpretation but also to the available data.

And that distinction is important; a risk assessment should communicate not only what we believe, but also how strongly the available evidence allows us to believe it. The study also illustrates the value of post-well calibration. By examining both discoveries and dry wells, teams can identify recurring reasons for success and failure and use those lessons to improve subsequent exploration assessments.

This closes an essential loop of prediction, outcome, learning and recalibration. Without that loop, probabilities risk becoming internally consistent numbers that are never tested against reality.

MORE COMPUTING POWER CAN AMPLIFY BOTH INSIGHT AND CONFIDENCE

None of this is an argument for less sophisticated seismic imaging, simpler ▶

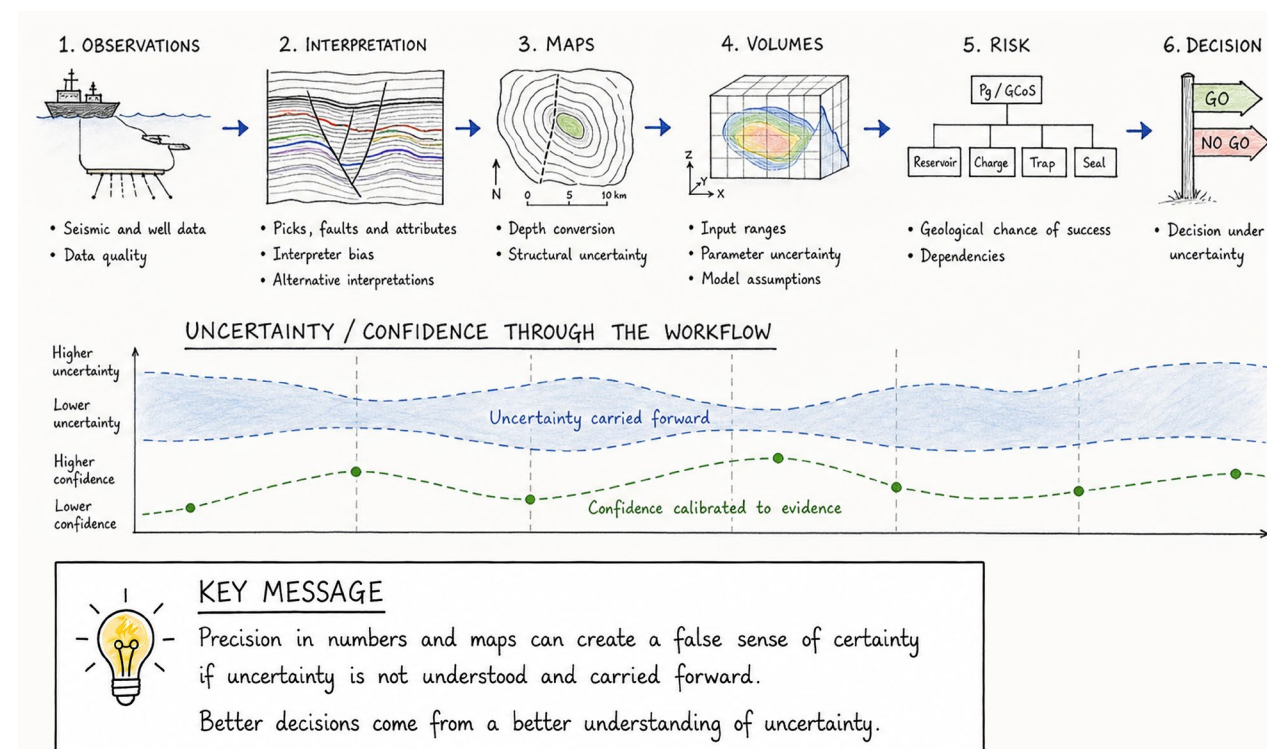


Figure 2: Keeping uncertainty visible through the workflow. Uncertainty should be recognised, characterised and, where possible, quantified and carried forward – all the way to the decision.

models or less quantitative analysis. Advances in seismic processing, modelling and computing allow us to constrain the subsurface more effectively and examine geological hypotheses in ways that were previously impossible.

At the same time, increasingly sophisticated models may become visually and numerically more convincing. A model can therefore become more detailed, more internally consistent and more visually persuasive – without necessarily becoming proportionally more geologically certain.

The risk is that computational sophistication may be mistaken for independent geological validation. This distinction becomes increasingly important as exploration workflows incorporate automation, machine learning and AI-assisted interpretation.

These tools may identify patterns that are difficult for an individual interpreter to recognise, but their outputs still need to be considered in the context of data quality, calibration, geological plausibility and credible alternative interpretations.

Technology is most valuable when it helps us test and challenge our geological understanding – not merely when it makes the preferred model more detailed.

PRECISION IS VALUABLE – PROVIDED WE KEEP ASKING WHAT IT MEANS

The solution is not to avoid quantitative methods, but to maintain a clear distinction between observations, interpretations, assumptions, uncertainty and confidence. A particularly useful question during any prospect review is: What evidence would make us change our interpretation? If the answer is unclear, we may be more attached to the model than the evidence warrants.

Bauer provides an example where a few metres of structural uncertainty mattered enormously for a low-relief accumulation. The Gulf of Mexico post-well studies demonstrate the value of understanding recurring failure modes and calibrating interpretation and risk against actual drilling results. Peder shows that getting one

element of the prognosis right does not necessarily validate the integrated prospect concept.

Different settings, but the same underlying lesson: Uncertainty should remain visible as observations become interpretations, interpretations become maps, maps become volumes, volumes become risks, and risks become decisions.

CONFIDENCE SHOULD FOLLOW EVIDENCE

Exploration will always involve uncertainty. Better seismic data, better models, better statistics, and better computing help us understand and reduce it. But they do not eliminate it. The danger begins when increasing numerical or visual precision is interpreted as increasing geological certainty. Perhaps the most important question therefore is not: How precise is our model? But rather: Is our confidence proportional to the evidence? In exploration, that distinction can be the difference between a sophisticated model and a robust decision. ■

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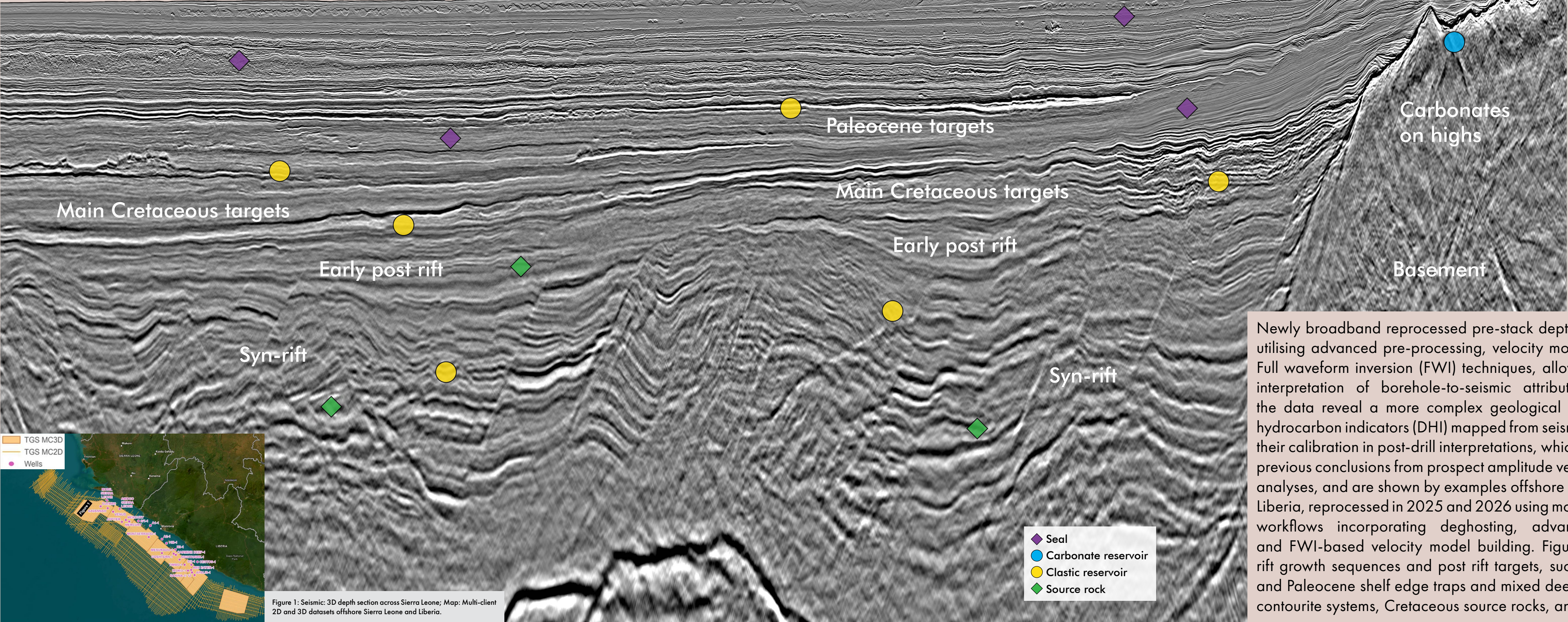


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What to do if reprocessed seismic changes the view on your prospect?



Newly broadband reprocessed pre-stack depth migrated data, utilising advanced pre-processing, velocity model building and Full waveform inversion (FWI) techniques, allow more accurate interpretation of borehole-to-seismic attribute ties. In turn, the data reveal a more complex geological context of direct hydrocarbon indicators (DHI) mapped from seismic attributes and their calibration in post-drill interpretations, which may contradict previous conclusions from prospect amplitude versus offset (AVO) analyses, and are shown by examples offshore Sierra Leone and Liberia, reprocessed in 2025 and 2026 using modern broadband workflows incorporating deghosting, advanced demultiple and FWI-based velocity model building. Figure 1 shows syn-rift growth sequences and post rift targets, such as Cretaceous and Paleocene shelf edge traps and mixed deepwater turbidite-contourite systems, Cretaceous source rocks, and regional seal.

New broadband reprocessing reveals geological complexities around post-drill well-to-seismic calibration

FELICIA WINTER, TGS

WHEN REPROCESSED seismic AVO analysis results change conclusions for mapped targets at borehole and undrilled locations, systematic AVO QC is essential to demonstrate that amplitude fidelity is preserved during reprocessing and improvements are achieved without compromising these attributes. Workflows that interrogate and showcase that the AVO fidelity is real and robust are especially important when multiple legacy surveys are combined, and provide a crucial quantitative indicator of how acquisition differences have been reconciled during reprocessing to provide a continuous volume fit for AVO analysis.

The Sierra Leone and Liberia case studies demonstrate how these improvements extend beyond individual well locations, supporting reliable regional screening with confidence in amplitude fidelity and, therefore, DHl mapping. Whilst specific QC metrics of spectral analysis, bandwidth evaluation and

amplitude decay studies can be performed, this article will focus on derivative control measures of AVO.

Pre-stack amplitudes across offset and angle, and the behaviour of the compressional and shear wave velocities (Vp/Vs), are visualised as impedance domain attributes such as relative extended elastic impedance (rEEI, using inversion) or reflectivity (rEER, using angle stacks) at a rotation angle of 27° (Went, 2021; Went and Hedley, 2023).

These are a function of the acoustic / elastic velocity relation and provide an effective bridge between well-scale rock physics understanding and regional-scale exploration scouting. Thus, by reducing sensitivity to wavelet effects and evaluating seismic responses in intercept-gradient domain, these attributes enable subtle reservoir and fluid effects to be mapped where conventional full stack amplitudes are insufficient.

Upon review of the reprocessing examples in Sierra Leone and

Liberia, we can see improvements on the rEER AVO attribute overlaid on final full stack migrated data, including amplitude continuity and seismic facies distinction (Figure 2A), lithofacies where calibrated with a borehole (Figure 3A). We can also validate the improvement in shallow gas accumulations, whose cross-plot response evolved from being ambiguous on legacy data to a consistent class IV on reprocessed partial angle attributes (Figure 2B). As shallow gas features are first-instance DHIs indicating fluids in the subsurface, understanding what we see and how the seismic attributes calibrate with these insights is a first step in mapping possible targets, charge and migration path scenarios on modern seismic 3D images.

BETTER ASSESSING THE DRIVERS BEHIND IMPEDANCE ANOMALIES

Residual ambiguity in amplitude behavior on modern processed

and QC'd data can often no longer be attributed primarily to processing artefacts and must instead be interpreted in terms of lithology, reservoir quality, diagenesis and pore space alteration. Figure 3 showcases the ongoing Liberia elastic FWI broadband reprocessing of several vintage 3D surveys. Post-drill assessment of the well to seismic ties the main target to brine sands, imaged on the ultra-far angle stack as Vp/Vs soft anomaly and interpreted as clean reservoir quality sands (Figure 3B), whereas on legacy amplitudes the well was interpreted as a hydrocarbon charge. This suggests that the low impedance anomalies downdip may be fluid related (Figure 3A). Modern 3D seismic with systematic AVO QC tied with well data rock physics for specific reservoirs allows interpreters to map anomalies more confidently. Such calibration also provides some indication of fluid-over-brine anomalies in basins that, during post-drill interpretation, have been revealed to contain both hard and soft sands, and a strong lithology anomaly in the impedance space (Went et al, 2024). Many such effects can be observed in the 3D images of the upper slope across the Sierra Leone and Liberia Basins. With structural image improvements and better continuity and clarity of seismic facies and attributes after reprocessing and AVO QC, as discussed in Figure 2, and re-interpretation of borehole rock physics,

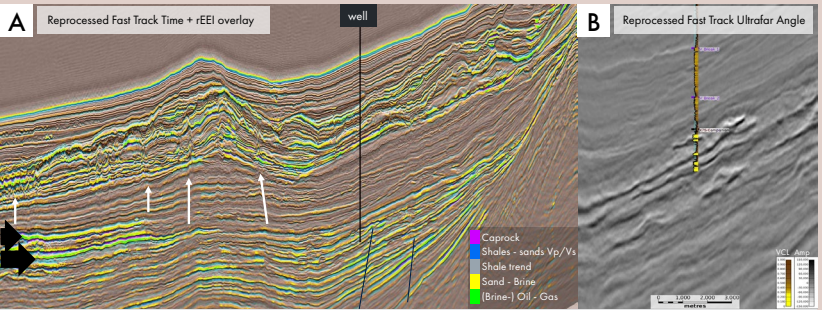


Figure 3: Offshore Liberia AVO calibration in and mapping from well. A) Bright gas caps directly above flanks of the slope channel indicate leakage due to buoyancy (e.g. white arrows). The updip well post-drill interpretation and AVO analysis shows that the AVO attribute is calibrated at the well location as a clean sand brine anomaly, as shown in B) as an ultrafar soft kick. Mapped anomalies downdip away from the well indicate an AVO anomaly more than the lithological anomaly and may well be fluid related (black arrows in A).

and updated well-to-seismic tie and Vp/Vs calibration, as discussed in Figure 3, Figure 4 shows initial results of analysis of known targets on the rejuvenated data set offshore Sierra Leone. The 3D composites display seismic full stack sections combined with wavelet similarity of the far offset stack (25 – 35 degrees) over mapped fairways. The Upper Cretaceous meandering channel (Figure 4A) highlights a maximum soft on the far stack, which is highlighted in green and likely indicates a fluid anomaly, in contrast with the surrounding complex highlighted in yellow being merely a lithology anomaly over the background shale trend. The slope channel fan complex (Figure 4B) also maps as a brine anomaly at this reservoir level over the top of a large slope-to-basin fan complex and indicates this layer is unlikely being charged. The deeper reservoirs of the

older and larger stacked fan complex (Figure 4C) seemingly map with a hydrocarbon anomaly over the crest of the stratigraphic trap of the splay.

WHY MORE DATA REQUIRES A MORE INTEGRATED APPROACH

While tools such as deghosting, advanced demultiple and FWI consistently improve pre-stack amplitude stability and bandwidth, enhanced data quality does not automatically lead to simpler or less ambiguous interpretation. Instead, improved imaging often reveals geological complexity that was previously unresolved in legacy datasets, shifting the primary source of uncertainty from data quality to subsurface geology and rock physics variability.

Legacy seismic data often mask geological complexity through limited bandwidth, unstable amplitudes and incomplete offset coverage, resulting in seemingly cleaner data but ultimately distracting from key risks associated with reservoir quality, diagenesis and pore space mineralisation, potentially leading to misinterpretations.

Modern broadband reprocessing removes many of these limitations, producing datasets that are demonstrably fit for purpose from a geophysical perspective but more sensitive to geological variability. Integrated and iterative interpretation workflows provide a structured and scalable approach to recognising this shift and to derisking exploration decisions.

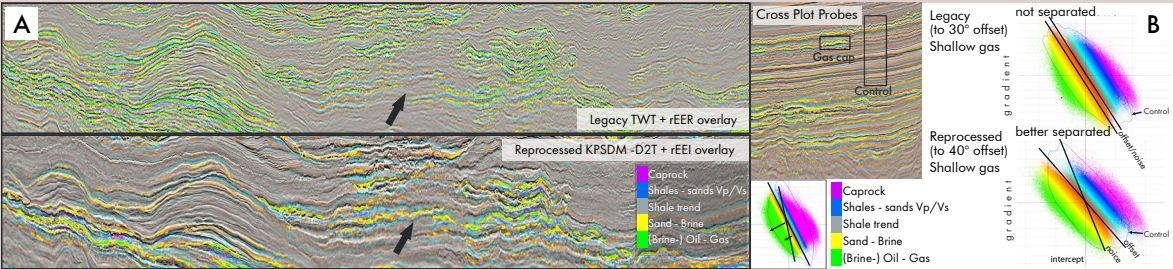


Figure 2: Offshore Sierra Leone, comparisons of legacy time stack versus 2025 reprocessed Kirchhoff depth migrated stack. A) rEER overlay on stack, the sections show improved consistency in seismic facies and attributes. The continuity of amplitudes, especially in offset at the target levels, removes false positives in the surrounding matrix. This amplitude recovery is due to a better signal to noise content in the reprocessed dataset and, also, due to better gather flatness that stacks the amplitudes over offset more accurately. B) A probe over a shallow gas pocket offshore Sierra Leone, as marked on the section with the rEER overlay, has been evaluated alongside a control probe over shale / clastics on the reprocessed data. The cross-plot of intercept versus gradient over both of these probes shows an anomaly on the reprocessed data. On the legacy dataset this shows an indiscernible class III-IV response, whereas on the reprocessed depth-to-time ultrafar angle stacks, clear class IV anomaly is visible.

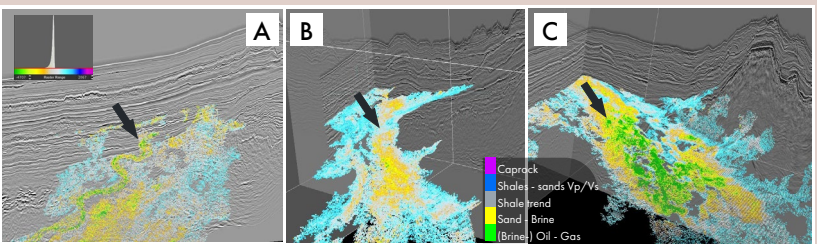
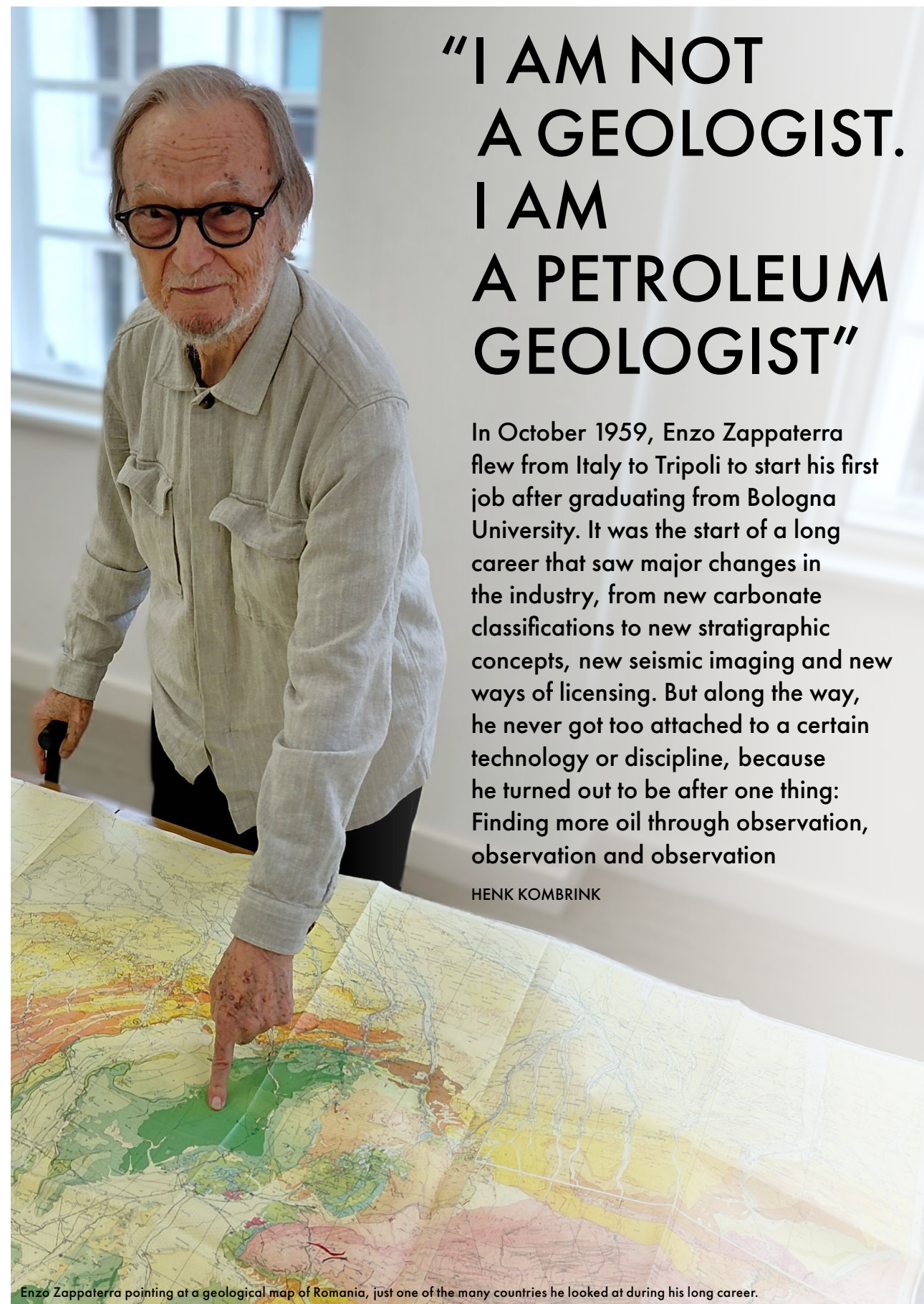


Figure 4: Sierra Leone. On the final far stack (25-35 degree offset) a wavelet similarity attribute picks out lateral facies changes over fairways and different AVO responses are colour coded by Vp/Vs anomaly, highlighting yellow for lithology or brine and green for transition from brine to likely hydrocarbons, each separating from the background shale trend in greyblue (equivalent displays to rEER and crossplots in Figure 2 and 3). A) The Late Cretaceous meandering channel highlighted in green is a maximum soft from the seismic attribute, indicating a likely fluid anomaly in contrast to the surrounding complex. B) the lower slope channel complex top reservoir is likely not charged, whereas the deeper reservoirs in the older splay seemingly map as hydrocarbon anomaly over the crest of this stratigraphic trap (C).

