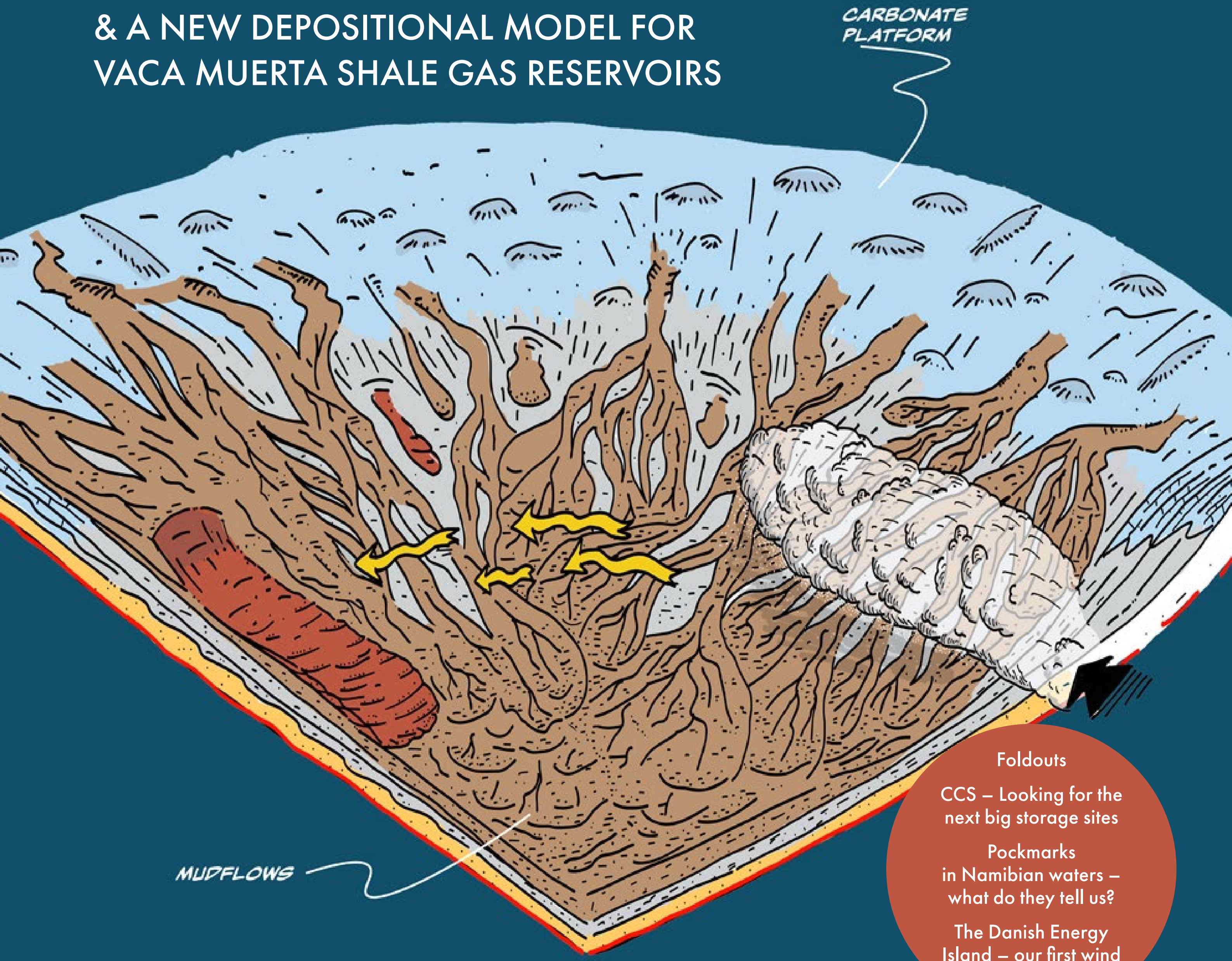
THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

VOL. 21

GEO ExPro 2 2024

GAS!

THE STATE OF GLOBAL GAS EXPLORATION & A NEW DEPOSITIONAL MODEL FOR VACA MUERTA SHALE GAS RESERVOIRS



Foldouts

CCS – Looking for the next big storage sites

Pockmarks in Namibian waters – what do they tell us?

The Danish Energy Island – our first wind foldout!

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Print
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GxP PUBLISHING

Energy all

I DO NOT get the black-and-white tone of the debate around fossil and renewable energy. You are either anti-oil or anti-wind. The media seems to play the game along those lines too, which I think is detrimental to forming a more balanced view.

As a magazine, we know that we will not change the course of this public debate, but coming to it from a subsurface perspective means that we cover both fossil as well as "new" energy. We acknowledge that the time of oil and gas is not over yet, whilst solutions such as geothermal, offshore wind and CCS are increasingly being trialed across the world. We report on it all because it is the subsurface that forms the common denominator.

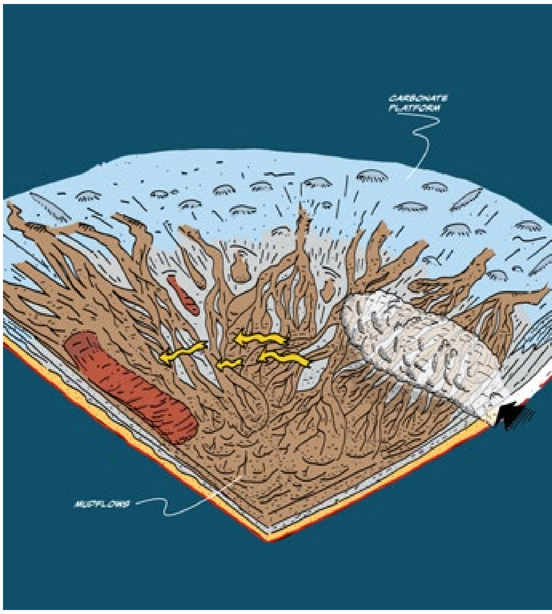
"We report on fossil and new energy because it is the subsurface that forms the common denominator."

With that in mind, we are very pleased to host our first wind seismic foldout in the magazine. Denmark is a country that has always been ambitious when it comes to the rollout of offshore wind, and the plans to build an offshore Energy Island was one of the ideas to give this a major boost. As a result, SolidGround and Geosurveys acquired an innovative seismic survey to better map the shallow and deeper subsurface for ground stability concerns. Have a look at the incredibly fascinating geology that is being imaged as a result!

Henk Kombrink

BEHIND THE COVER

Our cover story is about the state of global gas exploration. In contrast to what public narrative sometimes suggests, it turns out that there is no real gas shortage. The possibility to ship gas around the world has a major stake in that – as further explained by Carole Nakhle in her column on page 11. Shale gas production is another reason for this, as the Permian and other US basins have shown. And let's not forget the Vaca Muerta in Argentina. Here, we feature a depositional facies diagram drawn by Marcos Asensio from Argentina, beautifully illustrating how the Vaca Muerta fines were deposited – not by the generally accepted idea of "fallout" but by mudflows instead!



COVER ILLUSTRATION: MARCOS ASENSIO

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EAGE Annual 2024 – Technology and Talent for a Secure Energy Future

Short-term, secure and affordable access to oil and gas is a prerequisite for the welfare of a growing global population. Longer term, a transition to a dominantly renewable based energy system with mitigation of remaining carbon emissions is a prerequisite for a habitable planet for that growing population

FOLLOWING A VERY successful and well-attended 84th EAGE conference in Vienna, it is with great pleasure to announce the 85th EAGE Annual Conference & Exhibition in Oslo. The programme includes a state-of-the-art conference, exhibition, workshops, short courses, field trips, and community & student activities.

"We look forward to a broad and balanced Technical Programme built on in-depth discipline knowledge, focused on technical integration for holistic solutions and on cross-fertilization between oil & gas, CCS, renewables and infrastructure geosciences", says Erik Vågnes, Conference Chair.

The theme – *Technology and talent for a secure and sustainable energy future* – sums up the most important contribution by our EAGE community to the societies we live and work in.

Brace yourself for thought-provoking discussions that will ignite conversations on propelling us towards a sustainable energy future, all while harnessing cutting-edge technology and nurturing exceptional talent.

Further information at: eageannual.org

Look forward to engaging discussions on the dilemmas and opportunities impacting the geosciences in a rapidly changing world - welcome to Oslo!

AP2024: Exploring Asia Pacific's Energy Future

GESGB – SEAPEX Asia Pacific Conference, The Kia Oval, London 18-19 June 2024

GESGB AND SEAPEX have again joined forces to bring the third edition of this exciting event to London in June 2024. "AP2024: Exploring Asia Pacific's Energy Future" will present insights into wide ranging aspects of geoscience in the energy sector of the world's fastest growing region, as it strives to meet the demands of delivering clean and affordable energy for the future.

A comprehensive two-day programme is scheduled, featuring key IOC's, regional E&P companies, government Agencies, service providers and analysts covering topics including basin to reservoir scale case studies, frontier exploration to developments, geoscience technology applications and the role of geoscience in the Energy Transition.

AP2024 will once again be hosted at the Oval Cricket Ground and includes a large exhibition area for companies to showcase services and products - booth spaces and sponsorship opportunities are still available. A full social programme includes a Conference Evening at the venue (which may even feature some cricket) and on the final evening, the Young Professionals Group will be hosting an Energy on Draft event at a nearby pub.

A Farmout and Promotions Forum to present energy investment opportunities across the Asia Pacific region will be held on the afternoon of 17 June, prior to the main conference, and is followed by an Icebreaker event. Slots are available for companies wishing to present at this forum.

Further information at: asiapacific.ges-gb.org.uk
Colin Murray, Technical Committee Chairman of Asia Pacific 2024

The Asia Pacific Conference takes place on 18-19 June 2024

PHOTOGRAPHY: EAGE; SHUTTERSTOCK

Optimize Your Unconventional Resource Plays

The 2024 Unconventional Resources Technology Conference (URTeC) in Houston, Texas is set to focus on the latest science and technology applied to exploration and development of unconventional resources. Plan now to engage with professionals in all aspects of the unconventional E&P lifecycle

AMID RECENT fluctuations in oil prices and notable industry events, oil and gas majors are surging into 2024 with increased synergies from recent mergers and acquisitions, stabilizing their position in the energy security space.

As the industry's dynamic growth and innovations continue, ensuring that unconventional resources remain a significant component of the energy solution is critical for securing better results for long-term success, and a more efficient and inclusive energy future for all.

URTeC presents a unique opportunity for the world's leading professional geoscientists and engineers to connect, exchange ideas, and foster collaboration on ways of sustaining and propelling our industry.

Experts from around the globe will gather to discuss the integration between the subsurface G&G disciplines, geomechanics, formation evaluation, wellhead design, completion design, enhanced recovery, production forecasting, and the crucial environmental, social, and corporate governance factors. These topics, and more, will be discussed elaborately at the conference.

Further information at: URTeC.org

URTeC will be your best chance you'll have to exchange information, formulate strategic ideas, and solve problems to manage and optimize your unconventional resource plays.

Unearth the Energy Future with GeoConvention 2024

Hosted from Calgary in Canada, GeoConvention 2024 offers a truly hybrid conference through an immersive virtual experience

EMBARK ON AN immersive earth science and energy journey at GeoConvention 2024! This premier gathering invites geoscientists, engineers, and industry leaders to delve into cutting-edge insights, forging connections with global visionaries. Dive into diverse sessions, case studies, workshops, and exhibits showcasing the latest energy trends and innovations, providing hands-on learning experiences and a comprehensive understanding of the interconnected energy ecosystem for professionals and students alike.

From the latest in oil, gas and critical mineral exploration to the advancements in geothermal technologies and sustainable solutions in carbon capture, GeoConvention is a melting pot of ideas that go beyond industry silos.

Set against the stunning backdrop of Calgary in the Canadian Rockies, GeoConvention offers more than a conference—it's an exploration of ideas and a catalyst for advancement.

GeoConvention is an annual technical conference and exhibition produced, in partnership by the Canadian Energy Geoscience Association (CEGA), formerly Canadian Society of Petroleum Geologists and Canadian Well Logging Society and the Canadian Society of Exploration Geophysicists (CSEG). For 2024, the conference will be hosted live in Calgary at the Telus Convention Center and virtually through our online conference platform. GeoConvention offers delegates and attendees the opportunity to network, knowledge share and learn with fellow industry professionals, visit exhibitors and give back to the earth science community.

Further information at: geoconvention.com

PHOTOGRAPHY: AAPG; GEOCONVENTION

FIRSTS

"...Chevron has now acquired a stake
in exactly the same area it drilled the first two
wells in 50 years ago!"

Ian Cross – Moyes & Co

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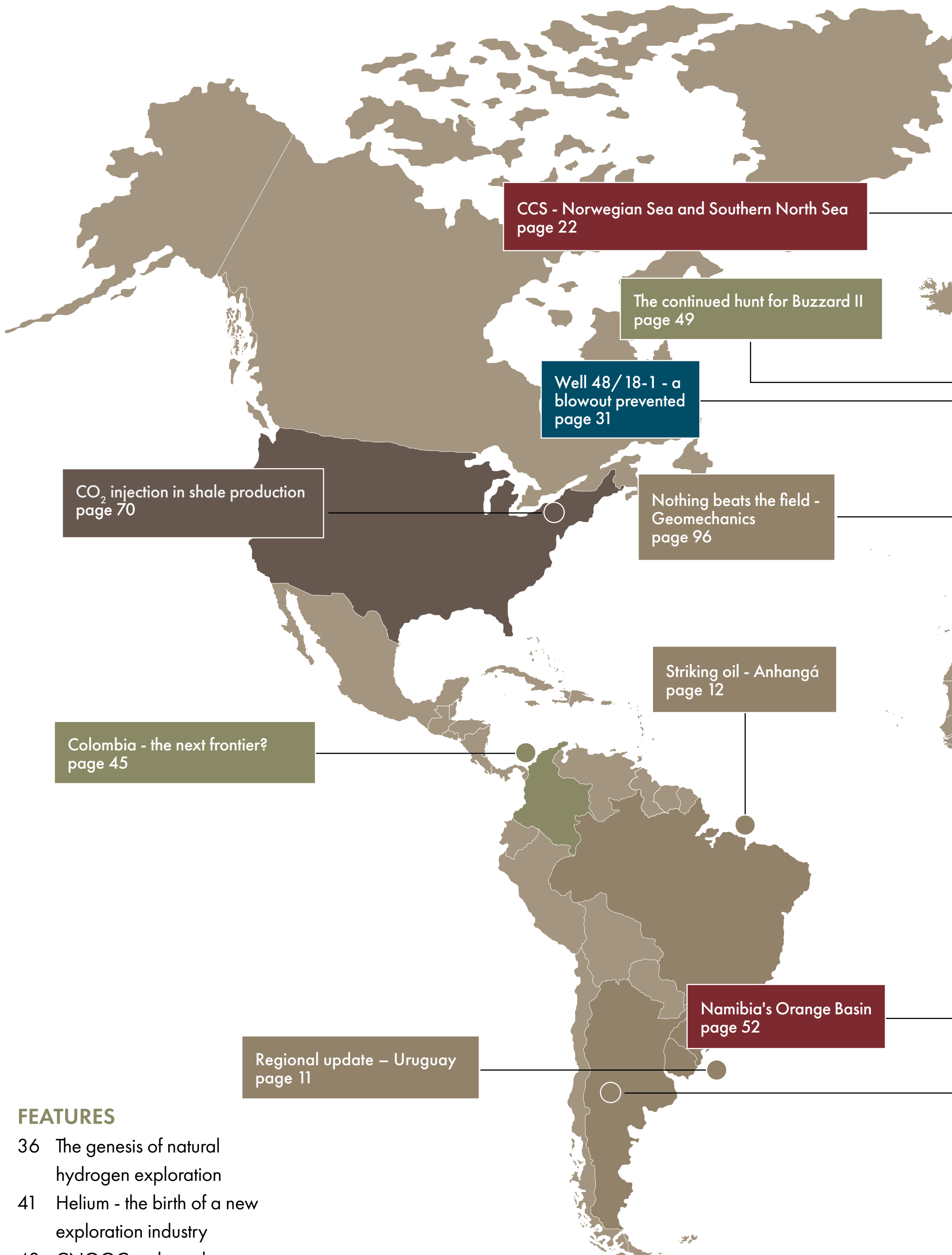

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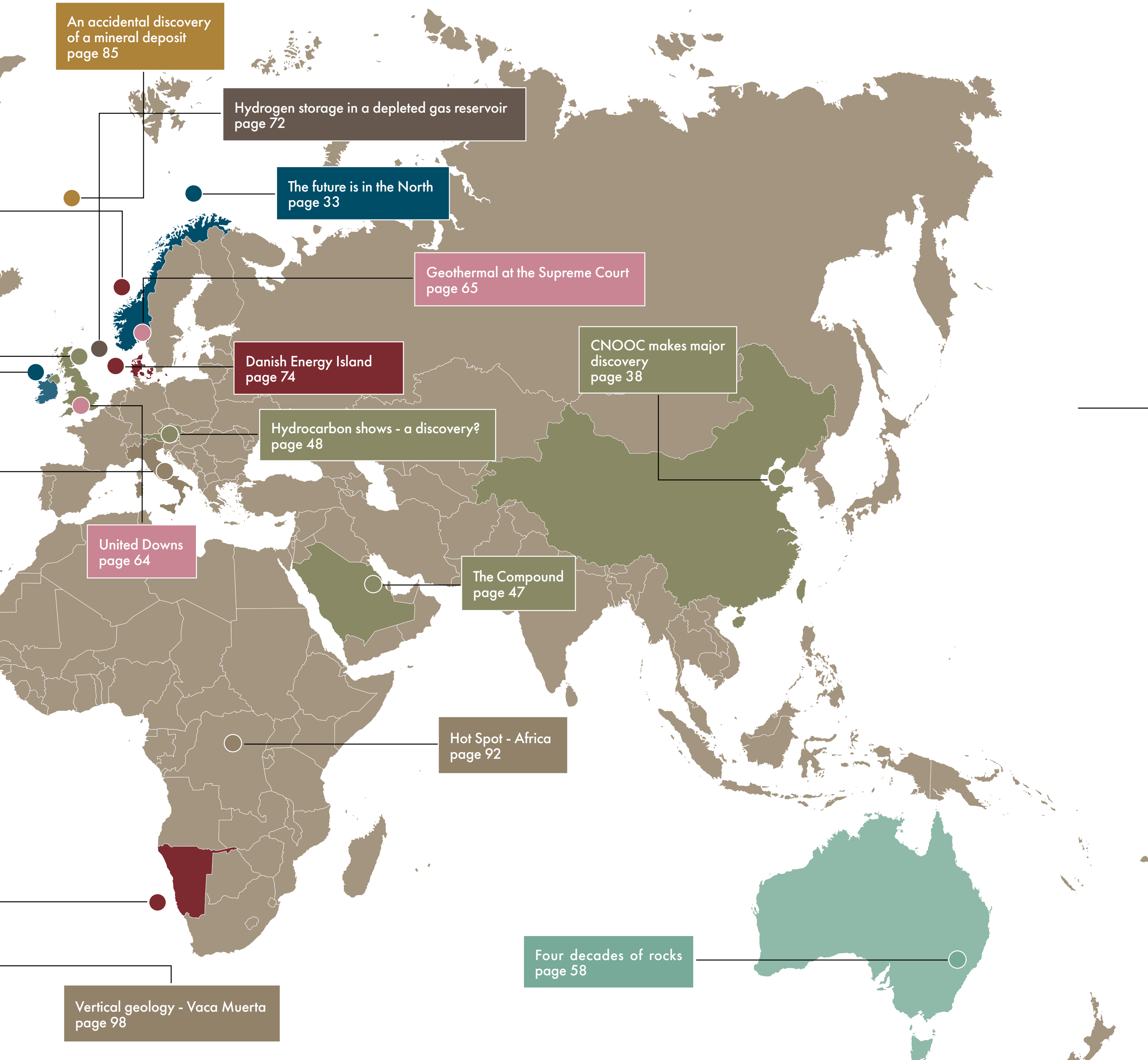

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The globalization of gas

Why the European energy crisis of 2022 should not have come ten years earlier

In 2022, Europe witnessed an energy crisis like no other in modern times. Natural gas prices soared, hitting a historic high of more than € 330 per MWh in August 2022. A year later, European energy markets seem to have shifted from scarcity to plenty; gas prices have hovered at a fraction of their 2022 peak, even though the main culprit behind the 2022 crisis – the war in Ukraine – is still ongoing.

Several developments have led to such a contrasting picture over a relatively short period, chief among them is the evolution of gas trade and primarily its globalization through LNG – a trend that is unlikely to be reversed.

Although gas trade remains largely a regional affair with only 24 % traded globally, gas markets are undergoing notable changes. The global LNG trade has proliferated in recent years, driven by increasing demand for natural gas as a cleaner energy source and the availability of new sources of supply from countries such as the US, Australia, Qatar, and East Africa.

Between 2011 and 2021, interregional LNG trade grew more than four times as fast as pipeline trade and in 2020, for the first time, the share of gas traded as LNG overtook that by pipeline. While regional gas markets continue to exhibit significant differences in consumption, production, transport infrastructure and pricing, with the advent of LNG, hitherto isolated regions have increasingly become interconnected, and a globalized gas market is gradually emerging, with major implications on pricing and the relationship between producers and consumers as well as geopolitics.

"...and in 2020, for the first time, the share of gas traded as LNG overtook that by pipeline."

Those changes have shortened the length of the energy crisis of 2022 in Europe; had the crisis occurred a decade ago, the impact would have been much more detrimental. ■

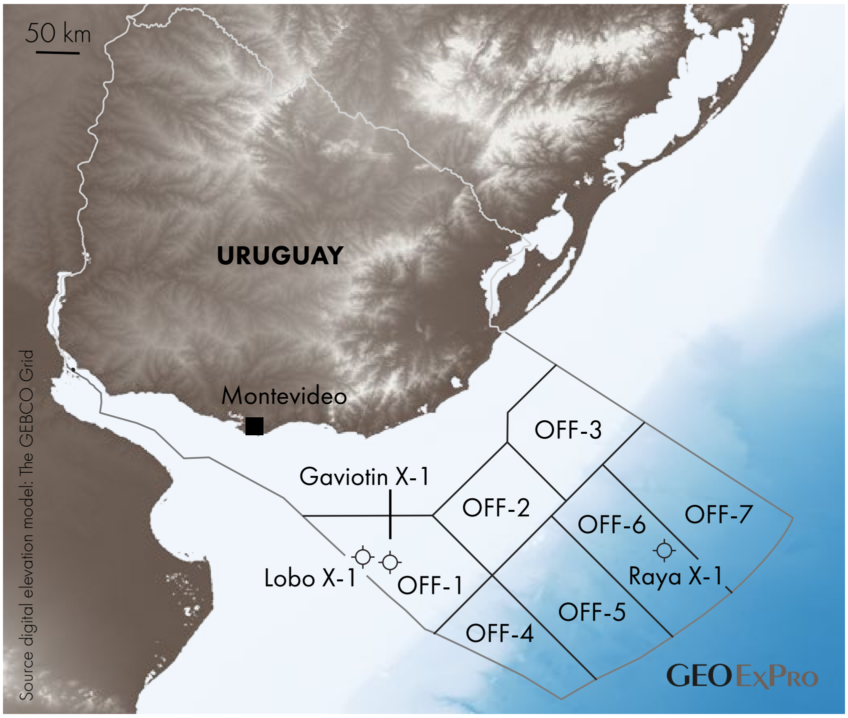
Dr Carole Nakhle is a leading voice in the debate on how the world's energy mix is evolving. She is the founder and CEO of Crystol Energy, a firm that specialises in energy investment, policy and strategies. In addition, she is a sought-after interviewee for various TV channels and has many advisory roles that complement her busy agenda.

Uruguay – from totally open to totally licensed in just a few years

History is repeating itself in Uruguay. And Chevron plays an important role

When the Kudu gas field was discovered offshore Namibia in the early 1970s, Chevron jumped to the other side of the Atlantic to take acreage in Uruguay in a similar setting. It led to the drilling of Uruguay's first couple of offshore wells Lobo X-1 and Gaviotin X-1 in shallow waters near the offshore border with Argentina. The results were disappointing even though subsequent analyses showed that hydrocarbons had migrated through the area.

Over the next decades, the focus was on acquiring seismic data until Uruguay launched the first formal bid round in 2008, which was followed by Round II in 2012. The second round was highly competitive and among the winners as operator were bp, TotalEnergies, British Gas, Tullow and YPF.



In 2016, the first wildcat was drilled offshore Uruguay after 40 years. Raya X-1, operated by TotalEnergies and with ExxonMobil and Equinor as partners, was located in the Pelotas Basin, and set a record at the time for being the deepest water well in the world; a staggering 3,400 m. The high-profile well failed to encounter any significant hydrocarbons.

In 2019, buoyed by industry interest in the southern Atlantic, ANCAP introduced the Open Uruguay Round, a semi-annual open round process that continuously offers acreage. This format was a success and impressively within just a few years the country has gone from being totally open in 2020 to fully licensed in 2023. It also saw the return of major players back into the country. And the interesting thing is that Chevron has now acquired a stake in exactly the same area it drilled the first two wells in 50 years ago! It is certainly déja-vu for Chevron.

The Americans acquired a 60% stake in Challenger Energy's AREA OFF-1 in the Punta del Este Basin. Immediate work in the block involves a 3D seismic programme as part of the farm-in agreement in the next 18 months and this is expected to focus on two shelf margin prospects in the 550-800 m water depth range. Other work planned includes drilling in the Apache-operated AREA OFF-6 and 2,500 km^2 of 3D seismic in its AREA OFF-4 in which Shell is a 40% partner. Other blocks already have large amounts of 3D seismic data and firm work will involve the reprocessing of existing data in the current phases before firm drilling in the next period.

Meanwhile, 2024 activities offshore Argentina will be closely followed by Uruguay with major 3D surveys planned and of course the much-awaited Equinor-operated Argerich-1 deepwater well in the North Argentinian Basin. The well has both Shell and YPF as partners, giving them involvement into the deepwater of adjacent countries geology, and in Shell's case both sides of the southern Atlantic in similar settings. ■

Ian Cross - Moyes & Co

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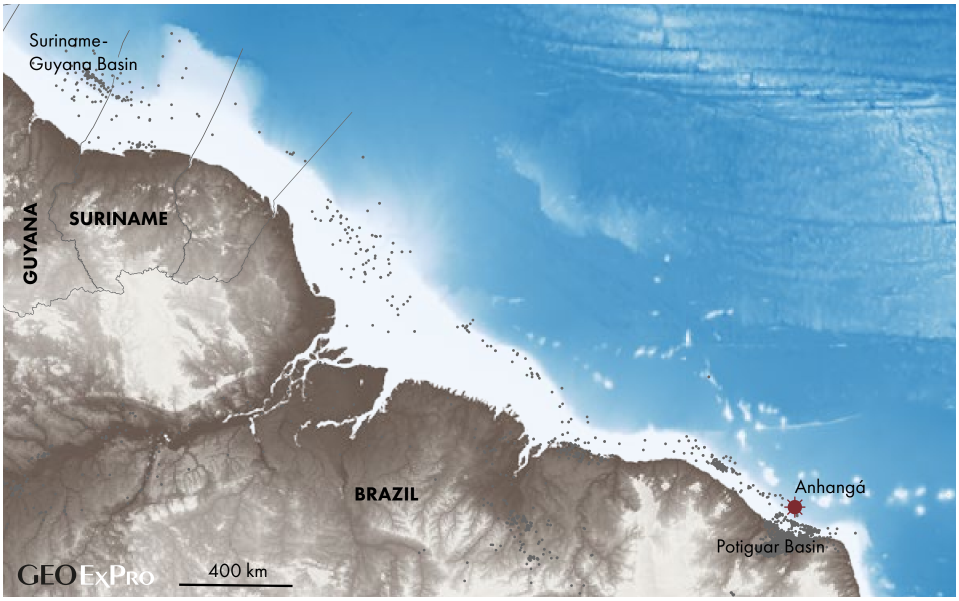
Hydrocarbon find at the far eastern end of Brazil's Equatorial Margin

Discovery still needs further work to prove commerciality, but a comparison to what is happening further west is easy to make

Early April, Petrobras announced the discovery of hydrocarbons in the ultra-deep waters of the Potiguar Basin in Brazil. The well, named Anhangá, found hydrocarbons in turbidite reservoir sands of Albian age. Specific mention was made by the operator - who holds a 100 % stake in the block where the well was drilled – that the find is significant considering the exploration success in the Suriname-Guyana Basin. That is why we plotted both areas on one map, showing the distance between the two.



And as the map clearly shows, the distance between the two areas is significant and amounts to around 2,600 km. Yet, given the age of the find in Brazil, which is only a little older than most of the discoveries in the Suriname-Guyana Basin, the similar depositional facies of the reservoir and the overall setting along the margin, it is not strange to see some excitement following the news release.

The Potiguar Basin is located at the far eastern end of the Brazilian Equatorial Margin, which correlates to the West African Equatorial Margin and the Benin Basin on the opposite side of the Atlantic. The basin has a rich history of oil exploration and production in both the onshore and shallow waters, and is probably the most densely drilled area (onshore) that is shown on the map. In that sense, there is a clear difference with the Suriname-Guyana Basin, where onshore exploration has never taken off to the same extent except from a few discoveries in Suriname. However, very little is known about the offshore deep and ultra-deep water areas of the Potiguar Basin.

"In that sense, there is a clear difference with the Suriname-Guyana Basin, where onshore exploration has never taken off to the same extent except from a few discoveries in Suriname."

THREE SOURCE ROCKS

In a paper published in the Journal of South American Earth Sciences in 2021 about the exploration plays of the Potiguar Basin in Brazil, the authors write that deep and ultra-deep waters of the area represent one of the most important frontier basins on the Brazilian Equatorial Margin, especially after the discoveries made on the West Africa conjugate margin (Jubilee, Tweneboa).

Three source rock intervals were identified by the authors; Late Berriasian-early Barremian lacustrine shales, Aptian-Albian evaporitic marine shales and Cenomanian-Turonian deep water marine shales. A maximum TOC of 21 % was measured in the Aptian-Albian source rocks, which classifies these as the most promising. Combined with the fact that these are thermally mature in the area as the authors write, it may not be too much of a surprise to have found hydrocarbons in the Anhangá well given that the reservoirs are of the same age and are probably very close to the source rock. ■

Henk Kombrink

COVER STORY

"We've been looking for oil, but we have found a lot of gas instead"

Graeme Bagley – Westwood Energy Global

THE STATE OF GLOBAL GAS EXPLORATION

As the world has seen a dramatic shift in gas supply routes due to the Ukraine war, we take a look at gas exploration activities around the world. Is there a shortage of gas, or not? We asked analysts from Westwood Global Energy for their insights. This is further complemented by reports from Colombia and Venezuela; countries that many will not associate with gas straight away but two places with a lot of potential.

HENK KOMBRINK

"IF WE LOOK back at the years before the pandemic and the Ukraine invasion, the only countries where we saw a consistent search for gas were the countries around the East Mediterranean and probably in Malaysia with Petronas being quite active on that front. That was kind of the steady state scenario", says Graeme Bagley from Westwood Global Energy.

We spoke to Graeme and his colleague Joe Killen to hear more about the global gas exploration outlook.

Then, the situation changed completely, as we all know. With Europe being shut off from the piped gas supply directly from Russia, there was a sudden peak in interest in LNG as a means to guarantee security of supply. It also sparked the idea that a shortage of gas would soon kick in. But is this sentiment correct?

"If we go back to around 2008 and look at the high-impact wells drilled from that year until now, it turns out that companies have often found gas when they were looking for oil", says Graeme. "Around 70 % of the high-impact exploration wells drilled over that time targeted oil specifically, with the remainder of them looking for gas, but the results of those wells show an entirely different picture. It is rather the opposite, with around 60 % of resources found being gas and the rest oil." This is particularly true for the African margins, both on the eastern and western sides. And what did that mean? It resulted in a lot of gas being stranded!"

"Based on these observations, the picture of there being a global gas shortage is probably not correct", explains Graeme. "And, what we are seeing now is a pattern of gas prices going back to pre-covid levels, albeit with a difference between prices in NW Europe and North America. This has alleviated some of the concerns that were raised when price peaked a couple of years ago."

"In that framework, we still see the East Med as an area where exploration for gas continues to be the main target, with the idea to both supply local markets as well as piping it to northwest Europe. But as said above, there are many other places where there is plenty of gas, gas that is not necessarily seen as an asset."

"We've been looking for a lot of oil, but we have found a lot of gas instead"

"For instance, there is a lot of associated and non-associated gas in the Suriname-Guyana basin, amounting to around 35 Tcf", says Joe. "Given the very limited local market, the only way to monetise the gas at scale is through LNG, which then competes with the North American and Middle East LNG supplies. That explains why only 200 Bcf of gas has been commissioned until now for gas-to-power projects in Guyana, which is really tiny when you look at the potential", Joe continues. "In that sense, Guyana is a classic example of the challenges gas developments face, at a time when all the capex goes to oil developments. For now, the produced gas is being re-injected, but at some point this will need to be developed "

SOUTH AMERICA

In Brazil, recent exploration more outboard has found more gas, which is often quite high in CO_2 as well", says Graeme. Deep-water gas that is also high in CO_2 is not the easiest to develop and will likely be stranded for now."

"In Colombia, the picture is different, and we have seen some recent dedicated gas exploration there that has resulted in finding gas", continues Graeme. "The country may also soon see the deepest-ever well spud, at > 4,000 m, which is targeting oil but may hit gas. Because there is a local developed market in Colombia, it means that there is a much better outlook for developing gas infrastructure."

AFRICA

West Africa, Senegal and Mauretania are prime examples of countries where gas developments have struggled in recent years. "We have seen GTA being delayed, delayed and delayed, because of complex development, a limited local market and therefore the need to build an LNG scheme", says Graeme. "This has resulted in bp announcing a 1.1 billion USD cost impairment in the region because of the delays and cost overruns. Additionally, last year bp walked away from the Yakaar-Teranga discovery in the same area, which also contains gas and was seen as the biggest discovery in the world in 2017. We think that subsurface complexities played a role in this decision too, with low resource density, heavily compartmentalised reservoirs and water interfingering with the gas. The discovery would need more appraisal drilling before this can go anywhere. The last gas discovery was Orca, where the PSC will end fairly soon and if nothing happens, it will then be back into the government's hands."