PORTRAITS

“Drilling wells could easily last for around five years, because the geologists were uncertain of their jobs once the results came in – especially when it was a dry well”

Enzo Zappaterra



“I AM NOT A GEOLOGIST. I AM A PETROLEUM GEOLOGIST”

In October 1959, Enzo Zappaterra flew from Italy to Tripoli to start his first job after graduating from Bologna University. It was the start of a long career that saw major changes in the industry, from new carbonate classifications to new stratigraphic concepts, new seismic imaging and new ways of licensing. But along the way, he never got too attached to a certain technology or discipline, because he turned out to be after one thing: Finding more oil through observation, observation and observation

HENK KOMBRINK

PHOTOGRAPHY: HENK KOMBRINK

Enzo Zappaterra pointing at a geological map of Romania, just one of the many countries he looked at during his long career.

When I walk round the corner of the street, only 50 m away from the Arar office in Central London where I am going to meet with Enzo Zappaterra, I already see him waiting at the front door. He is 91, uses a stick for walking, but his eyes are sharp as he recognises me and reaches out to give me a hand.

Most interviews I run are online, but for this one I decided to travel down. Not only because of Enzo’s incredibly long career – he is still working after spending 66 years in the business – but I was also told that he keeps a nice collection of maps and other pieces of geological art from all over the world. And that happened to be true. We spent the first part of our meeting looking at a wide variety of cross-sections, well correlation diagrams and composite well logs from Libya and Indonesia, drawn in a way you don’t see anymore. “We had drafting departments at our disposal,” Enzo says, smiling.

In this article, we will walk through Enzo’s long career. The focus will be on the earlier part of it, during which he worked for Chevron and its affiliates, mostly because it is now quickly becoming part of a history not many people will have a direct connection to anymore.

FOSSILS IN A STREAM AND RIGS IN A FIELD

“Do you really want to become a priest?” Enzo’s parents asked when he told them he wanted to go to university to study geology in Bologna. They had mistaken geology for theology. “Geology was very much unknown to them,” Enzo says.

His parents had a farm in the Po Valley, west of Ferrara. But even though his parents were not particularly into geology, Enzo had come across the science on a couple of unrelated occasions during the last phase of his lyceum years.

In summertime, as his parents were busy on the farm and he couldn’t afford going on holiday himself, Enzo used to go to summer camp with the Jesuits in the Dolomites. It was free, which helped. One of the members of the community took Enzo hunting for fossils. “Fossils?” he asked, “do you find those here?” “Sure,” the man said, as he showed Enzo the rounded pebbles in the stream before cracking them open using the geological hammer he brought with him. It triggered Enzo’s imagination. A totally different experience took place close to home, where drilling rigs had started to show up in the Po Valley, targeting gas in Pliocene fluvial sands. It equally intrigued Enzo, and he tried many times to talk to someone at the rigs, only to find that they were fenced off. Until he got lucky and found a geologist at one of them, whom he could briefly talk to.

These two unrelated experiences were enough to make up his mind, and Enzo entered university, together with ten other students, in 1954. Palaeontology turned out to be his favourite course. “It’s the only one I had a cum laude for,” he says. “I knew all of the fossils by name.”

By the time he graduated five years later, in 1959, 35 students had embarked on studying geology. “It was a sign of the

time,” he says. With the rise of oil production and exploration, the demand for geologists had risen, and more people were driven towards it. “Geology as a discipline even made it into the newspapers,” he says. “I think the student numbers rose even more in subsequent years.”

However, after graduating, the oil industry was not waiting at the front door just yet. Luckily, Enzo won a scholarship for six months, and he continued his palaeontology work. But staying in academia, as quite a few of his fellow students did, was not for him. He was already dreaming about going international.

Unfortunately, though, the two local Italian companies – AGIP and Ausonia Mineraria – were not interested in his services as a micropaleontologist, the specialism he had chosen during his studies. What else could he do, he thought, as he had moved back to his parents’ house in the Po Valley. Then he got an idea, as he read the journal *Micropaleontology*. There, he found a list of correspondents, some of whom worked in the oil industry, and he started writing letters. “I think I wrote about four or five letters,” Enzo says. It was in March-April 1959. Then he went on holiday and spent the summer on the beach in Italy. By September, when he was back at his parents’ place, his mum woke him up from an afternoon nap one day and said that there was someone on the phone for him.

The man at the other end of the line introduced himself as Doug Klemme, and he started speaking to Enzo in broken Italian. “I’m happy to speak German as well,” said Enzo, who didn’t master English yet. So, they continued in German. Klemme, who was American, served in the infantry during the Second World War, both in Italy and in the Alps, so it is probably during those years he picked up these languages. “Sorry, but what company are you working for?” asked Enzo, who had not caught this yet. “Amoseas,” said Klemme.

It was only after he spelled out the name fully that Enzo recognised he had indeed sent a letter to Amoseas: American Overseas Petroleum. They had a short conversation, during which Klemme told Enzo that he was particularly interested in his Miocene stratigraphic work. “They subsequently offered me a position in Tripoli, Libya, but wanted to meet me in person in Rome first, at the Caltex office, another Chevron affiliate,” Enzo says. So they met in Rome, and that was it; Enzo was offered a job. Within six months of graduating, he secured himself a position with the company he would be part of for 41 years. Just by using the back cover of a scientific journal.

LEARNING THE ROPES ON THE RIGS

When Enzo arrived in Tripoli, he was welcomed by the Amoseas personnel manager and the chief geologist. He was subsequently stationed at the Mehari hotel for a few days but was expected to find his own accommodation soon after. “I was on probation, so there was no safe expat cushion,” he says. Enzo found a room in the flat of a Sicilian family, which neighboured a local family who were by then fasting for Rama- ▶

dan. Enzo was totally unaware of this tradition, so he lay wide awake in the evenings as the family could finally start eating and celebrating. He spent these sleepless hours studying English instead.

At work, Enzo was also thrown in at the deep end. A desk was ready for him, with a microscope on it, and he started working straight away without any introduction. Cores and cuttings came in from several well sites across the country, and he was tasked with identifying the age of the rocks that had been drilled through. “We did everything ourselves,” he says, “from prepping the cores to preparing thin sections. It was amazing to be part of this team.” And even though he was in the lab, the work was still real-time, with drilling decisions based on the analyses he performed. He did well, building up a stratigraphic chart of the part of the Sirt Basin he worked in. After six months, he was offered a permanent job.

Then, he was soon asked to go to the rig sites to do more real-time paleontological analysis and identify which part of the stratigraphy they were in. “How great it was to see oil-soaked cores coming out of the hole, whilst building up a picture of the platform and basin setting of the classic Sirt Basin,” he says. “There is no better thing to experience for a 25-year old than seeing the real rocks with oil coming out of the well.”

It was in the Sirt Basin where Enzo really gained his carbonate stratigraphy experience. “What do you do when you see these rocks coming up at the shakers? You classify them first according to what you learned at university: Calcirudite calcilutite, calcarenite, oolite. Later on, he started following the Folk classification.” The problem was, though, when he took this to the chief geologist, he had no idea what Enzo was talking about. “I decided to ditch Folk, and used the newly published Dunham classification that looked at texture rather than composition instead. For reservoir geology, that was much better.”

There was time for some breaks too, for instance when Amoseas was drilling in the Cyrenaica Basin in the northeast of Libya. Particularly known for its Tertiary dolomites, it was not uncommon for wells to lose circulation for up to a whole month on end. So what do you do when that happens? “You



The Libyan desert in 1960 – a rocky one, no sand or sand dunes.

just take the Land Rover, and you go for a ride across the desert, whilst all sorts of junk is being thrown in the well in an attempt to stop the drilling mud from disappearing,” laughs Enzo.

INTRODUCING NEW STRATIGRAPHIC CONCEPTS

In 1965, after more than five years in Libya, Enzo was promoted to chief micropaleontologist in the Amoseas Port Harcourt office in Nigeria. “It was a different world,” he says, “from the carbonates in Libya to the siliciclastics of the Niger Delta.”

It was in Port Harcourt where Enzo learned some very practical lessons on well correlation. “The chief geologist was always of the inclination to correlate a sand with another one 2,000 km away,” he says with a smile. “And what if the sand is not there? No problem. He puts an unconformity or fault in between the wells.” Based on the micropaleontological analyses Enzo subsequently did on these wells, he could show that it was the shales correlating with the sands. There was no need to put in an unconformity or fault at all. “The chief geologist was obviously not too happy with me at that point,” Enzo laughs, because his (mis)interpretations also made it to the head office in New York. It was in Nigeria where Enzo learned how a litho- or chronostratigraphic correlation had quite some implications on the connection of the reservoirs.

Enzo did not get the chance to stay in Nigeria long. The Biafran Civil War broke out due to rivalries between ethnic groups in 1967, and he and his wife, whom he had met in Libya, were told from one day to the next to pack their bags – only their essentials – and get onto a plane. They were flown back to Italy, stayed with his parents for a while again, until he was called to London to work on Nigeria from there.

In 1968, Sumatra would become Enzo’s next posting, with Caltex, another Chevron affiliate. “My job title was regional geologist,” says Enzo with a certain degree of satisfaction. “Finally, they recognised that I needed to look around, that my mind was not focused on a postage stamp.”

That also translates to why I don’t work on computers,” he adds with passion. “I still print most of my documents, especially seismic lines and well logs, because I want to look

at them from different angles and perspectives. I feel confined when I’m staring at a screen for too long,” he says.

In Indonesia, Enzo learned how geologists often think too much in layer-cake zonations. “I was the first one who could show, based on paleontological work, how several formations that were previously interpreted as being vertically stacked in the basin to be each other’s lateral equivalents instead,” he explains. “I applied Walther’s Law of stratigraphy there, a concept that started to become more common in those years.”

This seemingly simple insight, as it may seem now, was something that the company took note of. Enzo was able to solve a practical geological problem elegantly. He had also cemented his reputation as an oil explorer, because when he and his fellow paleontologists were asked to write down their achievements in the affiliate so far, Enzo was the only one who mentioned the word oil in his report. Because, in his view, that is what it was all done for, at the end of the day. “For some others, the technical discipline was often much more of an end goal, rather than the oil. I just saw all these things as tools rather than academic exercises,” Enzo says.

That business-driven attitude is possibly the reason why Enzo was offered a job by both Caltex’ parent companies; Texaco and Chevron. But he didn’t need to think long about which one to accept: “The letter from Texaco said “Dear Sir”, and the one from Chevron “Dear Enzo”. The cultural difference between the two companies was expressed in just the letters’ opening words.

THE AMERICAS

The first stop for Enzo with Chevron was New Orleans, in late 1972, as a geophysicist. As always, he was thrown in at the deep end and started working on the federal lease sales in the Gulf of Mexico. “It was an exciting time to be a geophysicist,” recalls Enzo, “because in those years, the realisation came through of the value of DHI’s or bright spots. We had secret meetings about it in New Orleans and in Houston, because we thought that only a few companies were aware of this new technology and we had to prevent this from leaking out to our competitors.” It also meant working crazy hours, to a point where he and his team were told by the boss to take it a bit easier.

Following his lease sale experience in New Orleans, Enzo spent sixteen years in the San Francisco and San Ramon offices, California, with Chevron Overseas (1975-1991). During that time, he was involved with many international exploration programmes across the world.

Brazil was one of the countries Enzo got to work in, between 1977 and 1982, and given that this was much earlier than the pre-salt boom that the offshore experienced over the past 20 years, it is interesting to look at the dynamics at the time. And that dynamic was very much coloured by what had happened in Venezuela, where the oil industry went through a wave of nationalisation. “Management was very wary that this could also happen in Brazil,” Enzo says, “and were reluc-



Checking the Lower Cretaceous for source rocks in the Southern Recôncavo Basin, north of the town of Salvador, Brazil.

tant to go very big.” The main drilling targets were obviously shallower than the ones we see today. “There was no way we could see beneath the salt,” Enzo says, “the quality of seismic data just was not there.” Instead, the company focused on post-salt exploration and drilled a few wells. However, results were not great. “We found CO₂ and H₂S in a Santos basin well,” Enzo says, “and a discovery of around 15 MMbbl, which wasn’t commercial at the time.” In those days, a company like Chevron required a discovery the size of 100 MMbbl at least, especially because oil prices were not that high.

THE LONDON YEARS

In 1992, Enzo was transferred to the Europe team in the London office. Although the UK North Sea was the most important region for this team, it never became Enzo’s focus. Instead, he was more involved with exploration projects in the Mediterranean, whilst he also helped convince management to take a look at the Norwegian sector where the company hadn’t been very active.

Albania had also appeared on the exploration radar, possibly thanks to a relatively new way of licensing that became a trend in those years: the seismic option. Rather than committing to drill a well straight away, the well became contingent upon the results of a seismic survey. “That is rather common today,” Enzo says, “and nobody gets excited about it any more, but at the time it really turned our opportunities upside down.”

The seismic data in Albania looked good, revealing a well-developed four-way closure, and Enzo became quite involved with the project that resulted in the drilling of well A4-1x in 1993. It was one of the first offshore wells drilled in Albanian waters, in 720 m of water, which was considered very deep at the time. “I even went out to the rig, which was a semisub and much bigger than the ones I had been on offshore Nigeria in the 1960s,” says Enzo. ▶

“YOU GO, WE STAY”

In the early 1990s, Chevron announced the move of its headquarters from San Ramon in California to Houston. But it wasn’t the first time this happened. Enzo remembers a similar moment during the late 1980s, when he and his colleagues received the news of a corporate move to the Lone Star State, mostly for tax reasons. However, when he arrived home and told the news to his wife and two kids over dinner, they put away their cutlery and said convincingly: “You go, we stay.” In the end, Chevron did not move, probably because California realised what this meant in terms of lost tax revenue. 35 years later, taxes was likely not a critical part of the decision.

PHOTOGRAPHY: ENZO ZAPPATERRA PRIVATE ARCHIVE



Enzo (left) on the rig drilling the A4-1x well offshore Albania, 21 October 1993. On his right is Abdyl Xhaja, Mineral Energy Resources chief.

Even though the well discovered biogenic gas in the post-Messinian section and oil in a pre-Messinian reservoir, the combined size of the discovery at around 100 MMboe was not big enough for Chevron to develop. “Remember,” says Enzo, “it was deep water, and a different time from today. There was still not that much interest in gas either.” But convincing Albpetrol, the state oil company, that this was a non-commercial discovery was another matter. They wanted the development to go ahead.

“It is important to understand that the state oil company had a very different way of doing business,” says Enzo. He had found out about that during a visit to the country a couple of years earlier, when it was still in the grip of the communist party even though dictator Enver Hoxha had already left the scene. “When we arrived in Tirana by plane, we saw that the airport was surrounded by trenches,” he said, as he and his colleague were picked up by members of the secret service in a black limousine. “The roads were deserted; there was no one around. It was icy, and the hotel we stayed in only had a couple of hours of (warm) water a day. The sixty per cent liquor they offered us in the morning didn’t give much respite either.”

“Basically, the state oil company had one exploration model, and that was to drill to the carbonates, as that was where most of the oil was found,” says Enzo. In addition, drilling wells could easily last for around five years, because the geologists on these wells were uncertain of their jobs once the results came in – especially when it was a dry well.

“Against that culture, we had to explain to them that a barrel of oil extracted from this deepwater discovery would cost much more than buying a barrel of oil from Italy. It took us months to get that message across,” says Enzo. “They had no clue what an uneconomic discovery meant. In other words, you really have to put yourself in the situation of the country you’re in at the moment, and don’t expect the same rulebook you’re used to at home.”

During the oil price crash of 1998, the annus supra horribilis, according to Enzo, he came to the office only to find out that there was very little or no more work to do. “Everything came to a standstill,” he says, “there was nothing. We sat there and turned ourselves to streamlining processes in case things would get back to business again.” Then, Enzo’s upbringing on the farm came to the fore. “Planning was something so natural to me,” he explains, “because as a farmer, you have to always plan for the worst, as you never know what the weather will do next year. That’s why farmers are almost always conservative.”

In some ways, the company did plan for the longer term. It did not make the explorationists redundant, because there was the anticipation that things would turn around again. And it did. At the end of the day, Enzo survived the 1998 crash, but retired from Chevron two years later, in April 2000.

THE SECOND CAREER

It was not the end for Enzo. Not at all. In fact, he embarked on a second career, which continues to today. There is not much space left to describe it all, but he continued working as a petroleum geologist all these years. The Eastern Med formed a big part of that, looking at newly acquired seismic, all the while he also continued evaluating exploration opportunities across the world.

Another long-standing working relationship Enzo is still enjoying is with Fatih Alpay, a former drilling engineer from TPAO, who set up his own E&P company Arar in 2002. The company is now successfully producing oil from the Bag field in Turkey – from an area that was previously thought of having no prospectivity – and has growth plans that Enzo helps materialise through his decades-long experience.

Before we leave his London Arar office, where we have been talking for around four hours Enzo shows me a printout of a well log of a recently drilled well in Turkey. “Look at the logs,” he says, “it’s these kinds of things that keep me alive; isn’t it wonderful to look at these and ponder about how it all works down below?” he says, whilst he points to a fracture system identified on the logs, most likely filled with oil.

We walk to the bus stop on Piccadilly where we say goodbye. I am blown away by the sheer length of Enzo’s career and the stories he told me, the changes he witnessed in the industry over the years and the fact that he is still very much in the middle of it. A great story, a story that started by taking an interest in knowing more about fossils in a mountain stream and the rigs that dotted the Po Valley landscape. ■

PHOTOGRAPHY: ENZO ZAPPATERRA PRIVATE ARCHIVE

GEO THERMAL ENERGY

“Cooling induced by cold fluid reinjection explains the mechanical destabilisation of a section of the fault of a size likely to generate the seismicity observed”

Clément Baujard and Vincent Maurer – ES-Geothermie

Why the Rittershoffen geothermal plant came to a halt

Understanding induced seismicity after ten years of operation

CLÉMENT BAUJARD AND VINCENT MAURER, ES-GÉOTHERMIE

SINCE the onset of production at the ECOGI geothermal plant in Rittershoffen (France) in 2016, which is based on one injection well (GRT-1) and a production well (GRT-2), both reaching the same fault zone in granitic basement, an average of around one hundred induced events per month were recorded. Practically all of these were small, with magnitudes below 2. However, in December 2025, a sequence of significant induced events with magnitudes up to 2.6 (PGV 14.6 mm/s) was observed near the wells that led to its immediate shutdown.

All these events are considered induced by the activity of the plant due to the proximity of their locations to the injection well, their

depths and the temporal correlation with the operation.

The highest magnitude events were located about 500 m north of the GRT-1 well, at a depth corresponding to the reservoir, and are close to the fault structure in the granite. The compatibility of their focal mechanisms, both in terms of azimuth, dip and mechanism (normal fault), shows that these events are most likely linked to a reactivation of a portion of the fault zone, over a length of about 300 to 400 m.

The injection pressure at well GRT-1 in operational conditions was rather low, and no significant change in the operating conditions was reported prior to the seismological events, meaning steady-state pressure conditions. Moreover, the events are located between

the production and injection well, i.e. in a region where an even lower pressure is expected. Therefore, a purely hydraulic mechanism cannot directly explain this sequence.

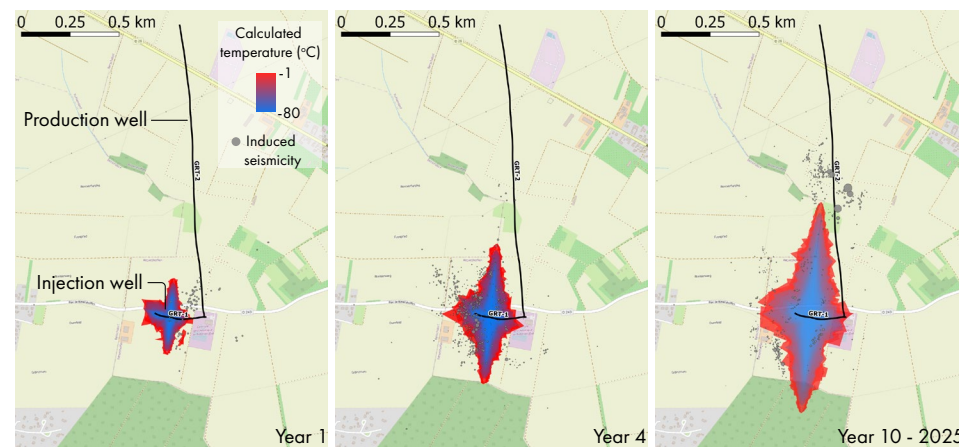
The evolution of the cooling profile around the injection well was calculated using a 3D hydrothermal model. The model incorporates a simplified but structurally realistic representation of the reservoir, including the main geological units and major faults identified from 3D seismic. It is calibrated against operational data and a tracer test carried out in 2021 – 2022.

The distribution of induced events suggests a direct relation between the evolution of the temperature profile and the reactivation of pre-existing structures, with a corre-

spondence of the location of the events with the cooled zone. Numerical simulations were then carried out to calculate the impact of the temperature change on the stress field and the consequence of this change on the fault stability, considering different fault geometries and stress fields.

It appears that the cooling induced by cold fluid reinjection explains the mechanical destabilisation of a section of the fault of a size likely to generate the seismicity observed in December 2025. Indeed, the thermal contraction of the rock due to cooling induces a reduction in stress that goes beyond the cooled volume and can affect large portions of nearly critically stressed segments of this structure, and whose intensity is locally much higher than the reinjection pressure.

Thus, this mechanism is a new parameter to be taken into account in seismologic risk management during geothermal project design and operation. In order to reduce this risk and to resume operation at the Rittershoffen site, different solutions are currently under review, with the aim of minimising the extension of the cooling profile along the fault by reinjecting at a greater distance from it. ■



Simulated cooled zone after 1, 4 and 10 years and relative locations of recorded induced events occurring during year 1, 4 and 10. The ten-year operating figure shows the December 2025 sequence.

The market challenges that force the shallow geothermal industry to continue innovating

If you want to stay in business in the shallow geothermal drilling industry, there is no other way than to embrace external cost pressure whilst trying to drive down installation costs

WITH A SUMMER like the one Europe had this year, one would think that the shallow geothermal market is experiencing a busy time. At the end of the day, the loops can not only be used for heating, but for cooling too. The reality is a bit different, as I learned from talking to some industry insiders.

Escalating material costs are a serious burden for many operators, with both fuel and the cost of plastics used for the U-tubes having risen sharply in the last few months. This is also what Signhild Gehlin told us about the Swedish market earlier this year (GEO EXPRO Vol. 23, Issue 3, 2026), when she attributed this to rising oil prices.

The high upfront investment that is required for a shallow borehole remains an issue too, especially when

people can equally choose an air source heat pump. One way this upfront cost of drilling a borehole can be softened is to share a well amongst several households and create a mini heating network. It is something that seems to happen more often these days.

Increasing competition is another factor that drives prices down. The fact that there are more drilling companies can of course also be seen as an indication that there is more demand for their services, but at the moment it looks like market demand is not sufficiently buoyant.

“Low prices per drilled meter remain the problem across many European countries”
– Industry insider

Is it therefore a surprise that some companies have decided to throw in the towel? Celsius Energy announcing cessation of operations in France is probably the most visible decision in this space. Knowing that they are a spin-off from SLB, a company that is used to generating profit in the oil and gas industry, they must have been unimpressed with the margins that are being generated in shallow geothermal. As one insider told me: “These guys came in with an oil and gas mentality, thinking they were going to revolutionise the shallow geothermal industry because ‘they knew better...’”. These two industries are completely different. The only similarity is tapping the ground for a resource.”

What remains is innovation in drilling to drive down installation costs further. The recent news from US company Dig is clearly aiming at that. They use a jet grouting technology to “drill” the hole, and only need to go one way because both the drill string and the nozzle stay behind in the borehole when the target depth has been reached. The borehole will then be used as a heat exchanger using a coaxial loop.

Someone with hands-on experience with this type of drilling told me that this approach makes sense, but that drilling into harder rocks and depths beyond 150 – 200 m may be a problem. The presence of fractures, gravel and thin aquifers may also pose a risk because it can lead to loss of water. However, a spokesperson from the company told me that they are capable of drilling into hard rock as well. ■

Henk Kombrink



A bit and drill strings at a shallow geothermal project in Aberdeen, Scotland.

PHOTOGRAPHY: HENK KOMBRINK

A unique look back at a successful geothermal project

Rarely is a geothermal reservoir engineer fortunate enough to check a 30-year forecast

ELLIOT YEARSLEY



THE SALTON Trough in Southern California's continental rift zone is one of the world's largest geothermal trends, hosting a series of geothermal fields. One of these is Heber, operated by Ormat. In 1991, while working for Ormat, I was asked to write a Development Plan for a Heber field extension under the name of the Second Imperial Geothermal Company (SIGC), which included drilling more injection and production wells. A crucial element of the Development Plan was to include a thorough analysis as to why a previous geothermal project referred to as the San Diego Gas & Electric (SDG&E) project, with wells drilled close to the existing Heber project (HGC), had failed.

To start with, it was necessary to collate all the available well test and production data, in order to build a model that enabled me to do a history match of pressure data. This exercise showed that the HGC project experienced accelerated pressure drawdown as a result of the SDG&E project coming online at that time, demonstrating

that the SDG&E wells were situated too close to the existing wells of the HGC project.

And not only the placement of the production wells needed rethinking, the planned location of the injection wells needed rethinking too. I decided to distribute the injection wells to shield the HGC wells from the pressure drawdown caused by SIGC and proposed a combination of peripheral injection on the edge of the reservoir (utilising existing injection wells) and in-field injection within the reservoir between the SIGC and HGC projects.

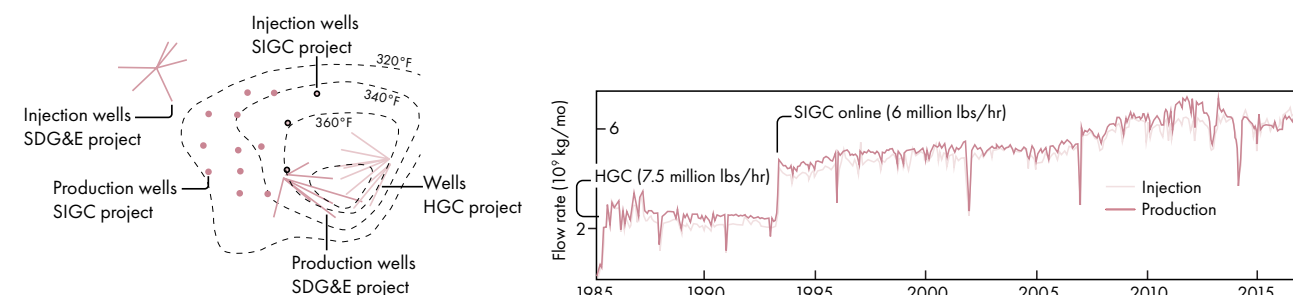
Shortly after completing the Development Plan, I left Ormat and started working elsewhere. In the meantime, the SIGC wells were drilled as planned, and started producing in 1993. Then, in 2024, I noticed a paper published on Heber in Nature. This presented a good opportunity to review the production history over nearly the entirety of the intended project life, from 1993 to 2020.

Total field production from that paper is shown here. This plot shows that the SIGC project had no ma-

terial impact on HGC production, which was the original goal. Total field production increased from 7.5 M lbs/hr for HGC alone to a combined 13.5 M lbs/hr, accommodating the incremental 6.0 M lbs/hr from SIGC. This production rate continued steadily to 2005, gradually increasing in later years to maintain high capacity factors. Reconstruction of performance at individual well level also indicated that production from both Heber projects was sustained.

The 10-K filed for 2025 by Ormat Technologies Inc. indicates that the capacity of the Heber geothermal field is 91 MW (gross) today, which suggests that the field still operates approximately within its original parameters, more than 30 years after SIGC was brought online.

For meaningful geothermal production forecasting, I would give the same advice now as I received 30 years ago. First, seek out and listen to experienced geothermal reservoir engineers and geologists, and second, use well testing and history matching as your basis. Some things don't change. ■



Production history of Heber geothermal project – HGC and SIGC. The well location map is based on a scan of the original development plan.

ILLUSTRATION: MODIFIED AFTER JIANG ET AL. (2024)

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Equatorial Guinea: Douala and Rio Muni risk reduction

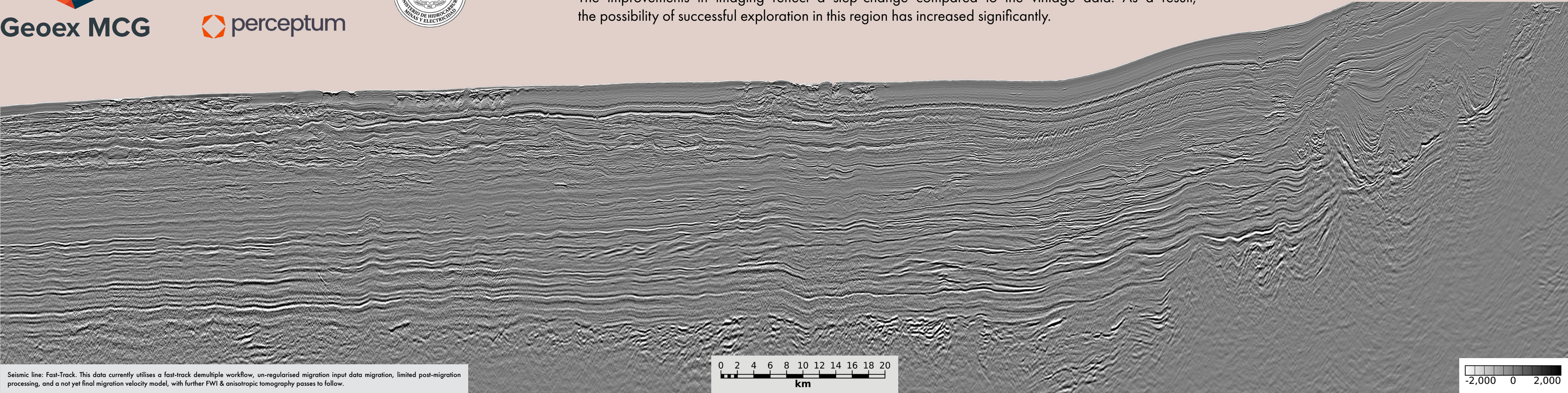
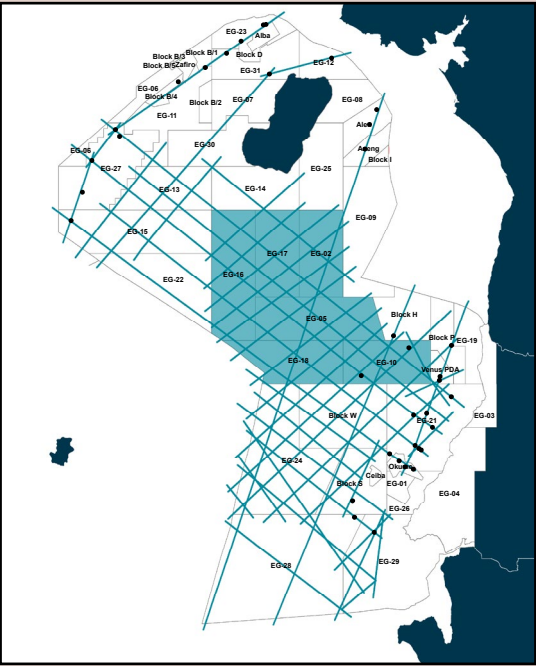
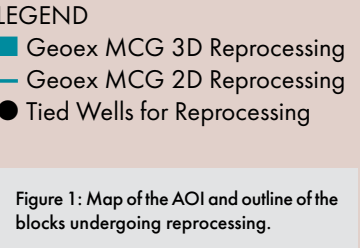


In frontier environments there is an added degree of risk with exploration. To mitigate the possibility of a dry well and make more informed exploration decisions, the best available data is required. Equatorial Guinea (EG) is a frontier with a twist. The central section of the offshore (Geox MCG’s AOI, (Figure 1) remains considerably underexplored. Two wells have been drilled in an area spanning >9,600 km².

However, the surrounding proximal locations have had a series of discoveries namely Zafiro, Asen / Aleng and Ceiba / Okume. Distally, in Sao Tome & Principe, the technical success of Falcao-1 and the oils found within the Ubabudo-1 well, suggest that the petroleum system elements in the AOI are present.

Geox MCG in association with the MHME (Ministerio de Hidrocarburos Minas y Electricidad) and partners Perceptum & DUG Technology (DUG) have embarked on the reprocessing of 6 x 3D volumes as well as a regional 2D dataset that ties over 30 wells to ensure the best possible imaging and velocity model is created for this frontier domain.

The improvements in imaging reflect a step-change compared to the vintage data. As a result, the possibility of successful exploration in this region has increased significantly.



Seismic line: Fast-Track. This data currently utilises a fast-track demultiple workflow, un-regularised migration input data migration, limited post-migration processing, and a not yet final migration velocity model, with further FWI & anisotropic tomography passes to follow.

DW-FWI and MP-FWI to deliver the margin’s most advanced datasets

MIKE POWNEY, GEOEX MCG, JULIAN SHERRIFF AND STEPHEN DOYLE, DUG TECHNOLOGY

FRONTIER MEETS OPPORTUNITY – HIGH OPERATOR INTEREST

Exploring in frontier domains is seldom offered the benefit of existing infrastructure, available seismic and 30+ wells to tie but due the success of the periphery of the offshore Equatorial Guinea, this is a reality.

Discoveries in Equatorial Guinea were first made in the 1990s with the successful drilling of the peripheral Niger Delta in the NW of offshore EG. This was followed thereafter by the discovery of the Ceiba and Akume field in the southeasterly domain. The Aseng and Alen fields were drilled in the 2010s in the NE.

Geoex MCG’s AOI in EG does not yet have any discoveries but was drilled by the Ballena-1 (L-1) & Banyan-1 (L-2) exploration wells. These efforts demonstrated hydrocarbon shows but did not encounter commercial discoveries, although exploration decisions were made on the 2010 legacy PSTM data.

Encouragement of a working petroleum system in the AOI is further provided by distal drilling in Sao Tome and Principe where hydrocarbon shows and reservoir sands have been encountered demonstrating a possible petroleum system beyond the AOI.

It is believed therefore that this area does demonstrate good prospectivity which has been reflected by a recent “license stampede” with Chevron, ENI, ConocoPhillips and Galp all accessing acreage in the area or in close proximity, highlighting the

current industry feeling towards the AOI.

COMPLEX GEOLOGY, EXCEPTIONAL DATA

Geologically, the offshore of EG is complex. Categorised as an oblique passive margin, the break-up and subsequent rifting began in the Neocomian (145-130 Ma) resulting in oceanic crust development in the Aptian (~120 Ma) period.

The margin is characterised by four main tectonic phases. These include a pre-rift (pre-early Cretaceous), syn-rift (Berriasian-Aptian), transitional / early post-rift phase between the Aptian-Turonian and finally, a passive margin phase extending from the Turonian to the Paleogene. The margin is then significantly influenced by the advent of the Cameroon Volcanic line which is a 700 km-long NNE-SSW trending linear belt of volcanic islands and seamounts.

These tectonic phases have led to a considerably favourable environment for hydrocarbon generation. During the Albian-Turonian, restrictive environments created excellent source rocks with a predominant deposition of oil-prone, marine shales coeval with many of the worlds famous “ACT” source rocks.

Other basins in the area, such as Rio Muni, have also indicated that source rocks are in the correct maturity window, aided by post-Senonian deposition. A further active source rock inferred in the Paleocene-Eocene is also postulated in the AOI as an additional interval of interest.

Numerous sedimentary input points have been identified and established as high-quality reservoirs throughout various geological timeframes. Examples of this are outlined by the following:

- Cretaceous sands in Ceiba, Okume / Oveng, Venus and Jupiter have been drilled and, in some instances, produced from.
- Paleogene Sands encountered within the Coco Marine well in the Douala Basin as well as the L-2 well within the study area.
- Lower Miocene sands in production from the Aseng and Alen discoveries
- Middle-Upper sands encountered in the Alba discovery, namely the Isongo Sands

The above sands are primarily interpreted as variably confined, upper to middle fan turbidites which require both the regional reprocessed 2D data to understand the regional entry point into the basins as well as the new 3D volumes to explore where these large sands may have subsequently been dispersed / deposited. As is clearly demonstrable, there are multiple source and reservoir pairs which provide a plethora of exploration opportunities offshore Equatorial Guinea.

From a trapping perspective, the NE-SW trending fracture zones demonstrated across the basin, have contributed to the routing, rerouting or cessation of large channel systems and are key crustal features that require improved imaging. The syn-kinematic reactivation of these large structures provided a critical control on the

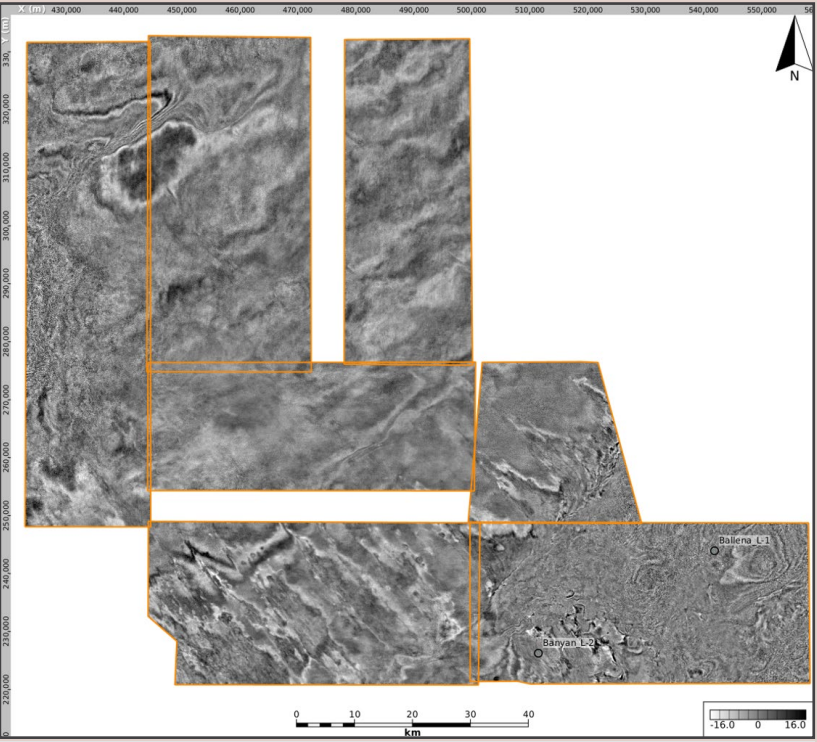


Figure 2: Time slices through the reprocessed data prior to survey matching – event continuity is clear on this fast-track output.

deposition of reservoir sands, formation of structural or combination traps and provides insight into the Late Cretaceous-Tertiary burial and the subsequent maturation history (Lawrence et al, 2016).

Due to these complexities, developing a key understanding of the relevant timings of deposition, heat flow and formation of petroleum systems requires data that provides the best imaging. Prior to the reprocessing of this data, only a PSTM volume was available. Now, with the combination of over 30 wells, Geoex MCG with our associated partners are able to provide the industry with the data required to unlock this prospective margin.

METICULOUS METHODOLOGY – SOLVING THE SUBSURFACE

To understand this complex interplay of the tectonic framework and depositional environments in more detail, a thorough reprocessing campaign of both 2D and 3D data is required. This has allowed for the transformation of legacy data to a modern DW- &

MP-FWI dataset in PSDM resulting in the identification and subsequent mapping of channel fan sands out onto oceanic crust.

The reprocessing is set to improve the continuity of the reflectors allowing for the mapping of clinoforms and distal sand channels and fans (see foldout). DW- & MP-FWI is implemented to ensure an accurate velocity model. This is further improved by the reprocessing of two regional 2D well tie surveys, acquired in 2005 and 2010. Offsets of these surveys are 8 km and 10 km respectively which represents the longest offsets in the margin. The orientation of these lines is well positioned to ensure maximum imaging of the key fracture zones that significantly impacted the sedimentary routing pathways.

While the examples shown clearly highlight a step-change in enhanced broadband, high-resolution structural imaging from the available legacy data, further improvements can be expected from the final products.

The data shown in this foldout utilises a fast-track demultiple work-

flow, un-regularised migration input data migration, limited post-migration processing, and a not yet final migration velocity model, with further FWI & anisotropic tomography passes to follow.

By imaging these topographic changes in the deeper section, lateral facies terminations can be discerned in a higher definition as well as providing an appreciation of the lateral continuation of key features. Despite the spatial continuation of the 3D surveys, the acquisition varies in orientation. To combat this, DUG’s reprocessing teams are ensuring that comprehensive survey matching is undertaken to reduce the acquisition impact producing a seamless blend. An example of timeslices through the data prior to survey matching can be seen in Figure 2, here demonstratable continuations across the blocks are observed.

THE MOST MODERN DATA IN THE MARGIN

By utilising both DW-FWI and MP-FWI (3D) to drive the velocity model, a state-of-the-art PreSDM product is available representing the most modern 3D reprocessing in the margin.

Geoex MCG and partners have complimented these data by reprocessing a regional 2D dataset which represents the longest offsets and the most thorough reprocessing flow of any present 2D data available.