"Angola recently made a move towards a regime that favours the development of gas", says Graeme. "In the past, gas was held by the government and the IOC's had no right to develop it. That led to a lot of stranded gas, of which Kwanza is a prime example. These terms have now changed, with the IOC's being able to market the gas they are finding themselves. This is starting to provide some movement in the country, but let's be clear that this is all gas development as a by-product of oil rather than dedicated gas exploration."

The 1 Tcf Kudu discovery in Namibia, which was made in the 1970's already, is another example of an old stranded gas accumulation that is not even in very deep water. It is an interesting case from a country that is now seen as the new global exploration hotspot. A hotspot for oil, not gas. "But based on the limited data we've got, we do think that there are fairly high ▸

NATURAL GAS: The best ally for Colombia's energy transition

The natural gas situation in Colombia is approaching a critical point in which every decision made will have direct repercussions on the country's energy future and its energy transition plans

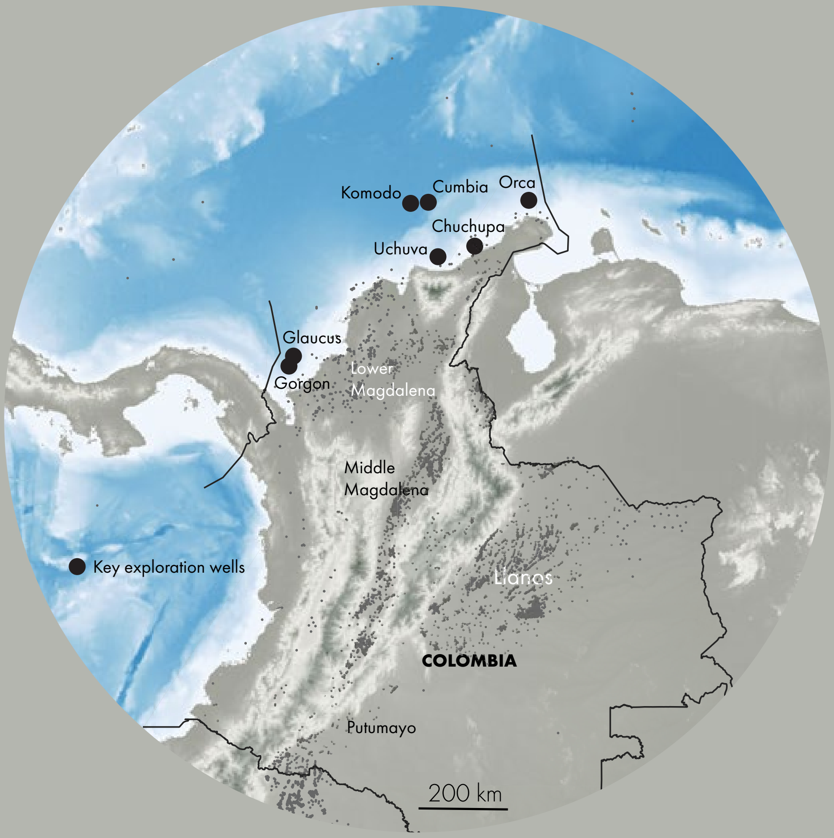
JUAN PABLO RAMOS, UNIVERSITY OF HOUSTON

ALTHOUGH natural gas production (1,050 MMcfd) in Colombia exceeds daily demand (960 MMcfd), the contrary could occur in the coming years with increasing demand and a slowdown in discoveries and decline in reserves.

The growth in demand is likely to unfold as over 1.5 million households that nowadays still rely on firewood for cooking are expected to elevate their living standards through the adoption of natural gas. Simultaneously, the nation's concerted efforts to mitigate emissions entail a gradual shift away from coal production, further fueling the momentum toward embracing cleaner energy alternatives like natural gas.

Encouragingly, Colombia has shown clear signs of additional natural gas potential across both its onshore and offshore basins in recent years, signaling a promising trajectory for future exploration and development endeavors. Onshore, operating companies have continued to report gas discoveries in the Lower and Middle Magdalena Valley, Llanos, and Putumayo basins, while the increase in GOR continues to be an opportunity to improve domestic gas production in mature fields and basins.

Offshore, the ongoing discoveries made by Ecopetrol, Shell, and Petrobras (Gorgon, Glaucus, Uchuva, and Orca) continue to give indications of the potential for developing new offshore natural gas reserves in Colombia. Likewise, exploratory plans in ultra-deep waters by Oxy, Chevron, and Ecopetrol (Komodo and Cumbia) add to the high potential that the Caribbean represents for Colombia's energy sufficiency. This potential is so clear that at the CERAWeek Energy Conference in Houston, Joelson Mendes, Petrobras' chief exploration and production officer, told Reuters that "there could be more gas than what Colombia needs."



Given Colombia's advantageous location with access to markets in Asia, Europe, and Central America due to its exit to the Pacific and Atlantic Oceans and its proximity to the Panama Canal, this increase in gas reserves could mean a business opportunity with the possibility of establishing LNG facilities thereby enabling direct exports to numerous markets – a longstanding objective of present regional operators. This plan to establish Colombia as a natural gas-producing province must be based on a cohesive and integrated approach among the different regional actors in the industry. This concerted effort is crucial not only for meeting the needs of both local and international consumers but also for aligning with national and global energy transition objectives. The potential is monumental, promising transformative impacts on both a national and global scale.

levels of associated gas in Venus and Graff though", says Graeme. "As in the Suriname-Guyana Basin, we think that the gas will first be re-injected for reservoir management purposes, deferring a decision on how to produce the gas." "At the same time, there will probably be a discussion between the government and the operators on this, adds Joe, "as it is likely that the government will prefer the gas to be developed straight away."

"Recent gas discoveries in South Africa have also resulted in plenty of resources potentially available for a fairly mature market", says Graeme, "but the competition with the mining communities and the risk of significant redundancies there has put the brakes on further exploration in the offshore. Again, it is a matter of local demand."

If we move further around the corner of Africa we arrive in Mozambique and Tanzania, again an area with huge stalled gas resources. "In Mozambique alone, there are 15 billion boe of stalled gas resources", says Joe. In Tanzania there is another 5 billion boe awaiting development. That's why any exploration happening in these countries is now targeted to oil, there is no point exploring for gas there."

MIDDLE EAST AND INDIA

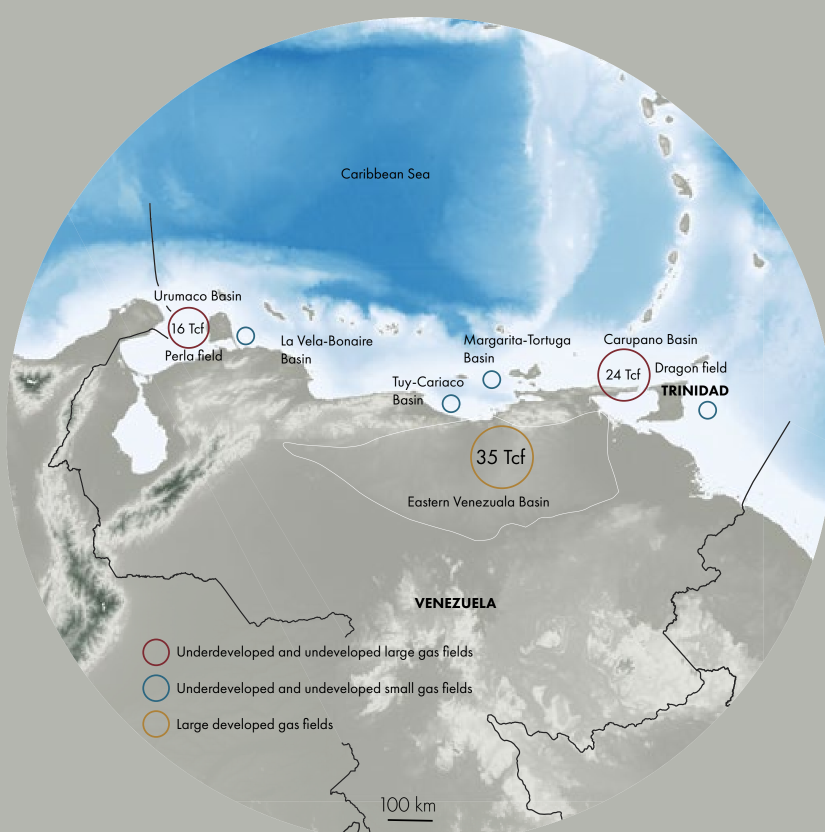
The picture in the Middle East is different. First of all, it is closer to Europe,

MUCH MORE THAN AN OIL COUNTRY

Venezuela holds impressive gas resources that form an opportunity to both develop the country as well as diversifying the energy mix

MAREL SANCHEZ, JUAN FRANCISCO ARMINIO, KATYA CASEY AND KEVIN SCHOFIELD, U3 EXPLORE

With 202 TCF, Venezuela accounts for 73 % of South America's total natural gas resources, but gas production has been minimal in localized domestic markets due to limited existing infrastructure and geopolitical uncertainty. Thus, giant gas discoveries offshore Venezuela are undeveloped due to a lack of investment, while onshore oil production in the Eastern Venezuelan Basin is accompanied by massive natural gas flaring estimated at around 706 Bcf per year in 2022.



OFFSHORE RESOURCES

The Caribbean margin of Venezuela has both discovered gas accumulations and the potential for new exploration. The total OGIP (Original Gas in Place) discovered to date amounts to 44.8 Tcf in the Caribbean waters from the Carupano (24.2 Tcf) and Urumaco (16.6 Tcf) basins.

A gas contract was recently signed for the Dragón field (6.5 Tcf OGIP) to be developed by Shell and the Trinidad and Tobago state with maybe even the potential to pipe gas there, and there is also a better developed local market. “That’s why we see dedicated exploration happening in Oman and the UAE for instance”, says Joe. “At the same time, though the volumes targeted there are not substantial and will not rock the market.”

“Qatar is an interesting example of the global gas race”, adds Graeme. On one hand, the country wants to export as much gas as possible through the production from its North Field and the associated LNG infrastructure. That means that there is an interesting tension in the internationally oriented Qatar Energy, which is now involved in international exploration programmes in the East Med, to not to find too much gas abroad, because it may directly compete with their domestically produced LNG.”

“In India, there is quite a push to develop a domestic gas market to supply a massive population with cleaner fuels. For that reason, especially the eastern margin of India has recently seen a push for exploration through a licensing round and we have identified potentially five high-impact wells in the country that specifically target gas resources in the next couple of years”, explains Joe. In that sense, India tops the charts when it comes to gas exploration in the immediate future. “But still, we don’t see India as a country that will soon become a net exporter of gas because of the geological challenges, and the large domestic market.”

“In summing up, we see that the sentiment that developed in the aftermath of the Ukraine invasion is not justified by the data. Globally speaking, there is no shortage of gas, and despite the increase in capacity of LNG, gas discoveries are still much more attractive when there is a local market to tap into. That was the case decades ago, and it still is the case now”, concludes Graeme. “Plus, we forget the pressure on LNG when it comes to the associated emissions: At the end of the day, piped gas is much more environmentally friendly than LNG.” ■

“In summing up, we see that the sentiment that developed in the aftermath of the Ukraine invasion is not justified by the data. Globally speaking, there is no shortage of gas, and despite the increase in capacity of LNG, gas discoveries are still much more attractive when there is a local market to tap into.”

firm National Gas Company to produce 100 MMCF per day and to contribute to the Trinidad and Tobago Domestic demand.

Other Caribbean basins of Venezuela such as Blanquilla, Tortuga Tuy Cariaco, Gulf of Paria, and Orinoco Offshore, are in the immature to early mature exploratory stage and hold additional potential not only in the identified and tested plays but also in new exploration concepts.

SUPPORTING SDG AND ENERGY TRANSITION

With abundant offshore and onshore gas resources, Venezuela has the potential to become a substantial player in the global gas market. Onshore projects serving the domestic market should be attractive to small players, while the LNG potential of large gas discoveries offshore should attract the supermajor IOCs. Realization of the full potential of Venezuela’s gas resources requires strategic planning for both discovered and yet-to-find resources and an understanding of their use in domestic and international energy markets.

Gas has been recognized internally and externally as an essential element in Venezuela's economic recovery and energy transition: For example, the European Union has proposed boosting Venezuela's natural gas production with funds from "Global Gateway", which will become available if the government guarantees fair elections in July 2024.

Diverting the large volumes of associated gas flared daily in Eastern Venezuela toward gas power generation aimed at minimizing carbon pollution may open business opportunities and provide incentives for changes in the current working practices. For example, as electricity generation from hydropower in the south of Venezuela has declined and increased in relative cost due to aging power-grid infrastructure, gas generation has become an increasingly attractive option for the electrification of towns and villages throughout Eastern Venezuela.

In addition to utilizing currently-flared gas, current production could also be used for power generation in energy-poor regions. For example, only two wells of the 16.6 Tcf NW Venezuelan offshore Caribbean Perla gas field producing 130 MMcf per day (where 1 MMcf per day generates 5 MW) could cover the power demand of the entire Zulia State. This is eminently achievable, as the development plan for the field, operated by CARDON IV, a 50:50 joint venture between ENI and Repsol, has fulfilled phases I and II, reaching 450 MMCF per day.

DIVERSIFYING SOURCES

As global energy markets evolve, diversifying gas supply sources becomes increasingly crucial. Venezuela's sizeable offshore gas resources, proximity to major markets, and industrial know-how can make the country a major gas player in the near future, including large-scale LNG developments in the eastern and Caribbean basins.

Supporting the search for large scale carbon storage sites

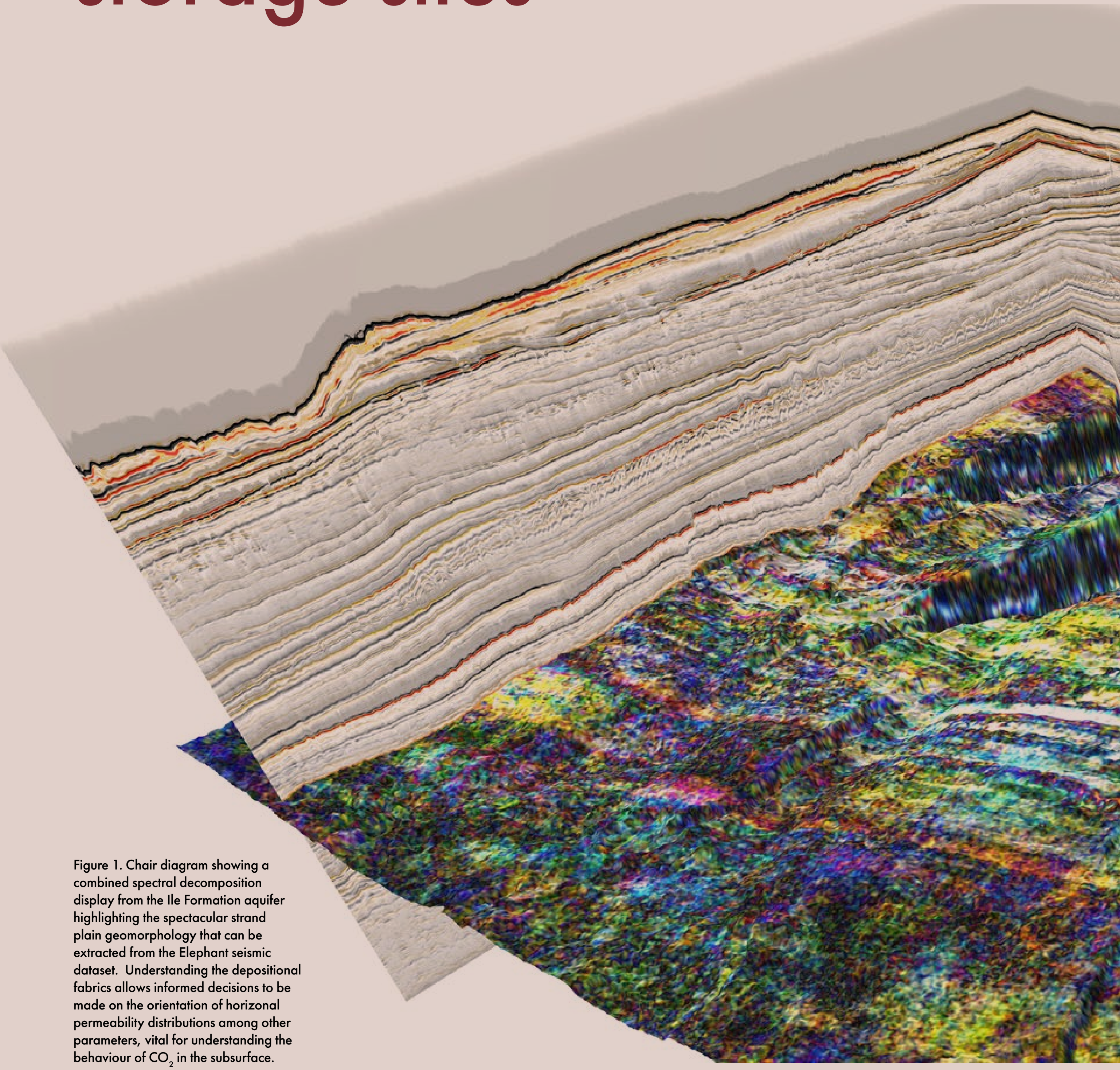
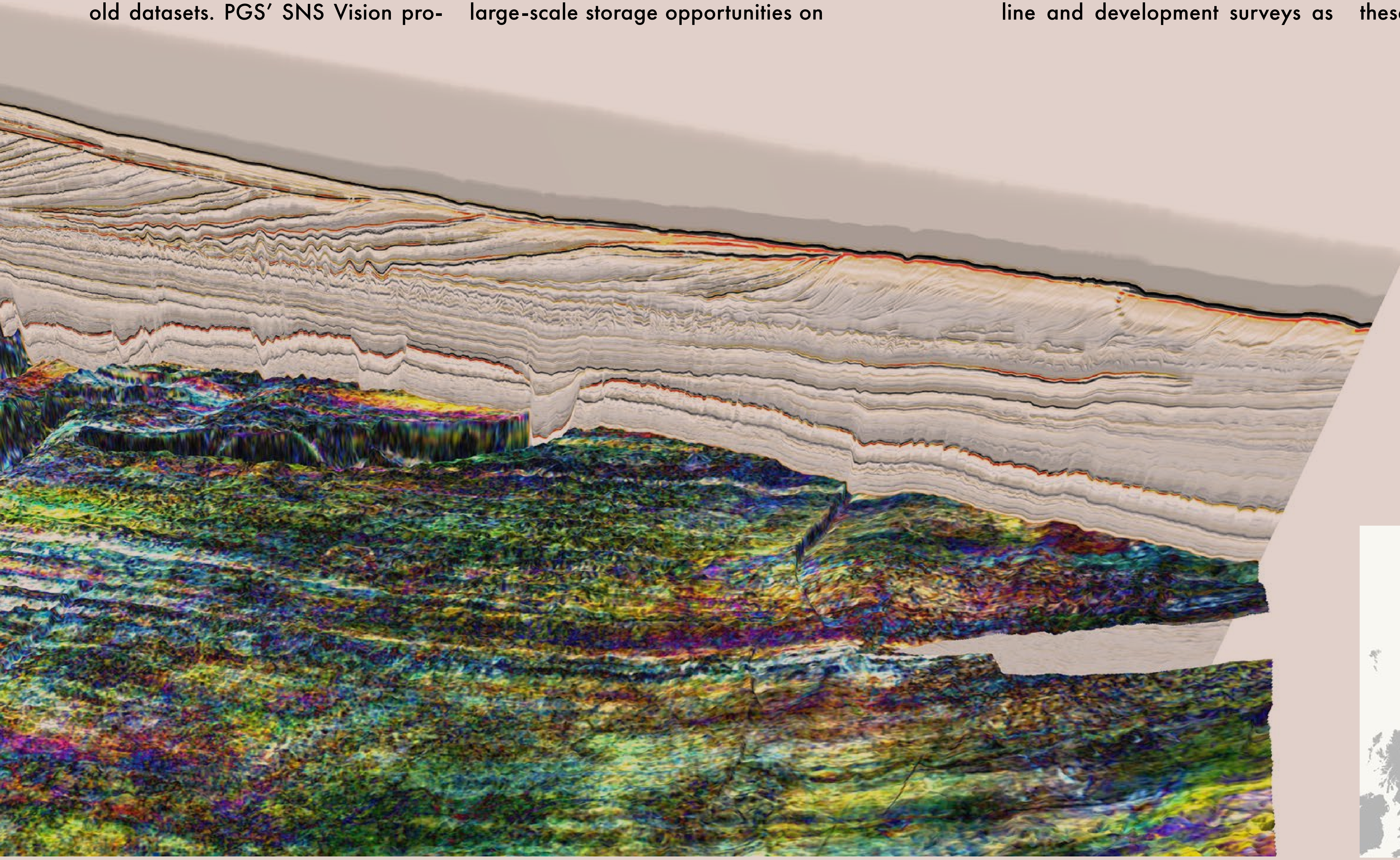


Figure 1. Chair diagram showing a combined spectral decomposition display from the Ile Formation aquifer highlighting the spectacular strand plain geomorphology that can be extracted from the Elephant seismic dataset. Understanding the depositional fabrics allows informed decisions to be made on the orientation of horizonal permeability distributions among other parameters, vital for understanding the behaviour of CO_2 in the subsurface.

PGS is focusing our efforts to support the cost-effective and timely development of new CCS projects, and in particular to meet the needs of site identification, characterization and monitoring. First through the rejuvenation of legacy data, which offers a gateway into new insights within old datasets. PGS' SNS Vision project across the Southern North Sea is a great example of this. Secondly, the opportunity to think differently about our existing MultiClient data library and to explore and develop new concepts within the data. PGS' Elephant project in the Norwegian Sea has demonstrated significant large-scale storage opportunities on library data. Finally, continued investment in technology, R&D and the commitment to new innovation is the third strand of PGS' efforts to support the delivery of new CCS projects. Here, we are focused on delivering the right solutions to new site developments with baseline and development surveys as well as building and delivering new collaborations to support the future of time-lapse monitoring where the developments are retaining the gold standard of 4D seismic monitoring. Part of this effort is to address the cost and efficiency imperatives required by these projects.



The role of the seismic industry in delivering successful CCS scale-up

NICK LEE, BILL POWELL, TILMAN KLUVER AND CYRILLE REISER, PGS

THE SEISMIC INDUSTRY has, for a long time, been involved in helping to support the development and successful operation of CCS projects. PGS' own involvement stretches back to the early days of the Sleipner project, operated by Statoil (now Equinor). The operator wanted an effective technology to monitor the developing CO_2 plume within the Utsira sandstone reservoir – that effective technology was 4D time-lapse seismic, and according to the UK's NSTA it remains the best available technology for such applications.

However, there are challenges to the scaling up and the development of more carbon storage projects. Cost and efficiency are two significant ones as the wider industry seeks to get more CCS projects moving towards the end of the decade and drive towards gigaton-scale capacity. These next generation of projects are not add-ons to hydrocarbon processing activities to address Scope 1 emissions, but pure abatement projects in their own right. Hence the economics of oil and gas projects are therefore not available to support projects through the life cycle, making the cost-value trade-off even more of an imperative for the technologies and solutions used to bring them to fruition.

Seismic operators like PGS are looking to play their part in helping to keep energy data relevant to these new projects, and to account for these challenges, while providing effective solutions to the ongoing development of this new segment as it scales to meet the storage targets laid out in international and national plans.

CCS SPECIFIC REJUVENATION OF SEISMIC DATA

Modern seismic reprocessing workflows offer an exceptional opportunity to rejuvenate old datasets using a variety of vintages to create new data that can drive fresh insights into the subsurface for CCS characterization.

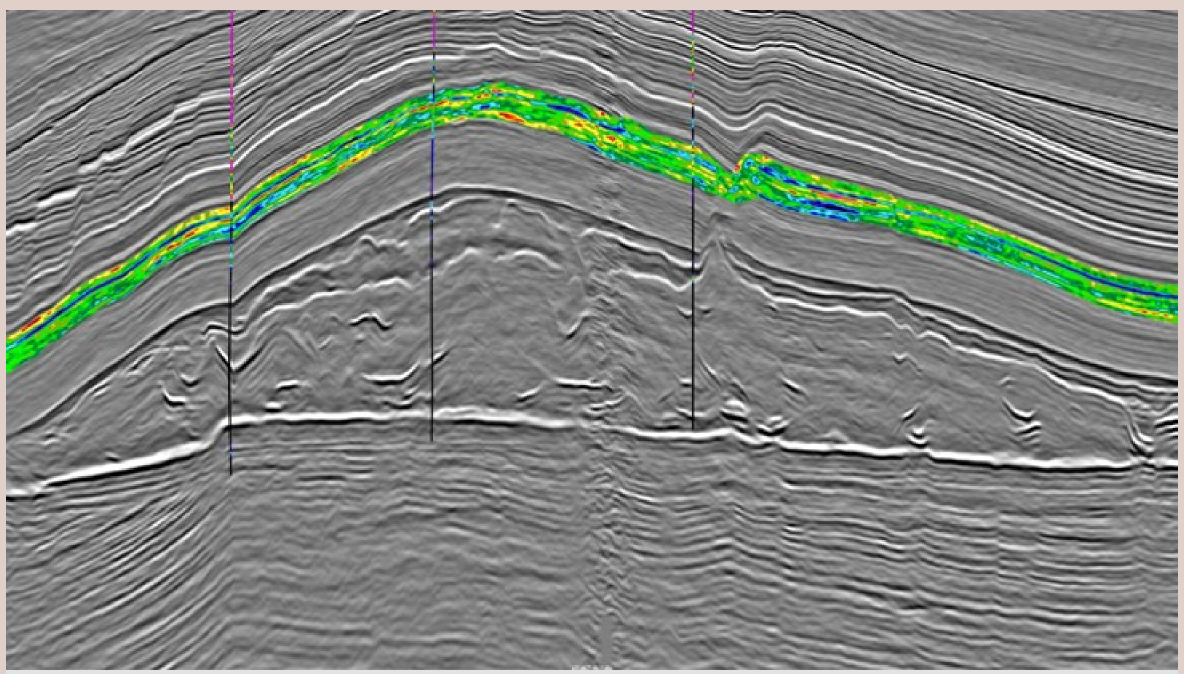


Figure 2. Seismically derived porosity over the BC 28 structure in the SNS Vision dataset allows a 3D understanding of the distribution of aquifer parameters which can be utilized directly in geological modeling and more sophisticated volumetric calculations beyond simple equations.

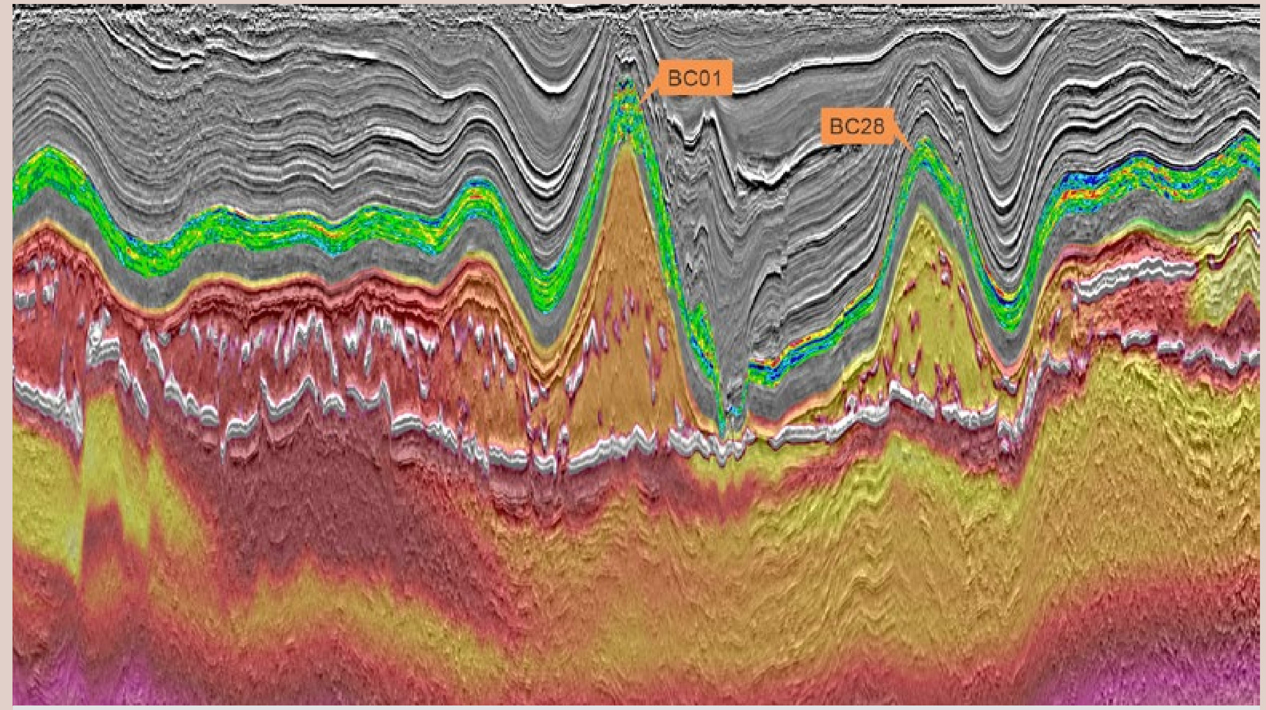


Figure 3. Seismic cross-section through PGS' SNS Vision data illustrating a co-rendering of the final PSDM stack, estimated porosity for the Bunter Sandstone Formation and the seismic velocity.

Reprocessing and merging of data have long been a mainstay of the seismic industry and PGS' own MegaSurvey projects are well known to provide exceptional coverage over large areas, making them excellent resources for early screening. However, as their original intent was to target often deeper petroleum prospects as off-the-shelf products, they are not optimized to resolve some of the challenges encountered on CCS projects.

PGS' SNS (Southern North Sea) Vision project is an excellent example of this (Figure 4). Historically, much of the data across the project area in the Southern North Sea has been focused on resolving structures and geology within the presalt section for gas exploration and development. While the presalt Rotliegend remains relevant for gas exploration and CCS, the focus has shifted to investigating potential within the post-salt section and the Triassic Bunter Sandstone Formation and its overburden to the seabed. With only a handful of fields developed in the post-salt section, less attention has been paid to imaging this interval and consequently this is sub-optimally imaged on pre-existing data and merge products.

An additional complication is the sparsity of well data, and this is particularly important where the calibration of rock physics models is required for quantitative seismic interpretation. This approach is particularly suitable for derisking saline aquifer targets in lean data environments. PGS' study of the Triassic Bunter Sandstone Formation BC28 structure, a candidate CO_2 storage location in the UK Southern North Sea (Figure 2 and Figure 3), is a case in point, where the inversion and rocks physics workflow demanded more data in the overburden than the wells could provide. A methodology was developed to address this, and a machine learning algorithm was used to fill the overburden data gaps and to allow the generation of reliable attributes for reservoir characterization.

UNLOCKING STORAGE OPPORTUNITIES ON MULTICLIENT LIBRARY DATA

With the extensive availability of high-quality, well-curated data sourced via online portals (e.g. Versal) accessing library data has never been easier, and within it lie excellent opportunities to develop robust concepts for future carbon storage sites.

Importantly, there is the opportunity to think differently about carbon storage prospecting within these datasets and thinking about data quality when identifying specific areas of interest for evaluation. This is because, in some senses, the ingredients necessary for a successful site can be relaxed when generating early storage concepts for consideration. Good aquifer and seal properties are of course required, but the risks around hydrocarbon charge to specific structures are absent, and there are large areas where subsurface understanding is sufficiently mature to make future oil and gas exploration activity unlikely. In saline aquifer exploration and screening it can be beneficial to look for high-quality data in areas where prospectivity is perceived to be challenging for oil and gas.

Over time, data has been acquired in areas peripheral to successful producing trends as attempts have been made to expand them. Where this data is modern and of high quality, a data-led approach to screening can be considered where advanced site characterization can be achieved on an existing dataset. This is both time and cost-effective. PGS' Elephant project in the Norwegian Sea area is an example of this (Figure 1). The Norwegian Offshore Directorate initially outlined a large migration-assisted saline aquifer concept within the Norwegian CO_2 Atlas in an area south of the Elephant dataset. We have been able to advance the development of this concept because of the availability of off-the-shelf high-quality data in an attractive location. The modern broadband 3D seismic data is more than sufficient to enable facies inversion workflows and seismic interpretation to be completed to screen and define the concept, as well as to assess in detail the subsurface risks associated with the aquifer distribution, seal and overburden units. This project has demonstrated how high-quality regional data can be used to great effect to define storage concepts within regional depositional systems, in this case the CCS-prospective Jurassic sandstones of the Norwegian Sea and North Sea (Figure 1 & Figure 5).

TECHNOLOGY AND INNOVATION DRIVING PROGRESS

PGS' acquisition of bespoke and high-end seismic surveys over the Northern Lights (Aurora and Smeaheia), Northern Endurance in the UK SNS, and Poseidon on the Norwegian SNS demonstrates that advanced geophysical solutions are very much in demand for carbon storage site development. While the acquisition of all these CCS projects (and others) utilized different survey designs and parameters, what they did have in common was the use of innovative seismic acquisition solutions.

The faith placed by the operators of these projects in novel solutions demonstrates that developers at the forefront of scaling CCS deployment in Northwest Europe, like Equinor and BP, appreciate the value that advanced seismic technology brings to the subsurface challenges presented by carbon storage site development. While legacy data may be sufficient for initial screening studies, high-end geophysical solutions remain relevant to take the projects through final investment decision development and into operation. The subsurface challenges are no less complex than oil and gas reservoir development and so it is natural that these advanced solutions, including innovative source-receiver configurations, are finding a home in the

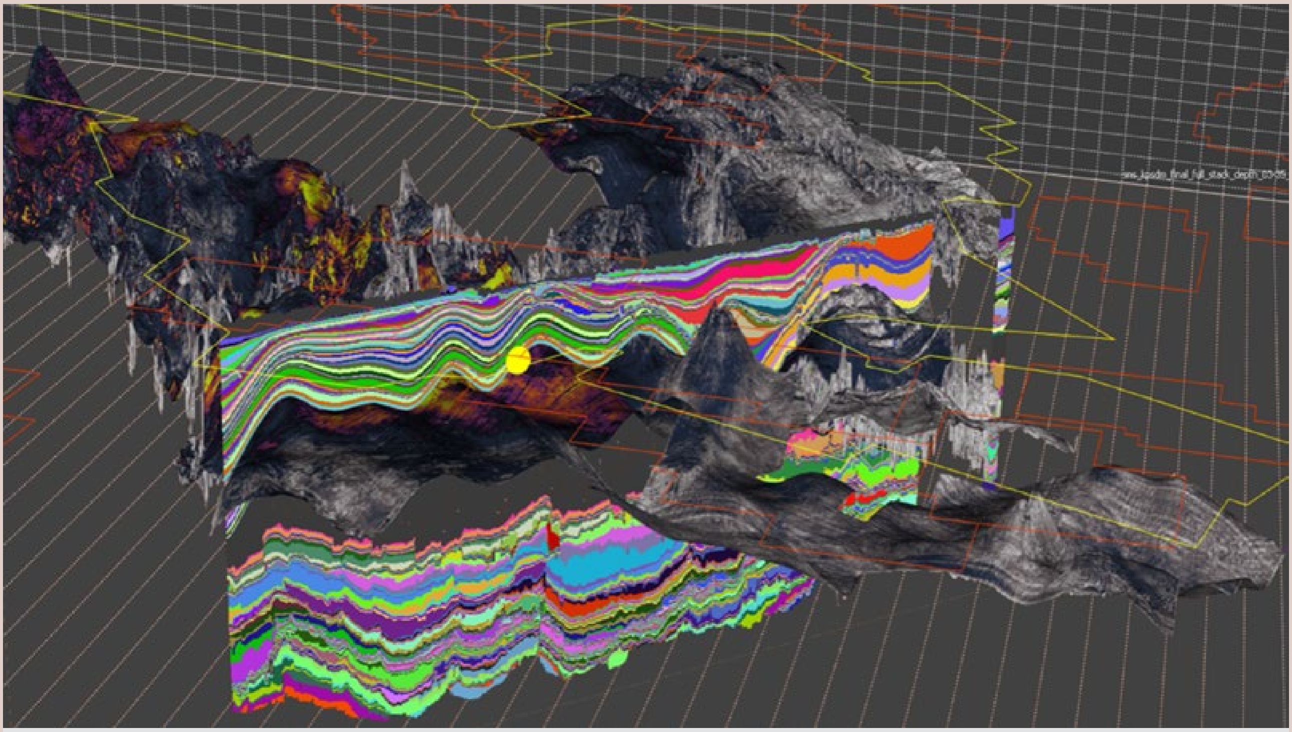


Figure 4. 3D representation of the Relative Geological Time model and the top of the salt over the 12 000 km^2 of reprocessed seismic data. The internal salt structure has been excluded from the seismic interpretation and the focus has been on the top and base salt. Interpretation RGT model produced using Eliis PaleoScan with PGS data.

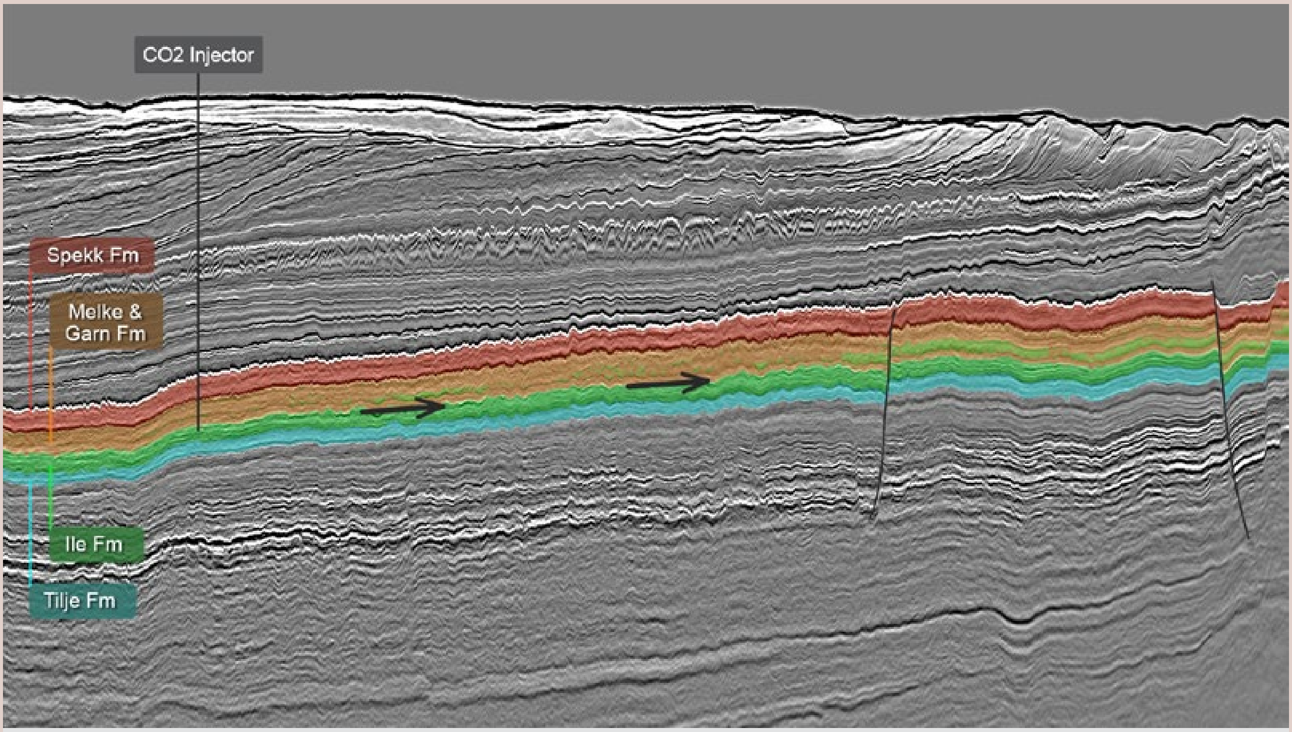


Figure 5. Regional schematic section through the proposed Elephant open aquifer storage site illustrating the prospective aquifer packages and the overlying Spekk Formation regional seal for carbon storage within Jurassic sandstones. The concept is a large-scale migration assisted store, with down-dip injection, allowing residual and solution related processes to contribute to the CO_2 storage.

subsurface development toolbox for the next generation of sites.

Looking to the future, PGS is also investing in R&D to support future site development and monitoring using seismic methods. An example of this is the CLEAN4D program, a collaboration between PGS and SINTEF, partly funded by the Norwegian Research Council. This project aims to deliver cost-effective, low emission options for time-lapse seismic surveys. The CLEAN4D aspiration is to enable time-lapse surveys using any acquisition technique that provides sufficient illumination to image the reservoir (or a specific target within the reservoir) to the required resolution, without the need to closely reproduce the acquisition geometry of previous surveys. By relaxing geometric repeatability, these new techniques have the potential to significantly reduce costs of acquisition while taking advantage of novel processing, imaging, and inversion techniques all the while ensuring that data quality for time-lapse monitoring is maintained or improved. As well as technical innovation, the project will also demonstrate the value benefits, addressing the cost imperatives for future carbon storage site monitoring programs. Strategies for optimum acquisition design will be developed, applying value-of-information (VOI) concepts to identify the best trade-off between added value and cost, including the contribution to reducing CO_2 emissions related to time-lapse seismic acquisition.

CHALLENGES FOR THE FUTURE

Until as recently as a few years ago offshore marine geophysical activities were focused on oil and gas site surveys and seismic acquisition projects. With the energy transition gathering pace the demands for these services and their capacity are now being spread across a wider range of segments – carbon storage and offshore wind adding directly to the draw on existing survey capacity within the industry. The development of these projects side-by-side also creates new challenges related to co-location of different industries vying to occupy and operate on the same areas of the seabed. Economic challenges also arise because of the different business models attached to the nascent carbon storage sector as well as other renewable segments. Cost effective, but technically robust options will be required.

PGS has already begun to meet these demands for innovation and to provide solutions to these challenges. Novel solutions for acquisition of 3D over storage sites have provided operators with the seismic surveys needed to resolve subsurface risks to capacity and containment. Investments and collaborations in future monitoring technologies will fulfil the promise of bringing cutting edge geophysical solutions to the next generation of monitoring for carbon storage sites. And products like SNS Vision and PGS' off-the-shelf library products mean that the sector does not have to wait to gain the benefits of PGS' advanced geophysical solutions.

NORTHWEST EUROPE

"We are about to drill unprotected into the reservoir. If you want to go on drilling this afternoon, you can put your arse on the rig in place of mine."

Wellsite geologist – Irish sector (1980s)

Are National Oil Companies the answer to addressing security of supply concerns across the North Sea?

What to do if these frontier areas are not moving ahead

"MANY COUNTRIES in the West have deliberately moved from being carnivores to vegans if that analogy can be used for the energy system", someone recently told me at a conference. I think it is an excellent way to describe what has happened in the political discourse over the past 10 years or so. From being addicted to oil and being totally fine with it, the West has now turned to renewables 100 %, whilst oil cannot be named anymore. From carnivores to vegans overnight.

But the reality behind party lines and media attention is different. Most countries that have made oil disappear from the vocabulary still depend on hydrocarbons for their primary energy consumption. And another factor has made an appearance on the agendas as well: Security of supply. Especially for countries like the Netherlands and the UK, once important exporters of energy, the reality of having to bridge a massive gap between energy demand and domestic production has certainly kicked in.

The change from being exporters to importers is of course driven by the fact that the meat in the North Sea has long been found, and these major fields are now maturing quickly. What is remaining of exploration activity in previous years has therefore focused on finding the chickens, or maybe even the eggs, that are left close to existing fields. That is the case even in Norway, where drilling activity is still the most buoyant from all North Sea countries.

Against that backdrop, it is no surprise that analyst Anders Wittemann recently argued for companies to take on more risk whilst exploring for new oil and gas accumulations. It will take a more audacious approach to find bigger volumes in areas where drilling has hardly taken place.

"But what would be the next step if operators active in the North Sea are simply not willing to start exploring the more frontier areas, despite all the good reasons to do so? "

But what would be the next step if operators active in the North Sea are simply not willing to start exploring the more frontier areas, despite all the good reasons to do so?

In a way, it is no surprise to see that especially in a country like the UK, where the political winds have been changing so quickly over the past few years, there is no company willing to put their heads above the parapet and go for what remains of the North Sea's unchartered territories.

The answer to this question is something that I happened to briefly discuss with a couple of people recently. And in both cases, it was not me coming up with it: It was brought to my attention. Two people, one from the Netherlands and the other from the UK suggested that a National Oil Company could be the answer to the burning question of how to address security of supply when it comes to hydrocarbons at a time when there is no commercial party interested in actively doing so.

A National Oil Company… that would be quite a deviation from a long period during which private investment was seen as the way forward. But, thinking about it a little more, it could well be the answer to trying to find what remains in the wider North Sea.

In the Netherlands, state player EBN might be in the position to take on this role. It already participates in many oil and gas fields and recently drilled its first (geothermal) exploration well too. The organization therefore has a major E&P knowledge base and the connections to drive things forward, such as is happening in the geothermal and CCS realms already.

In the UK, the NSTA would be the first organization one would think of probably, but the main difference with EBN is that the Brits do not actively partner in licences. The NSTA is much more a regulatory body, which obviously brings the oversight on what is happening across the basin but not necessarily the same spirit as an operator.

This all seems like a faraway scenario. But who knows what the energy future will bring. ■

Henk Kombrink

"We should have looked at that regional seismic line with more care before signing off on a plan for drilling"

How the close observation of a wellsite geologist prevented a blowout in a well drilled in the Celtic Sea

Flint layers in Chalk.

We, GEOLOGISTS, have the primacy of observation of rocks dinned into us during our earliest work in the field, with that message then reinforced by later events in our lives. For me, such reinforcement came in dramatic form in the spring of 1985. bp and partners were drilling exploration well 48/18-1 in the Celtic Sea south of Ireland. A young geologist, well trained to observe, was helping to log the well as drilling proceeded.

We hoped to find commercial quantities of gas in a regionally proven Cretaceous sandstone reservoir that underlies a thick section of Cretaceous Chalk, with abundant flints in the upper Chalk. We planned to drill down to just above the base of the Chalk before setting casing and putting a blowout preventer in place.

What happened next proves the power of observational geology over the most sophisticated modelling of the subsurface. As drilling approached the base of the Chalk, he observed from the cuttings that the depth at which the well entered flint-free lower Chalk came in a little higher than predicted. The young geologist was somehow able to call the Dublin office. He opened with words that demanded attention: "We are about to drill unprotected into the reservoir."

This observation was at odds with our meticulously prepared depth-model. But there was no contest: Always honour the observation. Drilling was stopped. Over the next few days, casing was run and cemented in the well. The blowout preventer was put in place. Shortly after drilling recommenced, the well entered the reservoir. The depth was as the young geologist had predicted. The reservoir contained enough gas to have severely damaged or sunk the rig in the absence of a blowout preventer.

"We are about to drill unprotected into the reservoir – we came out of the Chalk-with-flints early. If you want to go on drilling this afternoon, you can put your arse on the rig in place of mine."

What had we missed in our model? The basis of our calculation of depth from seismic velocities in the Chalk was proven correct by logs from well 48/18-1 itself, so we looked again at the regional setting on the largest available scale. We could eventually discern the gentlest of folds in the Chalk. The very uppermost Chalk was missing at the crest, along strike from well 48/18-1.

We should have looked at that regional line with more care before signing off on a plan for drilling. I was in charge, and it was my fault that we did not do so. For 15 years around the turn of the century, I was involved with training: The tale of well 48/18-1 always featured. ■

Bryan Lovell

This article is an extract of a longer piece on the role of observations from the rock record in the debate about climate change that was published in Geoscientist by Bryan Lovell.

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For Vår Energi, the future lies in the north

Near-field exploration and exploration wells in new areas will contribute to increased production of oil and gas in the Barents Sea

THE NORWEGIAN Offshore Directorate (NOD) has repeatedly called on the oil companies to conduct more exploration in the Barents Sea. It is in this area that the largest share of undiscovered resources are. One of the companies that seems to have listened to the NOD's advise is Vår Energi.

"We have a significant position in the Barents Sea, with stakes in Goliat, Johan Castberg and Snøhvit", pointed out Alessandro Barberis, VP Exploration at Vår Energi, during the NCS Exploration Strategy conference in Stavanger late last year.

Last summer, the company announced that it was buying the Norwegian oil and gas operations of Neptune Energy. The transaction was completed on 31 January. As part of the acquisition, Vår Energi secured ownership in Snøhvit and the associated Melkøya LNG facility – the only existing infrastructure for gas exports in the Barents Sea.

Alessandro Barberis, VP Exploration in Vår Energi.

PHOTOGRAPHY: SIMON ØVERÅS

"Venus can be a play-opener for us"

It is clear that the Barents Sea is the future for Vår Energi. As of today, the marine area only accounts for 9 % of the company's production, but as much as 45 % of the resources.

The exploration manager said that Vår Energi is scaling up exploration activities in the north, and pointed out that together with Equinor they have secured a drilling rig for 2024 – 2026, with an option for a further three years. In the best case scenario, they will therefore be drilling in the Barents Sea until 2029.

The exploration partly aims to increase the resource base around existing fields such as Goliat and Johan Castberg, and partly to make discoveries in new areas.

A PLAY OPENER

"Venus can be a play-opener for us", said Barberis. He was not referring to TotalEnergies' recent world-class oil discovery off the coast of Namibia, but the prospect of the same name west of Johan Castberg. According to the company, a discovery here could open up the Paleocene as an exploration model, and Vår Energi is positioned for further exploration over large license areas.

Barberis did not hide the fact that a possible gas discovery could be a "game changer" for the exploitation of gas in the Barents Sea. A significant discovery could be a good argument for building a pipeline, which would open up further investment and exploration in the north. A possible oil discovery can either function as a new hub in the area, or - if it is smaller - be connected to Johan Castberg, which will be put into production later in 2024.

Venus will be drilled very soon, and according to the strategy the company will drill 1-2 high impact wells annually going forward.

Today's gas export capacity from the Barents Sea is limited to the LNG plant on Melkøya. Earlier this year, Gassco published a report that concludes that the establishment of a pipeline appears to be the most profitable for society. ■

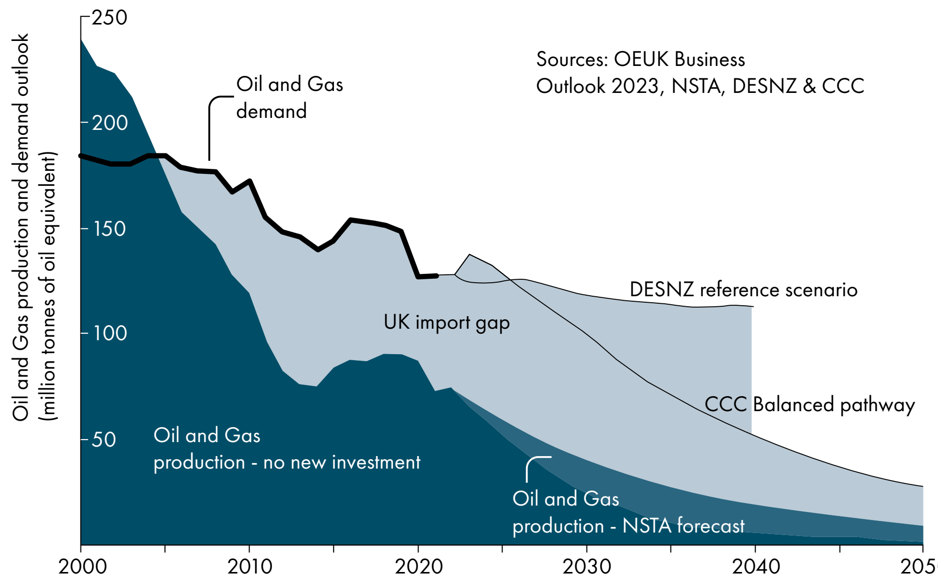
Ronny Setså

Making a case for domestic oil and gas production

In the polarised debate around phasing out fossil fuels, it is unpopular to plea for continued investment in oil and gas projects in the UK. But the numbers show that this is the right thing to do

Oil and gas currently provide 76 % of the total energy consumed in the UK. As the energy transition progresses, this will decline, but even in the most aggressive demand reduction scenarios, oil and gas are still estimated to provide at least 50 % of all UK energy needs over the period to 2050.

Currently, domestic gas production accounts for 44 % of the UK's needs, with oil taking a share of 67 %. These numbers may not look too bad, but given the maturity of most oil and gas developments across the UK Continental Shelf, the decline in domestic production will continue steadily as time progresses. That's why without significant new investment, by 2032 over 80 % of the UK's demand for hydrocarbons is expected to be met by imports.



This graph was put together by the Subsurface Task Force, a collective that promotes responsible use of the UK's subsurface storage and energy resources to ensure energy security, reduce the UK's emissions impact and deliver societal and economic value.

RESOURCE POTENTIAL

The UKCS has the resource potential to significantly reduce this import dependency, but requires the right investment climate to achieve this. The latest estimates published by the North Sea Transition Authority include 6.4 billion barrels of oil equivalent of contingent resources and 15.2 billion boe yet to find.

These numbers may look eyewatering, but if put in a context of a total volume produced from the UKCS already – 45 billion boe – the contingent resources and YTF's should really be seen as vehicles to slow down the decline in production from existing assets rather than bucking a trend. For that reason, there is no reason to claim that continued exploration will slow down the energy transition. It will only help reduce import dependency.

REDUCING EMISSIONS

In addition, UK production emissions are declining, and the industry is on track to meet its initial reduction targets enshrined in the North Sea Transition deal. Emissions intensity of UK production is lower than global averages and although some imports are currently better, new UK developments can match or improve upon these low-emission sources. This is because a new development that produces at plateau rates for a number of years will have a much lower carbon footprint than an older platform that still needs to run but with much less throughput.

On top of that, imported hydrocarbons will be primarily derived from higher emissions intensity supply, notably LNG. Replacing imported LNG (88.4 kg CO_2/boe) with new domestic gas production (ca. 3 kg CO_2/boe) has the potential for a material reduction in emissions, which is equivalent to removing tens of millions of internal combustion engine cars from the road.

In other words, despite the sensitivities around oil and gas exploration and production from UK waters, and the undisputed need to move to a cleaner energy system, the development of new oil and gas fields across the UKCS does not violate the spirit of the energy transition. ■

This article benefited from data put together by the UK Subsurface Task Force

Henk Kombrink

FEATURES

"In contrast to hydrocarbon source rocks that are rich in organic material, a good helium source are siliciclastic (meta)sediments enriched in heavy minerals."

Mariël Reitsma – HRH Geology

The genesis of natural hydrogen exploration

So far, natural hydrogen has mostly been encountered in the subsurface through hydrocarbon exploration wells and in mines. But more recently, dedicated hydrogen exploration wells have been drilled with reported successes. Where to look for more?

JAMES DODSON, HYDROGENESIS

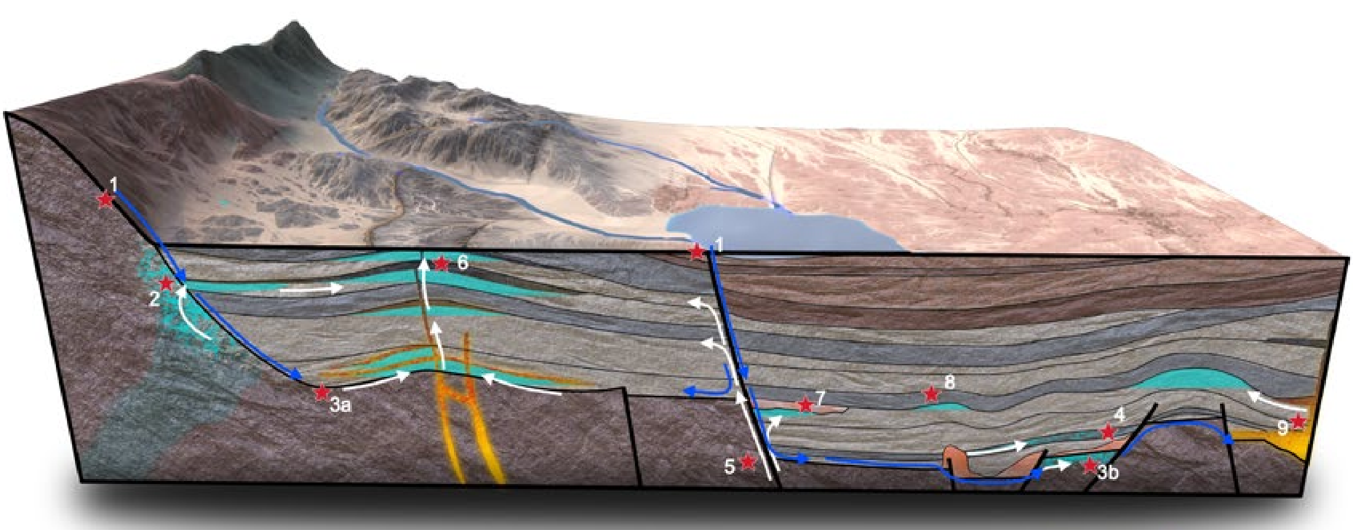
HYDROGENESIS believe that natural hydrogen exists in large quantities in the subsurface, we just haven't been looking in the right place. We are developing an exploration concept to pioneer this exciting and world-changing clean energy source and have a number of agreements in place, focused on the African continent.

For a few years now, hydrogen has been touted as being a significant contributor to decarbonisation of energy systems, industries and transport. Hopes, and major investments, have so far focused on blue - natural gas reformation coupled with carbon capture and storage - and green - renewable electricity powering electrolysers - hydrogen as methods to generate sufficient quantities to make a real difference.

However, both blue and green hydrogen have their issues – both are derivatives of another primary energy resource, with losses through inefficiencies and storage issues. They are also very costly at the moment: Hopes are for 2.5 – 4 USD/kg by 2030. According to the Hydrogen Council, announced projects, largely in green hydrogen, show 570 billion USD worth of investments through to 2030 but only 7 % of these announced investments have passed FID.

The natural hydrogen industry is beginning to receive more attention and a small number of companies have been able to raise money, though largely where the opportunity is to appraise the serendipitous discoveries. By far the biggest investment in natural hydrogen has been a $245M Series-B raise by Koloma in the USA, Q1 2024, which could well represent more than all the other investments into natural hydrogen combined.

A growing number of companies are now taking on the natural hydrogen exploration challenge from the geology up. A 'hydrogen system' is being developed and existing geophysical, geochemical and geological technologies are being repurposed. Investments are slow in coming,



Factors involving hydrogen generation in Intracratonic basins. 1. Meteoric water percolating into the subsurface. 2. Shallow hydrogen production from weathered BIFs. 3. Serpentinization of greenstone basement and/or oxidation of iron silicates and/or radiolysis at high Uranium/Thorium basement lithologies. 4. Thermogenesis of organic matter. 5. Hydrogen emanation from deep, crustal faults. 6. Trapped by volcanic sills. 7. Salt trap. 8 Trapping by mudstones. 9. Hydrogen generated by magmatism/local thermogenesis.

ILLUSTRATION CREATED BY LINA JAKAITE (STRIKE-DIP) but with green and blue hydrogen projects stalling, surely the time has come for natural hydrogen to be backed!

WHERE ARE WE LOOKING

We know what generates natural hydrogen, so the next step is deciding where on the planet to look. We need to identify our preferred areas for a hydrogen system to be present.

Clearly there is a huge natural hydrogen exploration playground when based purely on where we expect to find a source. Therefore, the next step is to postulate on where the generated hydrogen may find a reservoir, trap, and seal so that we can define meaningful plays and prospects.

From the later chart, obvious candidates for exploration are ophiolites, intracratonic basins - including the cratonic basement - with greenstone belts and BIFs, areas with high occurrence of layered basic intrusions and areas of known granite and uranium ores.

Another aspect that needs to be considered is the presence and flow of water. There are a number of ways that water can interact and be available to the mineralogies required for the production of hydrogen in the subsurface, but a better understanding is needed to more accurately predict the effect on prospectivity.

INTRACRATONIC BASINS

Intracratonic basins are likely to be the lowest-hanging fruit for natural hydrogen exploration due to their favourable, relatively simple geology, having multiple hydrogen plays and comparative ease of access. There are known natural hydrogen occurrences in intracratonic basins around the world, such as in Kansas, US and the Taoudeni Basin in Africa. In the Taoudeni Basin in Mali, the Bourakebougou hydrogen field stands out as a natural hydrogen poster child. ▸

NATURAL HYDROGEN GENERATION

There are several processes that generate natural hydrogen, with a few likely to generate sufficient quantities to trap and exploit. Oxidation and radiolysis are the two main generating processes likely to yield these quantities in areas with potential for suitable reservoir and seal rocks. Others worth investigating are high-temperature, overmature thermogenesis of organic matter, mantle seepage and friction along major fault planes.

Oxidation

Serpentinisation describes a range of hydration, oxidation, and reduction reactions that affect ultramafic rocks, forming an alteration in mineral assemblage. When water is the oxidant in these reactions, H2 is formed. Serpentinisation commonly occurs in oceanic crust at temperatures from ambient (~0 °C) up to ~400 °C. On land, it occurs in ophiolite complexes at lower temperatures (generally <200 °C) and greenstone belts that form large chunks of Precambrian basement.

Oxidation reactions not associated with serpentinisation have also been shown to produce H_2. These reactions involve iron-bearing silicate minerals found in a range of rock types (basalt to granite) and occur at a range of temperatures, from cool, shallow aquifer environments, to hotter hydrothermal alteration.

Iron oxides, such as in banded iron formations (BIFs), are another potential kitchen. Through weathering of BIFs, with O_2 as the oxidant rather than water, hydrogen generation could occur at or near the earth's surface. The free hydrogen generated may remain trapped in the newly formed minerals and then released into the subsurface post-burial. These reactions could also occur with water on BIFs that exist beneath young sedimentary cover and where there is low heat flow.

Radiolysis

Naturally occurring radioactive decay splits molecules of water, creating radiolytic H_2. Generation of radiolytic H_2 depends on the relative proportions of potassium to uranium and thorium, the water-to-rock ratio, the geometric relationship between the water and the rock, attenuation of the radioactive particles (stopping power, or stopping distance), and water purity. Radiolysis is most intense at the water-rock interface and so radiolytic H_2 production rates will be highest in fine-grained rocks, with high water-filled porosity, and high concentrations of radioelements.

Thermogenesis

Molecular hydrogen is both generated and consumed during the petroleum maturation process, and overmature hydrocarbon provinces are another potential hydrogen source. Past the dry gas window, at temperatures of over 300 °C, hydrogen generation is abundant, with the free gas likely to remain within the pore spaces of the organic-rich rock.

Magmatic/Mantle Seepage

Hydrogen is a common component of volcanic gasses, with higher concentrations associated with higher magmatic temperatures. Studies of various volcanoes have shown significant quantities of hydrogen are constantly emitted. Another deep source of hydrogen is from the degassing of the mantle, constantly seeping up through the crust. This has the potential to be focussed at major crustal faulting, acting as the fluid conduit and fill traps where a good reservoir and seal exists.

Mechanochemical

Molecular hydrogen is a common component of fault gases and sometimes increases in concentration are associated with seismic activity with researchers investigating whether earthquakes generate H_2. Lab experiments show evidence that the grinding of silicate minerals in the presence of water can lead to the formation of free hydrogen. When extrapolated, the models suggest large quantities - several magnitudes larger than the other generation methods - of molecular hydrogen are generated during significant earthquake events.

Multiple plays exist in intracratonic settings, including shallow weathering of BIFs and oxidation of other iron-bearing silicates, serpentinization of greenstones, radiolysis in areas of heightened Uranium and Thorium occurrence, high temperature magmatic intrusive opportunities, thermogenesis in the deepest and hottest parts of the basins and deep sourced leakage through crustal scale faulting.

Reservoir lithologies and trapping structures are a known quantity in intracratonic basins, with a number having a long history in hydrocarbon exploration. Sealing lithologies are also known to exist, with hydrogen likely to be held by mudstones as well as salt and some intrusive lithologies. Thermogenic processes are likely to leave generated hydrogen trapped in the mudstone, requiring fracking and a number of basement-water interactions (including BIFs) will leave free hydrogen to exist in the weathered fractures.

In cratonic areas, we are reliant on meteoric water percolating into the subsurface, often over timescales of 10,000s of years and potentially over great distances.

OPHIOLITES

Ophiolites around the globe are known to emit natural hydrogen and the dominant sourcing process for these emanations is the serpentinisation of the ultramafic rocks. Serpentinisation is a fast process, on a geological timescale which gives two main play concepts; one requiring historical trapping of hydrogen within the accretionary melange/forearc sediments that are subsequently covered by the ophiolite. The other concept is current day serpentinisation at the base of the ophiolite, at depths where the temperatures reach between around 200 – 350 °C, with the hydrogen moving up through faulting within the geological section into traps.

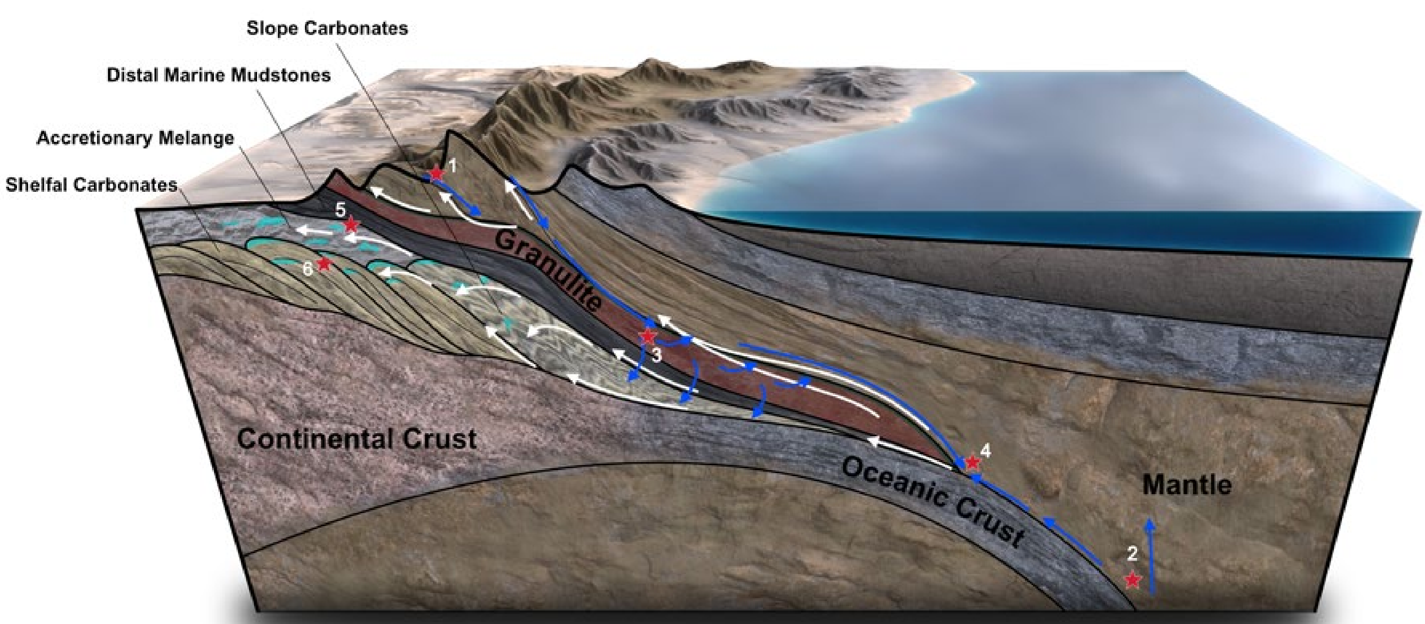
In ophiolites, de-watering due to metamorphic processes generates water in areas where hydrogen is generated, as well as dehydration of the subducting slab. Meteoric water will also find a way to depth through the many faults associated with the tectonics.

HOW ARE WE LOOKING

One major benefit of natural hydrogen exploration is that we already have the methods, technologies, and a huge workforce with the perfect skillset. We can leverage the oil industry for know-how, with an almost identical methodology; identifying source, migration, reservoir, trap and seal. The major difference being different source rock requirements, including modelling of the hydrogeology.

As most prospectivity is onshore, exploration for natural hydrogen will go through a funnel with large-scale, low-cost studies followed by increasingly costly geophysical acquisition including regional airborne projects, then targeted seismic and ending up at the point of wildcatting wells.