Exploration in deeper (still <2,400 m) waters, offshore EG requires high-quality velocity models to accurately map and delineate key structures and petroleum system elements. This dataset provides the needed definition to undertake a task of this nature. We believe that this will ultimately provide the catalyst required to make discoveries in the central portion of offshore Equatorial Guinea.

SUBSURFACE STORAGE

“Reservoir and wellbore models need to be coupled because there is a high risk of pressure starting to oscillate in the modelling environment, which is not a reflection of the subsurface situation itself”

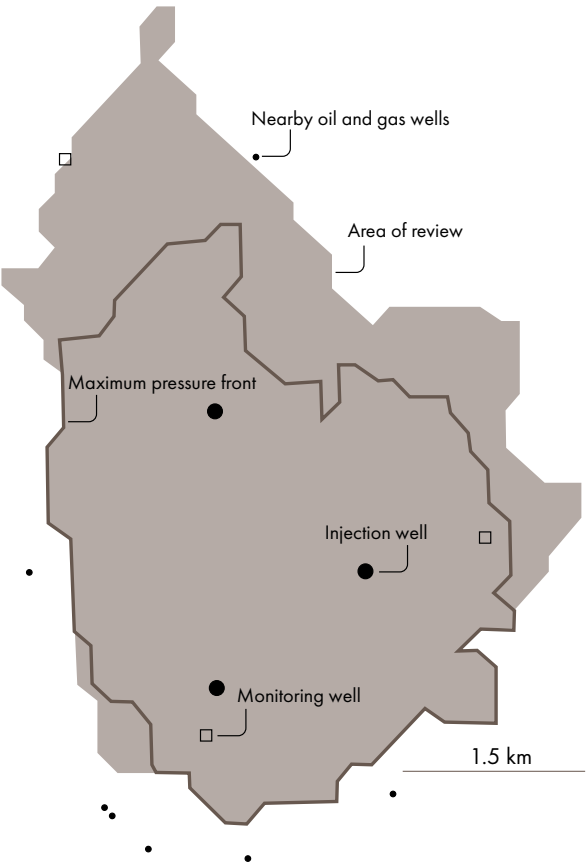
Denis Voskov – Technical University Delft

A rosy pressure picture

The public domain permit document on ExxonMobil's Rose onshore carbon storage project again shows that pressure data are key and partly confidential

EXXON MOBIL recently got the go-ahead to develop its Rose carbon storage project onshore Texas, which means that a network of 900 mi of pipeline will now be constructed to connect industrial emitters with a storage site that consists of three wells in an area west of Beaumont. The company already completed the wells in 2024, targeting two reservoir intervals: The Fleming and Upper Frio formations of Miocene age.

These reservoirs are classed as saline aquifers, which means that the critical element of injecting the CO₂ is pressure space. That's why it is interesting to take a look at the target formations for a better understanding of thickness and connectedness, because these factors will



The extent of the review area for ExxonMobil's Rose carbon storage project, showing how legacy oil and gas wells are situated very close to its boundary. The maximum pressure front lining up with the review area's boundary in the south leaves hardly any pressure wiggle room.

Henk Kombrink



determine if there is sufficient pressure space to store the 54 M t of CO₂ that is planned to be injected over the planned lifetime of 13 years. And of course, it will be equally interesting to see if any pressure data are provided in the public version of the permit document.

The document contains well schematics that also allow inspection of the thickness of the targeted sands. For example, in the case of well Labelle Properties No.1, the thickness of one of the Upper Frio sands is 700 ft (217 m) already. The N/G is not provided, but this thickness is definitely a reasonable one, also because a second Frio reservoir of even greater thickness is also present in the well. The younger Fleming sands that have been drilled are not planned to be perforated initially, but will be perforated later.

In other words, the thickness of the reservoirs seems positive. In terms of 3D architecture, given that these are shallow marine and deltaic sands, there is probably a high degree of connectedness too.

Now, let's take a look at what the lengthy permit document says about pressures. And guess what the case is? The critical pressure data have been made confidential. For instance, the column that lists what must be the initial reservoir pressure in the drilled reservoirs on page 640 has been blanked. In the same table, both the fracture pressure and the maximum allowable BHP are listed, but without knowing the starting point, it is not possible to know how much pressure space there actually is. There is a graph in the document that indicates, based on modelling, that the maximum pressure anomaly due to injection will be 200 psi.

A map in the permit document does provide some insight into how far the pressure front will migrate from the injection wells. And I must say that is not far at all, only a few kilometres from any of the injection wells. Of course, I have not performed a reservoir simulation, and we don't know the pressure space, but my gut feeling is that the reservoirs must be very high quality and very well connected to end up with such a limited pressure front as shown in the permit document. A pressure front that also nicely aligns with the area of review as well, with legacy oil and gas wells situated just on the periphery. This is going to be an interesting project to monitor.

SOURCE: RAILROAD COMMISSION CLASS VI PERMIT NUMBER: 57803

Better understanding of hydrate formation in carbon storage projects

And why this needs a coupled well-reservoir modelling approach

"WELLBORE and reservoir simulators have typically been separate things", says Denis Voskov from the Technical University in Delft, the Netherlands. "In most applications, you simply don't need to couple them, because there is a certain reservoir state that you can put as a boundary condition for the wellbore simulator."

But in the case of CO₂ injection into a depleted reservoir, there is a high risk of hydrate formation as a result of rapid cooling as the CO₂ enters a severely pressure-depleted reservoir. And in that situation, injectivity drops as a result of hydrate formation, affecting the immediate wellbore environment. "It is for that reason we need the coupling of the reservoir and the wellbore models," explains Denis. "The conditions in the wellbore and the near-wellbore region continuously influence each other. Changes in bottom-hole pressure and temperature affect the reservoir response, while changes in the near-wellbore region, such as hydrate formation and reduced injectivity,

A PARTICULAR SETTING

The pressure-depleted reservoirs in the North Sea, such as the Triassic Porthos reservoir as well as the Rotliegend Leman reservoirs, are fairly special because of the extent of depletion – sometimes just a few bars compared to an initial >200 bar pressure. This is mainly because these reservoirs are often compartmentalised by faults and have therefore not experienced significant pressure support from aquifers. If there is more aquifer support, pressures build up more easily, leading to a smaller risk of hydrate formation.

feed back into the wellbore conditions. A coupled model allows these interactions to be captured consistently."

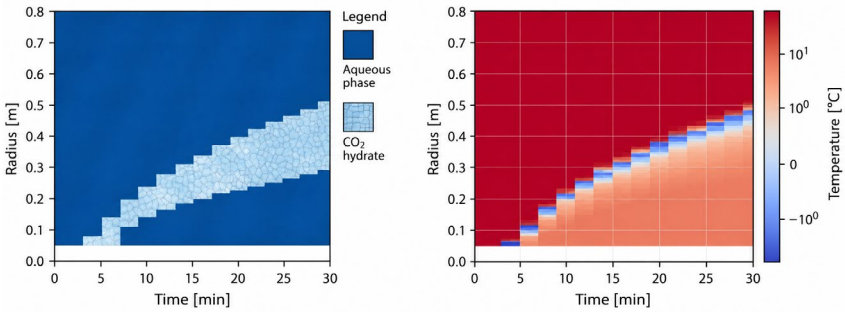
Denis and his team have been working on their coupled model, which is named DARTS-well, since 2024. Simulation results have shown that the formation of hydrates is a dynamic process. "As the initial hydrates form very close to the wellbore," Denis explains, "we see that, under certain well, reservoir, and operating conditions, some of these hydrates dissociate again because of temperature build-up. That's what you can see in the graph here, where the area of hydrate forma-

tion moves away from the wellbore as injection progresses."

"So are these modelling results shedding more light on the question whether these hydrates form an issue or not?" I ask. "We think that the dissociation of hydrates closer to the wellbore is probably too slow not to impact injectivity," Denis says. "It is for a reason why EBN's Porthos project, which is going to inject CO₂ into a depleted Triassic reservoir in the North Sea, is injecting the CO₂ in a gas phase initially to prevent the risk of hydrate buildup. Commercially, it is not what a developer wants, because the injection rate is much lower. The problem for the operator is that they have to guarantee continued injectivity."

Denis and his team recently presented their model at a conference in Portugal and have also published a paper about it. He stresses that the coupled model can also be used to simulate fluid behaviour of other fluid injection projects. "For instance, we use the same coupled well-reservoir formulation to model the deep geothermal project on the TU Delft campus, simulating brine degassing in the production wellbore to enable more accurate monitoring and interpretation of the process."

Henk Kombrink



The left graph shows how hydrate formation already starts after a few minutes of CO₂ injection due to the cooling (right). Initially, this takes place close to the wellbore, but as time progresses and injection continues, the hydrate front migrates further into the formation away from the wellbore following the temperature front, whilst some dissociation of hydrates near the well takes place at the same time. Our model shows that this process will affect injectivity, which is the very reason why the Porthos CO₂ storage project in the Netherlands will initially inject CO₂ in gaseous form.

Global gas storage projects on the rise

Both countries that already have a gas storage industry, as well as new ones, are working on and looking into expanding storage capacity

THERE IS a lot of discussion in Europe at the moment around low levels of its gas storage reserves as winter is approaching. Will there be enough? According to some analysts, it will be tricky. Where Europe gas storage has traditionally been used to provide additional gas for heating in the winter months, there are multiple reasons to invest in this form of energy storage, with gas as a swing producer at times of low renewable energy output being one example. Security of supply and increased data centre energy demand are other obvious ones. It may therefore not be too much of a surprise to see that globally, the number of countries that are investing in gas storage projects seems to be on the rise, as a contact with knowledge on the matter recently told me.

In the USA, the country with the largest gas storage capacity in the

world (138 Bcm), Oil and Gas Watch Magazine reported that companies are planning up to 16 new gas storage projects in salt caverns, all in Texas, Louisiana and Mississippi. Being a combination of new projects as well as the expansion of existing gas storage projects, the added storage space (10 Bcm) will increase the currently available storage space in caverns by 50 %. The drivers of this are multiple, with increased gas output from the Permian, more LNG terminal construction along the Gulf Coast, data centre demand and the energy transition – more flexible gas output – all mentioned.

Most gas in the USA, and in the world, is stored in depleted gas fields. But in contrast to what one might think, the state of Michigan has the highest storage capacity (20 Bcm), followed and probably soon overtaken by Texas (19 Bcm).

China is also very actively expanding its gas storage capacity, with Reuters reporting that it added 6 Bcm in 2025 alone. With a total capacity still lagging behind the USA significantly (around 30 Bcm compared to 140 Bcm), the policy to shift away from coal in favour of gas means that further growth is expected in China during the years to come, with one source writing that a working capacity between 80 and 100 Bcm is the aim in the years to come. And China wouldn't be China if it were not involved in projects abroad as well. An example is a large gas storage project in the Aksaray Province in Türkiye, where 40 new salt caverns are under construction to store up to 5.2 Bcm of gas.

But there are also some countries that are new to the subsurface gas storage game. For instance, Brazil is currently working on its first subsurface gas storage project to support the power grid during times when renewable output will be low. The depleted Pilar gas field will be converted to a store of 0.1 Bcm, potentially to be upgraded to 0.5 Bcm in due course. India is also planning on constructing its first strategic subsurface gas storage projects, with state-run ONGC taking the lead. Like in Brazil, depleted hydrocarbon reservoirs seem to be the main candidates for storage.

On reflection, there are multiple reasons for the expansion of subsurface gas storage capacity. But there is no doubt that the role of gas as a swing producer in a more renewable-dominated grid is one of them. A clear sign that the energy transition is slowly progressing. ■

Henk Kombrink

PHOTOGRAPHY: 63RU78 VIA ADOBE STOCK



Gas processing station.

SEABED MINERALS

“The Pisco Basin was shallow marine, not a deep-sea environment by any means – it’s exceptional to find cobalt-rich polymetallic nodules in this setting”

Ivana Cárcamo – Valencia

Invisible gold discovery in Japan

Pyrite is commonly called “fool’s gold” due to the mineral’s metallic luster and brass-yellow colour that resembles the precious metal. However, a discovery in Japan really had researchers fooled; pyrite in the Higashi-Aogashima knoll caldera contains the highest ever measured concentration of gold

THE TINY volcanic island of Aogashima, located 360 km south of Tokyo, consists of Quaternary extrusive rocks and experienced its last eruption in 1785. 12 km from its shores is a submarine caldera, aptly named Higashi-Aogashima, which literally means “east of Aoga island”. The oval-shaped caldera measures 7.5 km by 6.5 km and has three active hydrothermal fields with black smoker chimneys and sulphide mounds.

Japanese researchers have discovered gold-enriched pyrite in the active zones (Morishita et al., 2026). The concentrations are so high

that they report some results in weight per cent (wt.%) rather than the more commonly used parts per million (ppm). One sample yielded as much as 1.9 wt.% gold, or about 19,000 ppm, the highest concentration ever recorded in pyrite.

Although that is a decent amount of gold, it doesn’t mean it is visible, not even under the microscope. The gold isn’t present as nano-sized inclusions or particles; instead, the gold atoms are incorporated into the pyrite crystal structure.

How does this invisible gold end up in pyrite? Pyrite forms from hydrothermal fluids at various stages of the black smoker’s life cycle. In this case, the pyrite deposits

with the highest gold concentrations have a colloform texture. This rounded mineral texture is indicative of rapid precipitation, which is the result of the large temperature difference between the upwelling hydrothermal fluids and the surrounding seawater. The hydrothermal fluid is quenched as it exits the vent, and this results in quick crystallisation of pyrite on the outer wall of the chimney. The upwelling fluid is enriched in gold and other trace metals, and the quick nucleation of pyrite gives the opportunity for abundant impurities, such as arsenic, lead and copper, to be incorporated into the FeS₂ crystal lattice. The researchers found a general positive

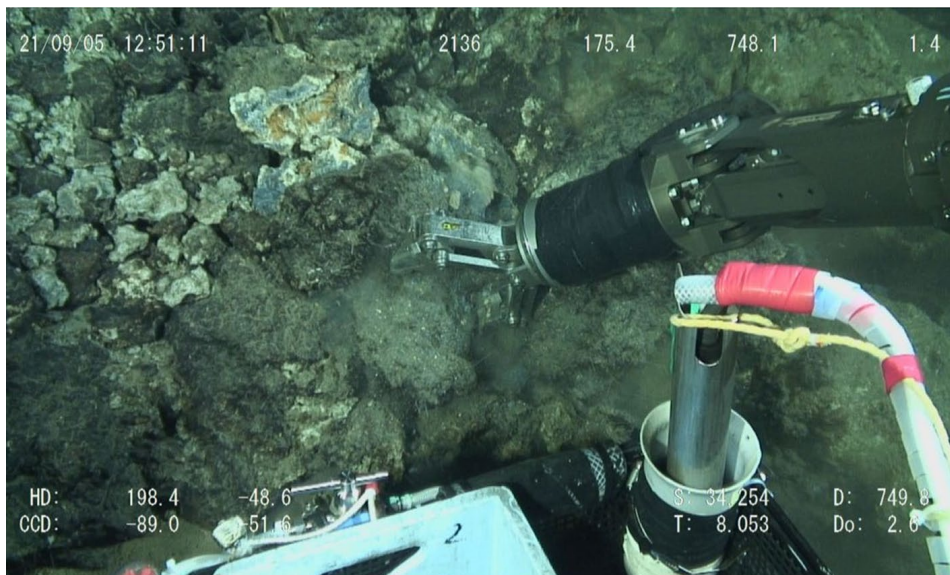
correlation between the total amount of lead, copper and arsenic in colloform pyrite, and the gold concentration. The replacement of iron and sulphur distorts the pyrite crystal lattice and creates space for gold atoms to be incorporated too.

Even though pyrite is the most abundant sulphide mineral in submarine hydrothermal vent systems, in terms of economic potential, the key metric is the grade of the deposit as a whole rather than the concentration within individual minerals. Still, the findings are noteworthy; the bulk-rock gold grades in Higashi-Aogashima range up to 275 ppm, with an average of 102 ppm, far exceeding the 0.01 – 43 ppm range typically reported from seafloor massive sulphide deposits worldwide.

Another factor relevant to potential future development is the depth of the deposits. The hydrothermal field lies in water depths of about 700 to 820 m, relatively shallow compared to many other seafloor sulphide deposits. However, as of yet, there is no talk of commercially exploiting this invisible gold deposit, and Higashi-Aogashima knoll caldera remains of scientific interest only. ■

Ronny Setså

SOURCE: MORISHITA ET AL., 2026



ROV sampling of the Higashi-Aogashima knoll caldera.

Polymetallic nodule discovery onshore Peru

Studying deep-sea mineral deposits is not an easy task. They’re often found kilometres below the ocean’s surface, making in-depth investigation of the full geological context difficult. That raises the question: Are there any terrestrial analogues that can be studied without the need for a submarine or oxygen tank?

IT’S AUGUST 2022, and undergraduate students from the Pontifical Catholic University of Peru are on a structural geology field course in the Pisco Basin, 200 km south of Lima. Although they are there to look at faults, they keep noticing centimetre-scale, black, rounded rocks protruding from the outcrops and can’t help but wonder what they are.

They take samples, and back at university they land on the desk of Professor Lisard Torró, who identifies them as manganese oxide nodules. Lisard explains he immediately knew this was an extraordinary find: “This is a hot topic; these nodules can be related to other critical elements too, such as cobalt, nickel and lithium.” A quick analysis indeed confirmed their high manganese and cobalt content, meaning they are similar in composition to polymetallic nodules found on the abyssal plain of the Clarion-Clipperton Zone in the Pacific Ocean.

“This discovery deserved further investigation, so I asked Ivana Cárcamo-Valencia, one of the students who found the nodules, to study them for her thesis project,” tells Lisard. Ivana went back to the Pisco Basin several times to map the stratigraphy and its relationship with the nodules. She also discovered veins, concretions and even remnants of bioturbation filled with manganese mineralisation. There are chimney-like structures in the shallow marine sediments that, together with the veins, served as fluid pathways. They discharged in permeable zones, allowing larger volumes of oxides to precipitate.

SOURCE: CÁRCAMO-VALENCIA ET AL., 2025



Freshly cut manganese oxide nodule embedded in sandstone.

All observations clearly confirm that the mineralisation is post-sedimentary.

After classing the nodules as diagenetic, the next question is the timing of mineralisation. Did this take place while the basin was still submerged or during uplift and dewatering? Given the age of the host sediments, the manganese oxides must have precipitated during the Pliocene or later while the Pisco Basin was rapidly uplifted during the late Pliocene, triggered by the subduction of the thick Nazca Ridge beneath the South American Plate. For that reason, the timings to distinguish between pre- and syn-uplift mineralisation are tight. Planned age dating will eventually determine the precise moment of precipitation, but Ivana adds:

“Keep in mind that the basin was only shallow marine at the most, 100 m or less water depth, not a deep-sea environment by any means, so either way it’s exceptional to find cobalt-rich polymetallic nodules in this setting.”

It is remarkable that these nodules have been preserved. Under normal conditions, they would quickly corrode and disintegrate when exposed. However, the extremely dry coastal desert environment has been their saving grace. All in all, the polymetallic nodules from the Pisco Basin are not a direct analogue for their deep-sea cousins, as the latter grow directly on the sea floor, but they do seem an easier alternative to explore and potentially mine. ■

Mariël Reitsma

Seamount summit crusts

A German-led research expedition to the Louisville Ridge in the southwest Pacific highlights significant cobalt and rare earth potential in seamount summit crusts, though seafloor conditions may be challenging for future extraction efforts

S EAMOUNTS are abundant in the world's oceans, numbering in the tens of thousands, with some estimates exceeding 100,000. These submarine mountains, mostly extinct volcanoes, rise at least a kilometer above the seafloor but don't break the water surface. From a resource perspective, they attract attention because many are coated in ferromanganese crusts enriched in critical metals such as cobalt, nickel, and rare earth elements.

The iron-manganese oxide crusts host diverse benthic faunal communities. The aim of the research cruise SO 313 was to investigate the occurrence and economic potential of ferromanganese crusts, alongside benthic species distribution and localised hydrographic features.

In June 2025, an international team of geologists, geochemists, biologists and physical oceanographers set sail to the northern section of the Louisville Ridge in the Pacific Ocean. The ridge is a chain of more than 70 seamounts which formed as the Pacific Plate moved over the Louisville hotspot. The study area encompassed six seamounts, located northeast of New Zealand. Bathymetry mapping using a multibeam echosounder showed that the mounts are guyots, decapitated seamounts with a relatively flat top. The summit plateaus formed when the volcanoes were exposed above water. As the Pacific Plate drifted away from the hotspot, the lithosphere cooled and contracted, causing the seamounts to subside to well below sea level.

Thomas Kuhn, chief scientist of the expedition and employed at the BGR, presented the preliminary results at the Seabed Minerals 2026 conference in Norway. "The topography is rough," Thomas noted, referring specifically to the seamount slopes, which are prone to erosion, slumping and mass wasting. "These steep gullies, ridges and exposed volcanic rocks limit the formation of continuous, thick crusts on the slopes. In contrast, the summit areas offer relatively stable and flat conditions, more favourable to long-term crust growth."

A key control on crust prospectivity is sediment cover, which is strongly influenced by factors such as the size of the summit plateau and local current regimes. On the investigated seamounts, sediment coverage ranged from nearly nothing on the small Burton seamount to about 60 % surface coverage on the much larger Seamount 420. However, on the summits of both guyots, the expedition was able to sample up to 5 cm thick layered crusts growing on volcanic substrate. In places, large numbers of sessile animals, such as corals and sponges, were attached to the crusts.