A portfolio will be key. Clearly a lot of work needs to be done to be able to systematically explore in the right places and successfully drill accumulations of a size that justifies the expenditure. If this can be done, an excellent, future-compatible energy source will be realised. ▶



Factors involving hydrogen generation in ophiolites. 1. Meteoric water percolating into subsurface. 2. Water from metamorphic dewatering and/or dehydration of subducting slab. 3. Hydrogen flowing from area of serpentinization into foreland sediments. 4. Serpentinization at depth. 5. Hydrogen trapped in foreland sediments from historic serpentinization. 6. Hydrogen trapped in folds from recent generation.

HydroGenesis

ILLUSTRATION CREATED BY LINA JAKAITE (STRIKE-DIP)

	Radiolysis	Serpentinisation	Fe-Silicate oxidation	Fe-oxide oxidation	Thermogenesis	Magmatic gasses
Oceanic lithosphere	Neg	High	High	Low	Neg	Med
Ophiolites	Neg	High	Low	Low	Neg	Med
Cratonic basement	High	High	Med	Med	Low	Neg
Intracratonic basins	Med	Low	Low	Low	Med	Neg
Granite	Med	Neg	High	Low	Neg	Med
Layered basic intrusions	Low	High	Med	Low	Neg	Med
Metamothpic zones	Var	Var	Var	Var	Med	Var
Magmatism	Neg	Neg	Neg	Neg	Neg	High
Uranium ores	High	Var	Var	Var	Var	Var
Evaporite deposits	Med	Neg	Neg	Neg	Neg	Neg
The deep Earth	?	?	?	?	?	?

Summary of the hydrogen generating processes (top row) related to different potential hydrogen source rocks (left column). Assessed based on whether there is a high, medium, low, negligible or variable potential for each particular process to occur in each rock type. Question mark denotes uncertainty of contribution.

WHAT TO DO WITH AN ACCUMULATION

A major consideration with all types of hydrogen is how to best use it – it is not easy to transport or store for long periods of time, mainly due to having low energy density by volume. This is an even more pertinent question for geological hydrogen, as it is unlikely to be discovered in convenient locations for end use.

There are several use cases for hydrogen, including existing industries of fertiliser production and in oil refining. Large investments in blue and green are being justified to target the decarbonising of some hard to abate industries, such as industrial heating (e.g. steel production), shipping, aviation and even ground transportation. A bit more blue sky, there are even proposals for hydrogen grids to replace natural gas grids to fuel hydrogen boilers and hobs.

In Africa, where HydroGenesis is currently focussed, the best use cases would be direct electrification to the grid or to generate ammonia for fertiliser use as both are major requirements on the continent.

READY TO TEST THE SCIENCE

There are many subsurface processes known to generate natural hydrogen, with the most pressing research addressing where we might find lithologies to store and trap the hydrogen so that we can exploit the resource in substantial enough quantities. Oxidation, radiolysis and thermogenesis in intracratonic basins as well as serpentinisation in ophiolites present the best opportunities.

To realise the potential, investment dollars are needed, which should be a no-brainer when considering the amount being committed to green and blue hydrogen projects. If released, there are a growing number of companies ready to test the science and bring about an era of clean energy based on an abundant and cheap natural resource. ■

Helium - the birth of a new exploration industry

Multiple dedicated helium discoveries have recently been made, but reserves have yet to be proven

MARIËL REITSMA, HRH GEOLOGY

24 % OF THE weight of the universe is made up of helium. Yet, on earth it is a rare element. This is problematic because many industries, such as the medical field, tech manufacturing and space programs are heavily reliant on helium owing to its unique properties. Helium is an inert gas with an extremely low boiling point. It reaches liquid state at 4 degrees above absolute zero and hence can be used for cooling to extremely low temperatures.

Only a small portion of helium currently found on Earth is primordial in origin and has been present since the formation of our planet. Most helium formed over geological time by radioactive decay of uranium and thorium. Alpha particles emitted during radioactive decay are in essence helium atoms. Eight helium atoms are formed during the decay series of U to Pb and seven during Th decay. In the photo shown here, evidence of uranium decay in apatite can be seen.

Apatite crystal showing evidence of uranium decay. The short, dark linear features are fission tracks. Fission tracks are formed when an uranium atom splits into two large nuclei. Helium is not released during this process. However, the number of fission tracks is an approximate for the total uranium content of the mineral. It is known that only roughly one in two million uranium atoms decay through spontaneous fission. This indicates how much uranium is present in the mineral and as a consequence how much helium has been formed. The crystal is ~150μm in length.

SOURCE: SYRACUSE UNIVERSITY

ALMOST LIKE A PETROLEUM PLAY

In contrast to hydrocarbon source rocks which are rich in organic material, a good helium source are siliciclastic (meta)sediments enriched in heavy minerals. Yet, the rest of the play system is very similar and helium and hydrocarbons can be found together.

Due to the long half-lives of uranium and thorium, it takes an extensive period of time to accumulate significant quantities of helium in their source minerals. Substantial heat is then required to release helium from its source mineral, after which fluid flow is needed to pick up the helium present in the pore space and transport it further through the subsurface. If the helium-enriched fluid becomes trapped in a rock with good reservoir properties and an exploration geologist manages to find it, the reservoir can be produced.

SERENDIPITOUS FINDS

Virtually all helium produced to date was transported to its trap by hydrocarbons and discovered by accident while exploring for natural gas. Concentrations as low as 0.3 % helium in natural gas can be traded profitably once separated. The United States, Algeria and Qatar are currently among the largest helium producers. Globally, Qatar has the largest estimated helium reserves at 10 billion m^3. However, it hasn't fully capitalised on its production potential yet, making the USA the largest producer at the end of the day.

There is no room for complacency though. Helium reserves from the long-serving fields in the USA are rapidly dwindling while global demand is soaring. This has created a demand for a new industry that is specifically exploring for helium, rather than solely relying on serendipitous discoveries of the noble gas alongside hydrocarbons. Better yet, this gives the opportunity for 'green' helium exploration, where helium is mainly associated with nitrogen rather than hydrocarbons or CO_2, hence giving the gas a lower carbon footprint.

USA

Targeted helium exploration has kicked off globally with large projects currently ongoing in Africa, Australia ▶

Drilling of Helium One's Tai-3 well in Tanzania.

and North America. In the USA, new helium fields are being developed in Arizona by Desert Mountain Energy and in Colorado by Blue Star Helium, both in close proximity to depleted historic fields. These assets are predicted to come online this year.

More remarkable is the exploratory work by Pulsar Helium in northern Minnesota, in a region traditionally known for iron ore mining. In 2011, a borehole targeting nickel had an unexpected blowout of non-flammable gas. Gas flowed for 4 days with no apparent reduction in pressure. According to David Oliver, who was tasked to cap the borehole, the gas was rushing out at such speed that it 'screamed like a jet engine'. In February this year, Pulsar Helium drilled what they coined the Jetstream #1 appraisal well, measuring concentrations up to 13.8 % helium along with CO_2 and N_2. Their next step is to flow test the well.

TANZANIA

Southwest Tanzania is another emerging helium hot spot. Exploration kicked off when analyses showed excessive helium degassing from hot springs associated with the East African rift system. Two companies, Helium One and Noble Helium, have each drilled exploratory wells in the Rukwa basin in the past year. The wells are located near the basin margin fault closure. The helium is contained in multiple shallow, stacked reservoirs. Gas shows are both present in the rift infill sediments, with free gas occurring as shallow as 85 m below the surface, as well as in the fractured granitic basement at about a kilometre depth. This is true 'green' helium, where nitrogen is the carrier gas and only traces of CO_2 and no hydrocarbons are present.

AUSTRALIA

Last year, Australia ceased LNG production from the Baya-Undan field in the Timor Sea. As a consequence, this simultaneously halted the co-production of helium, the only domestic source. Central Petroleum now plans to fill this gap in the market by building a helium recovery unit near the Mereenie gas field in the Amadeus Basin, southwest of Alice Springs. The Mereenie gas stream contains only 0.2 % helium. However, Central Petroleum is due to drill 3 wells in nearby fields with much higher prognosed concentrations.

However, the highest ever recorded helium concentration (17.5 %) was paradoxically discovered while drilling Australia's first dedicated natural hydrogen wells. Gold Hydrogen drilled 2 wells on the Yorke Peninsula near Adelaide late last year. The preliminary results are positive with regards to permeability and gas flow to surface and the company is now proceeding with an extended production test.

In summary, although multiple helium discoveries have recently been made, this is only a first step. For most of these finds, exact reserves and producibility still have to be proven. However, it is exciting to see that helium exploration is becoming an independent industry that will hopefully guarantee supply for the decades to come. ■

SOURCE: HELIUM ONE

CNOOC makes largest offshore hydrocarbon discovery in special rock formation. What is that about?

FRACTURED

A recent headline published by media outlet OGV read: "CNOOC makes world's largest offshore hydrocarbon discovery in special rock formation." Reading through the article, it said that CNOOC found the world's largest metamorphic rock oilfield of around 1.5 billion barrels of oil in China's Bohai Sea. That certainly sounded interesting, but still a bit cryptic.

Fortunately, the CNOOC website itself presented a better description of what was discovered in the Bohai Sea, the waters sandwiched between China and North Korea in what is the northwestern extension of the Yellow Sea. The press release mentions that the main oil-bearing play is an Archean buried hill, which obviously translates to basement reservoir. Still a rather special reservoir, but not something totally unheard of. Fractured and weathered basement reservoirs can be found in several places across the world, for instance in Vietnam, Yemen, Norway and the UK.

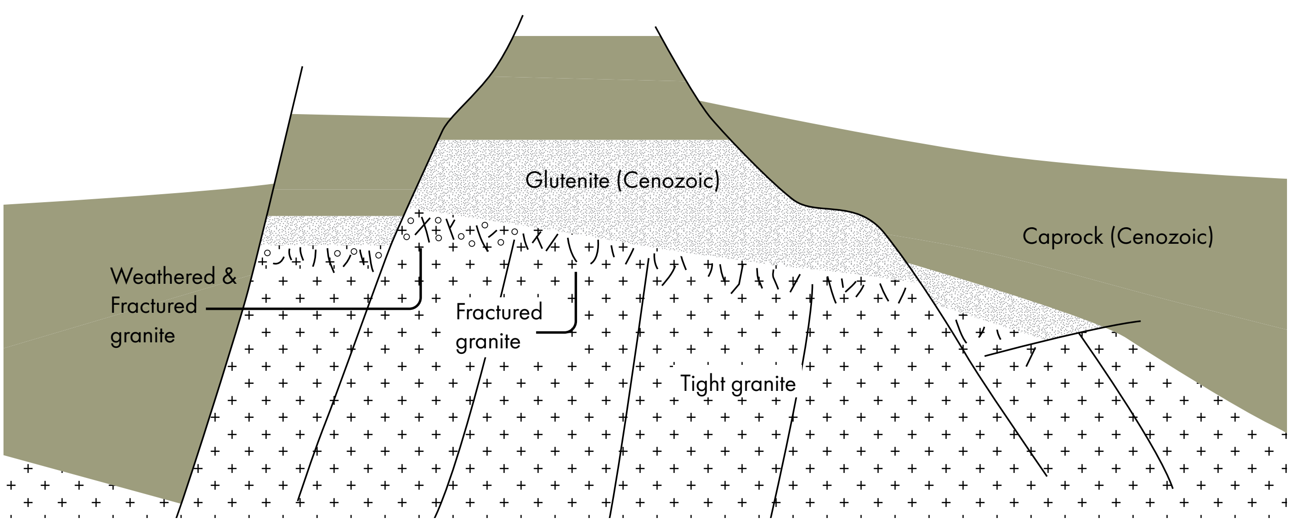
BURIED HILLS

It turns out that the Bohai Sea is a key area for the buried hill play concept, and a paper published on this area in 2019 shares some good insights. A cross-section from the so-called BZ-19-6 oil field in the paper shows a typical basement play, with tight granite at the base, followed by a fractured zone, in turn overlain by a fracture zone that also contains weathered granite in places, meaning there is some porosity in that particular interval in contrast to the granite below. Another paper, published this year, even mentions the recent discovery and describes dissolution pores that are primarily distributed along fractures. This subsequently increased the porosity of these fracture-related reservoirs by ≤ 12%.

GLUTENITE

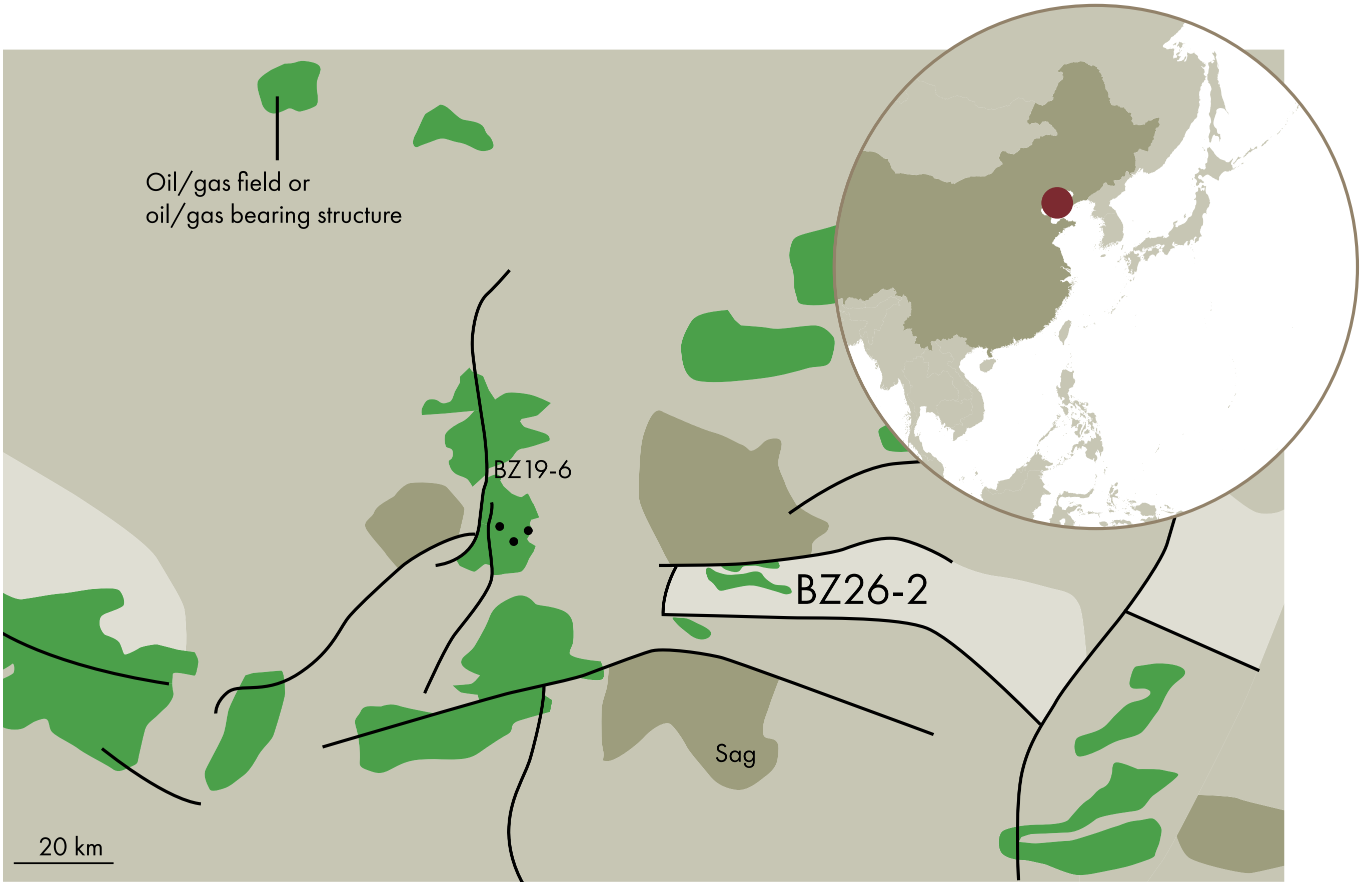
Another interesting observation from the cross-section is the presence of a coarse-grained interval of what the authors name glutenite, which seems to be a term mainly in use in China. This type of reservoir represents coarse-grained clastics that are characterised by intergranular dissolution pore space. In this case, the glutenite is a lot younger than the basement rocks and could represent what remains of an inverted series of (half) grabens in which these conglomerates were deposited in Paleocene and Eocene times.

We have not been able to reconstruct where the announced discovery (Bohzong 26-6) was made, but if it is in the BZ-26 structure as shown on the map, it is not far from the BZ-19 area where the cross-section is from. That then sparks another question. How much oil and gas ▸



CROSS-SECTION REDRAWN FROM: HOU ET AL. (2019)

Cross-section from the so-called BZ-19-6 oil field, Bohai Sea. It shows a typical basement play, with tight granite at the base, followed by a fractured zone, in turn overlain by a fracture zone that also contains weathered granite in places. Interesting also is the glutenite (coarse sandstones) on top of the granite - can this succession also be part of the reservoir?



Map showing oil and gas finds in the Bohai Sea buried hill play area. It is believed that the recent discovery is in the block named BZ26, as there was a small find already that bears the same BZ26 code.

COMMENTARY

Many people commented on this article when it appeared online. Tako Koning, a seasoned petroleum geologist from Canada, added that the recent CNOOC basement discovery is within an area where in the past five years some major-to-giant size oil and discoveries in Precambrian Archean basement were made.

He also added that Chinese geoscientists have really developed great expertise in E&P with basement oil and gas reservoirs, which is not too much of a surprise given that the world's largest basement oil and gas reservoirs are in China including the giant-size Jiaqiu basement field onshore.

And finally, Tako also mentioned that the overlying "Glutenite sands" are probably part of the weathered granite rather than a sandstone that was deposited later. Looking at the cross-section, it does make sense and we will further investigate the exact nature of the Glutenites.

Some other readers are a bit more skeptical about the discovery. "I'll be awaiting some more details", said Marcos Asensio. Baharudin Isa commented that he is "not sure how good this discovery was, as there is no mention of production rates." Finally, Andrew Fawcett says it is early days but he expressed concern about the productivity per well since it is offshore.

is actually in fractured basement and how much is in the overlying coarse grained clastics?

OIL IN SANDSTONES

We have seen this scenario before, at a similar play, but far away from the Bohai Sea. In the West of Shetlands, in UK waters, Hurricane (now Prax Exploration and Production) operates the Lancaster field in fractured basement rocks. Our analysis at the time showed that rather than producing only from fractured basement, a contribution is clearly made from overlying coarse-grained clastics.

Looking at the BZ-19 cross-section from the Bohai Sea, it looks very similar to Lancaster with possibly an even thicker succession of coarse grained clastics overlying basement. Reflecting on that, it is worth asking the question how much of the oil in the Chinese play is from fractured basement and how much is from the overlying clastic wedges. The Lancaster case in the UK clearly suggested that the sands are a contributor, and if the announced Chinese discovery is in a similar setting as the cross-section from the article, it surely indicates that the reservoir may in fact not be as special as it initially looked. ■

Henk Kombrink

REDRAWN FROM: HOU ET AL. (2019)

Is the Colombian Basin on its way to become the next big frontier?

Recent studies and well results strongly suggest the presence of a thermogenic petroleum system in an area that has thus far been considered a biogenic gas play

LUIS CARLOS CARVAJAL-ARENAS, LUCIA TORRADO, JUAN PABLO RAMOS AND PAUL MANN

THE DEMAND for replacing O&G reserves along with the development of modern drilling and imaging technologies has pushed the boundaries of offshore exploration to new limits. By applying data-lead concepts, the industry has been able to test high-risk-high-reward hydrocarbon plays resulting in successful exploration campaigns like those conducted in Guyana and Namibia. If we continue to follow this approach in other unexplored basins, then we can agree that the deepwater Colombian Basin is on its pathway to potentially become one of the next big frontiers.

Since the first commercial offshore gas discovery made by Chevron in 1979 with the Chuchupa well, the industry has proven the presence of a biogenic gas play along the nearshore Colombian Caribbean coast (Figure 1). For the last 20 years, the O&G industry has focused its technical and commercial efforts on the exploration of deeper-water targets by drilling 11 exploratory wells until today, which has further confirmed the extension of this biogenic gas system. It is no surprise that these drilling campaigns have also brought new insights into an active thermogenic system with untapped potential in the region.

A DOGMA THAT NEEDS TO BE RE-EVALUATED

Aside from the technological challenges that O&G companies face by exploring deep to ultra-deepwater frontier areas like the Colombian Basin, we have to consider a three-decades-old geologic dilemma of two opposing models that have attempted to explain the origin of the Caribbean region. It is key to solve and understand this paradigm because it conditions the crustal architecture of the basin, and thus, the potential presence or absence of an active thermogenic petroleum system sourced by an organic-rich Cretaceous source rock.

In simple terms, the Pacific or "allochthonous" model considers that the Caribbean plate was formed in the Pacific region from a mantle plume active during Late Cretaceous times. This thickened the oceanic crust, which subsequently drifted relatively towards the east to its present-day location. In contrast, the "in-situ" model proposes that the Caribbean Plate formed in-place by the opening of the Americas since Jurassic times.

By solely favouring the Pacific model, which seems to be the preferred dogma in Caribbean tectonics, then the preservation of potential Cretaceous source rock and its petroleum system wouldn't be possible. In turn, this would deem the area not as prospective as it could be if the "in-situ" model would be the preferred one. ▸

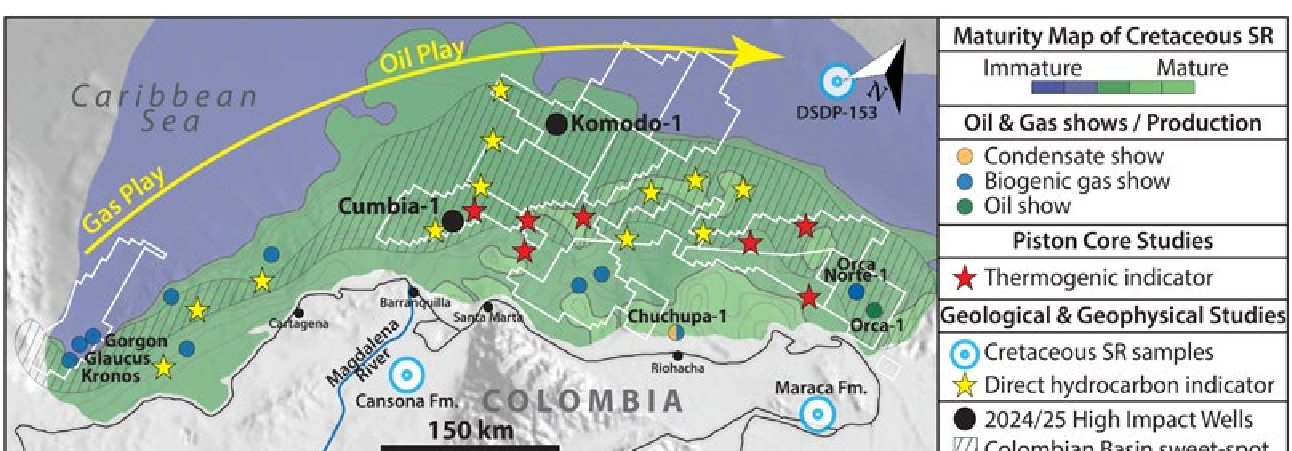


Figure 1: Location map of the Colombian Basin highlighting sweet spot for thermogenic play.

A current study conducted by the Conjugate Basins, Tectonics, and Hydrocarbons (CBTH) Consortium at the University of Houston uses several newly acquired 2D and 3D seismic datasets, which has evidenced the dramatic heterogeneity of the crustal structure of the Colombian Basin. This new study challenges both opposing tectonic models to an extent that we may consider that one single model simply doesn't fit all. Elements of both models - a hybrid model if you will – may be the way forward. Further details on this new study will be discussed in an upcoming publication.

A GLIMPSE OF THE EXISTENCE OF AN ACTIVE THERMOGENIC PETROLEUM SYSTEM

In a recent interview, top-executives at Ecopetrol stated that the 2024 Orca Norte-1 well is a "gas discovery with a different composition than what was found at Orca -1". More importantly, it was confirmed that the Orca well "not only encountered gas, but also instances of heavy oils and crude oils", which is currently being further studied by Ecopetrol. But, the analysis does also show that there is "an even bigger gas potential for the country."

Are Ecopetrol's comments confirming the presence of a potential thermogenic system on the Colombian offshore a surprise? Maybe not so much. Previous authors already reported thermogenic signatures on piston core studies, oil slicks, oil seeps, heavy isotopic signatures mixed with biogenic gas samples, and condensate fluids derived from early production from the Chuchupa well. In fact, Carvajal-Arenas included all previous observations and proposed a thermogenic hydrocarbon system for the Colombian Basin with mature Cretaceous (?) source rocks underneath areas like the Magdalena fan system and the South Caribbean Deformed Belt. To add to that, we believe that an active younger Eocene petroleum system could be also present in the Colombian offshore (Figure 1).

All these pieces of information seem to now be coming together, pointing in the direction of an active thermogenic petroleum system and the need to re-evaluate the prospectivity of the Colombian Basin and current Caribbean tectonic models.

A HIGH-IMPACT WELL: IT IS TIME TO GO DEEPER

A new family of wells will be drilled in the coming months testing deeper areas of the Colombian Basin. Oxy and Ecopetrol are planning to drill the Komodo-1 exploratory in the second half of 2024. It will be the first well to drill in the Colombia ultradeep-water basin, and it will test a 4-way anticlinal structure, with class 3-AVO anomaly, conformable with structure. And last but not least, the prospect features a double flat spot. The Komodo-1 well is expected to have a water depth record of approx. 3,950 mbsl, and targets turbiditic Mio-Pliocene sandstone reservoirs (Figure 2).

Even though the Colombian Caribbean Sea is already classified by many as a biogenic gas province, let's not forget several examples of overlooked basins that ended up yielding some of the biggest oil discoveries seen over the past few years. In Namibia's Orange, source rock presence and maturity were continuously debated following the discovery of the Kudu gas field in 1974, until TotalEnergies' Venus giant oil discovery came along in 2022. A similar thing can be said about the now famous 2015's Liza world-class oil discovery in Guyana, where previous wells mostly encountered heavy oil along the coast. Also, keep in mind the Campos-Santos success story, considered a gas province for many decades - just like the Colombian Caribbean offshore- until the pre-salt play was tested in 2006. With lessons like these, should we consider that the Colombian Basin is on the pathway for a big discovery? ■

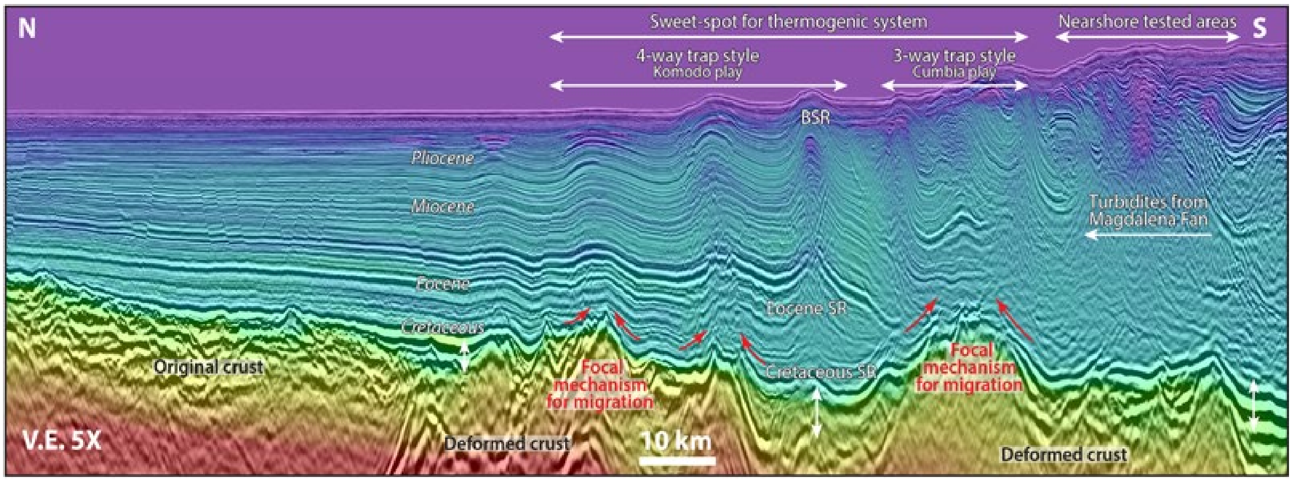


Figure 2: Seismic section overlain by velocity model showing proposed play types in the Colombian Basin.

In the heart of the global economy

Dammam in Saudi Arabia is a special place in the history of oil, because it so clearly defines the continuous importance of the fluid since its discovery in the area in 1938

THE ARAMCO compound – where most of the work is done to keep the Saudi oil machine turning - is still situated in the exact same area where the story of oil began for Saudi Arabia 86 years ago. I was lucky enough to get a glimpse of the properly secured compound recently when I attended the IPTC conference and a friend was so kind to show me his house.

"Once in, you don't feel like being in a secured area", my friend told me before we were picked up from Al Khobar where we enjoyed a nice meal and wandered around the big coastline projects that so clearly define the new ambitions of the country's ruler, Mohammed bin Salman Al Saud, or MBS.

The outer ring of the compound consists of the Aramco office blocks, and the inner circle is where employees live. We did not visit the offices but continued towards the centre of the compound.

Once in the residential areas, what is very apparent is the typical American style of housing. If unaware, one would surely think that this would have been a housing estate in one of America's early suburbs. Lawns nicely cut, American cars sitting on drives, STOP signs at every crossing, and typical bungalow-style houses.

And that is not a surprise, as it was the Americans who not only found the oil in the first place, but then also helped build the infrastructure to start exploiting it. Aramco stands for Arabic and American oil company.

The compound residents have little to complain about in this unique place in the desert. A golf course, perfectly maintained parks, schools, gyms, everything is catered for here. "I don't often leave the compound", my friend admitted. "I don't feel like being locked up at all."

On our way back out – I stayed in a normal hotel in town – we passed the place where the first oil discovery was made in Dammam. It is still within the perimeter of the compound – something that I had not foreseen when looking up the place on Google Maps. Dammam-7 was the seventh well in a row that finally found commercial quantities of oil in the Dammam dome – the previous wells had all TD'd at shallower depths and had only resulted in shows or rapidly declining production tests.

And behind the little monument, there are work yards and well heads visible, all clearly demonstrating the continuous activity in the area that all focused on one thing: Getting more out from those fields that kickstarted Saudi's oil bonanza 86 years ago. ■

Henk Kombrink

Hydrocarbon shows don't necessarily mean a significant find

It is too early to call a discovery when no logging nor pressure measurements have taken place

"MCF ENERGY Announces Significant Gas Discovery in Austria", was the headline of a press release issued recently by Canadian player MCF Energy. That sounded like exciting news initially, but when reading the accompanying text, it may have been a bit early to call this a discovery. Namely, wireline logging and pressure testing were yet to be carried out: "A suite of wireline logging tools, along with an MDT formation test tool, will be deployed for downhole pressure measurement, inflow testing, and formation fluid sampling in the targeted zones", said the same press release.

Why would you announce a discovery when the actual proof is not there?

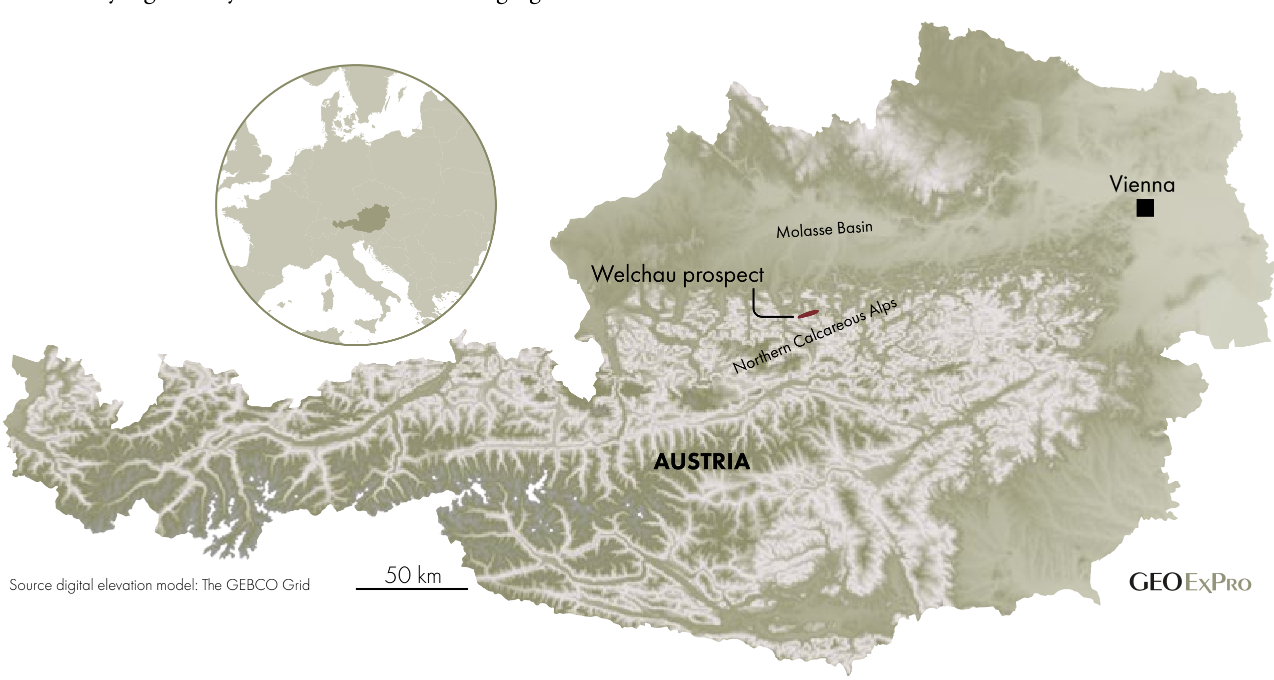
There are many wells where shows were reported that never made it into a commercial development. In fact, it can probably be stated that it is quite rare to drill a well into a sedimentary basin without any signs of hydrocarbons. As an example, well 30/7-7 in the Norwegian North Sea reported major gas shows in the Jurassic, but a subsequent DST failed to get gas to surface because of the formation being tight. More recently, in the Suriname-Guyana hotspot, CGX and Frontera had some explaining to do to investors. They needed to make clear that the announcement of a significant hydrocarbon-bearing Santonian sandstone interval did not equal a similarly thick pay zone. The devil is in the details, details that can be measured through a proper wireline and pressure testing campaign.

Back to Austria. The Welchau well, drilled by both MCF and Australia-based ADX, targeted the Steinalm reservoir. It is a fractured Triassic limestone that already proved to contain hydrocarbons in a well drilled nearby (Molln-01) in 1989. The press release also emphasised that above the reservoir, a 380 m sealing unit was found, belonging to the Lunz Formation. The presence of a strong gasoline odour released from the core is also being described in support of the potential of this "discovery".

But, let's not forget that this is all circumstantial evidence. The presence of a sealing unit is not a guarantee that a closure exists, and with this well being located onshore in a tectonically complex area, who says that there are no leaks? And, as geologist Rick Bass describes in his book Oil Notes, the importance of logging operations cannot be overstated. Only after completing a log run, a well can be properly classed as a success or a dry hole.

For all these reasons, it is too early to call Welchau-1 a discovery. An announcement of this kind should be made after the well has been properly logged and pressures being taken. Only then a valid statement can be made, and only then investors should embark on purchasing a few shares. ■

Henk Kombrink



The sequel: The hunt for Buzzard II continues

In a recent GEO EXPRO article, Neil Hodgson, Lauren Found and Karyna Rodriquez from Searcher described how the re-processing of overlapping 3D seismic surveys of 1999 to 2004 vintage revealed an exciting 'Buzzard' age sand fairway in proximity to the Buzzard Field, UK Central North Sea. Within this new fairway, Finder Energy have identified a large (mean 150MMboe recoverable) prospect called 'Whitsun'

HARRY DYE, MATT ENGLAND AND HENRY MORRIS, FINDER ENERGY

THE PROSPECT is located in the Peterhead Graben, a sub-basin in the geographically more extensive 'South Halibut Basin', home to numerous Upper Jurassic fields and discoveries of which the giant Buzzard Field, located just 15 km to the northwest remains the largest discovery to date. The field has already produced >800 MMboe and is expected to continue production post 040.

So how could a prospect of this size in such proximity to a giant like Buzzard have evaded the drill bit for so long? Given it has now been over twenty years since well 20/6-3 struck pay at Buzzard, some will feel that given the sub-basin has been tested by nine wells to date, yielding only one undeveloped oil discovery (well 20/8-2), it must lack the critical elements necessary to form a functioning petroleum system. The problem with such preconceptions is that they are often formed on the back of outdated ideas.

EXPLORATION HISTORY IN THE PETERHEAD GRABEN

The Peterhead Graben has undergone two phases of exploration. The first, in the early 1980s, saw five wells drilled to target hydrocarbons in the lateral equivalents of the prospective Ettrick and Piper sandstones. Rather ironically, given their conceived 'risky' nature, the 20/8-2 discovery well was the only well of these five to target a stratigraphic trap and the only well to find pay (8.5 net pay and an ODT in Buzzard sandstones). Subsequent geochemical analysis of the oil has shown it to be expelled from an early mature source rock and most likely sourced from the Peterhead Graben. The remaining four wells drilled on structures failed to find any significant Upper Jurassic reservoir, although three of them did find poorly developed stringers or tight sands with occasional oil shows. ▸

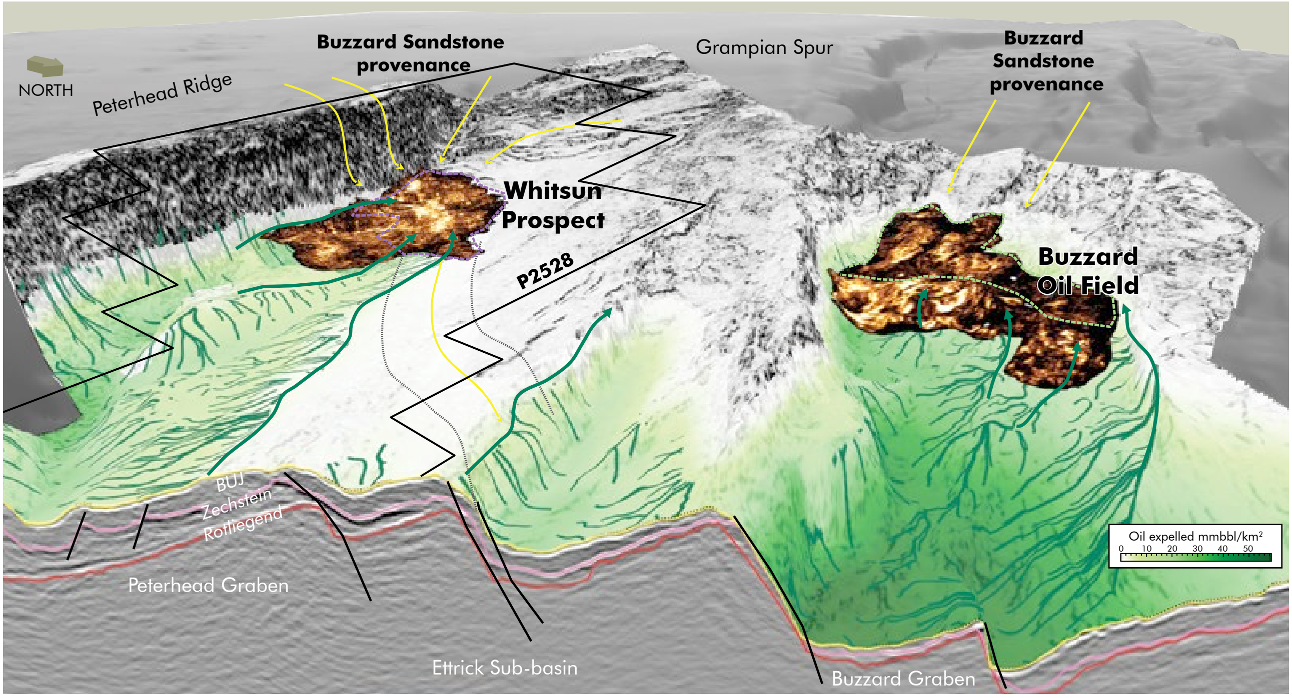


Figure 1: Base Upper Jurassic 3D view with oil expulsion from the J62 surface and Buzzard age amplitude anomalies.

Three wells were subsequently drilled between 2003 and 2004. All wells were intended to test stratigraphic traps with Upper Jurassic turbidite reservoirs, analogous to the then recently made Buzzard discovery. Only one well encountered well-developed sandstones, now known to be shallow marine shoreface sands, disproving the geological model at the time of drilling. The other two wells only encountered thin, poorly developed sandstone stringers now interpreted by Finder to represent deepwater channel levee deposits. Oil shows were seen in some of these sands, again providing evidence of an active kitchen. These thin sands provide the 'plumbing' to connect the thick and oil-mature pods of Kimmeridge Clay source rock in the depocenters to the sweet spots of the Buzzard deepwater sand fairway.

Recent mapping done by Finder on the latest reprocessing of the vintage 3D seismic data has identified what appears to be a deepwater Buzzard channel downdip of the failed 20/11-1 exploration well. It is this channel feature that provides the reservoir for the Whitsun prospect (Figure 1).

THE WHITSUN PROSPECT

The Whitsun prospect is a Buzzard sandstone stratigraphic trap located on the western edge of the Peterhead Graben. The reservoir is mapped within the J64 interval and is trapped by dip closure to the east, pinchout to the north and west supported by mapping and proximal wells and downthrown fault bound /pinchout out to the south. The reservoir is thought to be excellent quality Buzzard deep-water mass flow sands sourced from the Scottish Mainland and transported eastward into the Peterhead Graben. The prospect is sourced and sealed by the Upper Jurassic Kimmeridge Clay deep marine shales. Due to the prospect's aerial extent and mapped gross reservoir thickness, Whitsun has a material resource potential of up to 770 MMbbl STOIIP (P10).

UNDERSTANDING THE REGIONAL RESERVOIR STORY

In a sub-basin with the majority of wells encountering hints of mass flow sands and a more developed reservoir interval in the 20/8-2 well, reservoir presence was a key element to fully understand. New geological studies were undertaken, including gross depositional environment mapping and developing geological models. The study was complemented by new biostratigraphic analysis by Merlin Energy Resources and regional mapping on the newly reprocessed "Big Buzz" seismic data.

In core data, the Buzzard sands show excellent reservoir quality within mass flow sand channel complex facies and are textually mature indicating recycling in a shallow marine shelfal area (19/8-1 and 19/15-1). Within the Peterhead Graben, thin non-reservoir sands are encountered within the mainly shale-dominated Buzzard and Ettrick intervals. It is thought that these sands could indicate the outer extremities of the main Buzzard mass flow sand fairway within the Peterhead Graben.

Combining the biostratigraphic analysis along with the newly reprocessed Big Buzz data allowed the Upper Jurassic to be broken down into age-equivalent intervals, enabling

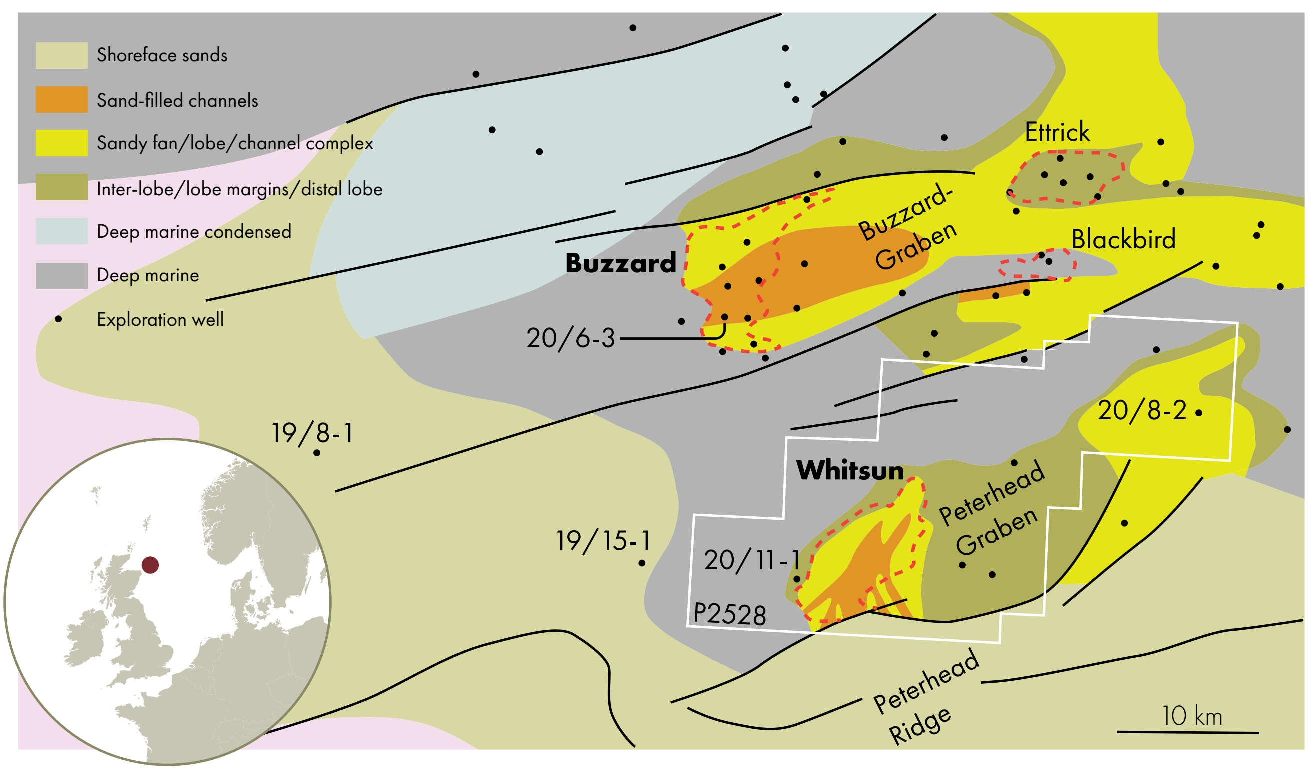


Figure 2: Finder Energy generalised Buzzard (J56-J65) gross depositional environment map.

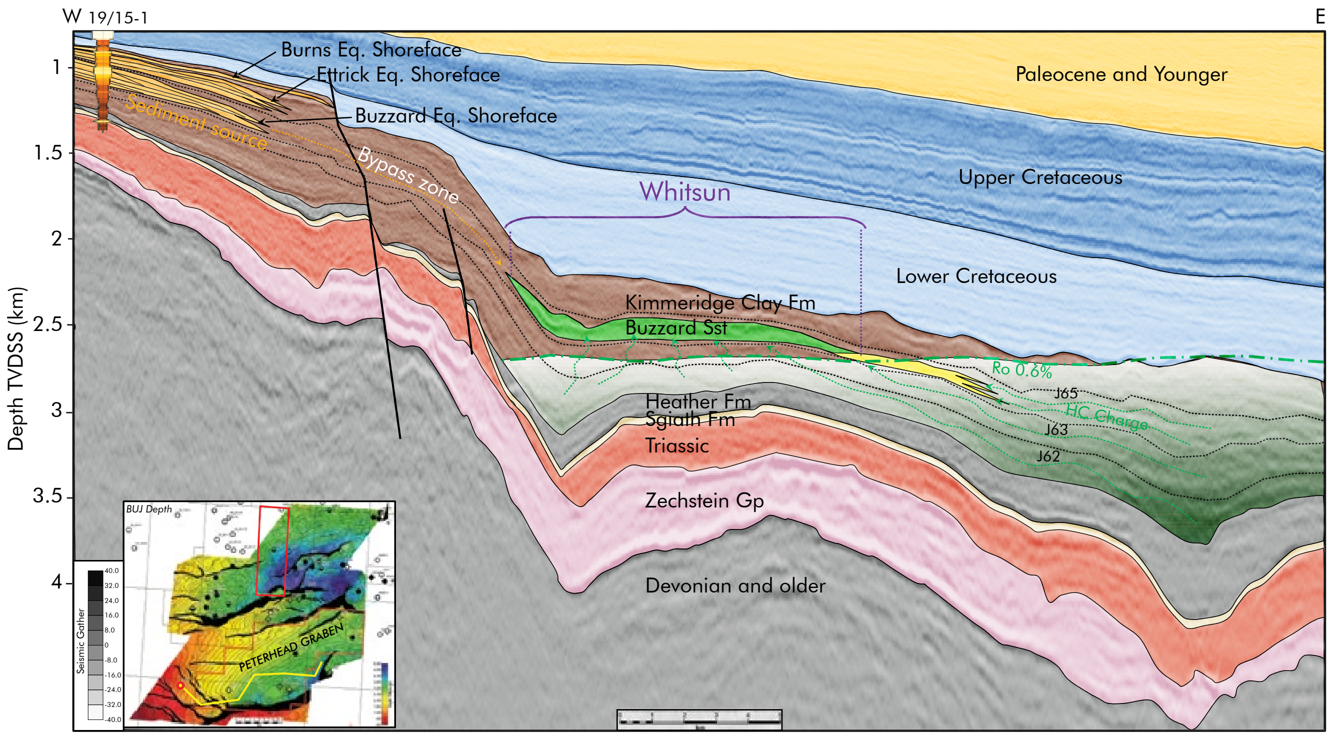


Figure 3: Geo-seismic line through the Whitsun prospect with the reservoir source to the west and mature kitchen beneath and to the east of the Whitsun prospect.

detailed and confident geophysical attribute analysis. Within the Buzzard interval in the Peterhead Graben, a clear seismic amplitude anomaly is seen as an elongate SW-NE trending feature comprised of thinner multiple channels feeding into a wider channel complex (Figure 1). The seismic amplitudes are consistent with geological model and explain how the previous wells missed the main sand fairway.

PETERHEAD GRABEN MATURITY AND CHARGE

Although proven in the 20/8-2 discovery, and with the presence of oil shows in surrounding wells, charge and migration was another key area of focus in the Peterhead Graben. This was due to the depth of the very top of the Kimmeridge Clay being immature in some areas of the sub-basin. Finder Energy contracted APT to further understand the charge potential of the sub-basin.

The Peterhead Graben contains a very thick gross Kimmeridge Clay interval. However, not all of this sequence will be source rock that is able to charge the Whitsun reservoir. A source rock and charge model was constructed assuming a net effective source rock thickness based on offset well data, which is significantly less than the mapped gross Kimmeridge Clay Formation isopach. Additionally, the present-day depth of this source interval was varied. The image in Figure 1 shows the oil expulsion yield from this net source interval modelled along a horizon that is on average a little over one hundred meters below the Base Whitsun reservoir interval. The charge mechanism into Whitsun involves short distance of vertical migration from the source rocks into the overlying J64 sands, followed by relatively short distance lateral migration up-dip into the Whitsun reservoirs (Figure 3).

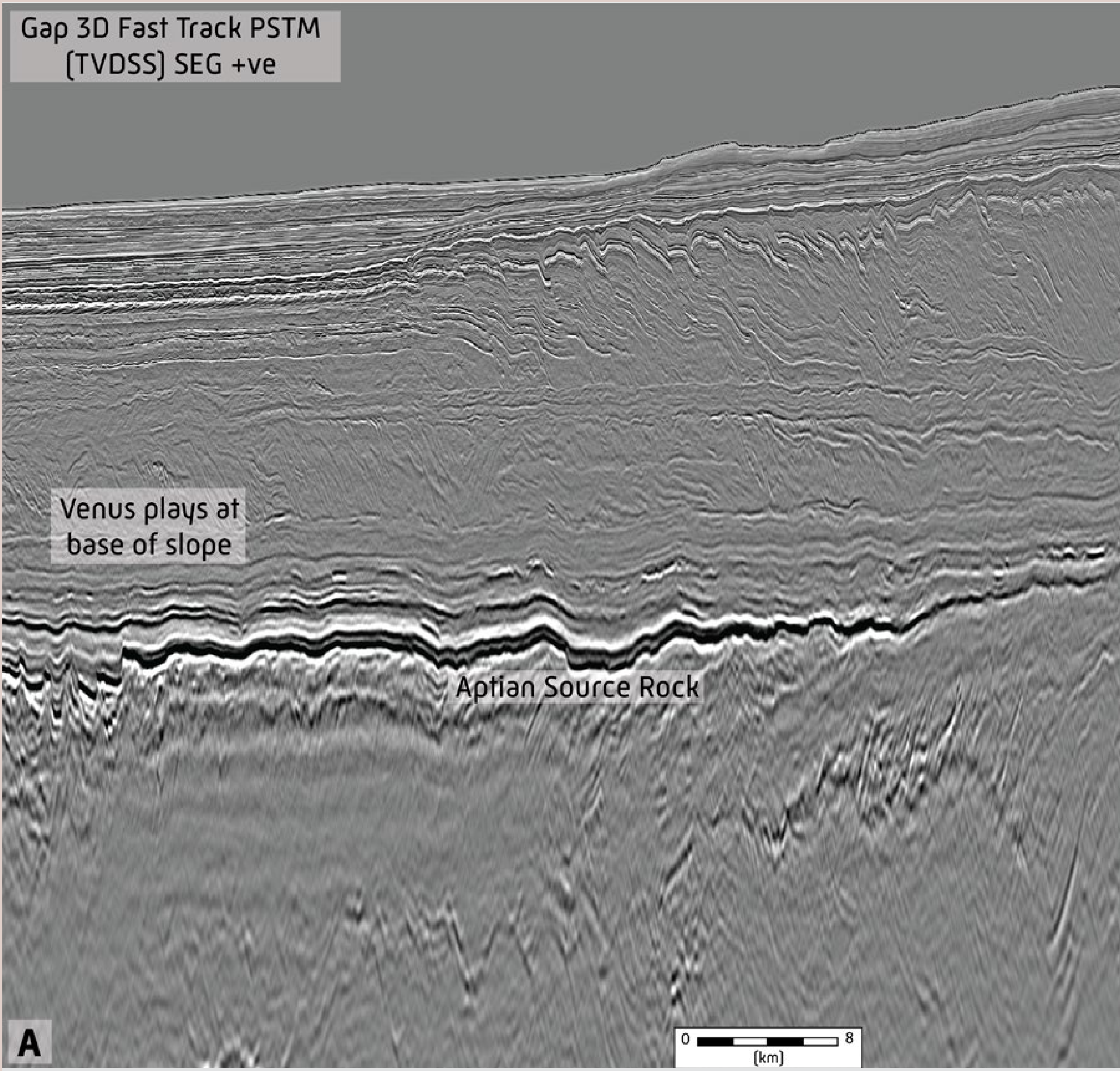
A detailed charge model using traditional fetch cell and advanced Spider 3D migration and Monte Carlo calculations was calibrated to wells, fields and oils in the area. In the Peterhead Graben, the model shows the shallower Kimmeridge Clay units (above Whitsun) are marginally mature as expected. However, the thick Jurassic J56-J63 interval (directly below Whitsun reservoir) is shown to have good maturity and source rock potential in wells. This combination results in the expelled oil likely to be low maturity/GOR (<200scf/bbl).

Some uncertainty exists with fetch cell extent and migration pathways due to limited well intersections in the source rock kitchen, nevertheless the model shows the Peterhead Graben source kitchen provides sufficient generation and expulsion to fill the Whitsun Prospect.

DRILL-READY

Robust technical work carried out on all the key elements and insights from newly reprocessed seismic data has uncovered strong technical evidence to support the viability of the Whitsun prospect which has now been derisked to a drill-ready status. Due to a simple well design and a shallow target depth, only a relatively cheap exploration well is required to test this high material size prospect with local infrastructure nearby. Finder is searching for a like-minded partner to join in testing this exciting prospect with the drill bit. ■

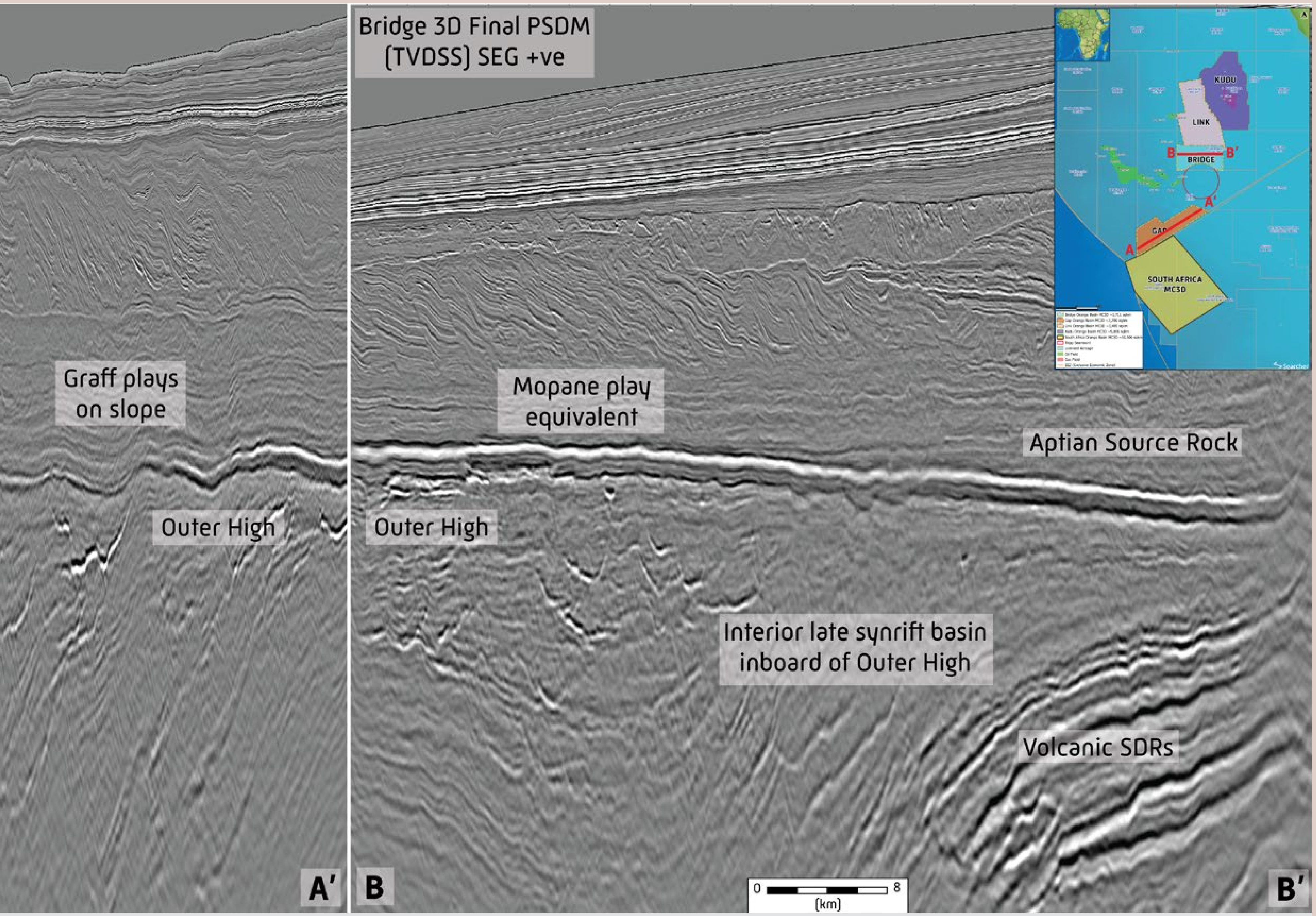
Namibia's Orange Basin and the holey slope mystery



This foldout line, which is a composite of the Gap and Bridge 3D surveys acquired in 2022 and 2023, prominent holes were imaged on the seabed, and Searcher is looking into them...

Searcher

NEIL HODGSON, KARYNA RODRIGUEZ AND LAUREN FOUND, SEARCHER



In the Orange Basin of Namibia and South Africa, a hole appears on the gently dipping clastic slope. In time, it slowly creeps down the slope as if moving under gravity and leaving a filled-hole trail behind it. Sir Arthur Conan Doyle wrote that "the world is full of obvious things which nobody by any chance ever observes". Such is this hole – a hole with seemingly no purpose. Yet, it has a meaning.

When Searcher acquired the first multi-client 3D in the Orange Basin of Namibia in 2021 over the southern part of PEL 85, Rhino operated acreage inboard from Shell's Graff-1 discovery, we had the thrill of seeing Upper Cretaceous channels onlapping onto the Outer High - which has since become known as the Inner Basin Mopane play - and as the AVO type-III anomalies jumped out of the section, they arrived with some surprises too.

ON DIP LINES (See Figure 1), we can see several almost triangular notches, divots or holes in the seabed, some 1.5 km in width and 250 m deep. Upslope, the divot wall is at a lower angle than the downslope face, which is truncated, and erosional. The upslope face is mirrored in the subsurface by a set of reflectors that extend to the same depth and look for all appearances like prograding units marching back up the slope.

On 2D seismic, these features were initially interpreted as meandering slope channels, cutting into the seabed substrate and winding in and out through the plane of the section. The prograding units would be lateral accretion surfaces in this model. However, on 3D seismic these notches are almost circular to oval, and not connected to any slope channel features at all.

By taking a time slice we can see the relict circular to oval features, now sediment-filled, in addition to the long, thin trails extending through the top 200-300 m of the section (Figure 3, time slice marked on Figure 1). These trails run directly downslope (from east to west) and are as wide as an individual seabed notch. The notches in the seabed cluster in the west of the image, as well as following the clinoforms to the east, the trails stretch almost across the whole image. On the dip section of Figure 1, we can see that whilst to the west there is a recent set of these features, we can see another set, similar to these but older to the east. Whilst each notch in the seabed has migrated from east to west (downslope), yet through time the start of the notch trails has also moved from east to west. So what mechanisms might drive these observations and, frankly, why do we care?

Before we stop making observations, one more. To the south on the time slice in Figure 3, one can make out a distinct 10 km west-east trending zone that shows thin circular disturbances, representing fluid movement pipes in the upper section. On the dip sections of Figure 1, there are several sets of these pipes. What each set has in common is that 400 m above the start of the visible pipe, they widen into a cone shape. The earlier pipes therefore have their sediment-filled cones preserved in the upper section, whilst the later pipes reach the modern seabed.

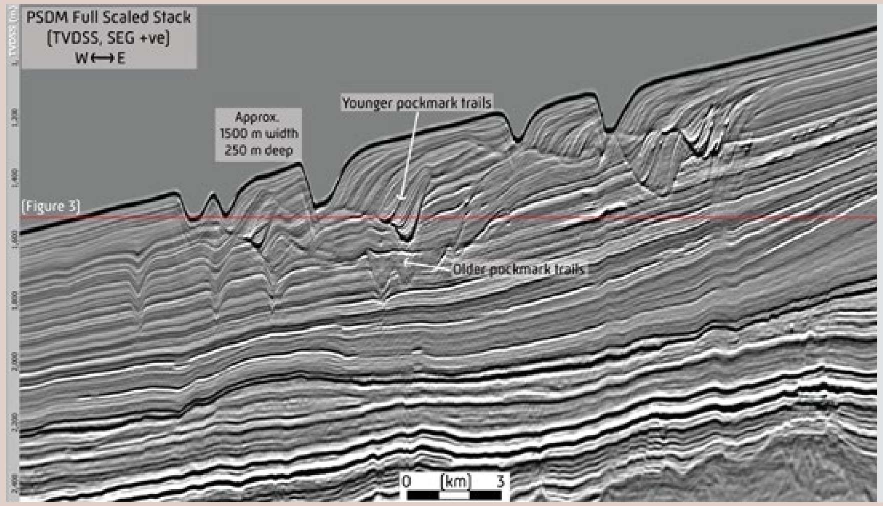


Figure 1: A zoom of a W-E dip section within the Bridge Survey showing the mysterious seabed notches.

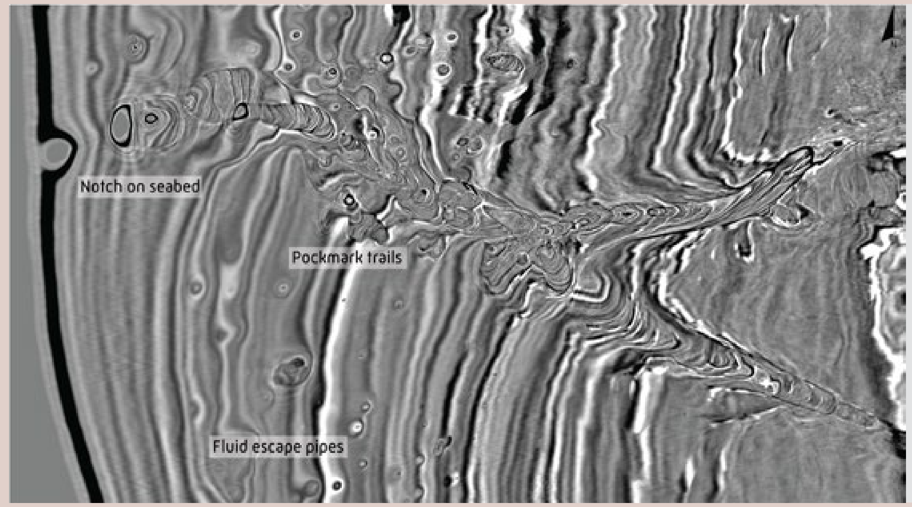


Figure 3: Time slice at 2.0 sec TWT through the pockmark trail.

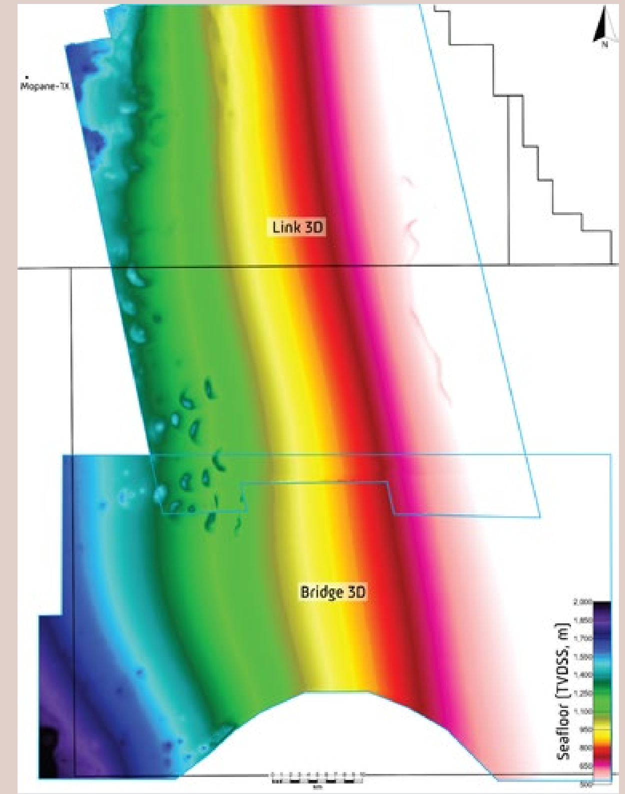


Figure 4: Seabed in PEL 85 and PEL 83 showing a discrete pockmark N-S band some 10 km across.

FLUID ESCAPE

These latter features indicate the importance of the migration divots. Of course, we are not the first to see these or indeed recognize their significance. In 2012, Satieng Ho, Joe Cartwright and Patrick Lubert published on migrating pockmarks from the Lower Congo Basin, reporting very similar observations of a similar phenomenon. The model that they derived was that fluid escape (either gas or oil) creates a pockmark in the seabed, with currents - presumably holding sediment in suspension - running over the seabed downslope either rapidly fill the pockmark or by a process of cut and fill, migrate the pockmark down slope, creating the pockmark trail. Repeated periods of pipe formation related to breaching a sealing of pressure cells.

MIGRATING SOURCE ROCK MATURATION

If we were to accept the pockmark model and make the leap that the location of the pipes and pockmarks are telling us something about a maturing hydrocarbon system below, then we might propose that earlier in the Tertiary, the Aptian source rock started to be effective further to the east, and then with time, this maturity became effective further west. This is consistent with the Tertiary clastic prism prograding east to west away from the shore, loading and presumably maturing the Aptian source as it went.

The implication is that even the Aptian across the whole Inner basin is mature, at least for oil generation. The significance of this derives from the Mopane 1X and Mopane 2X discoveries drilled just to the north of PEL 85. Both discoveries are located inboard of the Outer High, so are not charged from the Venus discovery source rock to the west. Mopane 1X and 2X have encountered light oil accumulations.

When we look at the seabed over the area near Mopane 1X, utilizing Searcher's 2022 multi-client 3D seismic over PEL's 85 and 83, we see that the pockmark trail extends on a north-south trend up to close to Mopane 1X. This observation has been corroborated by sea surface slick identification around the Mopane discoveries, as reported on by Clément Blaizot. However, pockmarks and pipes at the seabed are seen virtually nowhere else (Figure 4).