Kuhn states that the Louisville Ridge appears more prospective than many other seamount regions in terms of cobalt, rare earth elements and yttrium content. However, for the seamounts to be attractive targets for future exploration and exploitation, both the technical difficulties of mining irregular terrain in at least a kilometer-deep water, and the broader environmental impact, need to be addressed.

Ronny Setså

PHOTOGRAPHY: SIMONE STURM



Ferromanganese crust on (reworked) volcanic ash layers.



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Beyond AI: Why the future of geoscience software is trusted subsurface intelligence

Geoscience software is changing again, but the shift is larger than cloud migration or the addition of artificial intelligence to established interpretation tools. Operators increasingly face a challenge beyond generating more interpretations or AI predictions: How to transform heterogeneous data, models and knowledge into trusted subsurface intelligence that can be reviewed, reused and applied with confidence.

The next generation of G&G software will combine scientific applications, open data foundations, AI-assisted analysis and human expertise within governed decision workflows. EarthNET provides a practical example of how exploration, reservoir characterisation, unconventional and CCS teams can connect data, interpretations and decisions in transparent, evidence-based workflows. The future is not autonomous geology. It is trusted subsurface intelligence with provenance, uncertainty and expert accountability built into the workflow

EIRIK LARSEN, EARTH SCIENCE ANALYTICS



START WITH THE GEOSCIENTIST, NOT THE SOFTWARE STACK

A modern geoscientist rarely works in one clean software environment. A regional screening task may require seismic volumes, well logs, core data, well reports, pressure information, stratigraphic charts, public-domain material, basin studies, analogue fields, interpretation projects, spreadsheets and a growing set of AI-assisted outputs. In unconventional settings, the same task may also require consistent

curve families across hundreds or thousands of wells, completion and production data, and rapid comparison of changing interpretations.

The problem is not a shortage of applications. The challenge is that evidence, assumptions and decisions are distributed across too many places.

The geoscientist therefore has to ask practical questions: Which data can I trust? Which interpretation is current? Which model generated this prediction? Which assumption is critical? What

uncertainty matters for the decision? Has the output been reviewed before it is used in an investment discussion? These are not simply data-management questions. They are technical questions because they determine whether a result is fit for a subsurface decision.

This is why the software conversation is moving beyond AI. AI can accelerate interpretation, prediction, conditioning, retrieval and reporting, but acceleration creates value only when outputs can be understood,

challenged, reused and governed. In consequential workflows, human review is not a slow exception to automation. It is part of technical validity.

EarthNET illustrates the emerging response to this challenge. Rather than asking geoscientists to abandon established tools, EarthNET is positioned to connect governed data, geological context, domain AI and expert review so that teams can move from fragmented information to harmonised evidence, trusted intelligence and better decisions.

FROM INTERPRETATION WORKSTATIONS TO INTELLIGENCE SYSTEMS

The history of G&G software can be viewed as an additive evolution. Specialist workstations embedded expert workflows in digital tools. Integrated platforms connected seismic interpretation, wells, mapping, geomodelling and reservoir studies within shared projects.

Cloud and open data foundations expanded enterprise access, scale and interoperability, while AI-enabled workflows now accelerate classification, prediction, quality control and

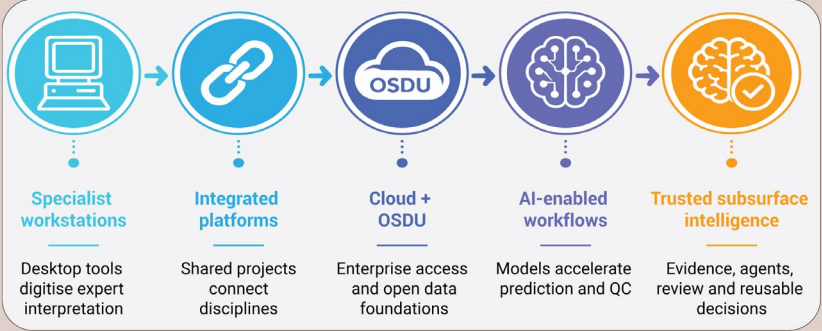


Figure 1: Specialist workstations, integrated platforms, cloud and open data foundations, AI-enabled workflows and trusted subsurface intelligence coexist rather than replace one another cleanly.

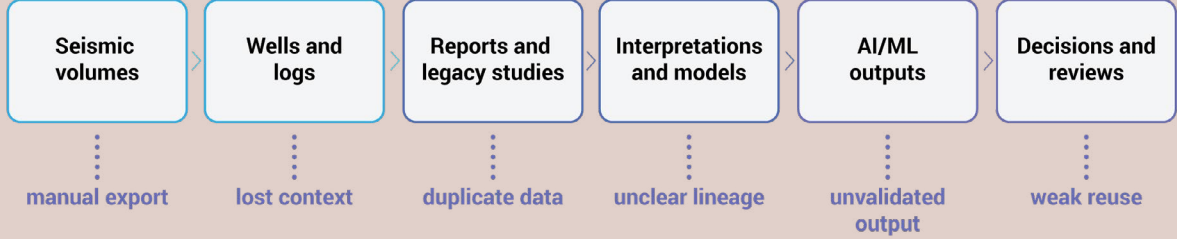
interpretation. The emerging next generation seeks to connect these capabilities into trusted subsurface intelligence systems.

This evolution is important because most operators work in multi-vendor environments where scientific applications, enterprise data services, specialist tools, in-house methods and historical project archives all continue to create value. These technologies are not being replaced. Their scientific maturity, user familiarity and extensive project histories remain important strengths. The challenge is that modern decisions increasingly span their boundaries. A workflow may depend on enter-

prise data, interpretation software, AI-assisted analysis, historical reports and review by multiple specialists. The strategic question is therefore not which single platform wins, but how data, science, models, evidence and decisions remain connected across the workflow (Figure 1). The purpose of the next generation is to preserve scientific depth while reducing friction between data access, interpretation, AI assistance, technical review and decision making. Trusted subsurface intelligence emerges when governed data, domain science, AI and expert judgement operate together in traceable, reusable and defensible workflows.



Figure 2: Eight converging technology trends are reshaping geoscience software, driving the transition from isolated applications toward trusted subsurface intelligence systems.



Today the geoscientist often becomes the integration layer

Figure 3: Fragmented subsurface data, knowledge and evidence must be harmonised into a shared geological and operational context, enabling domain science, AI and expert review to transform information into trusted subsurface intelligence for decision-making.

WHAT IS DRIVING THE NEXT GENERATION?

Several technology trends are converging. Their importance lies less in the individual buzzwords than in how they combine around workflow adoption, trust and decision quality. Figure 2 highlights eight of the most important forces driving this transition.

FROM HARMONISED DATA TO TRUSTED INTELLIGENCE

The phrase ‘AI-enabled geoscience’ can hide a critical distinction. A prediction, classification or generated summary is an output. Subsurface intelligence is an output that has retained enough evidence, geological context, uncertainty and review history to be used responsibly in a decision. The pathway is therefore not simply data to AI. It is fragmented data to harmonised context, harmonised context to trusted intelligence, and trusted intelligence to better decisions.

Harmonisation is more than moving files into one location. Data must be aligned sufficiently for the intended workflow: wells and curves need consistent identities and units; seismic and interpretations need usable spatial and version context; documents and prior decisions need discoverable relationships; and AI outputs need links to their source data, model versions, assumptions and limits. Trusted intelligence depends on end-to-end

traceability from evidence to decision. Fitness for purpose remains a technical judgement.

EarthNET is positioned at this intersection. Its role is not to replace established interpretation applications or enterprise data foundations. It is to help connect governed data, domain applications, AI-assisted outputs and expert review within a traceable workflow. In that model, value does not come simply from generating more answers. It comes from preserving the context that allows answers to be challenged, improved and reused. Figure 3 summarises how fragmented subsurface information can be transformed into trusted subsurface intelligence through harmonisation, AI and expert review.

HOW TRUSTED SUBSURFACE INTELLIGENCE CREATES VALUE

The value of trusted subsurface intelligence is not limited to a single workflow or technology domain.

Across exploration, reservoir development, unconventional resources and emerging CCS applications, geoscientists increasingly need to integrate diverse datasets, interpretations, models and prior knowledge while maintaining context, traceability and technical oversight. When fragmented information is harmonised into a shared geological and operational context, domain science, AI-assisted analysis and expert

review can work together to reduce uncertainty, improve efficiency and support more defensible subsurface decisions. The following examples illustrate how these principles can create value across different subsurface workflows.

EXPLORATION: FASTER SCREENING WITHOUT LOSING JUDGEMENT

Consider a frontier or near-field exploration team reviewing a large acreage position. Screening requires regional studies, well results, seismic coverage, structural elements, play concepts, source-rock information, analogue fields and previous internal interpretations. AI can help retrieve, summarise and correlate this material, but the workflow becomes trusted only when the geoscientist can inspect the sources, understand confidence and record why a lead was accepted, rejected or deferred.

A connected workflow can reduce time spent searching and reconciling evidence while preserving the geological reasoning behind opportunity ranking. The asset-value connection is direct: More opportunities can be screened, critical uncertainties can be exposed earlier, and future teams can understand why a prospect was matured, parked or dropped. The result is not simply a faster presentation. It is a more durable exploration memory.

DEVELOPMENT: RESERVOIR CHARACTERISATION IN A CONNECTED WORKFLOW

In development settings, value often depends on connecting well control, seismic attributes, rock physics, inversion results, static models, production evidence and uncertainty. AI-assisted property prediction or seismic interpretation can be useful, but results must be checked against wells, geological plausibility and known limitations. A model that performs adequately across a broad dataset may still be unreliable in a particular facies, acquisition vintage or structural setting.

Trusted subsurface intelligence therefore requires bidirectional quality control: Testing the model at known control points and challenging predictions away from control. It also requires the capture of human review. If an interpreter modifies a predicted horizon or rejects an AI fault segment, the correction is valuable technical learning. Subject to permissions and governance, that learning should remain available to improve subsequent work rather than disappear inside a local project.

UNCONVENTIONAL RESOURCES: CONSISTENCY AT SCALE, JUDGEMENT AT THE DECISION POINT

Unconventional resource workflows amplify the harmonisation challenge.

Teams may need to compare large well populations assembled from multiple vintages and sources, with inconsistent curve names, units, sampling, quality and completeness. Geological interpretations must then be connected with seismic properties, petrophysical indicators, completion information and production response. Scaling the workflow depends on consistency, but commercial decisions still depend on geological and engineering judgement.

AI can assist with log conditioning, missing-curve prediction, interval characterisation, seismic property prediction and opportunity ranking. These outputs become trusted only when users can trace the underlying data, inspect quality-control results, understand applicability and review uncertainty. A connected intelligence layer can help teams compare like with like, preserve the reasons behind ranking decisions and carry learning from one area or campaign into the next.

CCS AND NEW ENERGY: UNCERTAINTY MATTERS MORE WHEN DATA ARE SPARSE

The same principles apply in CCS and other emerging subsurface workflows. Storage screening often depends on sparse well control, legacy seismic, regional interpretations, seal assessment, containment risk, pressure behaviour and analogue reasoning. AI can help locate evidence and generate candidate interpretations, but confidence must be bounded. A technically attractive

storage concept is not decision-ready until its evidence, uncertainty and assumptions are visible.

In low-data settings, the most valuable output may be a clear account of what is not yet known: Missing logs, weak seal evidence, unresolved fault behaviour, outdated velocity models or untested assumptions. Decision-makers need a transparent view of confidence and data gaps, not only a polished AI-assisted answer. Figure 4 illustrates how these capabilities combine to create value across subsurface workflows.

TRUSTED SUBSURFACE INTELLIGENCE AS A VALUE STACK

The value stack starts with governed data, but it cannot stop there. Harmonisation makes evidence usable across workflows. Domain science provides geological meaning. AI and retrieval add speed and reach. Human judgement provides accountable review. Asset value emerges when these layers operate together with provenance, uncertainty and reusable learning.

Faster technical cycles: Less time is spent searching, conditioning and reconnecting fragmented evidence.

Better use of available evidence: Legacy reports, wells, seismic, interpretations and expert reviews become more findable and reusable.

Reduced rework: Assumptions, model outputs, decisions and corrections remain connected across project handoffs.

More defensible decisions: Reviewers can inspect sources, uncertainty, model context and approval history.

Scalable expertise: Specialist judgement becomes more traceable and reusable across teams, assets and time.

WHAT THIS MEANS FOR OPERATORS, VENDORS AND GEOSCIENTISTS

For operators, the challenge is to avoid rebuilding a monolithic silo in a new cloud form. A flexible architecture creates value only when responsibilities are clear: Authoritative sources, data stewardship, model ownership, approval gates, evaluation data and review workflows all require operating discipline. Interoperability is a means, not the end. The end is better, faster and more defensible decisions.

For software providers, the opportunity is to preserve mature domain science while opening workflows to enterprise data services, cloud execution, AI and better evidence handling. Specialist providers can contribute focused technical capability, but their output must remain connected to the broader decision workflow. The competitive distinction increasingly lies in workflow trust rather than isolated feature lists.

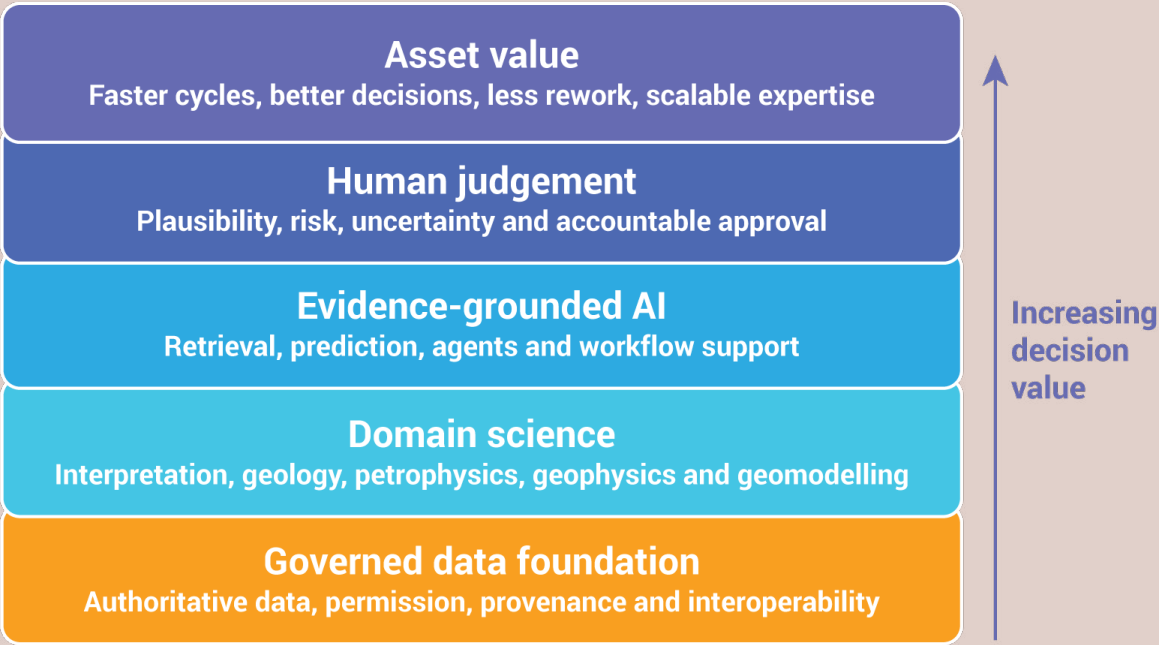


Figure 4: Governed data, harmonised context, domain science, evidence-grounded AI and accountable human judgement work together to create asset value.

For geoscientists, the opportunity is professional leverage: Less time moving and reconciling information, and more time testing interpretations, framing uncertainty and challenging models. This does not diminish expertise. It increases the value of expertise by making technical judgement more visible, reusable and influential at the decision point.

WHERE EARTHNET FITS IN THIS EVOLUTION

EarthNET is positioned in the subsurface intelligence and workflow layer. It complements established interpretation, petrophysics, modelling and data-platform investments by connecting governed enterprise data, specialist geoscience applications, domain AI and expert technical review. Its strategic role can be summarised in three linked functions: Harmonise, govern and enable decisions.

Harmonise. EarthNET can provide a connected context across disparate subsurface inputs and outputs, including wells, seismic information, interpretations, documents and AI-assisted results. The objective is not uniformity for its own sake. It is sufficient consistency, identity, context and quality information to support a defined technical workflow. Harmonisation reduces the burden on the geoscientist as the manual integration layer.

Govern. Trusted intelligence requires more than accessibility. Data lineage, model context, assumptions, uncertainty, reviewer input and intended use need to remain associated with the output. EarthNET's positioning therefore emphasises evidence and technical review, so that AI-assisted results can be inspected, challenged and improved rather than treated as opaque answers.

Enable decisions. The commercial value appears when harmonised and governed intelligence improves a real decision: Which opportunity to mature, which interval to test, which prediction to accept, which uncertainty to reduce, or which evidence gap requires new work. EarthNET is therefore best understood not as another isolated application, but as an enabling layer that helps existing data, software, AI and expertise work together more effectively.

BEYOND AI

The next evolution of geoscience software will not be defined by a single application, a single data platform or a single AI model. It will be defined by the ability to connect evidence, science, models, workflows and human judgement into technically defensible decisions.

That is why trusted subsurface intelligence is a useful framing. It shifts attention from outputs to decisions, from pilots to adoption, from data access to fitness for purpose, and from automation to accountable human-AI collaboration. The future of G&G software is not autonomous geology. It is better-supported geoscientists working in systems that preserve context, provenance, uncertainty and learning.

EarthNET provides a practical expression of that future: A layer for harmonising disparate subsurface evidence, connecting domain applications and AI, retaining technical context, and supporting expert review. For operators, this can mean more value from existing data, software and expertise. For geoscientists, it means the opportunity to spend less time reconnecting information and more time improving the quality of subsurface decisions.

NEW GAS

“Helium One is looking at the migration path, while we think helium is accumulating in structural traps on our acreage”

Charles FitzRoy – Rift Helium

Updip advantage in the Rukwa Basin

Over the past decade, the Rukwa Basin in western Tanzania has become a hot spot for helium exploration. Charles FitzRoy, CEO of Rift Helium, explains the advantages of being a third mover: High concentrations of helium have been proven, the geology is better understood, and the government has adjusted its regulations

IT ALL STARTED when two geologists who were exploring for gold read an article in the local paper about helium seeps in the Rukwa Valley. They decided to make a detour and check it out for themselves. The men saw gas bubbling up in the lake and decided to fill an empty water bottle. Lab analysis indeed confirmed that the bottle contained significant levels of helium.

That's how helium exploration in Tanzania, and particularly the Rukwa basin, got its start. First through exploration and drilling by Helium One and Noble Helium, and now third mover Rift Helium has taken up acreage and obtained government permission to start ground work.

GREEN LIGHT

Charles FitzRoy tells GEO EXPRO what the company has in store and its confidence in finding a commercial helium reservoir. "The recent achievement of securing the environmental impact certificate is an important milestone for Rift," he explains, "we now have the green light for a 3D seismic survey and to drill up to three exploration wells." With £8 M raised from investors, there is nothing that stands in the way of the campaign kicking off.

Rift Helium's Upepo project comprises three license blocks on the south-eastern shore of Lake Rukwa. The most promising part of the acreage is adjacent to where Helium One drilled the Itumbula West-1 well. The Itumbula discovery found around 5 % helium dissolved in water and trapped



Charles FitzRoy in Tanzania.

within fault zones that extent into the basement. "Our seismic analysis shows that we are updip from Itumbula-West," Charles explains, "Helium One is looking at the migration path, while we think the helium is accumulating in structural traps on our acreage." Rift Helium's data interpretation shows multiple three-way dip closures in the rift sediments that cover the faulted basement. The expectation is that helium is migrating from deeper levels and pooling as free gas at about 600 m depth.

TARGET RANKING

The 3D seismic survey will bring more clarity on the rifting-related subsurface structures, a huge improvement from the legacy 2D seismic that has

been used up to now. To get a drill in to the ground as quickly as possible, seismic reprocessing of the key areas will be fast-tracked, this will allow for quick data interpretation and ranking of the targets. The locations for the exploration wells can then be determined. "The aim is to start drilling in the first half of 2027, after the rainy season," explains Charles. "It will be an exciting and busy time that should culminate in the discovery of a commercial helium reservoir."

And the two geologist that initially sampled helium in an empty bottle? They gave up on finding gold and have been actively and successfully exploring for helium around the globe ever since.

Mariël Reitsma

PHOTOGRAPHY: RIFT HELIUM

The Bald Eagle has landed

Pulsar Helium has measured unexpectedly high helium-3 concentrations at its Topaz project in Minnesota, comparable to those found in lunar regolith. A closer look at the region's magmatic history explains why the elevated helium-3 levels are not that surprising

THE NORTH-EAST corner of Minnesota, sandwiched between Canada and Lake Superior, is covered with dense pine forest; glaciers have smoothed the terrain during the recent ice ages. "It's a spectacular place," says Nick Schofield, who is both Pulsar Helium's chief geologist as well as a professor at the University of Aberdeen. "It can be challenging to do fieldwork; key outcrops are sparse and often very small." That is maybe why the Duluth Complex, the second-largest igneous complex in the world, is still poorly understood.

The Duluth Complex is situated towards the northern end of the Midcontinent rift system, which, a billion years ago, tried to pull the American craton apart and failed. Nick explains: "A massive amount of magmatism was associated with the rifting event; there are lavas in the main rift basin and the intrusive complex away from the rift axis."