THE KEYS TO A NEW WORLD

If the pockmarks are indeed telling us something about hydrocarbon maturity in the Aptian, then we can make a second jump. The Inner Basin extends southeast from the PEL83 and 85 area in Namibia, and into South Africa's Orange Basin. Here, on legacy 2D data, we see identical pockmark trails, and so, we believe this tells us something very exciting about the presence and effectiveness of the Aptian within the Inner Basin of South Africa (Figure 5). No wells have yet been drilled into the Inner Basin to test the Lower Cretaceous, but when such exploration occurs – it might be a great comfort to know that the Aptian is as mature there, unsurprisingly enough, as it is in Namibia's Inner Orange Basin. As Sir Doyle may have remarked – "there are lots of obvious things that go unobserved – but some of them are the keys to a new world".

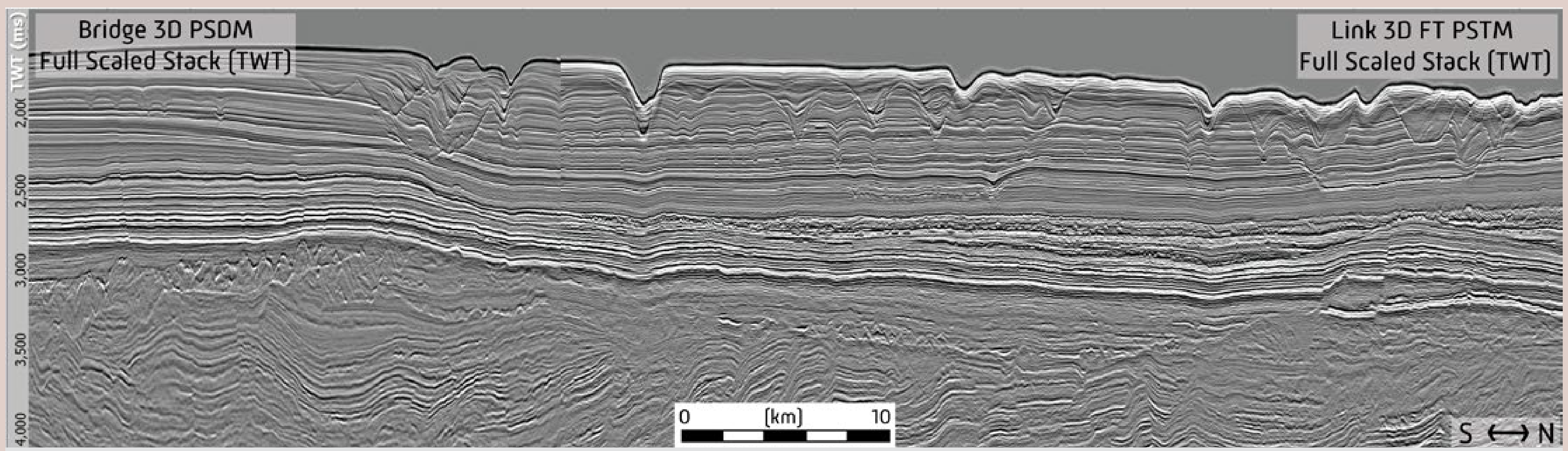


Figure 2: S-N strike section from Bridge and Link multi-client 3D's. In strike direction, the notches vary from symmetrical and erosional, to occasionally showing narrow laterally prograding bedforms, always very restricted in their extent.

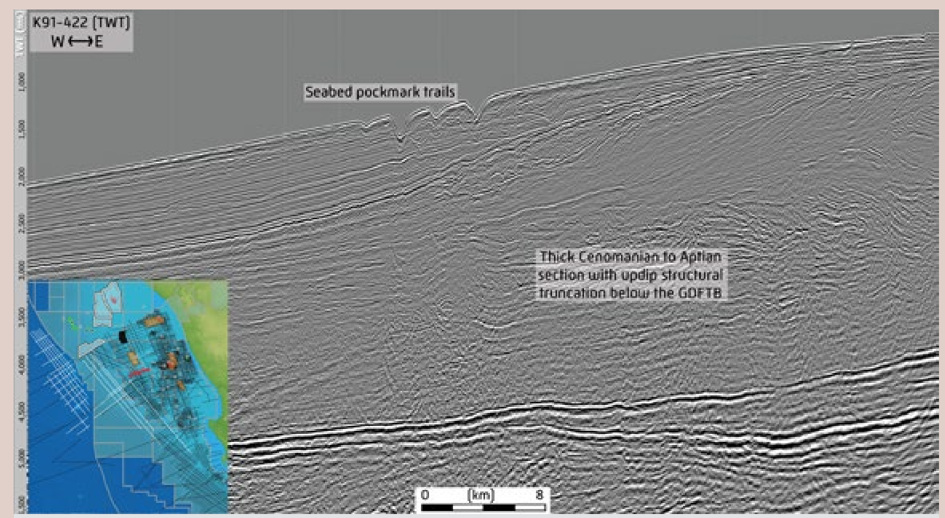


Figure 5: Legacy 2D data over the Outer High and Inner Basin of South Africa's Orange Basin, on trend with part of the Inner Basin of Namibia. Note the pockmark trail at the near-surface, indicating a working hydrocarbon system there.

PORTRAITS

"As far as upstream oil and gas professionals go, I can't see a time where people on the rigs will ever be replaced by AI because the data needs to be collected in the first place."

Amanda Barlow – Wellsite geologist

FOUR DECADES OF ROCKS

Familiarising yourself with the location of the lifeboats is a top priority when starting on a rig you haven't worked on before.

PHOTO: AMANDA BARLOW

Amanda Barlow spent 40 years on rigs as a wellsite geologist. Here, she talks about the downturns, technical learnings, the role of technology and the future of the profession

HENK KOMBRINK

"FROM WHEN I was in primary school, I wanted to become a geologist", says Amanda Barlow when I speak to her whilst she sits in her kitchen on the Gold Coast, south of Brisbane, Australia. "Where my fascination comes from? I don't really know, but my mother's father was a bit of a fossicker - a person who is good at searching for minerals. He worked in the mines in his early career and built up a small rock collection. He gave it to me when I was young, which must have triggered something! I became the proud owner of a geological hammer at the age of 10, which is also telling!"

And looking at rocks certainly became a thing throughout Amanda's life. After graduating in 1983 from the School Of Mines Ballarat, about 100 km west of Melbourne, she has built up an impressive list of drilling projects she has been involved with, be it in gold and base metals mining, coal seam gas exploration or conventional oil and gas. And the list of projects continues to grow until today. "Flying in and flying out is a lifestyle that suits me", she says. But it is not always easy….

COPING WITH DOWNTURNS

In the concluding chapter of the book she wrote and published during the first years of the oil price crash that started in 2014, Amanda wrote: "With every rig that got "cold stacked" there were hundreds of workers being made redundant. It wasn't dependent on your experience or your position - it just came down to where you were when the music stopped."

She wrote this in 2016, when she came off her last contracting job for Woodside in the Carnarvon Basin, Western Australia. The wells she helped drill were commitment wells for the licence, but there was no new work in sight. For that reason, she concluded the book by saying: "I don't know how long it would be before I'd be back on a rig but hopefully not too long. Now it's my turn to play the waiting game."

Amanda's waiting game was a tough one. "I had to sell the property I invested in just before the downturn kicked in, to the point where I only had a car left! Then, someone told me to become an Uber driver, which I had not thought of at all. And it worked very well; I spent about 9 months driving people around and managed to pay my essential bills that way. It is easy to complain about the disruptive nature of a service like Uber, but believe me it is keeping a lot of people out of poverty", Amanda reiterates.

At the end of the day, the waiting game worked out for Amanda though. "One never knows when good times return, but the fact that I'm getting calls from recruiters again is something that I haven't seen for a long time. It is a good feeling for sure, much better than continuously having to chase recruiters to get back to me."

The return of the good times does not mean that the pendulum is back where it was at a similar moment during the previous upturn. "The way wellsite geologists are recruited has changed", says Amanda. "All contracts are handled through recruitment agencies, which have multiplied exponentially in the past 10 years. It's increasingly harder to get a job if you don't have prior experience with the companies or have a track record with the recruiting agencies. It's impossible to know how the O&G companies will recruit wellsite geologists for their campaigns…whether they will select individuals on their experience or just go for the cheapest tender."

"During the downturn, this was especially difficult because some ▸

companies were just going with the recruitment agency that submitted the cheapest tender, but you don't know what agencies are going to be bidding for the job. And you also don't know whether to submit your CV to multiple agencies for the same job. There seem to be no rules anymore."

FIGHTING THE OLD BOYS' CLUB HAS ALWAYS BEEN MY BIGGEST CHALLENGE

"On top of that, this industry has a historical male-dominated generational workforce due to women not being encouraged to work in the industry until recent decades. There's a network of career wellsite geologists in Australia who have worked with each other throughout 40 years or more of working in the oil and gas industry, who have the deep experience and connections to get prioritised for jobs when they become available", says Amanda. "I had to break into that network after working in mineral exploration for 20 years first."

Working in oil and gas was a midlife career change for Amanda when she was in her 40's. Perseverance, networking and staying relevant has paid off. Now the oil and gas industry is on the cusp of another bull market, and possible supercycle, due to the lack of capital flowing into the industry during the previous decade, and opportunities are again presenting themselves, especially for people who have already had some skin in the game. As the critical skills shortage kicks in, the tables have finally turned in favour of the geologists and the recruiter's calls are finally coming in again!

> "And you also don't know whether to submit your CV to multiple agencies for the same job. There seem to be no rules anymore..."

DEVELOPMENT DRILLING IN AUSTRALIA

The downturn was not the only cause for the plunge in drilling activity in Australia. The Barossa field drilling campaign by Santos came to a sudden stop a few years ago after complaints from the local community. It made the government that had signed off on the plans look bad, which caused them to cancel all other projects that were already permitted in case something was missed. This backlog of projects is now getting into motion again, with Santos recently getting renewed permission to start drilling on Barossa. Similarly, Woodside has plans to start drilling on the significant 11.1 Tcf Scarborough development. Shell is also doing a couple of development wells on Crux, and Inpex is continuously looking at infill wells on Ichthys.

"THE TOOL MUST BE BROKEN"

Amanda has mostly been drilling appraisal and development wells throughout her career. With offset well data always available in these cases, there is limited scope to see something genuinely unexpected in terms of geology. However, her stint in Myanmar, drilling in the deepwater area of the Rakhine Basin at more than 2,000 m, brought an experience that stuck with her since. And it is related to the unique geological setting of the place.

"The deepwater area of the Rakhine Basin is characterised by the presence of large-scale gravity slides and extensive debris flows of Mass Transport Deposits (MTD), which had been interpreted as a result of two interacting depositional systems: the Brahmaputra Fan (part of the Bengal Fan) inputting sediment from the north, especially during the Miocene; and the uplifted Rakhine margin inputting sediment from the east during the Upper Pliocene–Pleistocene", Amand explains.

"These debris flows can cause major seismic problems when attempting to image the geology below them because they can absorb a large proportion of the high-frequency seismic energy. They clearly stood out on the seismic data we were working with", she continues.

"There was also an interesting effect in the resistivity data that was collected in these wells, with intervals where all 4 resistivity curves showing a dead straight line and all on top of each other. On a number of occasions, the operations geologist and petrophysicists in town complained that there was something wrong with the LWD tools as the resistivity curves looked erroneously too straight and all channels were giving near identical readings", says Amanda. "When looking very closely though, one could already see that the curves showed minor differences, clearly suggesting that the tools did work."

"It was only when it happened a second time, and people in town questioned the reliability of the data collected, that I remembered having the same concerns on a previous well, and when I reviewed the previous data, it turned out to be collected over a zone of MTD material. I think it is the highly compacted nature of the MTDs that caused the resistivity curves to be overlapping that much; there is simply no porosity or permeability in these systems, so no invasion of any drilling fluids either. I have seen a lot of geology, but a sedimentary succession being so tight as these MTDs is something that I have never encountered somewhere else", Amanda concludes.

A KOREA PHOTO MOMENT

In her book, Amanda describes the moment she comes onshore and hears the news about the share price hike a company had just experienced as a result of the well she contributed to drilling safely. "It is a great feeling to be part of such a success story", she says.

It does not always work like that though. In Korea, Amanda worked on a well in the Ulleung Basin. The Koreans were very keen to develop a domestic production base, so they were following operations very closely. "At

Retrieving reservoir fluid samples from the wireline tools is a critical part of the formation evaluation process.

PHOTO: AMANDA BARLOW

first, there were good indications from the wireline logging that we had encountered good reservoirs", Amanda explains. "This caused rumours that a photographer was coming out to the rig to take photos of the moment a new gas discovery could be confirmed."

"We had taken downhole gas samples, which were analysed on the rig straight away. With everyone waiting in anticipation, ready to transfer the news back to shore, the first analysis came in. Only CO_2. I'll never forget this, also because I needed to rush up 10 flights of stairs to collect the jars one by one on the deck, and phone my boss from the wireline logging unit that was level with the drill floor."

"And whilst we were doing all this, we noticed a couple of fighter jets circling above the rig, coming lower and lower. At first, we thought it was really cool, but as the planes got closer, everyone suddenly stared at each other and thought – should we feel worried about this? Combined with the fact that we knew submarines were continuously observing us as well as navy vessels, it makes you acutely aware of the sensitivities at play in that part of the world."

"It was only when it happened a second time, and people in town questioned the reliability of the data collected, that I remembered having the same concerns on a previous well."

HOW NEW TECHNOLOGY HAS CHANGED LIFE ON RIGS

With all the talk about technology going to replace the human workforce, it is interesting to see that Amanda's observations from being offshore paint a picture that one would not necessarily expect. "Rather than seeing fewer people on rigs these days, there are more!", Amanda says.

"Advances in technology have meant that an incredible amount of data is now collected in every well that's drilled. AI will most certainly be able to make more reliable interpretations as more and more data is fed into models over time. I don't imagine AI will replace jobs in the industry though, just enhance the results that earth scientists can produce by the extra compute that AI will enable."

"As far as upstream oil and gas professionals go, I can't see a time where people on the rigs will ever be replaced by AI because the data needs to be collected in the first place. The systems on the rigs will certainly become more technically advanced but the job of collecting the data will still require humans…at least in my lifetime!"

"A telling sign of this is the fact that every generation of MODUs (mobile offshore drilling units) becomes bigger and more technical than its predecessor. And this also goes for the POB ▶

(persons on board) limits… bigger rigs which require more technical specialists to operate the complex systems on them. While downstream operations may suffer a thinning out of the workforce, the upstream operations have seen anything but this happening. The data collection step is the most fundamental building block that AI needs to work with. It will always be the case that "boots on the ground" remain an essential part of the resources industry."

"For instance", continues Amanda, "if a well uses Managed Pressure Drilling technology, it comes with a whole crew in itself. The same applies to mud recovery systems for the top hole section before a marine riser is run. It's not like the drill crew will all of a sudden start doing that stuff too. Reflecting on that, when I started working on rigs, they had only 100-120 people on board; nowadays it is common to have 180 or more, with drill ships going above 200 easily. In that sense, it looks like new technologies are not so much replacing existing ones, but rather adding to what was already there."

THE FUTURE OF THE WELLSITE GEOLOGY PROFESSION

"Wellsite geology is a very difficult role to get a start in", says Amanda. "It's generally a job that oil companies hire contractors for because of the non-consistent and unpredictable work involved. With the oil and gas industry being so cyclical, and now with the added uncertainty of ESG mandates trying to slow down production of hydrocarbons, I would only recommend a career as a wellsite geologist to those who could weather the storm of unpredictability."

Maybe the above is a reason why there does not seem to be a new generation of wellsite geologists waiting to get started. But there is another reason too. "As there is no real degree for well site geologists, the most common springboard to become one is to be a mudlogger for a while. And with mudlogger positions being by far the lowest paid position on the rig, it may not be difficult to imagine that people don't warm up to fulfill these roles, especially by Australians who can get much better-paid jobs elsewhere."

"Consequently, you see less and less Australians filling mudlogging roles as the skills shortage kicks in with the current bullishness of the minerals and oil and gas industries. Entry level mining jobs are far more attractive to geology graduates than mudlogging jobs. The mudlogging positions are generally filled by a foreign workforce of geologists who have not had the good fortune to have access to opportunities outside of the oil and gas industry, like Australian geology graduates generally do."

"And for those doing the mudlogging jobs for the bigger oilfield service companies, I see that nowadays most are trained up to become data engineers rather than wellsite geologists", says Amanda. "There's not a very clear career pathway to get to the wellsite geologist position without committing to a lifetime of working away from home. It's not an entry-level job so gaining years of experience in the field is necessary to acquire the skills and competencies required. For mudloggers and data engineers who are working in a salary position with a third party operator, and have a reasonably reliable work structure, it's hard to make the leap to the very unpredictable job of an independent contract wellsite geologist."

LIFE IS GOOD

Despite the unpredictability in terms of work, Amanda reiterates that she is very happy. She lives on her own, but her ex-husband is still her best pal and their three healthy, grownup, and independent children are scattered around the country. It leaves her ample time to focus on her major hobby – running marathons around the world. By the time this article goes to print, Amanda will have finished her 78th marathon, and maybe even her 79th, both to be run in the US. "I'll certainly get to number 100 in the next few years!" ■

GEOTHERMAL ENERGY

"The project went through 38 roller-cone bit runs, and guess what roller-cone bit cuttings do when drilling through a fracture zone?"

Kevin Gray - Black Reiver Consulting

How to explain the low energy output of one of the UK's flagship geothermal projects?

We spoke to a geothermal drilling expert to find out

IN SEPTEMBER last year, the UK Government announced a list of renewable energy projects that qualify for a minimum price guarantee for the energy delivered to the grid. Geothermal projects were among the winners for the first time, and the United Downs project in Cornwall, southwest England, was one of them.

However, the estimated energy offtake from United Downs looks a little low: only 2 MWe. Higher output can reasonably be expected for such a flagship and expensive project, where the producer well reaches more than 5,000 m and temperatures over 175 °C are confirmed. What might be the cause for an energy output this low?

To learn more about what may have caused all this, I spoke to Kevin Gray from Black Reiver Consulting, who has been working in the geothermal space for years and knows how to drill a geothermal project properly. Kevin is a real advocate for the geothermal industry, but at the same time, he does not shy away from being upfront about the risks of not sticking to a competent drilling strategy. The United Downs project seems to be an example of a project where a competent drilling strategy was missing.

The project targeted a major fault zone in the granitic basement. Hot brines from a depth of around 4,100 m are supposed to be brought to the surface to power an electricity plant, with the cooled fluid subsequently re-injected at a depth of around 2,100 m into the same fault zone where it was produced from deeper down.

As virgin granite has no permeability, any fluid flow into the wellbore relies on natural fractures. Therefore, it is critical for high-profile projects of this kind to preserve the permeability as much as possible during the drilling process.

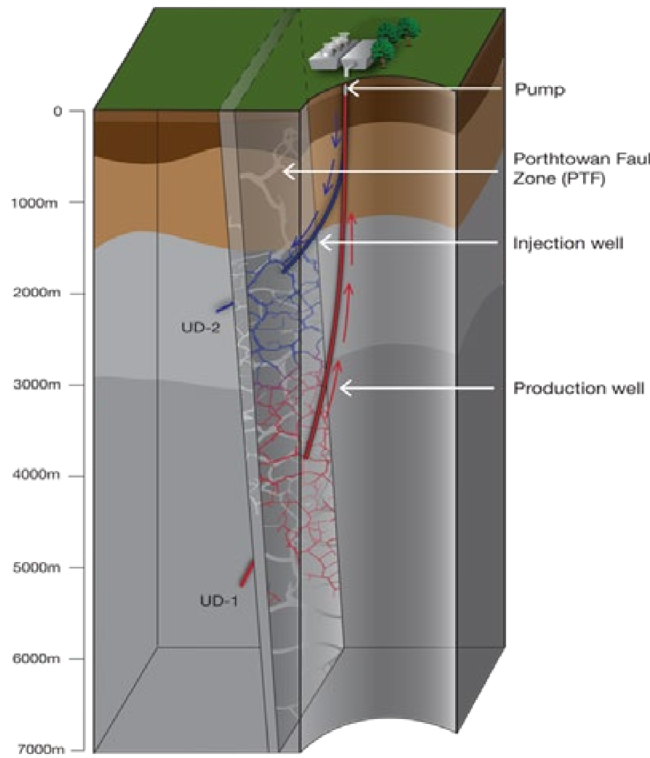
"This is easier said than done because penetrating a naturally fractured zone is often associated with mud losses while drilling and, therefore, the risk of clogging up the fracture space", says Kevin. "And that is most likely the thing that went wrong here."

"An explanation as to why the fracture space was clogged up so badly is the type of drill bit used", continues Kevin. "The project went through 38 roller-cone bit runs, and guess what roller-cone bit cuttings do when drilling through a fracture zone? The cuttings can completely pack off your fractures, decreasing their capability to accommodate fluid flow."

Kevin further explains that there are bits on the market that can do a much better job, as it is in this particular realm where a lot of innovation has been taking place over the last few years.

"On that basis, it looks likely that there was no proper assessment of the type of drill bit to be used", Kevin concludes. "Sure, even with the best bits, it will always be a challenge to prevent any formation damage completely, but in this case, it seems that the low projected energy output can be directly related to the lack of a proper drilling strategy." ■

Henk Kombrink



Schematic representation of the Porthtowan Fault zone drilled by the two United Downs geothermal wells.

SOURCE: GEOTHERMAL ENGINEERING

> "The project went through 38 roller-cone bit runs, and guess what roller-cone bit cuttings do when drilling through a fracture zone?"

Shallow geothermal drilling is not without risk

More and more shallow boreholes are being drilled in Norway to utilize geothermal energy for heating purposes. It is a positive trend, but not always without consequences, as a recent case in the Supreme Court has shown

IT IS NOT every day that geological expertise is brought to the Supreme Court. Late last year, Norway's highest court dealt with a claim for compensation for subsidence damage to a detached house. The damage had occurred as a result of drilling a shallow geothermal closed-loop borehole on a neighboring property. The subsurface turned out to be key in the verdict.

The Supreme Court ruled that it was the owner and the drilling company who were responsible for the damage that occurred to the house.

The homeowners had previously lost the case in the district court and the court of appeal. The reason why the Supreme Court made a different decision regarding liability may be the expert report from the Geological Survey of Norway (NGU) on the subsidence risk when drilling in areas with marine clay.

In many areas in Norway, marine clay rests directly on an undulating surface of basement rocks. Because these clays are practically impermeable, hanging water tables are frequently found. And because the underlying bedrock is often well-fractured, facilitating groundwater flow, penetration of the higher-pressure clay layer by a well can lead to groundwater making its way to the bedrock. In turn, this leads to compaction of the clay, with subsidence as a result.

Especially if houses are built partly on clay and partly on bedrock, which was the case in the example given above, differential compaction can lead to significant structural damage.

Researcher Hans de Beer from NGU emphasizes that the challenges of drilling shallow geothermal boreholes should not be overestimated, and a solid understanding of the subsurface is required.

The hydrogeologist points out that leaks can be avoided or remedied with relatively simple measures. By adding sealing compounds to the part of the borehole that penetrates the clay and somewhat into the bedrock, leaks can become a thing of the past. If the driller uses sealants that conduct heat, it can also increase the energy efficiency of the borehole.

This is not an industry practice yet, as it costs a little extra. But the price of such a measure is a fraction of the costs of leaks. “I hope and believe that this will become a standard in areas where marine clay is encountered during drilling”, emphasizes de Beer. ■

Ronny Setså

PHOTOGRAPHY: RANDI KALSKIN RAMSTAD

The two connected tubes of a closed geothermal loop drilled in 2017 in Trøndelag. Antifreeze is circulated through the tubes to utilize the heat at a depth of up to 200 metres.

MANY BOREHOLES

Shallow geothermal boreholes retrieve the heat from the groundwater from a couple of hundred meters deep. In most cases, this is a closed system based on a circulating heat carrier (antifreeze) which is fed into a heat pump, before it is sent back down. Since 2020, 13,878 shallow geothermal boreholes have been drilled in Norway. The trend is increasing, and drilling is going deeper. It is therefore important that tighter regulations are put in place, not least of which require the sealing of wells.

And the winner is…

Shallow geothermal energy production may soon be more important than deep geothermal energy production in the Netherlands

It is a development that is not often talked about or highlighted in the media, but data on subsurface energy production using water as a carrier clearly shows how important shallow geothermal (~200 m) is becoming in comparison to deep geothermal (2,000-3,000 m). As someone with insight on the market told me at a conference recently: "Were you aware that about 100,000 shallow geothermal loops are being drilled per year?"

The data, provided by Statistics Netherlands, illustrates how shallow geothermal energy production has built momentum over the past years, starting about 20 years ago in 2004. And, in contrast to deep geothermal energy production, which has even seen a flattening off when it comes to energy produced in recent years, energy harvested from the shallow subsurface has continued and even accelerated.

It is a testament to the relative ease with which shallow boreholes are being drilled. Rather than a lengthy process requiring all sorts of studies and red tape, a 200 m borehole is often drilled in a day and only requires a notification to the relevant authorities. The type of investment is of a very different nature too; shallow closed loops are affordable for those who have saved up some money, while a deep geothermal doublet is only a possibility for larger corporations, backed by subsidies on top of that.

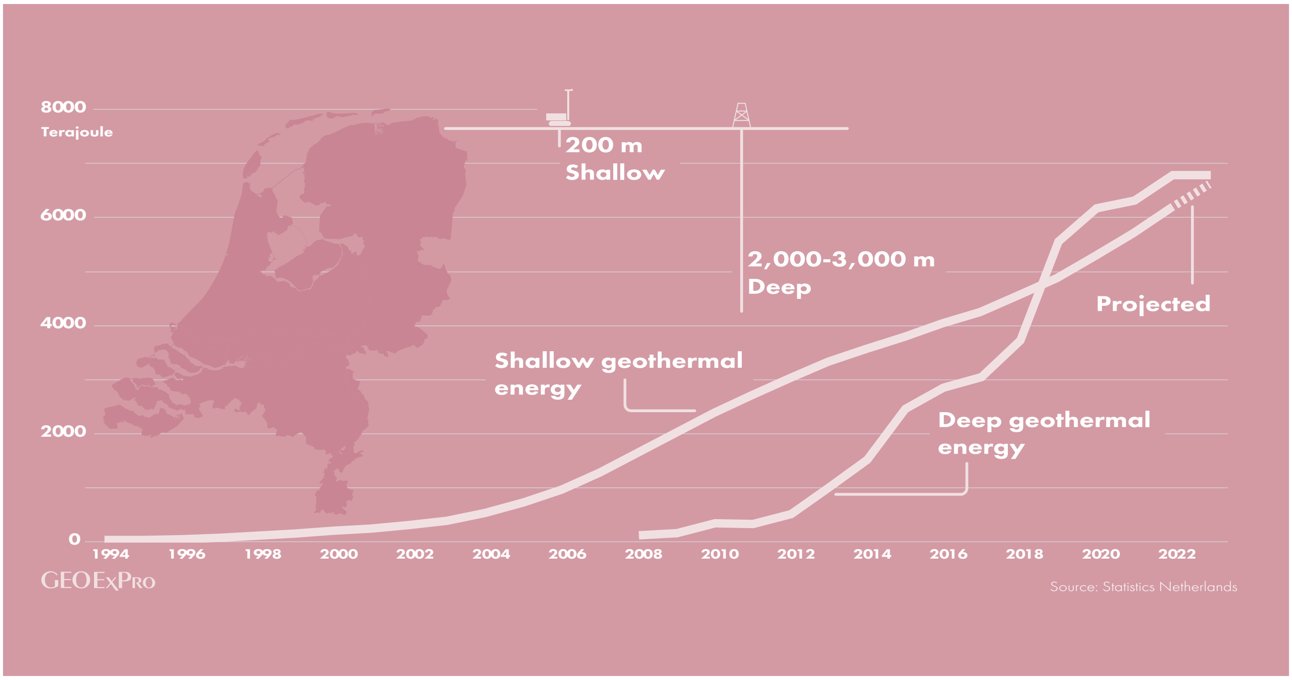
That is also reflected in the types of projects these systems are being drilled for. Deep geothermal projects in the Netherlands are mostly drilled for heating greenhouse complexes, whilst an individual shallow loop is mostly used for a single house.

An advantage of shallow systems is the closed-loop nature; circulation of the fluid takes place through a tube that is connected downhole by a u-shaped connector. That means there is only one borehole required, whilst deep geothermal open loop projects in the Netherlands depend on an injector and producer well, drilled at a certain distance from each other (around 1 km). In addition, deep open-loop systems come with scaling, corrosion and sand production challenges.

Of course, the energy produced by a shallow geothermal loop is very modest compared to a deep system. A single shallow borehole can produce between 2 and 20 kW each. That means a deep geothermal open-loop project consisting of a 10 MW doublet is equivalent to around 1,000 shallow boreholes of 10 kW each.

But given the rate at which these shallow boreholes are now being drilled, not only in the Netherlands but in many other countries too, I feel that the domestic heating transition is bound to come from the shallow subsurface rather than its deeper equivalent. ■

Henk Kombrink



Brushing up on your geothermal vocabulary

Two authors from Iceland have set themselves the monumental task of succinctly summarizing and illustrating all forms of geothermal energy production

IT MUST HAVE been a major exercise to write the paper that was published recently by authors Maryam Khodayar and Sveinbjörn Björnsson in the Open Journal of Geology (Vol. 14, no. 2). I know that firsthand, as Maryam told me that she needed some time to recover from pulling this project together. It is understandable – the authors reviewed and illustrated the myriad of shallow and deep conventional as well as unconventional geothermal systems that are currently either in use or are being developed.

If the overview demonstrates anything, it is that a lot is going on in the area of geothermal energy, from systems designed to operate at 1 m depth all the way to 20 km. This variety of concepts is not only a reflection of the different end-users for geothermal energy, from individual households to power plants, but it probably also reflects the ongoing race to find the most economic solution especially to tap into the deeper geothermal potential that exists at greater depths. Nobody will dispute the enormous amount of geothermal energy stored in the subsurface: The trick is to unlock it economically.

DRILLING IS KEY

Drilling is the key factor of geothermal developments that needs innovation to complete wells more efficiently. The faster a well can be drilled and completed, be it a 200 m or 20,000 well, the more manageable the costs will be. A good example of this is the rate at which shallow loops are now being drilled in London, with its challenging geology of unconsolidated Cenozoic sediments overlying Upper Cretaceous Chalk. Some time ago, it took two days to drill a hole, now it is possible to drill two in one day. At the other end of the spectrum, a company such as Quaise is looking to drill holes of up to 20 km depth using so-called millimetre wave drilling, tapping into temperatures over 374 °C.

CONFUSION

Through outlining all the different ways in which geothermal energy is currently being produced as well as planned to be produced, the authors have nicely laid bare some of the confusion that often arises.

For instance, the term ultradeep is sometimes used when authors mean ultrahot. Whilst ultrahot does not necessarily mean ultradeep – geothermal energy production from a volcanic area may be ultrahot, but may not be ultradeep - ultradeep does mean ultrahot as it taps into temperatures of up to 500 °C at depths greater than 7 km.

At the same time, it is not always clear what the difference is between conventional and unconventional geothermal systems. The authors point out that conventional systems only require drilling to produce the energy – permeability, heat and a fluid are present – whilst unconventional geothermal projects require interventions to generate permeability or require adding a fluid.

In conclusion, the article is worth a read for anyone wanting to brush up on their geothermal vocabulary. ■

Henk Kombrink

McGinness Hills is the largest pumped-well geothermal plant in the world. As of 2021, the installed capacity at McGuiness Hills is estimated between 150-170 MWe (gross).

SOURCE: FLICKR.COM/BLMNEVADA

SUBSURFACE STORAGE

"But is the secrecy around pressures something that we just have to accept in the same way as there is competition between oil companies chasing for oil or gas? I am not convinced of that yet."

Henk Kombrink – GEO EXPRO

Producing shale gas through the injection of CO_2

Using water for shale gas fracking operations is banned in New York State, USA. However, that has not stopped companies from looking for alternatives to get the gas out of the prospective Marcellus and Utica shales in the Southern Tier, the western part of the state

If the people living in New York's Southern Tier thought that shale gas production is not going to happen in their backyard because of the ban on using water for fracking, they could be wrong. Last year, a new company was formed under the name Southern Tier Solutions, and its main goal is to use CO_2 as a medium to frack wells in the area instead of water. But how feasible is this?

First of all, the CO_2 required to frack wells is not readily available, as the company admits on their FAQ page. However, with legislation towards limiting industrial emissions becoming tighter in the near future, the company states that they offer a solution to the storage part of the problem. Making money through producing gas will obviously help the business case. The question then remains how the production of methane and its subsequent use will offset the benefit of storing CO_2 in the reservoir.

Secondly, how suitable is CO_2 as a fracking medium? The Southern Tier website contains a fair amount of information to suggest that injecting CO_2 is a feasible way to extract the methane, even though shale gas reservoirs have never been used for carbon storage. It is mainly academic work from China that suggests that the absorption affinity of CO_2 is greater than CH4, which is what is required to produce the methane.

The company states that the Marcellus shale in the Southern Tier alone could accommodate more than 17,000 million tons of CO_2. It would still be interesting to see how much of the injected CO_2 is expected to be produced back – it seems unlikely that everything will be absorbed straight away in exchange for the previously absorbed methane.

PORE SPACE OWNERSHIP

Another point of interest is the question of who owns the pore space. American landowners are by law the owners of the underground mineral resources on their property. However, there is a grey area when it comes to the question of who owns the space between the grains. As Southern Tier Solutions write on their website, most US states apply the "American rule", which means that the land owner also holds the rights to the pore space. However, it also dictates that the land owner must first deplete the mineral resources before the pore space can be leased.

In the case of fracking with CO_2 and the simultaneous production of methane, the question of course is whether this can be seen as "depleting the mineral resource" first, given that it is taking place at the same time. ■

Henk Kombrink

The race for pressure space

Pressure is a key factor in successfully injecting CO_2 into saline aquifers and is therefore treated confidentially in some recent cases. But is this the right thing to do?