Plutonic activity lasted around 25 million years and culminated in the emplacement of the Bald Eagle intrusion. This is the location of Pulsar's Topaz project. The company has successfully proven the presence of a helium reservoir in the fractured igneous rocks and is now moving towards developing the field. The first step is understanding the geology in detail. To maximise the amount of subsurface data, Pulsar Helium drilled seven appraisal wells, coring five from surface as well as running wireline tools. One of Nick's tasks is to correlate the wells and build

a detailed subsurface framework. He explains that the Bald Eagle intrusion is mainly made up of troctolite, a mafic rock consisting of feldspar and olivine. It was emplaced in multiple pulses, with olivine crystals forming distinct cumulate layers. The cumulates are easily recognisable in the logs as density and resistivity spikes and can also be seen in the core. "The olivine layers correlate from well to well, which means I can make out where we are in the subsurface, and Pulsar Helium can accurately target key gas-rich zones", says Nick.

Helium formed during the Big Bang and some of it got trapped in the Earth's interior. Although helium-4 isotopes are continuously replenished through radioactive decay, helium-3 reserves are exclusively primordial and are dwindling as the gas dissipates to outer space. "The sheer size of the Duluth complex indicates it resulted from significant mantle perturbation and melting," explains Nick. "That is what brought helium-3 up to crustal levels."

That doesn't mean helium-3 concentrations are enormous at Topaz; up to 14.5 parts per billion in the Jetstream 1 well. But compared to 15 ppb in lunar surface rocks, the decision where to obtain the future fuel for nuclear fusion might still be a straightforward one. With now a firm understanding of the geology, Nick and Pulsar Helium's next task is to pick the locations of the production wells. Drilling will recommence in 2027.

Mariël Reitsma

Cross section of the Duluth Complex with the Bald Eagle intrusion in the middle.

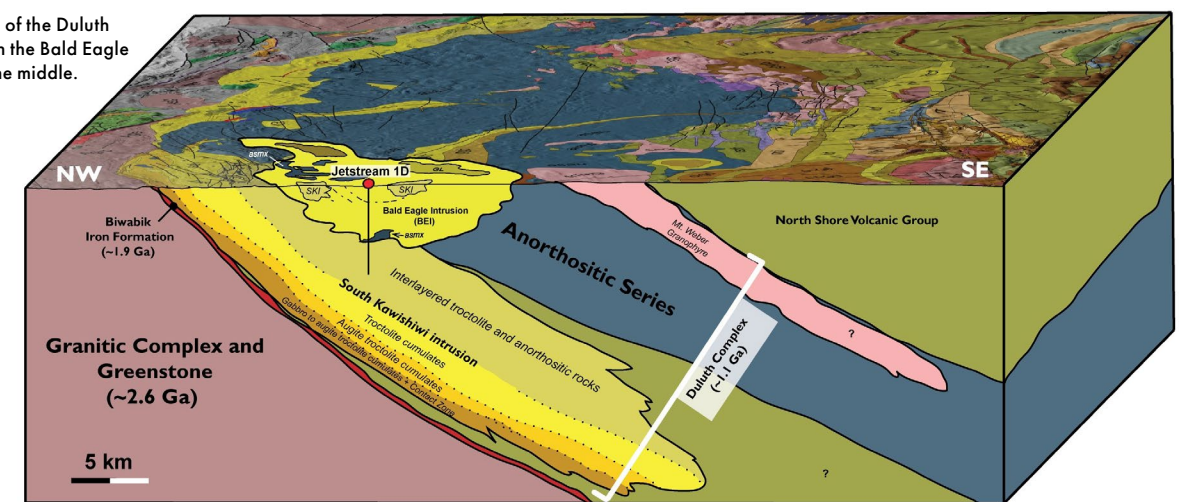


ILLUSTRATION: SCHOFIELD ET AL. (IN PREP.)

MAX Power’s hydrogen appraisal campaign

Canada is one of the frontier countries in natural hydrogen exploration. At the forefront is MAX Power, originally a mining company and now holding nearly 4,700 km² of hydrogen exploration acreage in Southern Saskatchewan

ARNOUT EVERTS, AEGEO

IN DECEMBER 2025, MAX Power drilled its first well targeting the Lawson structure, a Precambrian basement high draped by Cambrian clastics. Similar “buried hill” plays elsewhere in Saskatchewan and neighbouring Alberta and Montana are known helium reservoirs. Lawson-1 recorded hydrogen shows up to 28.6 %, mostly from the basement complex, whilst elevated helium readings up to 8.7 % were noted in overlying Paleozoic strata. An attempt to free-flow the well after casing perforation but without tubing fitted, resulted in momentary inflow of gas immediately followed by strong influx of formation brine. This suggests the well perforated near or into an overpressured water leg, with the brief, initial gas flux either comprising headspace gas or a very short gas column straddling the perforation.

MAX Power then acquired 3D seismic over the structure and mapped a 14.2 km² closure with around 100 m elevation upside relative to Lawson-1. A free gas cap updip of Lawson-1 could indicatively contain up to 200,000 t of hydrogen in the basement, with another 350,000 t potential in the basal Cambrian. Lawson-2 targeted the apex of the 3D closure. Elevated hydrogen readings were reported, but no flow was attempted. Lawson-3 was drilled 1.2 km south of Lawson-1 in a similar downdip position, to “triangulate the discovery”.

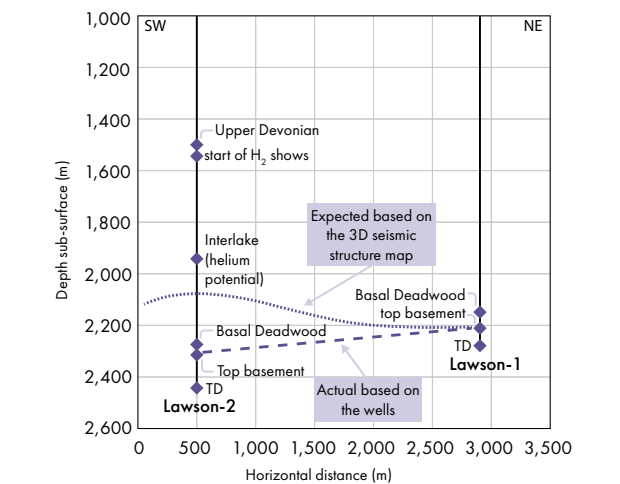


Figure 2: Schematic section across Lawson-1 and -2, illustrating the apparent discrepancy between the seismically mapped top-basement structure and the actual encountered tops. Lawson-4 encountered top basement around the same depth as Lawson-2.

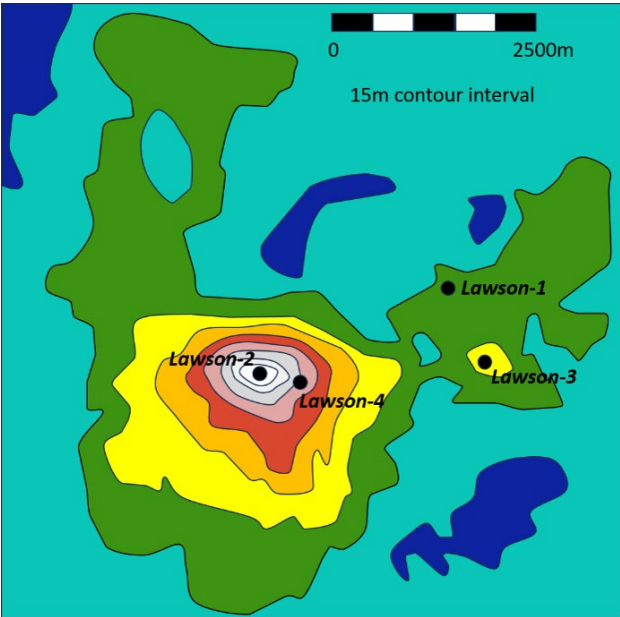


Figure 1: Approximate top-basement contours interpreted from Lawson 3D seismic image. Location of the four appraisal wells is indicative.

Little is known about its findings other than that some helium upside was noted in the Paleozoic formations. Lawson-4 again targeted the basement high. Like Lawson-1 and -2, it noted elevated hydrogen readings in the basal Cambrian and basement as well as elevated helium in the shallower Silurian strata, but again, no evidence of flow.

Unfortunately, MAX Power’s fragmentary and highly selective reporting makes it difficult to decipher what has been proven by the drilling campaign. One surprising result is that the top basement picks in Lawson-2 and -4, supposedly drilled up-structure, are some 100 m deeper than in Lawson-1. This brings into question whether the wells proved or disproved the existence of the seismically mapped 3-way closure. Maybe the closure is at a shallower level, e.g. at the top-Silurian unconformity? The structure may be more complex than initially suggested and the lack of reported flow in supposedly apex wells is not particularly encouraging. Whilst MAX Power claims “Lawson is advancing toward commercial evaluation”, public records leave many unanswered questions regarding the nature of this hydrogen system.

ILLUSTRATION: ARNOUT EVERTS

TECHNOLOGY

“We plot different fault interpretation scenarios straight onto a well path, because drilling through a fault zone that was initially missed, can lead to lengthy delays or even loss of a well”

Ed Anderson – Geoteric

Technology is not the bottleneck anymore

Ryan Mardani from DataEnergy in Calgary talks about his AI-based geoscience data start-up and how the company stays on top of the latest developments

CONFERENCES remain a great way to meet people who you otherwise wouldn't cross paths with. That sometimes leads to great conversations, and occasionally also an article. At GeoConvention in Calgary earlier this year, I met Ryan and his colleagues who were exhibiting. They were talking to potential customers about their company DataEnergy.

Having a background in geosciences and seeing how much subsurface data was not used to its maximum extent while working in the oil and gas industry, Ryan decided something needed to be done. He embarked on a master's in Geophysics at the University of Calgary, during which he took as many computing and data science classes as he could. "Normally, students do around four courses," Ryan told me during a video call, "but I completed twelve."

Following the completion of his degree in 2018 – before AI really became a buzzword – Ryan started to become serious about realising his ambitions. And he is still doing that now, with the help of digital AI agents. "We are four people working in the company," he says, "but thanks to advances in AI, we are assisted by around ten digital agents that work much like software developers and help us with development, testing and research."

"We are developing tools to assist real-time operational drilling," says Ryan. "Our current work combines drilling performance, subsurface context and predictive information to support decisions such as whether to continue drilling, monitor more closely or prepare for an intervention." Importantly, the AI does not directly control equipment. Recommendations are checked against engineering and governance rules and remain subject to human authorisation.

"Agentic AI is developing so fast at the moment," Ryan says, "that a software module or prototype that could have taken us around three months to develop before can now be created in around three days."

Rather than seeing the rapid pace of AI development mainly as a risk, Ryan sees modularity as the answer. "We try to build the system so we can adopt better models and new technology without rebuilding the entire industrial workflow around it," he says. "We are currently in talks



Ryan Mardani.

with a major operator in the Middle East," he adds, "but these things don't finalise overnight."

"A software module or prototype that could have taken us around three months to develop before can now be created in around three days"

"The way we approach it now," he continues, "is to scale up further as soon as we land a contract, such that we can keep delivering the most efficient solutions to the client." Ryan continues to work professionally as an AI engineer while building DataEnergy together with the team. The company is also exploring government programmes and grants for which it may be eligible as it grows.

The fact that such a small specialist team can now build and test sophisticated industrial AI systems is surely a sign that technology is not the bottleneck anymore. ■

Henk Kombrink

PHOTOGRAPHY: RYAN MARDANI PRIVATE ARCHIVE

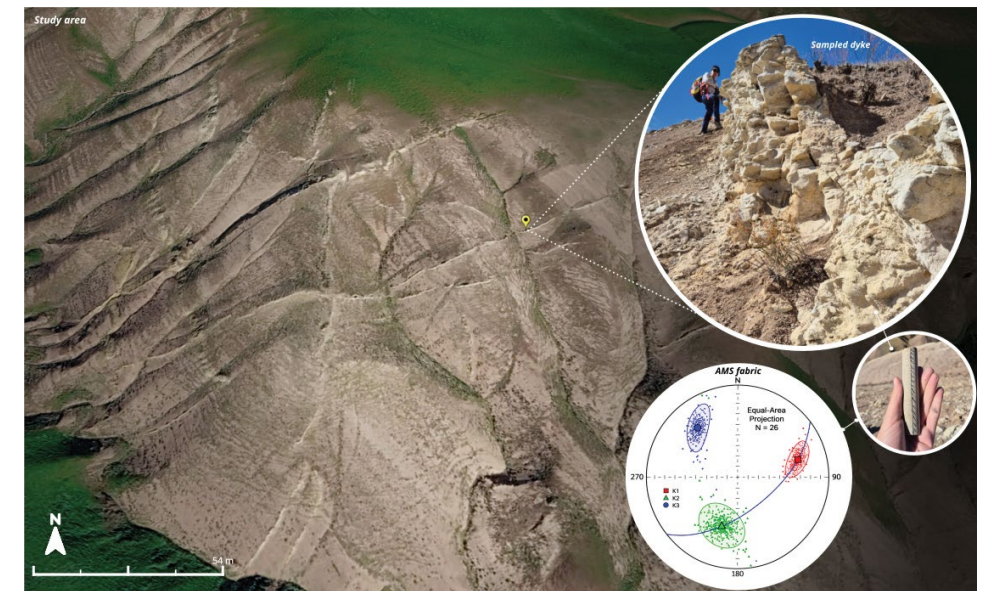
Disentangling the internal structure of sand injectites

Using cutting-edge technology, researchers from Brazil and Scotland are gaining better insights into how sand injectites formed, which helps better predict their subsurface architecture

IT'S A FRIDAY afternoon when I have a call with PhD student Caroline Azzolini Pontel from the Federal University of Rio Grande do Sul in Brazil and postdoctoral researcher Gustavo Zvirtes from Aberdeen University in Scotland, to talk about a fascinating project they are working on, using equally fascinating technology.

Caroline and Gustavo are part of a team that has taken samples during a field campaign in California, where they have been mapping sand injectites for many years as part of the Sand Injectite Research Group. This research consortium is based in Aberdeen and is currently in its fifth industry-funded phase. The samples they took are now being analysed using an array of new technologies to better understand the way they formed.

One of those is anisotropy of magnetic susceptibility (AMS), which is used to find out more about the direction of sand movement within the injectite. AMS is a technique that measures how easily a rock can be magnetised in different directions. If the magnetic minerals inside the rock have a preferred orientation, AMS can detect that internal fabric. The result is represented by three principal axes: K1 is the maximum susceptibility axis and defines the magnetic lineation, K2 is the intermediate axis, and K3 is the minimum susceptibility axis and represents the pole to the magnetic foliation. Here, we show a stereonet output from a sample that was taken from a sand injection dyke, MC15, as indicated in the aerial photo. The data reveal a clear oblique fabric orientation within a sub-vertical dyke. This is marked by magnetic foliation (K3 poles, blue) dipping approximately 60° to the southeast and a lineation dipping 30° to east-northeast (K1 repre-



Aerial photo showing the ENS-WSW trending sand injectites in the field in California, the sampling site and the sandstone mini-core recovered from the dyke, as well as the resulting anisotropy of magnetic susceptibility (AMS) stereonet.

sented by three principal axes: K1 is the maximum susceptibility axis and defines the magnetic lineation, K2 is the intermediate axis, and K3 is the minimum susceptibility axis and represents the pole to the magnetic foliation. Here, we show a stereonet output from a sample that was taken from a sand injection dyke, MC15, as indicated in the aerial photo. The data reveal a clear oblique fabric orientation within a sub-vertical dyke. This is marked by magnetic foliation (K3 poles, blue) dipping approximately 60° to the southeast and a lineation dipping 30° to east-northeast (K1 repre-

sented by three principal axes: K1 is the maximum susceptibility axis, red). In this way, the AMS data provide a clear, three-dimensional picture of the internal fabric developed in the final stages of sand emplacement.

Another thing Caroline and Gustavo are now in the midst of is the analysis of the 3D images that result from their samples being scanned in a very high-resolution 3D microscope based on particle accelerator technology. The facility is called Sirius, Brazil's fourth-generation synchrotron light source, where the researchers used the MOGNO beamline. There is just one of those in the whole of

South America. The resulting microtomographic and nanotomographic 3D images are of a resolution that not many have seen before. "One pixel in an image is about 0.15 µm," says Gustavo, "so that's 0.00015 mm."

"Using the particle accelerator and the AMS results, we are getting a better grip on how these sand injectites were emplaced," concludes Caroline. "This research will subsequently help predict the 3D architectures of these injected sands, which form part of the reservoir in quite some oil and gas fields around the world." ■

Henk Kombrink

A better appreciation of fault interpretation uncertainty when it comes to well planning

Following the investigation of a missed fault discovered during the drilling of a development well in the Tern Field, a multi-network workflow shows how interpretation uncertainty can be assessed and incorporated into well planning

THE FIRST article in this series examined how Geoteric AI Fault Interpretation revealed a subtle fault that had been missed in the original interpretation of the Tern Field seismic data (GEO EXPRO Vol. 23, Issue 4, 2026). But identification of the missed fault is only a first step: would different AI networks identify the same structure, and how can interpreters understand the uncertainty between their results?

That is where a newly developed workflow comes in, as explained by Ed Anderson, Head of Geosciences. Using the AI Hub, multiple pre-trained AI networks can be applied and compared within the same workflow.

Each network can respond to a different expression of faulting in the seismic. Rather than selecting one result and discarding the others, the outputs

can be compared to show where the networks agree and where their interpretations diverge. Another way of visualising the different scenarios is to assign a colour to each and overlay them in map or cross-sectional view. Where the result is white, all models agree; where specific colours remain, they do not.

"We can now also plot different fault interpretation scenarios straight onto either a planned well path, or an existing one," continues Ed. "Doing this creates a particularly insightful overview of the uncertainty that exists when it comes to fault interpretation, which is important to embrace rather than dismiss. Because we know that drilling through a fault zone that was initially missed can lead to lengthy delays or even loss of a well."

Applied to the same Tern Field well examined in the first article, the comparison shows that some faults are

This article is the second in a three-part series with Geoteric that demonstrates the benefits of AI-assisted fault detection through real case studies.

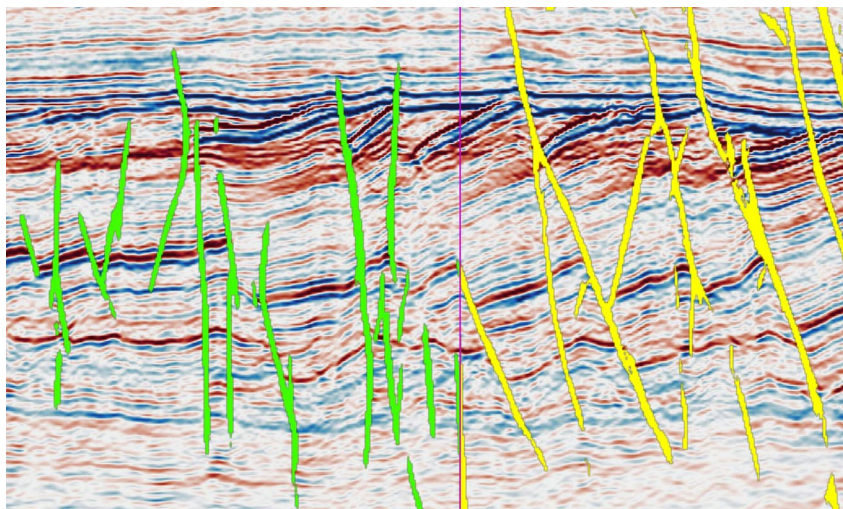
picked up by all interpretation scenarios, while others are not. That is not a problem; it allows geoscientists to better grasp the uncertainty that exists and plan accordingly. Agreement between the networks can increase confidence in a fault prediction, while disagreement highlights areas that may require further investigation before committing to a well trajectory.

It is also possible to go one step further and explore data uncertainty by assessing different forms of the original seismic data. "At the end of the day, we might have nears, mids or fars, and several vintages of seismic that were processed differently, all adding potential information," says Ed. "In our AI Hub, we can subsequently apply conditioning to see what difference it makes. All this happens live, meaning that it is a quick process and allows us to quickly ascertain different combinations as well."

The purpose is not to remove geological uncertainty, but to make it visible early enough to influence well planning. By bringing multiple networks, seismic inputs and conditioning options together in the AI Hub, subsurface teams can move from a single interpretation to a more defensible assessment of structural risk. ■

Henk Kombrink

SOURCE: GEOTERIC



Comparing different fault network interpretations on the fly.

INSIGHTS

"When I arrived back in the morning, the core was gone. Not dispatched to town as planned, but stolen in the night"

Geologist

It doesn't have to be that way

How corporate communication erodes trust

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

AN ENGLISH professor once discussed with his class how in language two negatives produce a positive, but two positives never produce a negative. From the back of the class came a dismissive: "Yeah! Right!"

I will get back to this.

I was at the EAGE Annual in Aberdeen. I was excited to be there and excited to contribute. The conference host and primary sponsor was bp, and it opened on the 8th of June with a razzmatazz ceremony. During that evening, I heard a senior executive with bp state that "Our people are our greatest asset". I nearly choked on my haggis canapé.

Why? On the 26th of May, the bp chairman was removed with immediate effect. If the Chairman isn't safe, then who is?

On the 31st of July, 53 days after that opening ceremony, bp issued a press release announcing it would be launching a process to market its North Sea business. An action that will affect hundreds of their people and their families. It appears that not only are their people not their greatest assets, even their assets are not their greatest assets.

I've been in and out of Aberdeen for 30 years, and I can assure you that bp, and others have been cutting people and disposing of assets for all of that time, and longer. It is in the fabric of the oil industry, and it's not going to change.

Meg O'Neill, bp's new CEO, started in that press release that their North Sea business "has world-class people, resilient assets" whilst later on 3rd August during the 1Q26 results she said:

"That is how we will make bp a simpler, stronger, more valuable company". A simple, strong corporate message. But then, in 2020, bp's then-CEO Bernhard Looney framed 10,000 redundancies as "the plan to make bp leaner, faster-moving". The same message attempting to justify the same actions.

To repeat, it's not just bp.

It takes a serious dislocation from the actualities of working in our industry to think that the oil companies and the associated service companies act in a manner that demonstrates their people are their greatest asset.

And yet, it doesn't have to be that way.

CNRL has been in Aberdeen for over 20 years and has never had forced redundancies. Is that long-term, disciplined cost control? Harbour Energy in Aberdeen has been booting out good people whilst Harbour Energy Norge has grown. Is that working with government policy and strong employment laws? And I recall in the downturn of 2016 a senior executive from Total being asked how many staff would be cut globally. The reply: "None, we'll be needing them all in a year or two". That reflects genuine belief that people are the most important asset.

I love geology, I love the oil and gas industry, and I also love my oil industry colleagues: brilliant and determined, innovative and visionary, grace and grit, and a necessary fortitude with so, so much humour. They deserve better than this dissonance between PR platitudes and real and damaging actions.

So, when I'm standing at the back of a conference and hear "Our people are our greatest asset", I think, Yeah! Right!



From Mars to the Mediterranean

Sam Rivas-Dorado brings some exotic fieldwork experience to the job that sees him supporting clients and building fracture systems in reservoir grids

"I'M FROM an area in Spain nobody really thinks about," says Samuel Rivas (Sam) when we meet up on Teams. By that, he means the green northwest corner of the country, Galicia, which is indeed a bit of an outlier in terms of rainfall. But Sam is now based in a more "typical" part of Spain, in Madrid, where he works in the RFD office mainly serving the wider Mediterranean region.

He brings some valuable experience to his role in client support and reservoir studies, having worked with CEPISA in Madrid for seven years before he joined RFD, as well as completing a PhD in his spare time. "I'd recommend anyone to think twice before embarking on that adventure," he admits, "it was a tough experience, but I worked on a fascinating topic for sure."

Sam studied how igneous dikes on Mars drive graben formation. And even though that sounds quite a few miles away from what he is currently involved in – fracture modelling – in fact, these topics are more related than one would think. "When magma pushes its way up in the crust, it generates fracture networks," explains Sam. "Not only on Earth, but also on Mars. Having to numerically model that process during my PhD has made me much more aware not only of the importance of fractures in the subsurface, but also how to model and propagate these things in reservoir models." And that is exactly what Sam is heavily involved in nowadays, especially in finding ways to make sure the population of fracture systems makes geological sense, as well as the upscaling into the reservoir model for flow simulation.

"It is only one thing to populate fractures in a model using the intensities and geometries we observe in image logs or cores," says Sam, "but that is only half of the work. Because we know through scientific work and industry studies that fracture densities are increasing as we get close to a major fault, for example. The same happens when we approach the crest of an anticline, and lastly, there is a close link between lithology and fracture density. That's why we take all these factors into account when we populate a reservoir model with a discrete fracture system."

This helps Sam and his colleagues build better reservoir models, as they

recently demonstrated when they built a model that simulated a field in Egypt's Western Desert. "The wells saw water breakthrough already after two years," he says, "much earlier than expected. We built a model without and with fractures in it, and could subsequently demonstrate that without fractures, it would be much harder to explain the early water breakthrough from the aquifers below the contact."

The Egypt case is not the only example Sam has worked on, and with the world moving towards the more challenging reservoirs to produce from, it is likely that there will be more to come.

Henk Kombrink



PHOTOGRAPHY: MAERSK

PHOTOGRAPHY: RFD



Sam ready to present one of his studies at the Mediterranean and North African Conference in Medina last year.

Contrasting fortunes in Sub Saharan Africa

Whilst East Africa continues to experience ups and downs in terms of oil and gas developments, there is enough to be upbeat about

PETER ELLIOTT, NVENTURES



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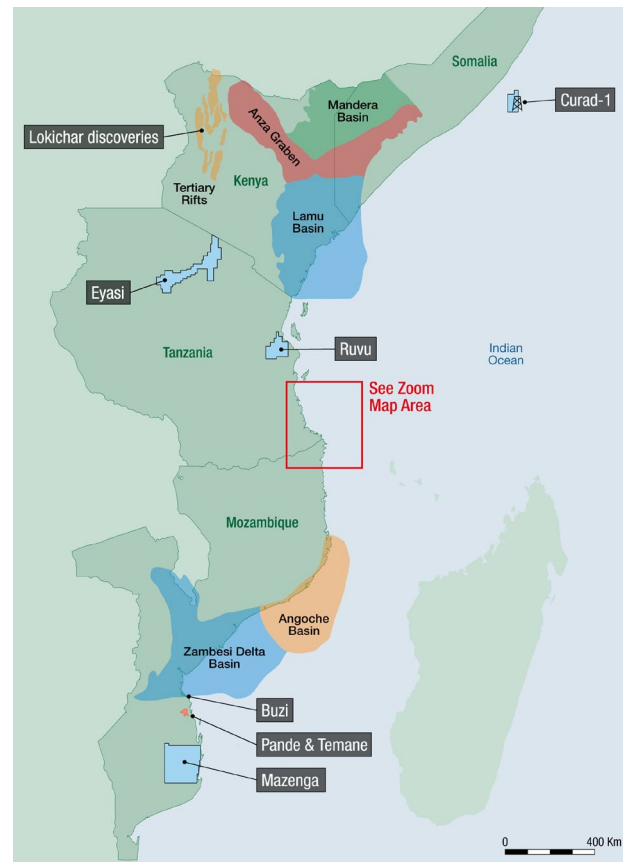
EXPLORATION is firmly back on the agenda for many oil and gas companies, regulators and NOCs. This is especially clear in Africa, where large tracts of open exploration acreage have been taken up. This is particularly the case in West Africa, with new basin-scale permits keeping the supermajors focused on finding the next “Liza”. East Africa, though, with its vast reserves both onshore and offshore, seems to be holding on to its reputation for slow progress. Intensive development programmes deep in the hinterland, the predominance of gas offshore (to date) and the slow progress towards improving oil and gas fiscal terms all play their part.

SOMALIA

But for those with the right mindset, uncertainty can also mean opportunity. Recently, Türkiye, via its state oil and service companies, launched a major exploration campaign offshore Somalia after both governments signed a wide-ranging cooperation agreement in March 2024. Soon after, a 15,000 km² 3D seismic survey was acquired by the Turkish research vessel Oruc Reis (June 2025) over Block 142 on the Mid Somalia High and blocks 152 and 153 in the Coriole Basin / Mogadishu Deep Basin. These blocks were subsequently awarded out of round to TPAO in April 2025. The Cagri Bey drillship is on location (August 2026), drilling the Curad-1 exploration wildcat on the Mogadishu Deep Basin Block 153. Success here would kick off a rush for acreage in a country that was abandoned by the supermajors in the late 1980s.

KENYA

Kenya has not seen any significant discoveries offshore since the 1970s Pate gas discovery and Sunbird in 2014 (BG at the time). Deepwater wildcats tested various plays at Simba 1 (TotalEnergies, 1977), Mbawa 1 (Apache, 2012), Kubwa 1 (Anadarko, 2013), and Pomboo 1 (Woodside, 2006). The Ministry of Energy and Petroleum is determined to raise the profile here and attract new exploration. The State Department for Petroleum (SDP) is expected to launch a major licensing round in 2027, for at least ten premium blocks, with preparations and pre-qualification in 2026. This will involve licensing new blocks across the Lamu, Anza, Mandera, and Tertiary Rift basins, as well as establishing



East Africa's major oil and gas basins and exploration areas.

a new National Petroleum Data Centre. With limited success offshore Kenya, all eyes are on the potential to develop the Lokichar oil discoveries, first drilled by Tullow in 2012. Auron Energy (Gulf Energy) bought the rights in 2025, and plans are underway for a major development.

TANZANIA

In Tanzania, mixed results over the years have led to reasonable gas production from two major coastal centres (Mnazi Bay and Songo Songo), while major multi-TCF gas fields have remained undeveloped offshore. The Tanzania Petroleum Development Corporation (TPDC) is expected to issue an Expression of Interest to find new partners and investors

for four blocks currently being managed by TPDC: Mnazi Bay North and West Songo Songo offshore, and Eyasi Wembere and Lindi and Mtwara Blocks onshore. Although this does not represent a new country-wide bid round, TPDC have often announced plans to do that soon.

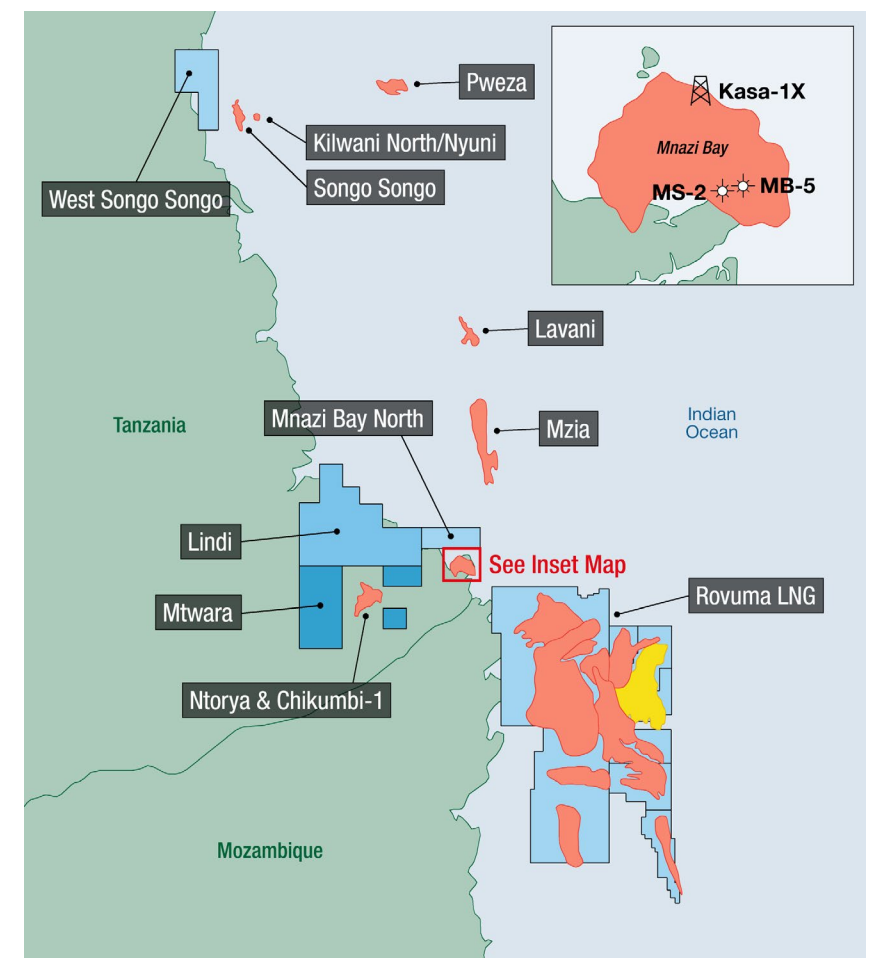
In the meantime, exploration efforts continue in Tanzania, albeit at moderate levels. Dods Resources drilled for gas onshore Ruvu block in 2015, with no clear progress updates announced. In the south, ARA and Aminex are planning a field development over the Ntorya gas discovery, first drilled by Aminex, Solo Oil and Tullow in 2011.

At the Mnazi Bay field, Maurel and Prom have been busy drilling the Kasa 1 well. Including the completion of MB-5 and MS-2 during the first half of 2026, the production potential of Mnazi Bay is now nearing 200 mmcfd.

A cornerstone of the Tanzanian gas industry, Songo Songo (1974) supplies a good proportion of industrial gas and local electricity in Tanzania. However, the ageing field, which is still producing around 85 mmcfd, is in need of redevelopment. Whether the new owners, Dubai's Amber Energy Investment (51 %) and Taifa Gas (49 %) can pull that off is now the question.

Immediately east of Songo Songo, UK firm Aminex, through Ndovu Resources, appears to continue to hold interest in the Kilwani North gas discovery and the Nyuni exploration opportunity, along with partners RAK Gas and Scirocco Energy.

There is also a “sleeping giant” offshore Tanzania, with the trend of major discoveries made in the offshore Rovuma Basin in Mozambique extending further north. However, these multi-TCF discoveries have yet to be developed. Companies like Shell (Pweza, Mvia) and Equinor (Lavani and Tangawizi) continue to evaluate these major gas fields with a view to monetisation if commercial terms improve.



Tanzania's key offshore gas fields, discoveries and developments.

MOZAMBIQUE

Mozambique is benefiting from a major LNG export industry thanks to enormous gas reserves offshore the Rovuma Basin in the north of the country. ExxonMobil and ENI, along with various international partners, now export around 6 mmtpa, with a further FID announced in 2026 for Rovuma LNG (18 mmtpa). TotalEnergies also has mature development projects for further LNG.

Onshore Mozambique, Sasol run one of their mainstay gas supply projects at Pande & Temane, with a gas pipeline to South Africa. The fields have produced well over the years (around 250 mmcfd), and Sasol continues to develop the resources there.

Elsewhere, exploration campaigns are planned and underway. ENI and CNOOC hold large blocks offshore the frontier Angoche Basin, while

CNOOC hold another two blocks offshore the Zambesi delta. ExxonMobil exited both basins recently. Onshore, further exploration is taking place around Pande & Temane, and the Buzi field is yet to be developed north of Temane. To the south, Aiteo have completed a magnetics and gravimetry survey over the large Mazenga block, ahead of possible seismic acquisition.

Whilst the basins of the west coast of Africa take centre stage, major oil and gas developments are finally bearing fruit in East Africa, and major opportunities lie in wait. Governments across the region are launching investor promotion, bid rounds and new opportunities to participate. The challenge remains to draw the eye from the West African hotspot and re-focus on these established and promising oil and gas-producing countries in the east.

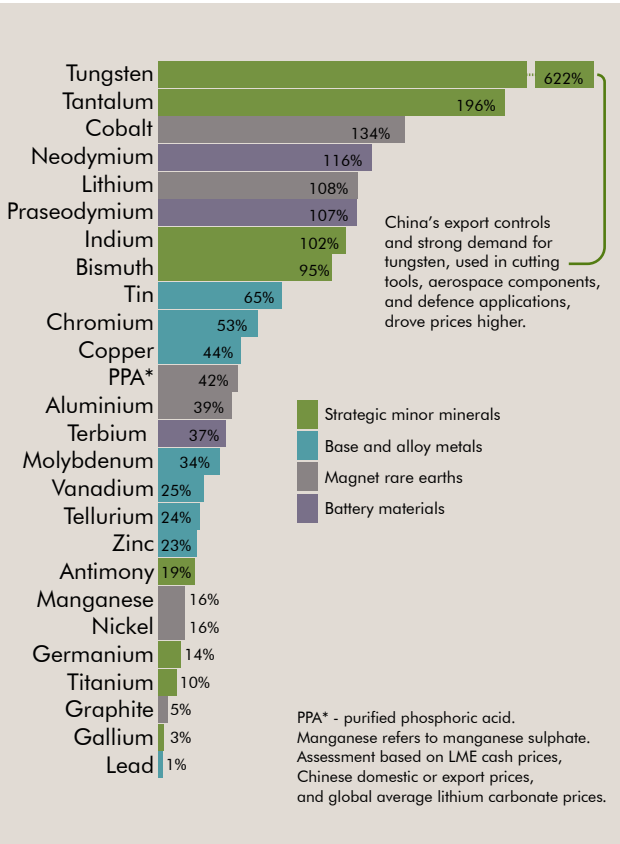
Critical minerals

What are the 2026 prices telling us?

ISTVÁN NAGY-KORODI

CRITICAL RAW materials have spent the last few years moving from specialist discussions into energy strategies and geopolitics. Most of the debate has focused on future demand. How much lithium will batteries need? Where will the copper come from? In 2026, another part of the story is becoming difficult to ignore. Prices are moving, sometimes strongly. Between January 2025 and April 2026, tungsten increased by more than 600 %, tantalum rose by almost 200 %, and cobalt by around 130 %.

Commodity prices move for many reasons, and one year does not define a long-term trend. New production comes online, inventories change, governments intervene, and buyers react. Still, the pattern is interesting. Some of the largest increases are not in the world's biggest metal markets, such as copper, but in comparatively small markets such as tungsten, tantalum and indium. This is where the meaning of "critical" becomes important. Critical does



Critical mineral price changes, January 2025 – April 2026.



not necessarily mean rare. An element can be relatively abundant in the Earth's crust and still become difficult to obtain economically.

China occupies a major position across numerous critical-mineral supply chains. Other commodities show similarly strong geographic concentrations: cobalt in the Democratic Republic of Congo and nickel increasingly in Indonesia.

Higher prices do not automatically create new mineral supply. This is partly a geological problem, as new deposits have to be found, characterised and shown to contain sufficient concentrations and tonnages of recoverable material. But discovery is only the beginning. A project must then move through resource definition, permitting, financing, metallurgical testing, infrastructure development and ultimately production. For many critical minerals, this can take years or even decades. This helps explain why relatively small mineral markets can respond so strongly when supply becomes constrained.

For geologists, perhaps the more interesting consequence of higher prices is therefore not simply where we should search for new deposits, but whether we should look differently at geological systems we already know. We traditionally describe projects by their primary commodity: A copper project, a lithium project or a nickel project. But geological systems are rarely so simple. Hydrothermal fluids transport suites of elements, while magmatic and sedimentary processes can concentrate groups of metals. Some economically important materials, including germanium, gallium, tellurium and rhenium, are already produced mainly or partly as by-products.

That raises a simple question: What else are we not looking for? Old mines, tailings, processing residues and even subsurface brines may contain elements that were never systematically analysed because nobody considered them economically interesting at the time. Higher prices do not automatically turn these materials into resources, but higher prices change the point at which it becomes worth asking the question. Perhaps that is the more interesting message behind the figure. The challenge is not simply finding more critical minerals. It is understanding our existing geological systems better, looking beyond the primary commodity, recovering more from what we already produce and creating more diverse supply options. The price movements of 2026 may eventually moderate, but the geological questions behind them will remain. ■

ILLUSTRATION: REDRAWN AFTER BRUNO VENDITTI, ELEMENTS.VISUALCAPITALIST.COM

Have we reached a point of singularity in the subsurface? Probably not

Buried within the prepared remarks of ExxonMobil's recent Q2 earnings call was a quiet yet significant revelation

DAN AUSTIN, SEKAL



THE STABROEK Block moved from discovery to one of the largest offshore developments in the industry in little more than a decade, operating 30 % faster and at costs 20 % below the industry average. But that's not what caught my attention. The company directly attributed its unprecedented success in Guyana to the usage of cutting-edge technology – boldly stating that these applications have the potential to unlock approximately \$2 B of net present value.

Deepwater exploration traditionally requires months or years to process seismic data. In Guyana, ExxonMobil altered this timeline by unleashing proprietary in-house technology, including an Exploration Agent and elastic Full Wavefield Inversion (eFWI) technology. Trained on massive volumes of glob-

al data, one AI model identified known Guyana discoveries with a 90 % success rate and rapidly surfaced four entirely new prospects previously invisible to traditional methods.

Earlier in the year, I highlighted a similar trend in the Norwegian Continental Shelf (NCS). It is surprising to see AI having a significant impact in two very different basins. The maturity of the NCS – both commercially and digitally – lends itself well to the development and application of AI. However, in a frontier basin such as Guyana, theoretically it should be limited by the availability of ground truth.

To me, the statements from ExxonMobil make it apparent that globally applicable foundation models in both the well and seismic domain are now mature enough to carry out a significant amount of legwork. In this endeavor,

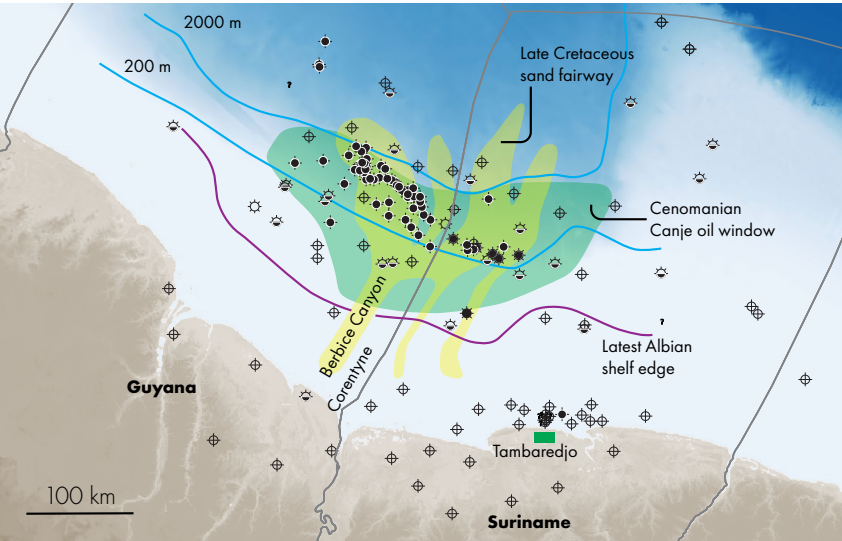
our, ExxonMobil analysed data from 50,000 wells globally. It would take a conventional project an estimated 15 years to complete an analysis of that magnitude, whereas AI executed the task in a matter of weeks.

When evaluating these breakthroughs, we frequently measure AI against human performance, but it is equally vital to evaluate it in reverse. At its core, an AI is mathematically compelled to provide a coherent output; stitching fragmented data into a smooth narrative of absolute certainty that reflects its training. This trait is undeniably powerful – it is exactly what allowed the model to rapidly surface four entirely new prospects.