ANOTHER PRESSURE plot without values on the Y-axis! That's what I thought when watching Eirik Jenssen's presentation at the Dig X Subsurface Conference in Oslo recently. Eirik works as a Reservoir Engineer for the Northern Lights Joint Venture in Stavanger, which aims to inject up to 37.5 Mt of CO_2 into a Lower Jurassic aquifer in the Troll area, Norwegian North Sea. I was surprised, because it was not the first time. The same happened during Michael Larsen's talk about the Danish Nini West injection project in December in London. It made me think there is something about pressures that is probably not being shared too easily.

Admittedly, back in December, when Michael was asked about these very pressures during the Q&A, he did disclose the numbers. This time though, when I asked Eirik after his talk, he said that he could not share this information with me. Why are pressure data so sensitive?

COMPETITION

For injection of CO_2 into a saline aquifer, which is the case in the Northern Lights project offshore Norway, pressure management is very important. It is the pressure build-up during CO_2 injection that will ultimately determine how much of the liquid can be stored in the reservoir. As soon as the fracture pressure of the overlying sealing unit is reached, injection will need to stop. And probably a little earlier than that to build in a safety margin. So, the "ultimate stored volume" is heavily dependent on pressure development, which explains the sensitivity.

In addition, Northern Lights is also a vehicle with three major oil companies as partners, and there may well be slight differences in the approach taken by each company to arrive at the best pressure forecast.

Another factor is that the Northern Lights licence is adjacent to two carbon storage licences, one operated by Wintershall in the west and the other by Equinor to the east. It is therefore easy to see that the potential for pressure interference is a critical factor in case the same reservoir is being used for CO_2 injection. As Northern Lights will be the first project to start injecting, the neighbours will surely watch that space with interest, hoping that there will not be a significant effect on the pressure space in their adjacent licence areas.

IT'S NOT OIL AND GAS

But is the secrecy around pressures something that we just have to accept in the same way as there is competition between oil companies chasing for oil or gas? I am not convinced of that yet. As many people have already said, carbon capture and storage is a waste disposal business. A business that can only work if the emitters of CO_2 are taxed to such an extent that it becomes more attractive to capture the gas and dispose of it. There is no other economic incentive to drive it, and there is a lot of government money involved in making it happen too. In that (Northern) light, I think a case should be made for making pressure data readily available for other projects to draw learning from, also because carbon storage projects at scale are not that widespread yet. ■

Henk Kombrink

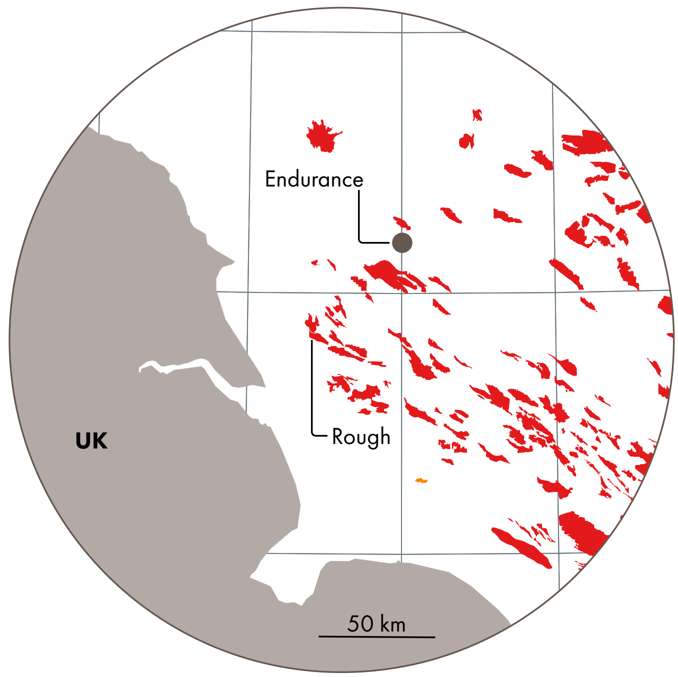
It's not the marbles themselves, but the space between them that is critical.

ILLUSTRATION: IMAGE CREATOR FROM DESIGNER (MICROSOFT COPILOT)

Hydrogen storage in a depleted gas reservoir – how easy is that?

Initial learnings from a study to convert the Rough gas storage facility into a hydrogen store

"WHEN ROUGH was under natural gas production and later as a gas storage facility, the geology was not considered to be particularly important ", said Katharine Howell from Exceed during her recent Aberdeen Energy Talk. Katharine presented together with her colleague Heikki Jutila on the work they have done so far on repurposing the Rough Field from a natural gas store to a hydrogen store.



MORE COMPLEX RESERVOIR

As gas could be easily injected and produced, the emphasis was placed on engineering challenges rather than the geology. The proposed change of use required a re-evaluation of the geology to investigate how the depositional and structural heterogeneities would impact different fluids. "The Rotliegend sandstone, which forms the reservoir unit in Rough, is the most common gas reservoir in the UK Southern North Sea and is characterised mostly by aeolian deposits", explained Katharine. "The pre-existing depositional model for Rough, which dated back to the 1980's, assumed that the field was also comprised of mostly homogenous aeolian deposits." A re-evaluation of the core and well data suggested a very different picture though.

"Closer inspection of the cores showed that the reservoir was predominantly fluvial with only minor aeolian sands", Katharine said. This change in depositional model suggested a much more complex distribution of reservoir properties, with a mix of poor-quality conglomerates, medium-quality fluvial sandstones and locally good-quality aeolian deposits.

MIXING

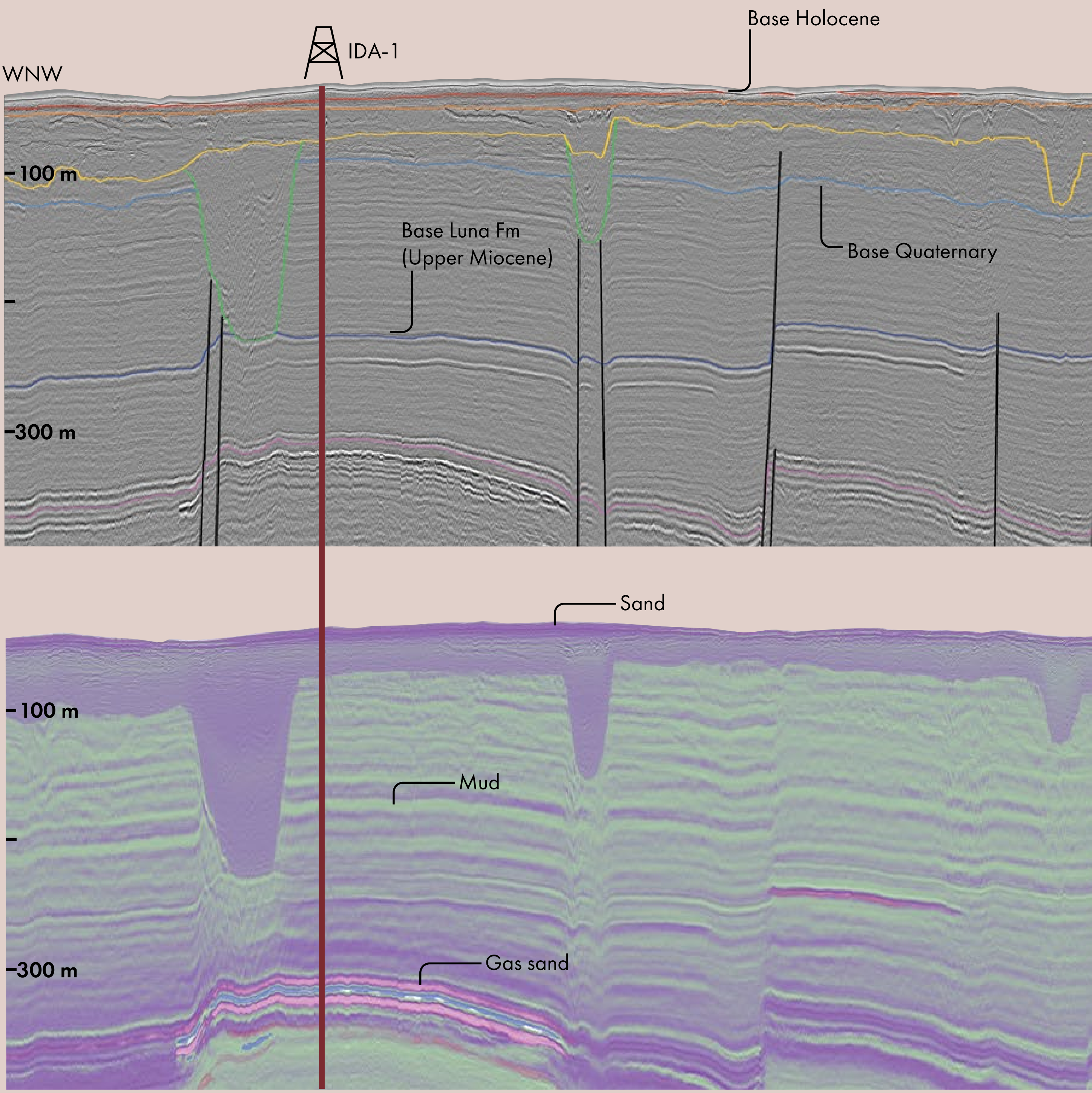
This new depositional model, combined with a fresh structural interpretation from seismic data, was used to create a 3D geological model that was used as a basis for simulating the dynamic behaviour of the reservoir when hydrogen is being injected and produced. During Heikki's part of the talk, he showed the plan for Rough which initially included creating a gas cushion by injecting CO_2 from the nearby Endurance project. The challenge of injecting CO_2 and hydrogen into the reservoir is they tend to mix with increasing contact time. The dynamic modelling carried out so far has shown that this is an issue during the first cycles of hydrogen injection and production, increasing the risk that the stored CO_2 will be reproduced. "This risk decreases as the number of cycles increases and reaches an acceptable level within 3 to 5 injection-withdrawal cycles", explained Heikki.

The Rough study has shown the importance of understanding the fundamentals of geology with a back-to-basics approach when assessing the suitability of gas fields for alternative uses in the future. ■

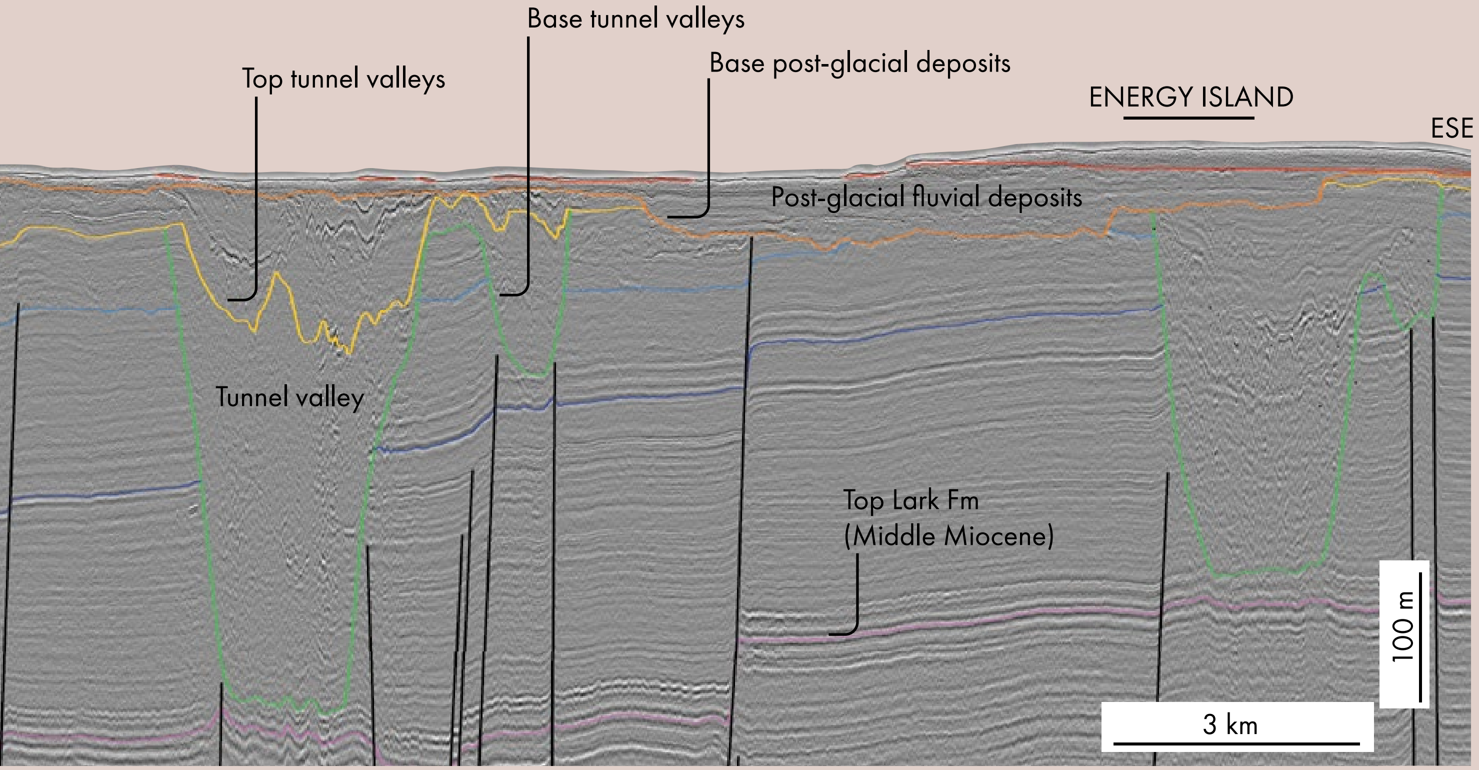
Henk Kombrink

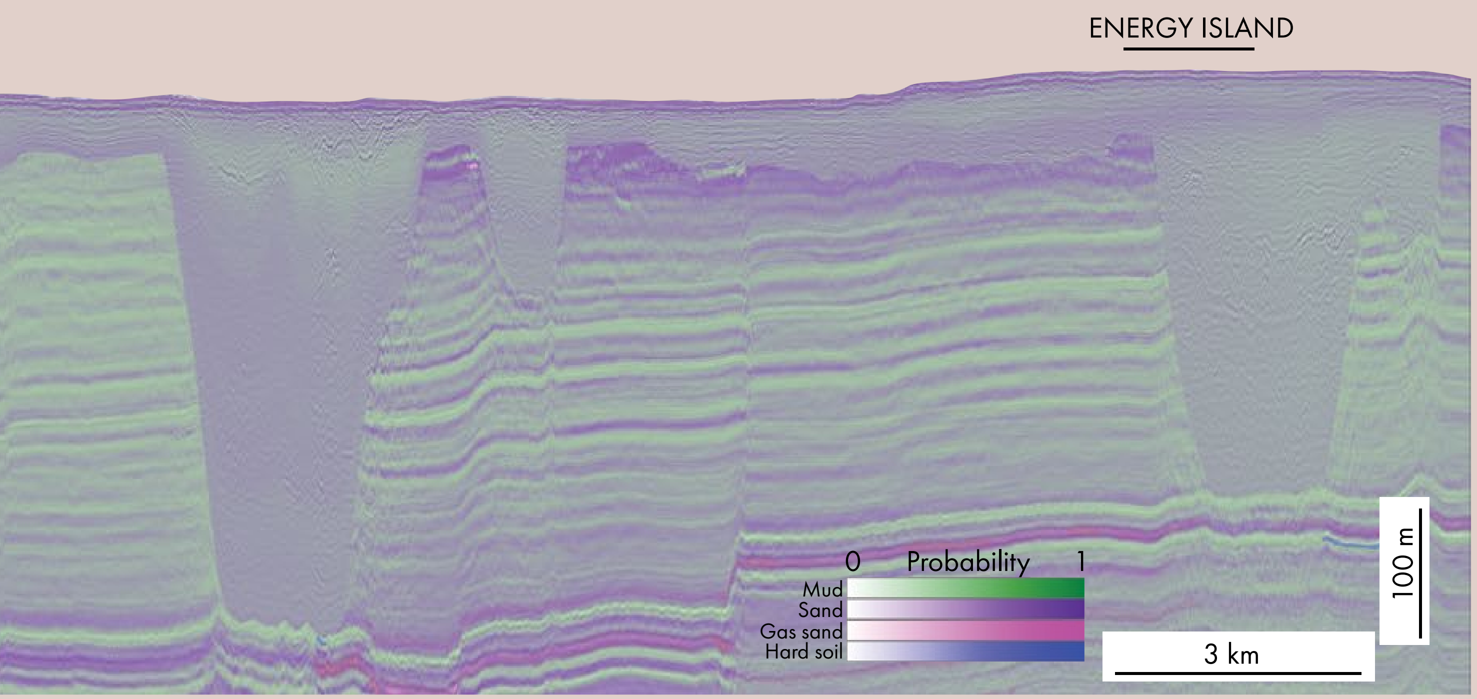
The Rough gas field was put into production in 1975. Following the cessation of production in 1984, it was used as the UK's largest gas storage site until 2017, after which some of the remaining cushion gas was produced as well. In recent years, Rough has again been used as a gas storage site, but with more limited capacity because of the lack of cushion gas support.

The Danish Energy Island



2D UHRS line between Energy Island site and well IDA-1, showing the general subsurface architecture (above) and soil type prediction (below) of Neogene to Quaternary deposits. Detailed imaging and soil characterization of glaciogenic to post-glacial landforms and deposits of Quaternary age reveal several buried tunnel valleys exhibiting distinct stages of valley infill and variable sediment content: Outwash deposits from glacial meltdown, including glacio-fluvial and lacustrine deposition and Holocene marine sands. Pre-Quaternary deposits are affected by a large extensional fault system, possibly related with deep Zechstein salt tectonics. Gas pocket within Upper Lark sand layers are clearly recognised at IDA-1, but gas is not detected elsewhere. The soil classification, plotted by highlighting the most likely soil type, should be read as follows; mud (green), sand (purple), gas sand (magenta), hard soils (dark blue) and lignite (dark red). Data from Danish Energy Agency.





GeoSurveys geophysical consultants

SolidGround

Bridging the gap between seismic acquisition and geotechnical parameterisation

How a Portuguese and Danish consortium took on the challenge to map and characterise the shallow and deep subsurface for the Danish Energy Island in a cost-effective way

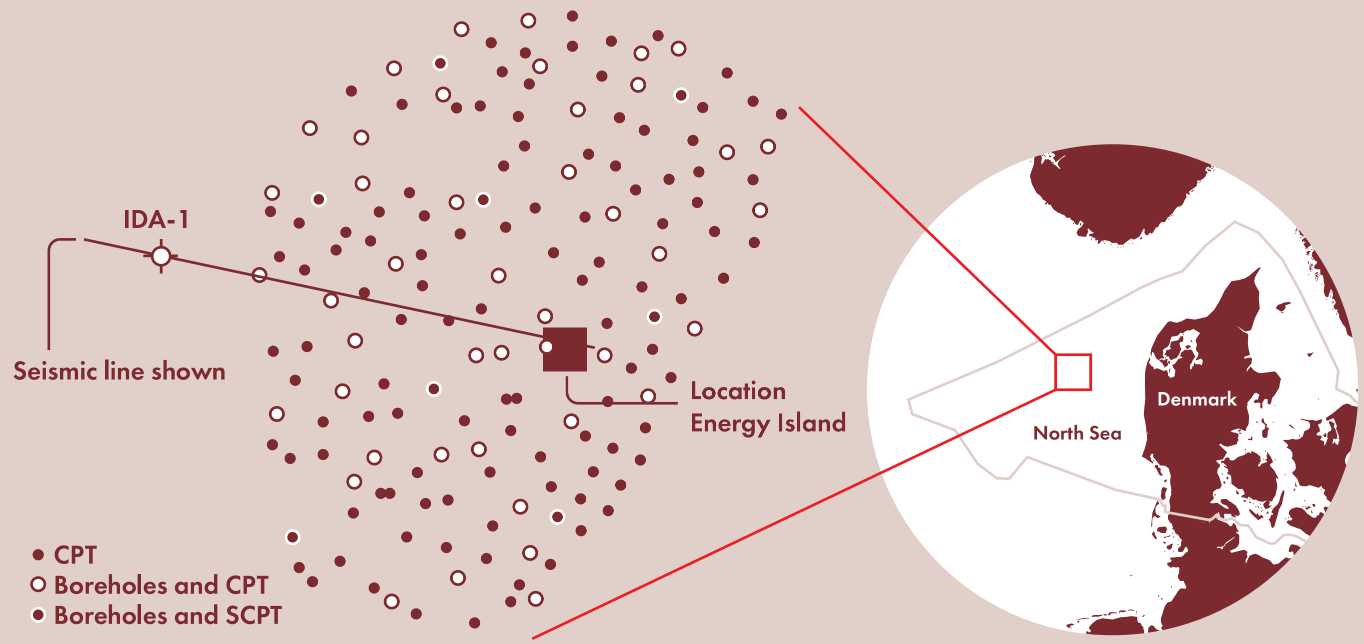
MARTIN BAK HANSEN, LOUISE SANDBERG SØRENSEN AND JENS COLBERG-LARSEN, ENERGINET, ANA MAIA AND HENRIQUE DUARTE, GEOSURVEYS, AND BRUNO STUYTS AND ESBEN DALGAARD, SOLIDGROUND

Around 100 km west of the Danish coastline, a big project was planned in the shallow waters of the North Sea. As announced in 2022, the Danes planned the construction of a so-called Energy Island. This island should gather electricity from surrounding offshore wind farms for distribution into the electricity grid in Denmark as well as to surrounding countries. It is a unique project, being so far from the coast, requiring an advanced understanding of not only the shallow subsurface, but also the geology deeper down in order to prevent any ground movement risks.

Denmark-based SolidGround and Portugal-based GeoSurveys were challenged to map and characterize the subsurface of the area in the most cost-effective yet technically advanced way.

For this unique project, an understanding of the geotechnical parameters of the subsurface was needed down to around 800 meters depth.

This could be done by drilling a very expensive and sparse grid of boreholes. However, it was decided to first map the area by integrating multi-scale seismic and geotechnical data. This enabled optimising the location of the boreholes and resulted in a much better spatial understanding of the geotechnical parameters and potential geohazards.



The analysis focused on determining the elastic parameters of the sedimentary layers spanning from the seabed to the Top Chalk surface. This information, which was validated by CPTs, has significantly contributed to assessing and mitigating settlement risks in the vicinity of the future Energy Island.

The interpretation of the seismic data was done through the integration of the UHRS and HRS data and along with available well data (IDA-1) and numerous CPTs (see map).

This also allowed a quantitative approach through which geothechnical parameters like Young's Modulus and Poisson's Ratio could be calculated across the seismic volume, in turn validated by the CPTs taken throughout the study area.

The figure below shows that there is a good match between the seismic inversion results and the CPT data, providing confidence to the use of seismic data for the 3D mapping of geotechnical parameters. In other applications, like wind farm foundations, cone resistance is not only important for QC and sanity check, it is also an important parameter for the design phase.

In addition to the mapping of geotechnical parameters through seismic inversion, the classification of basic soil types is another important outcome of this project, which has greatly helped better understand the geology of the area.

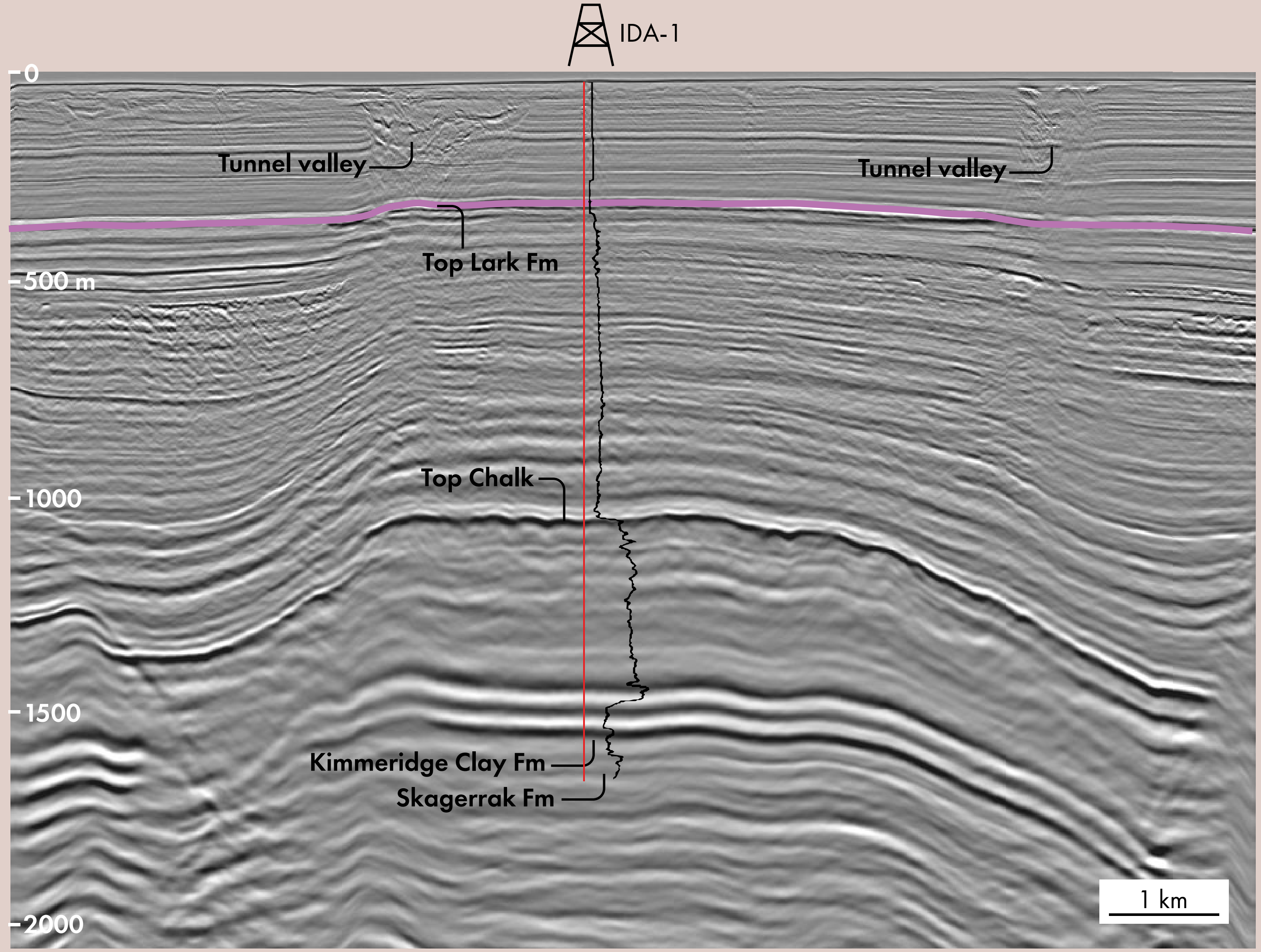
SEISMIC ACQUISITION

The seismic acquisition parameters were chosen in such a way to map the subsurface to a depth of around 1500 m, which is beneath the top of the Chalk.

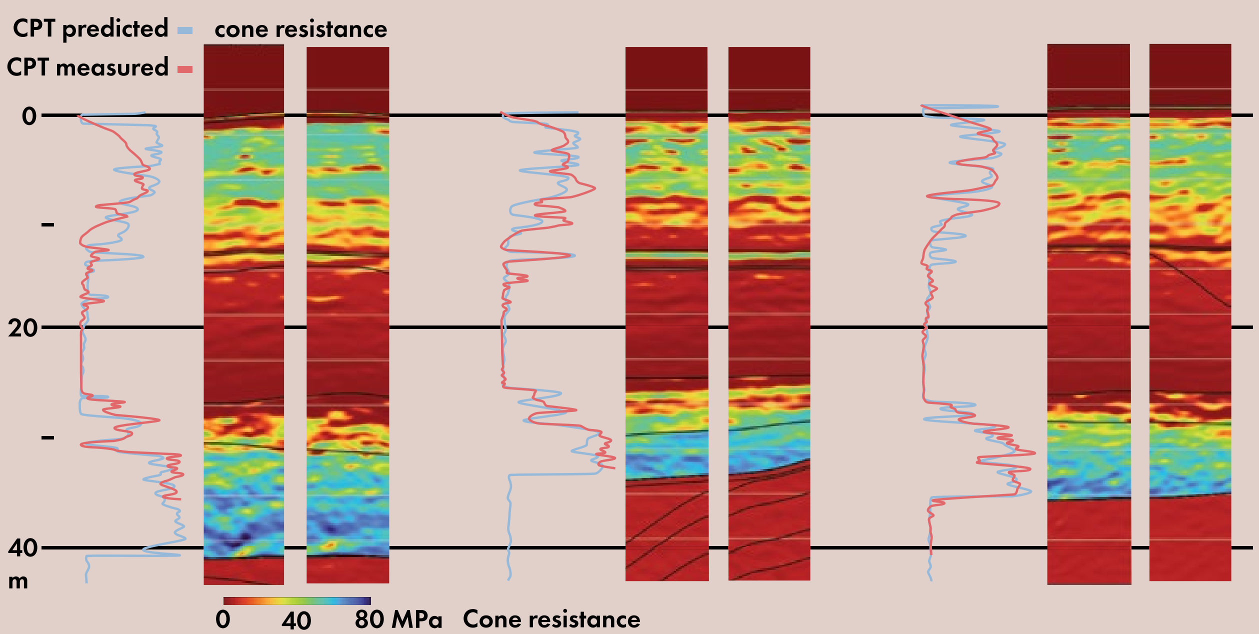
At the same time, the survey had to achieve high resolution in the uppermost sections, to obtain both deep and detailed information for amplitude variation with offset (AVO) inversion and seismic quantitative interpretation.

For these reasons, it was decided to go for a dual seismic setup with an advanced sparker system (from Geomarine Survey System, B.V.) and airgun sources to cover the higher and lower frequencies respectively. Air guns (120 Cui 4 x Mini G. cluster) were used to reach down to 1500 m below seabed at 3 m vertical resolution and a Triple 800 Sparker was used to allow higher resolution in the upper 200 m (vertical resolution between 0.5 and 1 m).

Cutting-edge pre-stack processing techniques were tailored for ultra-high and high-resolution data to meet project specifications, including deconvolution, demultiple, deghosting and migration. To maximise the benefits from both systems, velocities were integrated, aiming at enhancing detail retrieval not only for the uppermost layers with the ultra-high-resolution data, but also for deeper events using the high-resolution system.



2D HRS data along IDA-1 well, showing subsurface geology down to the Createaceous Chalk. Well log shown is p-wave velocity. Data from Danish Energy Agency.



By transforming inversion results into the CPT domain, a direct evaluation of the seismic inversion results against the CPT measurements becomes feasible. This integration links two independent measures, namely seismic data and CPT measurements. As three CPT locations from the study area demonstrate here, there is an overall high level of agreement between the seismic-predicted CPT properties and the actual CPT measurements observed. Data from Danish Energy Agency.

THE GEOLOGY

Thanks to the integration of seismic and borehole data, a detailed picture of both the shallow and deep subsurface of the area around the Energy Island could be reconstructed.

As the inversion results clearly show, the Miocene succession is dominated by fine-grained sediments, with some sandy intercalations especially near the top of the Lark Fm. These sands are gas-bearing in a limited area surrounding the IDA-1 well, but are not expected in the area of the Energy Island.

The Quaternary succession is marked by the occurrence of a series of tunnel valleys, carved by subglacial erosion. The infill of the glacial tunnel valleys can be seen to change from sandy in the west (purple colour) to mud-dominated in the east, beneath the Energy Island.

The subsequent infill of the tunnel valleys and their Upper Pleistocene and Holocene cover records a complex and highly dynamic environment with sediment deformation, re-occupation of valley incisions by pro-glacial drainage systems and outwash deposits from glacial meltdown, including glacio-fluvial and lacustrine deposition.

Thrust complexes and other glaciotectonic deformation resulting from glacial load and ice-push have also been mapped, along with post-glacial deposits associated with cycles of deposition and erosion related with sea-level transgressions and regressions.

The Holocene is characterised by marine sands, and the Energy Island itself is planned on top of a thick sand bank that shows a striking progradational architecture.

Acknowledgements: Special thanks to Geomarine Surveys Systems for their support with the UHRS system and acquisition operations, and to Ocean Infinity that led the survey as main contractor.

TECHNOLOGY

"The impacts of this tool also extend beyond palynology, promising to redefine the workflows in subsurface analysis and paleoenvironmental reconstruction."

David Wade – Equinor

Can map tools find relevant documents?

Geolocating documents is one thing, but what about finding those that are really key to what you are currently working on?

JESSE LORD, KADME

PUTTING DOCUMENTS and presentations on a map isn't anything new. To do this we can just look up our various place names (known as "toponyms") and then when these names are found in documents, attach the needed geometries. For example, a final well report for 15/9-B-24 can reliably be placed on a map within the Sleipner field. So can PowerPoint presentations mentioning the Sleipner wellbores, the PL018 license, and any document mentioning Sleipner itself.

Simply putting documents based on a single toponym like a wellbore leads to many results at the same location in a large database and it is hard to identify which ones are the most useful or relevant at any given location. Using a map-based approach offers limited additional benefit.

IMAGE SOURCE: MICROSOFT COPILOT

ASKING THE RIGHT QUESTIONS

Finding a better solution was not obvious and has not been tried in this way before. To tackle this challenge, we embarked on a research project with a major operator in Norway. The research project began by trying to break down the problem into key questions. What do we mean by "document relevance"? How do I find regional reports? What is needed to make the map useful as a filter for documents?

We could see that a new ranking algorithm for document relevance was needed. Counting most of the different toponyms in a document and scoring them by page occurrence (early in the document gives higher score) and toponym type (e.g. wellbores, fields, structural elements) allowed us to build a configurable algorithm that reliably ranks the most location-relevant documents in a given search area. The user can then click the ranked documents and see the toponyms associated with that document highlighted on the map.

INTRODUCING SPATIAL STATISTICS

The location-relevance enabled sorting is a very large improvement over the previous geolocation systems, but we felt it could be made better if the tool would also be able to differentiate if a report is regional i.e. the content deals with a large geographical area or if it is a local report that for example only deals with one specific wellbore. A spatial statistics approach was adopted to calculate the regionality of any document and the user has the option to filter for regional or local documents with a handy slider bar on the map.