However, that same certainty demands scrutiny of its 90 % success rate on known discoveries. While 90 % sounds triumphant, in exploration, that missed 10 % could easily represent the most crucial, unconventional commercial prospects that simply do not fit a smoothed-out global average.

Furthermore, we must ask why those four new prospects were previously invisible. It is entirely plausible that human geologists "missed" these conventional, global-pattern plays not out of oversight, but because they deliberately shifted their efforts toward nuanced, high-concept geology and local complexities.

Ultimately, while these AI-generated results sound incredibly impressive on an earnings call, without the contextual anchor of local ground truth, the industry's stance must remain rigorously sceptical, yet profoundly optimistic. ■



Ten years ago, the cluster of oil discovery wells in the deepwater Suriname-Guyana Basin did not exist.

The innocuous question that rarely has an innocuous answer: "Why did you study geology?"

And why this ultimately led to me becoming the owner of more than 150 oil and gas wells

NEAL S. TURLUCK

EVERY GEOLOGIST at some point gets asked the same question: "Why geology?" Nobody asks an MBA why they got an MBA; that story is assumed. Geology doesn't come with a built-in narrative, but with a shared curiosity from a shared adolescent fascination with "rocks".

What I feel is genuinely being asked with such a loaded question is: "What made you curious about the world around you?" or "How does the science of geology produce a rewarding and fulfilling career?" Those are the real questions hiding inside "Why did you study geology?" and the honest answer is rarely innocuous.

I studied geology because I wanted to understand the natural world around me. Most people, when moving through a landscape formed by complex and complicated processes, never give it a second thought. I wanted to be someone who did. But I also wanted to be someone who could share the greatest wealth this world holds. The wealth exploited by the mind and built from the world around us, all of which comes down to the rock.

What of the rock, though? Growing up in Michigan and racing sailboats around the Midwest, I'd catch glimpses of pumpjacks and hear people talk about oil and gas, but I never had a real introduction to the industry. What began as an instinct toward leveraging my future with a hedge against fiat currency turned into a genuine fascination with the subsurface.

I wanted to study a physical science, and I wanted to plant myself in the industrial backbone of this country, in something compelling, thought-provoking, and challenging. Initially, that meant hard rock: Igneous and metamorphic petrology, a path toward mining. But mining as an independent has a brutal barrier to entry: The capital, the permitting, the scale required just to start.

So, I asked myself a more pragmatic question: "If the goal is to be a natural resource developing scientist, what's the fastest way to get close to the source itself?" Drilling an oil well, relatively speaking, is simple. That pulled me toward sedimentology, structural geology, basic geophysics, and the all-encompassing petroleum system.

That pull became a career I didn't fully see coming. A Bachelor's Degree at Western Michigan University, field camp through Indiana University, field mapping across the



From left: Stitches Turluck, Neal Turluck, and Gail Turluck, the board of S & S Oil and Gas during a well workover.

Black Hills, Wyoming, and Montana. A Master's Degree at Western Michigan researching capillary rise in fine-grained sand. Internships at Riverside Energy Michigan and a utility company mapping storage reservoirs. Nights on drilling rigs in the Permian Basin, Michigan Basin, and Uinta Basin, describing cuttings by moonlight. Acquisitions consulting and mineral leasing while hanging my independent shingle at Transcendence Energy. And in October 2021, becoming President of S & S Oil and Gas by acquiring and operating 152 wellbores and 3,000 acres in Indiana within the Illinois Basin.

It wasn't a straight line. But it started with the same question everyone eventually asks: "Where does it come from and how does it get there?" For me, the answer was always the rock.

In this series, Neal will tell the story of working as a small independent in the oilfield, where producing a barrel a day more is not to be sniffed at.

PHOTOGRAPHY: NEAL S. TURLUCK PRIVATE ARCHIVE

How one biomarker does not make a new source rock

The observation of TPPs or tetracyclic polyprenoids in oil samples is all too frequently used as the single proof for the presence of a secondary lacustrine source in the Central Atlantic. There is often another and more straightforward explanation

GION KUPER AND RAINGARD HABERER-KUPER, MEADLANDS GEOCONSULTING AND ISLAY SUBSURFACE & ENGINEERING

WHEN WE are looking for new opportunities, visiting data rooms, or moving to a new asset, many of us find ourselves reading old reports to piece together the nuggets of information from decades of past exploration. This is currently happening especially for the Central Atlantic margins of Africa and South America, where there is a lot of recent and renewed interest.

The marine source rocks of the Albian, Cenomanian and Turonian (ACT) are the superstars here, but there are always hints at older source rocks, another oil in the mix. For instance, a report on the Tano-Ivorian basin reads: "...lacustrine derived oil is a major component of the oils found...". Similar phrases are speckled through reports from other basins. It seems that the ACT oils are harbouring the signa-

ture of older lacustrine systems that are apparently widespread.

Some prolific lacustrine source systems are well-documented along the Atlantic margins, notably in Gabon and Brazil. It is not a far-fetched idea to expect well-developed lacustrine source rocks to be present in other basins as well. But are the oil data telling us this?

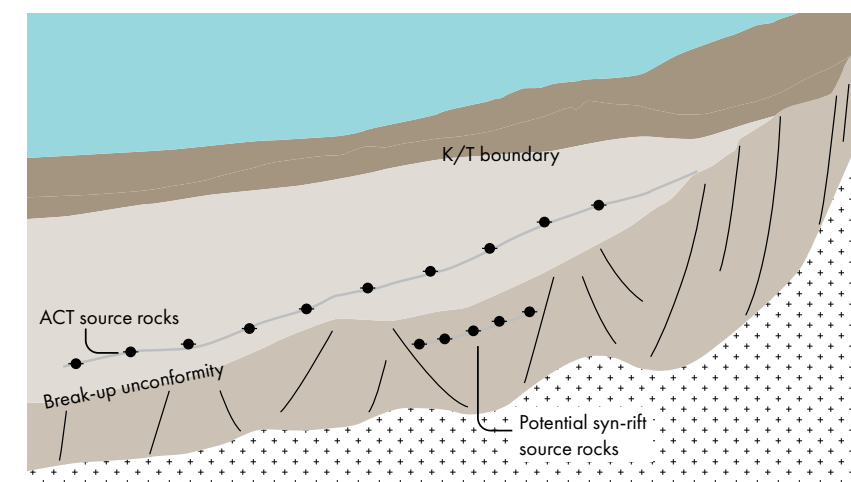
TPPs, tetracyclic polyprenoids, are biomarkers or molecular fossils. Holba et al. (2003) comprehensively described TPPs and their link to fresh- and brackish-water organic matter input in sediments. Finding these biomarkers prominently in an oil of otherwise clear marine origin makes you think. A lacustrine source rock contributing is a possibility. But if that is the case, there are other biomarker characteristics that you would then also expect to see in the oil.

If the lines we read in the old reports just refer to TPPs and very simply add the interpretation of a lacustrine source rock contributing oil, we're only halfway there. For an explorer, it is tempting to invoke a deeper petroleum system that will work where the ACT source rocks are immature, but are these geochemical data really telling us this?

Looking at extracts from marine ACT source rock samples from deep offshore wells in the region, one thing is striking about the biomarker fingerprint: a common, very significant presence of TPPs. Is it possible that the TPPs in the oils are therefore not showing any hidden extra source systems to chase?

The understanding of the origin of TPPs is not in question. Instead, the prominent occurrences in ACT source rocks throw up interesting questions about the depositional environment in the Atlantic when it was still a fairly restricted basin. River run-off and freshwater wedges stratifying the water column may have brought freshwater biomarkers to a marine setting.

For that reason, the interpretation of a separate lacustrine source contributing, often from a tentative line in a geochemistry report, may not always be the best possible explanation. There are most certainly lacustrine source rocks contributing to oil and gas along the Atlantic Margins, but there may be more wild geese to chase than there are big fish to catch.



Typical setting of Central Atlantic ACT and syn-rift source rocks.

A tale of a cave or how much in-place volume you might be missing

Severe losses. A ROP spike. Maybe even a bit drop. You are drilling a carbonate reservoir, and you just hit a cave. But is it just one isolated cavern or are there many other neighbouring ones?

FERMIN FERNANDEZ-IBANEZ, SUBSURFACE ALLIANCE

KARST PROCESSES occur across a wide range of scales in carbonate reservoirs, from dissolution-enhanced pores and vugs to meter-scale caverns. It is these larger, discrete features that interest us here. They can add significant pore volume and have a major influence on reservoir performance. Yet they are difficult to characterise because a well provides only a very narrow sampling window into the reservoir. But seeing one cave raises a far more interesting question: How significant is that single intersection?

Let's consider coastal karst developed along the margins of isolated carbonate platforms, and caverns that

develop within a freshwater lens, without requiring faults or fractures to guide their location. They commonly occur as broad, sub-horizontal, flattened bodies. So, imagine drilling a well and intersecting just one cavern. It is tempting to say that you got lucky and that one cave does not mean there are many more. But did you really get lucky? If you are in an area where your geologic concepts indicate a high probability of karst, chances are there are more.

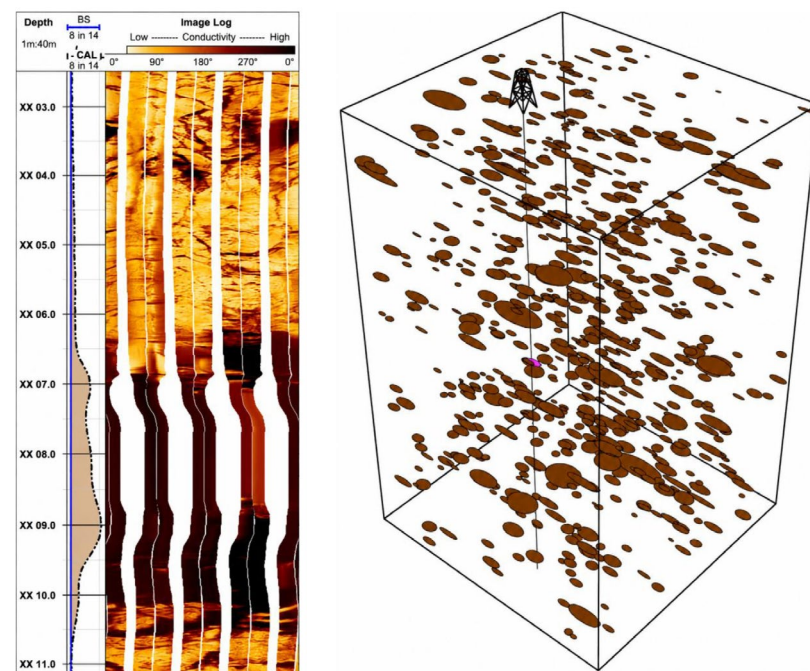
To test the idea, we built a model in which caverns were represented as discrete elements with dimensions similar to modern water table caves (the majority within the sub-seismic realm) and ran

a Monte Carlo simulation. Caverns were distributed stochastically within a $256 \times 256 \times 400$ m reservoir volume (roughly equivalent to 16-acre well spacing), and we focused on realisations in which the well intersected one and only one cavern. The question was simple: how many other caverns could we place around the well while intersecting only one? After 40 realisations, we found that a single cave intersection was consistent with somewhere between 670 and 768 caverns "hiding" in that reservoir volume.

One intersection, therefore, does not necessarily mean one isolated cave. It may be the only cavern the well happened to sample from a population of hundreds. And more importantly, the volumetric implications of the "missing caverns" can be significant. For the scenario tested and assuming caverns are 100 % open, that single intersection could imply an uplift in the in-place volumes of up to 14 %, with the greatest impact in low-matrix-porosity reservoirs. On the other hand, we also observed that some realisations contained as many as 500 caverns without the well intersecting a single one. In a karst-prone setting, not hitting a cave does not mean the caves are not there. This makes the geological concept and data that sample beyond the borehole (such as well tests) critical to understanding what the well may have missed.

Hit one cave, and there may be hundreds more. Hit none, and they may still be there. This small change in perspective, when supported by a sound geologic concept, can be a wake-up call that your in-place volumes may be missing more than you think.

ILLUSTRATION: MODIFIED AFTER FERNANDEZ-IBANEZ ET AL. (2019), SEARCH AND DISCOVERY ARTICLE #42424



Left: Example of a cave observed on a resistivity image log. Note the caliper enlargement and high conductivity associated with the feature, consistent with open pore space. Right: Example of a Monte Carlo realisation in which caverns were randomly distributed within a given volume. This realisation contains 705 caves, yet the well path intersects only one (magenta).

From thrust faults to landslides

When millions of years of deformation culminate in one catastrophic event

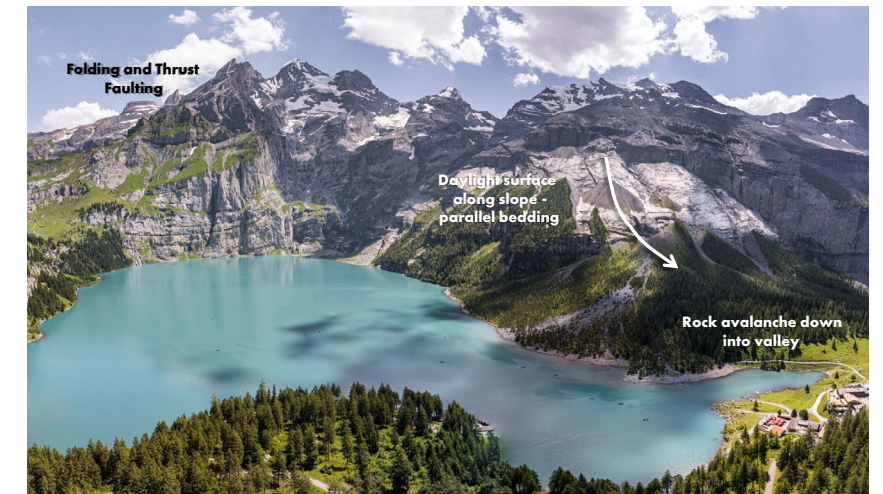
MOLLY TURKO, DEVON ENERGY



AS I HIKE the trail around Lake Oeschinensee near Kandersteg, Switzerland, my attention kept drifting away from the brilliant turquoise water toward the towering limestone cliffs across the lake. The scenery is breathtaking, and it is easy to understand why Oeschinensee lies within the UNESCO Swiss Alps Jungfrau-Aletsch World Heritage Site. But as a structural geologist, I found myself asking a different question: Why did the mountainside fail?

The answer may have begun millions of years ago during the Alpine Orogeny. As the African and European plates collided, sedimentary rocks deposited in the ancient Tethys Ocean were compressed, folded, and transported along large thrust faults. These tectonic forces built the Alps while folding and rotating limestone and shale beds into the steeply dipping orientations visible today.

Looking across the lake, the bedding appears to dip toward the valley, suggesting a slope where bedding planes may daylight. Although this observation would require detailed field mapping to confirm, published studies indicate that glacial undercutting created a daylighting condition for otherwise slope-parallel bedding



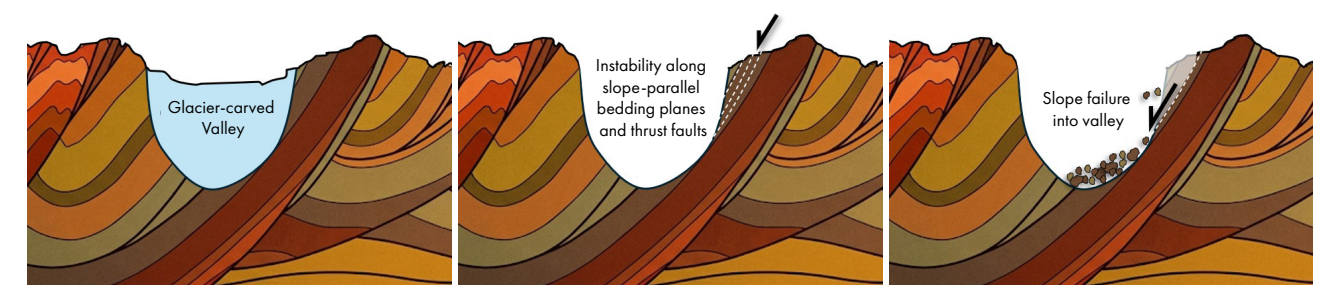
Once you recognise the rock avalanche on the right, the relationship to Lake Oeschinensee becomes obvious.

discontinuities, providing a plausible structural mechanism for failure. My interpretation is that Alpine thrusting rotated these beds into orientations favourable for gravitational failure, while glacial oversteepening removed support from the slope. An earthquake may then have provided the final trigger.

Approximately 3,200 years ago, a massive rock avalanche detached from the adjacent mountainside, damming the valley and creating the natural lake seen today. What appears to be a peaceful alpine landscape is, in fact, the product of millions of years of tec-

tonic deformation followed by a single catastrophic event.

Although every slope has its own geologic history, Oeschinensee illustrates a principle recognised by engineering geologists worldwide: mountain slopes are often predisposed to failure long before they collapse. The orientation of bedding, faults, and fractures may determine where future rock avalanches occur, while glaciers, rivers, or human excavation remove the support that once kept those slopes stable. Understanding structural geology is therefore critical for evaluating geologic hazards that threaten infrastructure and communities.



How glacial undercutting can create the circumstances in which, followed by an external trigger such as an earthquake, a rock avalanche occurs.

PHOTOGRAPHY: OESCHINENSEE.CH



What do you see here?

If you were here with me, what would you see in this outcrop?

Coring for beginners

A cautionary tale

IT WAS the summer of 1989. After a year of kicking around the North Sea, for several reasons I ended up in a Toyota Land Cruiser a few hours south of Jebel Dhanna, United Arab Emirates. We approached a land rig sheltering on the rocky desert floor under the bulk of a vast, crouching sand dune.

Prior to coming to the rig, I had paid a visit to the offices of the oil company in Abu Dhabi and met the wellsite geologist. It was the last time I would see him. I was tested on my knowledge of the Dunham Carbonate Classification – successfully avoiding the cement core trap – promised daily calls and weekly visits, and sent off into the desert.

The job was, on paper, very simple. These were the days before LWD, so the plan was drill, drill, drill, wait for the drilling break, circulate up a sample and then pull out to core. Job done.

The first few weeks were quiet. Steady drilling and casing runs. No excitement beyond the locals who wandered into camp every few days to see what they could ‘acquire’. Comms with the office in town were patchy at best. A single fax machine and radio in the Company Man’s office, strictly forbidden to lowly data engineers. Still, we had our instructions and the job seemed straightforward. Finally, we approached the reservoir section. I remembered the instruction. Drill until the jump in penetration rate, circulate for a sample and pull out to core.

It was here that the first problem arose. The Company Man had his own plans and his own schedule, and none of them included wasting time circulating for samples. Drill until the break, pull out of hole, run in and cut core. And since the Company Man was God, that is what we did.

The coring was easy – perhaps too easy – and we awaited the arrival on surface of the 30 ft of reef limestones hopefully dripping with oil. Sadly, what appeared as we laid out the core was definitely not reef limestones and not a drop of oil was in sight. Our drilling break had been caused by an anhydrite bed, and what lay before us in the old core boxes was just under 30 ft of beautiful, shimmering white anhydrite pillows, each delineated by a fine curtain of claystone. It looked lovely. It also looked like the end of my short career in the oil industry.

Inevitably, the core had arrived at surface just before midnight, and it was 2 am before we finally had it laid out ready for packing. I went back to the camp a mile away from the rig, dreading the conversations that I faced in the morning. But as it turned out, those difficult confessions would not be needed. When I arrived back in the morning, the core was gone. Not dispatched to town as planned, but stolen in the night. True to form, the locals had come into camp, taken



Anhydrite, especially when wetted, has an appealing look.

a fancy to the core and nicked the lot. Only small fragments of anhydrite remained, shimmering in the dawn light. Nobody had seen anything, nobody knew anything. The Company Man called me into the office, explained that the daily drilling report would say recovery was zero percent, core lost in hole, and we were going back drilling.

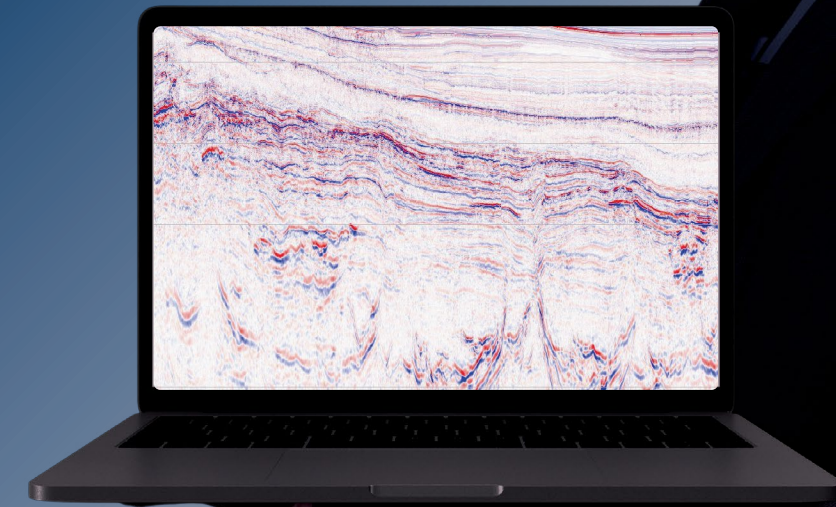
My career, short as it had been to that point, was saved, and I suppose I had learnt a few valuable lessons. I spent another year working round the land jobs in the Emirates before moving on to pastures new. And I can only assume that fragments of that core are decorating tourist mantelpieces in various far-flung parts of the world. ■

By a now-experienced operations geologist

PHOTOGRAPHY: HENK KOMBRINK

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