Based on this success, we are now adding this functionality into the Kadme Lumin document engine, such that other companies can benefit from the research. Finding the most relevant documents from the exact location of interest and that contain the chosen keywords has never been easier. ■

Answering the 3-billion fossil question

An automated way to interpret microfossils from palynology slides encourages uniform analyses across multiple wells and facilitates seamless well correlations that are integral for comprehensive field studies

DAVID WADE, SISSA STEFANOWICZ, ERIK ANTHONISSEN AND ALEX CULLUM, EQUINOR

THE SCAMPI project was born out of a daunting task. When Equinor started receiving digitalized microfossil slides they rapidly realized the importance of a scalable and efficient methodology to classify and study these ancient biological artifacts.

A massive and innovative project by the Norwegian Offshore Directorate (NOD) has the aim of digitalizing its comprehensive archive of palynology slides. It will deliver approximately 3 billion fossils, from the ~150,000 slides in this archive with ~20,000 fossils per slide. But this dataset can only propel the field of biostratigraphy into the digital age if the meticulous analysis required is somehow undertaken. In response to the challenge, Equinor has introduced a groundbreaking application of machine-assisted technology for the classification of microfossil images capable of working at a multi-well scale.

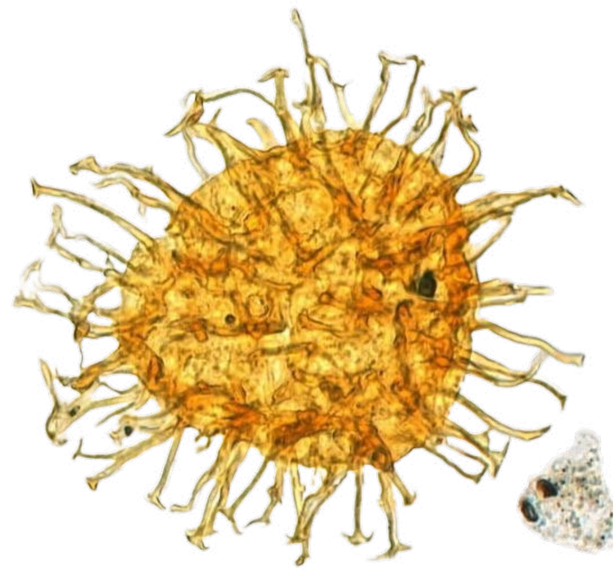
It has been demonstrated that latent-space clustering of microfossil image embeddings can be leveraged to identify meaningful groupings of fossils. By extending this approach with a Content-Based Image Retrieval (CBIR) they demonstrate a system which acts as a powerful search engine tailored expressly for the needs of palynologists.

"The impacts of this tool also extend beyond palynology, promising to redefine the workflows in subsurface analysis and paleoenvironmental reconstruction."

In their method, computer-vision techniques are used to automatically extract crops of all the individual microfossils from whole-slide images of scanned palynology slides. An arbitrary 'query' image can then be compared to every single crop among the millions obtained from any given well, promptly returning the most relevant matches for expert approval.

This process may be repeated for multiple 'queries' of known taxonomy, rapidly building up large numbers of expert-verified species identifications, drastically expediting the classification workflow.

These observations of dinoflagellate cysts, algae, pollen, and spores can then be plotted by depth to produce the distribution charts familiar to the discipline. Additionally, this approach encourages uniform analyses across multiple wells, facilitating seamless well correlations that are integral for comprehensive geological assessments at field and regional scale.



Dinoflagellate cyst *Systematophora placacantha.*

Crucially, efficiency does not come at the expense of reliability; Equinor's system is designed with a strong emphasis on auditability and explainability, thereby maintaining high levels of confidence in species counts. The analytical muscle of Scampi, powered by its sophisticated image processing algorithms, unlocks the potential for innovative workflows that were formerly infeasible. These include the calculation of reliable abundance ratios — a key element for meticulous palynofacies characterization, which is vital for accurate environmental and climatic interpretations.

The practical implications of such a system are monumental for the discipline of palynology. Equinor has recognized the transformative capability of this approach and is now integrating Scampi as a minimum viable product. The impacts of this tool also extend beyond palynology, promising to redefine the workflows in subsurface analysis and paleoenvironmental reconstruction. Scampi's heightened efficiency in analysis paves the way for a new era of speed and precision in fossil identification and counting. ■

PHOTOGRAPHY: EQUINOR

"In this case, we'd rather find the smallest prospect"

How to keep on attracting business in a basin where remaining prospects are getting smaller and smaller?

WHAT THE UKCS needs is a technical solution that would enable the production of the smaller pockets of oil and gas that remain. There was one presentation at the recent BEOS Conference in London that addressed this very thing. At the end of the talk, despite being aware of some of the limitations of the approach presented, I had a positive vibe about the future of the basin. And it is some positivity that is so desperately needed in an industry that is facing pressure from so many sides.

The presentation was from Stephen Molyneux from Australia-based Harvester Energy and Pivotree. He talked about a new solution that enables the economic production of smaller oil and gas pockets that are currently stranded on the UKCS and elsewhere. The idea is not new; Stephen referred to the BP Swops initiative that was launched in the late 1980s that also included a solution to enable production from small fields using a slim operational footprint. However, this never materialised, possibly because there were so many bigger prospects to chase first.

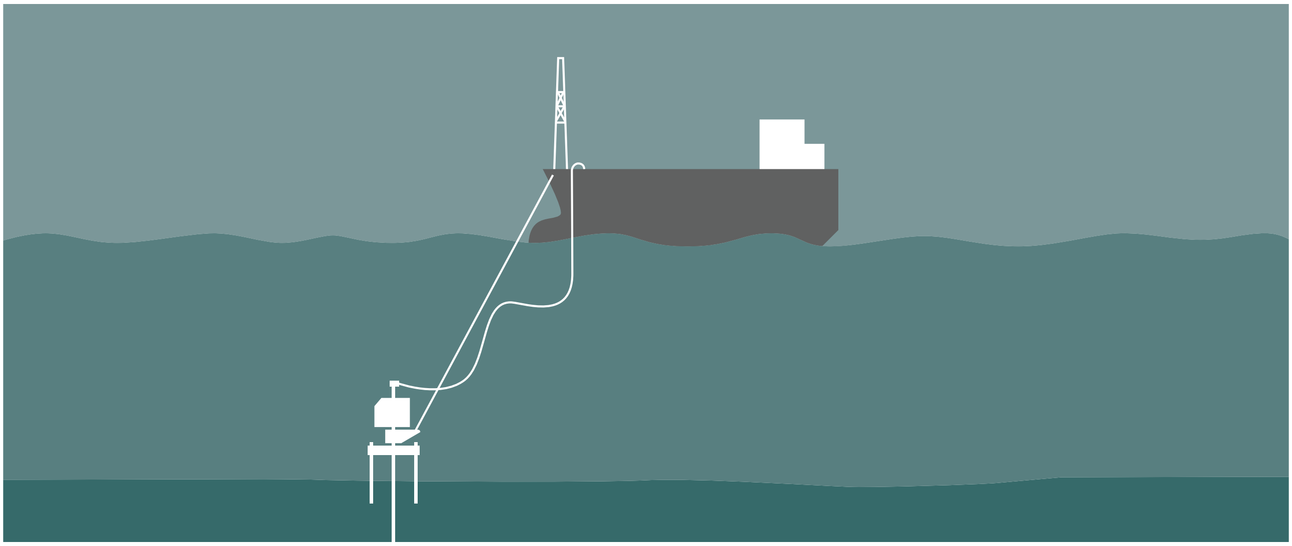
A SLIMMED-DOWN FPSO

But now, with the inventory of undeveloped discoveries and prospects being heavily skewed towards the smaller volume spectrum, the timing is probably much better for a solution to arrive that enables tapping into these. The Pivotree concept, as developed by Stephen's colleague Chris Merrick, relies on a simple self-supporting hydrocarbon production system that consists of a single production tree at the seabed that provides both well and flow control. At the same time, it is also the structural mooring of a slimmed-down FPSO unit that does not require a turret and therefore eliminates the need for costly upgrades of the vessel's hull.

Partner company Harvester Energy has recently been awarded two licences in the latest UKCS licensing round where the Pivotree concept is planned to be trialled. The licences are situated in blocks 29/7b and 22/12b, and cover the Curlew A and Phoenix discoveries respectively. Both discoveries are characterised by Cenozoic reservoirs with good reservoir properties. That is surely what is required when the Pivotree concept is going to be applied, as workovers or water injection are aspects that are harder to realise.

The company is looking at discoveries in the volume range between 2.5 and 50 MMboe, which often do not warrant standalone development using the more traditional concepts. Let's see if Pivotree can make these projects fly. And maybe this is blue-sky thinking on my behalf, but what if this concept could also work for a small scale redevelopment of the already abandoned giants? To me, this technology seems a good fit given the current state of the UK North Sea. ■

Henk Kombrink



Simplified sketch showing the Pivotree concept. Adapted from Pivotree.

DEEP SEA MINERALS

"Our perception of a good resource estimate of undiscovered resources is that we must take care of the uncertainties as best we can."

Harald Brekke - NOD

Drilling on the seabed

In May last year, a group of remote-controlled machines obtained core samples from the seabed in a mission to sample deep-sea minerals

"Drill cores are absolutely essential for understanding the geology of an area. When the Seabed Minerals Act came into force and the opening process was initiated, we saw that existing solutions were expensive and lacked the flexibility to function well in the deep sea"

THE DEEP SEA is pitch dark, but the two ROVs provide plenty of "working light" for the drilling machine that is standing on the seabed in the hilly, inhospitable terrain that makes up the underwater mountain range that stretches through the Norwegian and Greenland Seas and further north towards the Arctic Ocean.

The operation in the deep sea is unique. Never before have three remote-controlled machines worked in parallel for this purpose in the deeper parts of Norwegian waters. The data and the physical samples they have obtained so far can play an important role in the process that could lead to a new marine industry based on deep-sea minerals in Norway.

"We have tested new technologies and examined how we can carry out several operations related to environmental investigations, monitoring and exploration in parallel. By combining such operations, we can contribute to making the acquisition of knowledge more efficient and minimizing their environmental footprint", says Anette Broch Mathisen Tvedt.

She is the managing director of Adepth Minerals, one of the players that has positioned itself as an exploration company and technology developer ahead of a possible upcoming licensing round for deep-sea minerals on the Norwegian continental shelf.

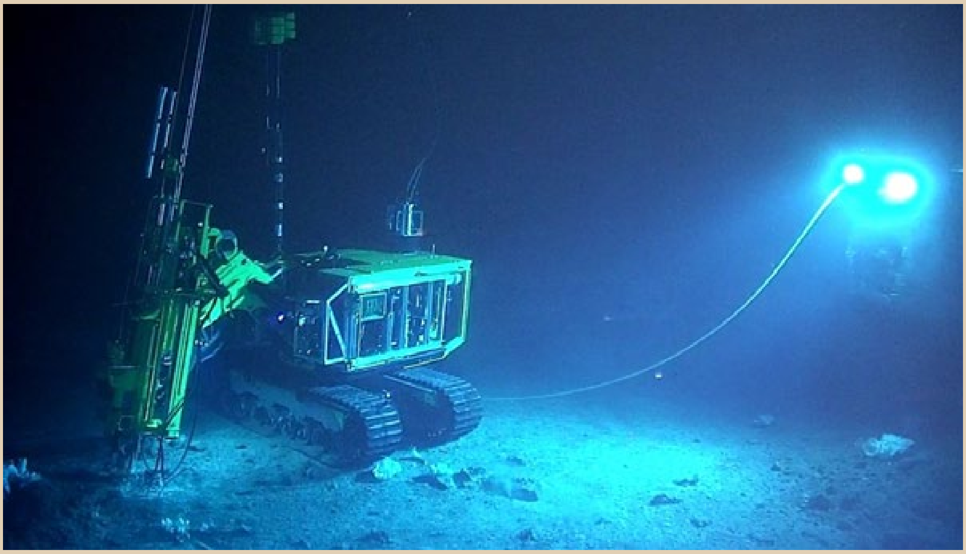
One of the key technologies tested during the cruise is FlexiCore, which has been developed by Adepth Minerals in collaboration with Seabed Solutions and DeepOcean.

The three companies built their own equipment that is adapted to small operations at great ocean depths. The criteria were that the equipment could deliver flexibility when the operator needs to drill in rough terrain, determine angles and adjust the drilling along the way.

"We have now tested and further developed the technology in several rounds - first on land, then at the quay, then in shallow sea areas, and now finally in the deep sea."

The project manager confirms that FlexiCore did its job on Mohnsryggen, even though the core recovery is something that was anticipated to be a bit higher. Three holes were drilled up to 18 meters deep, and the trip resulted in around 4 meters of core, which was less than desired. The concept has been tested though and has worked under the conditions for which it was designed. ■

Ronny Setså



The picture was taken at Mohnsryggen at a depth of nearly 1,200 metres. On the left, we see a Seabed Excavator with FlexiCore drilling at a selected height in the underwater landscape. An ROV provides assistance and working lights. A third ROV filmed the operation.

PHOTOGRAPHY: CENTER FOR DEEP SEA RESEARCH

An accidental discovery of a large mineral deposit

During a cruise in the Norwegian Sea in 2023, researchers unexpectedly drilled straight into a sulphide deposit. It may be the largest that has so far been detected on the Mohn Rigde

THE AIM of the drilling operation was to learn more about subsurface water circulation by drilling into a fault. But when operations began on the selected topographical high along the northern flank of the Mohns Ridge, it quickly became clear that the researchers had encountered something quite unique.

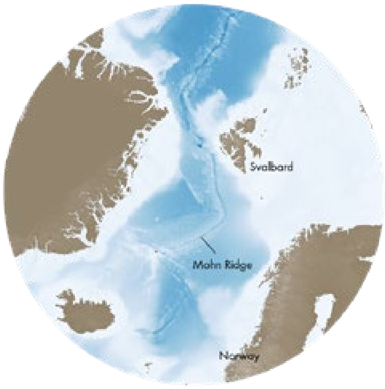
"We got a surprise. We had completely unintentionally drilled into a mineral deposit", said Rolf Birger Pedersen, professor and head of the Center for Deep Sea Research at the University of Bergen.

It was during the Deep Insight cruise in May last year, which was carried out by the partners in the EMINENT research project, that by a stroke of luck they came across a sulphide deposit.

EMINENT aims to accelerate the acquisition of knowledge about the deep sea and its geology, environment and mineral resources, and to develop and test technology relevant to these purposes. During the voyage, they were able to test FlexiCore, a newly developed concept for core drilling in the deep sea.

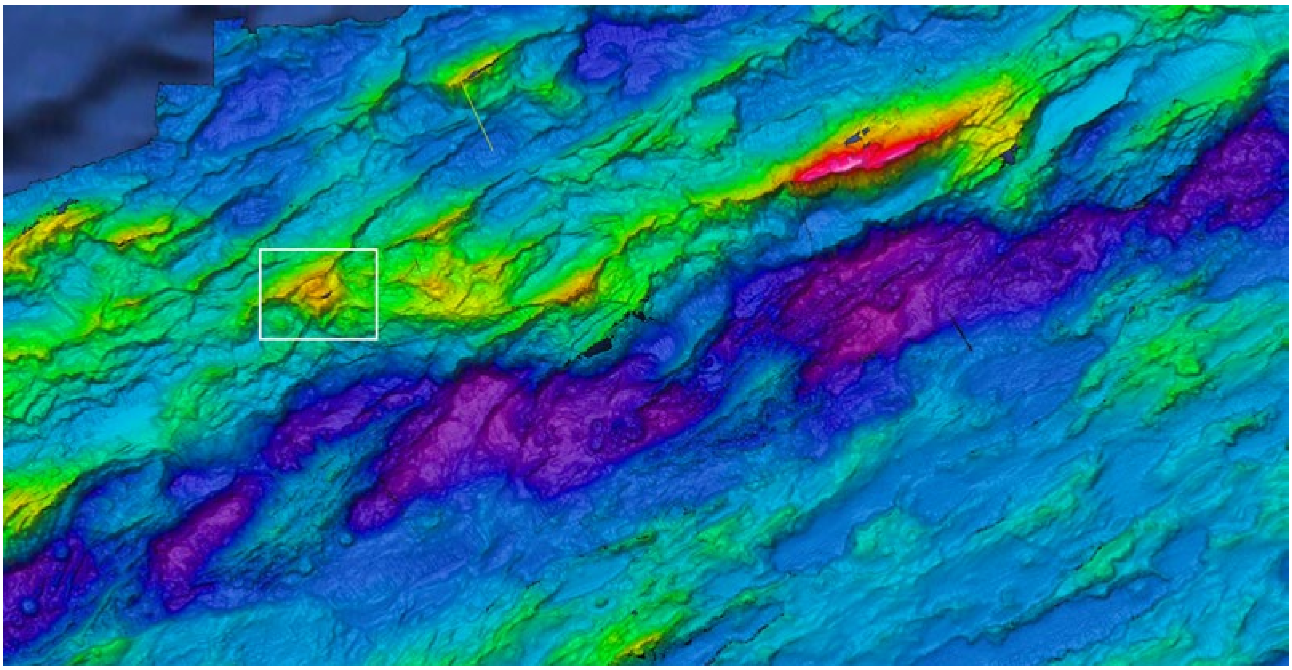
The discovery can rightly be referred to as the needle in the haystack. Along the spreading ridges in Norwegian sea areas, just over ten sulphide deposits have been detected so far, most of which are active hot springs.

Although there is still limited knowledge about the recent find, Pedersen maintained that the (extinct) deposit may be the largest of its kind along the Mohn Ridge. As the deposit was drilled using the new core drilling technology, the researchers have had the opportunity to make mineralogical analyses as well.



The analyses indicate an average copper content of just over two percent. However, it should be pointed out that only a small part of the deposit has been cored. ■

Ronny Setså



SOURCE: CENTER FOR DEEP SEA RESEARCH, UIB

Digital elevation model over the central part of the Mohn's Ridge. The location that was drilled during the cruise last year is marked by the white rectangle and is located on the northern flank of the ridge.

Mineral resource estimates for Nordic waters expose a rift between major Norwegian institutions

The Geological Survey of Norway and the Norwegian Offshore Directorate have seemingly used similar approaches to arrive at mineral resource estimates for the deep seas around Norway, but by looking at different datasets the conclusions are certainly not

A DEBATE has recently unfolded around how much copper – and related metals - are present in Norway's mid-oceanic ridge system, an area where mining could take place in the future as the search for metals needed for the electrification of society intensifies. The main players in this debate are the Geological Survey of Norway (NGU) and the Norwegian Offshore Directorate (NOD), who both have expertise in this domain. Here, we present a short summary of the main aspects of the debate, which is based on articles published in Norwegian on the GEO365 website.

Harald Brekke - NOD

Terje Bjerkgård - NGU

VOLUMES AND GRADES

First of all, there is the estimated amount of copper per 1,000 km² in the deep sea. Based on comparable deposits on land, the ore geologists at NGU last year arrived at an estimate of 0.18 million tonnes of copper per 1,000 km² when they published their resource estimate. In contrast, NOD's resource assessment arrived at a value twice as high - 0.36 million tonnes per 1,000 km² - based on analyses of samples taken from the area itself. This is not the only instance where the two organisations results differ though.

The NGU expects a grade of 1.47 % as a median value for copper, while they claim that the NOD's estimate median value is 2.27 %. That is 35 % lower. In a response, Harald Brekke, senior geologist at the NOD, puts forward that the 2.27 % represents a weighted average instead, arguing that a weighted mean must be compared to the arithmetic mean, not the median, and that their values therefore don't differ that much as the NGU suggests.

Brekke also adds that the NGU researchers have used the same statistical methods as the NOD and NTNU. This means that they calculate the resources with Monte-Carlo simulations of distributions for occurrence size, content and number of occurrences per area.

ENOUGH FOR MINING?

NGU geologist Terje Bjerkgård argues that a deposit on land could be commercial given a grade of ~1,5 % Cu, if the deposit is large enough. A possible future seabed mineral industry that will operate in rough terrain at great water depths far from the mainland will very likely depend on deposits with significantly higher levels than those we find in operational mines on land in order to achieve profitability. At the same time, the deposits must have sufficient tonnage to provide a lifetime that justifies the investment costs, with calculations indicating that commerciality for prospects of around 20 million tonnes of ore require grades of approximately 5 % copper.

Brekke subsequently states that one must not mix up a total estimate for a large area with the size and profitability of the individual prospects. He argues that there will be deposits that show higher concentrations than the NGU's median, even higher than the NOD's weighted average. And it is these prospects that need to be explored for.

DEBATE ON DATABASES

As stated above, NGU's estimates are based on a large data set from onshore sites, from deposits that have been drilled or are in operation. "The challenge with estimating the resource potential based on data from the seabed is that we currently have too little data, both from the seabed mineraliza-

tion and the host geology", Bjerkgård points out.

"Many of the samples are from chimneys, the structures that are built where the minerals are deposited in contact with the seawater. These samples often have higher metal contents than what is found in the sulphide deposits otherwise, and can contribute to an overestimation of the resources. To get a full overview of the presence of the various metals and in what concentrations they occur, one has to study all parts of a given deposit through detailed mapping and, not least, drilling."

The NGU researchers have therefore started with what they know best - volcanic massive sulphide (VMS) deposits on land. This database was reviewed and updated with the latest data on weights and tonnages so that only sulphide deposits formed in representative seabed environments remained.

As a response to this approach, Brekke states that it is impermissible to remove data only because it is perceived as uncertain. "Our perception of a good resource estimate of undiscovered resources is that we must take care of the uncertainties as best we can. It is from the range of uncertainty that opportunities emerge - both on the downside and the upside. As long as an analysis of content is correct, it can be used to assess and weigh the spread in a data set even if it is not itself representative as such. There is no guarantee that a database as a whole at this stage will become more representative by cleaning it down to only the "good" data.

"Our perception of a good resource estimate of undiscovered resources is that we must take care of the uncertainties as best we can."

Harald Brekke, NOD

"In our report", Brekke adds, "we also show how we have compared the marine data sets with an onshore data set from NGU's Fennoscandia database to assess which uncertainty range we should lie in, both in terms of size, content and density of occurrences. We have deliberately tried not to be too optimistic or too pessimistic and believe that our figures are scientifically very well justified and documented in the report."

BEHIND THE WORDS

What is really quite interesting in this debate is the different stances these Norwegian institutions seem to take in the debate around deep-sea mining. Whilst the NOD is clearly more optimistic – is there a relation to the exploration mindset of hydrocarbon explorers? – the NGU seems to make a case for continued onshore development of mines if you read between the lines. Could there be some more at play here? It is not unthinkable that the NGU would have preferred to lead the work on deep-sea research in Norwegian waters given their expertise in ore geology and mining. Instead, a lot of this work now falls under the remit of the NOD, and some folk at NGU may not have been too pleased with that. However, if there is one thing both parties can probably agree on, it is that more exploration is needed to further prove up economic quantities of critical metals. No matter what models or datasets one uses, it is ultimately more data that will form the basis for the big decision to go ahead or not. ■

Henk Kombrink

Oxidized sulphide sample collected by the Norwegian Offshore Directorate at the Mohns Ridge in 2019.

PHOTOGRAPHY: NOD

INSIGHTS

"A constant geothermal gradient is not a good rule of thumb to extrapolate temperatures - not even close."

David Rajmon

Permeability multipliers: allies or foes?

Raffik Lazar

Although permeability multipliers can be seen as short-term allies to overcome a challenging history match, in the long run, project economics might not be representative anymore

RAFFIK LAZAR, GEOMODL INTERNATIONAL

3D RESERVOIR modelling is built on 2 pillars: the static and dynamic reservoir models. The static model quantifies the architecture of the reservoir and the volume in place at initial conditions and it serves as a platform for forecasting the future performance of the reservoir. The second pillar is the dynamic simulation aiming at physically describing the hydrocarbon production scheme for the reservoir and is the backbone of the field development plan.

The commonly encountered challenge is that the validation of the initial reservoir properties can only be performed during the dynamic simulation stage through the "reverse validation" history match process. Past reservoir performance is thus used as a calibration to put confidence in the prediction of future production.

Permeability, perhaps the most critical reservoir property, acts as a cornerstone between the static and the dynamic domains. With increased production time, the history match process often becomes challenging and requires the introduction of "manual edits" in the initial static reservoir picture to satisfy acceptance criteria. In general, permeability is the main parameter to be manually edited as it has the most sensitive impact on pressure change, production rate, water breakthrough timing and evolution. And the most common way to modify the permeability model is to apply the infamous multipliers.

TWEAKING

Permeability multipliers represent swathes of the reservoir where a bulk permeability multiplier is applied to improve history match either locally or globally. General scenarios for an oil reservoir include permeability boost (multiplied by a factor > 1) when the simulated oil rate falls short against the actual performance of the reservoir. On the other side, permeability can be toned down (multiplied by a factor < 1) when water breakthrough comes early or water cut evolution is too rapid.

Because permeability is not measured directly at the well level other than well test and production performance, modelling permeability at initial conditions remains the most challenging reservoir property endeavor.

SOURCE: MICROSOFT COPILOT

Finding a relationship between porosity and permeability at plug scale and building permeability prediction log using machine learning algorithms are today's most popular workflows. Using permeability multipliers is ultimately a diagnostic informing that the dynamic of the reservoir is not properly represented by the static reservoir model.

The usual suspects are the presence of features that contribute to flow but are not captured at plug scale (think fractures or vugs), model resolution issues where the vertical resolution is too coarse resulting in an excessive averaging of the permeability or the elimination of outliers on the high side that were mistakenly attributed to spurious data points.

On that basis, with each permeability multiplier introduced in a reservoir model comes an erosion in predictive power to the point that future performance forecast is clearly at risk. ■

Activity and opportunities abound across the Africa region

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Having weathered the perfect storm of low oil prices, investor boycotts and global lockdowns over the last few years, high-impact exploration in Africa is back on the map

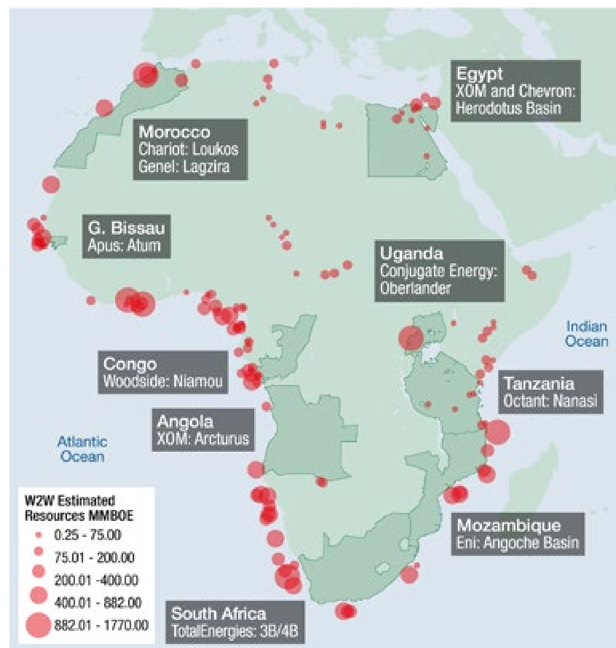
PETER ELLIOTT, NVENTURES

E&P across Africa in 2024 is off to a busy start, with clear signs the exploration industry is recovering from half a decade of under-investment. Exploration activity is still focused offshore and predominantly in deepwater, whilst appraisal and development remains focused in mature basins in shallow water and onshore. Onshore exploration remains woefully overlooked, although it's good to see new drilling and licence awards onshore in the Kwanza Basin in Angola.

ESTABLISHED BASINS TAKE THE LIMELIGHT

In terms of deal flow, established basins in Angola, Congo, Nigeria and Egypt take the limelight. The Orange Basin remains a focus for equity transactions, while large gaps remain in the West Africa Transform Margin and East Africa. Major deals of interest include the Renaissance JV (ND Western, Aradel, First E&P, Waltersmith and Petrolin) in Nigeria buying Shell's shallow and onshore portfolio, Perenco taking ENI's mature assets offshore Congo and TotalEnergies increasing its dominant position across the Orange Basin with deals on the Venus Block and also 3B/4B in RSA. Vaalco swooped on the Svenska stake in Baobab in CDI, which may in turn trigger more deals in this area.

Drilling activity over the last few months exhibits a similar trend, with a gradual upturn in activity, exploration in deepwater, and appraisal and development concentrated in shallow water and onshore. Whilst fast-paced exploitation companies like Panoro, Perenco and AOC take advantage of late-life field development, supermajors are left to push the envelope on deepwater frontier drilling. Of note are the new deepwater discoveries in Namibia at Mopane (Galp) and Mangetti (TotalEnergies), and in Cote D'Ivoire where Eni extends its run of success with another giant discovery at Calao with the Murene 1X well. Sasol continue to drill up gas in the PT area, and Invictus report promising results at Mukuyu 1 in Zimbabwe. However, there are no wildcat successes to report from offshore East Africa.



NEW DEVELOPMENTS

New oil and gas developments are coming on stream this year in Senegal (Sangomar) and Mauritania (GTA LNG project), while Eni are gearing up to produce 3 mmtpa LNG from the new Congo FLNG projects. Jubilee Southeast has proven successful for the Tullow Group in Ghana, although TEN is failing to deliver, and Egina West is up and running for TotalEnergies and partners in Nigeria. In mature basins firms such as Assala in Gabon and Perenco in Cameroon, Congo and Gabon continue to extract maximum value from late-life assets previously held by the super-majors.

A BUYER'S MARKET FOR EXPLORATION

Looking ahead, there are a good number of opportunities to continue the growth in E&P investment on the continent. A large number of active data rooms are seeking the attention of international new ventures teams. Many firms are seeking partners to fund new 3D, especially in promising areas like the Walvis Basin (Namibia) and the southern MSGBC. In general, it remains a buyer's market for exploration, with not many farm-in deals achieving more than ground floor terms, and a seller's market for appraisal and production, with many firms lining up to pick at the remains of mature producing fields and basins.

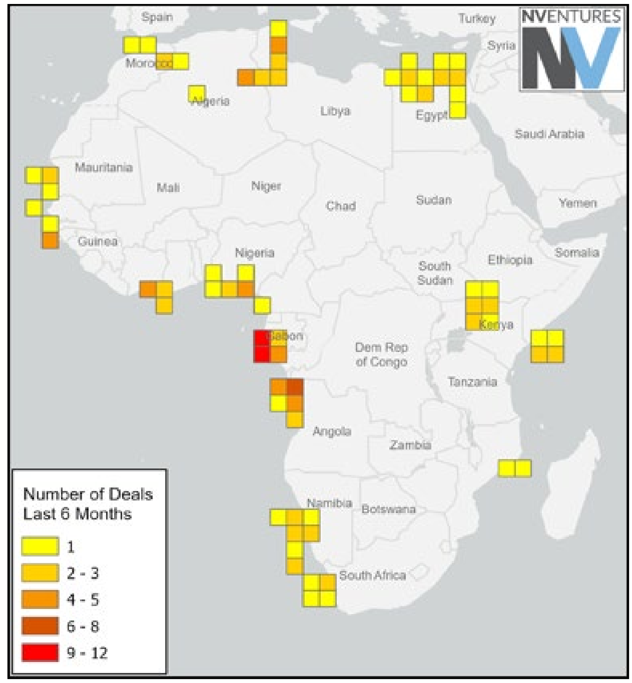
ACTIVITIES TO KEEP AN EYE ON

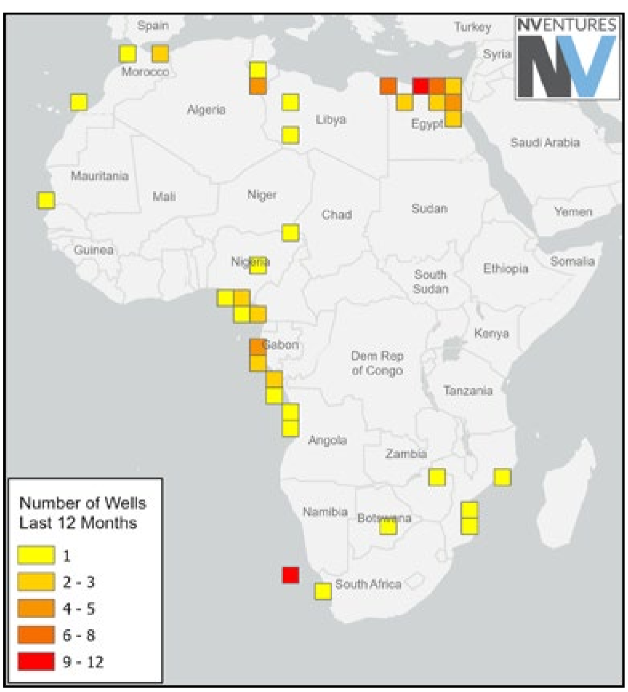
Major opportunities for drilling exist across the continent, with firms seeking partners or investment in high-impact drilling campaigns. In Ghana, Heritage and other firms have low-risk drilling opportunities in the Tano Basin in and around Jubilee. The MSGBC hosts a number of exciting opportunities to drill multi-billion barrel prospects, including Supernova in Guinea Bissau and Petronor in Gambia.

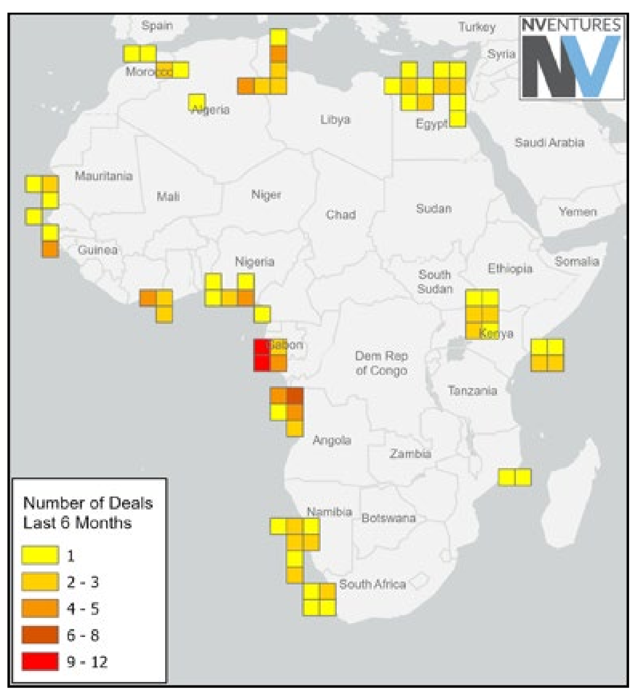
Several significant campaigns stand out, such as the planned wells in the Herodotus Basin offshore Egypt where ExxonMobil and Chevron separately have wells planned. In South Africa, TotalEnergies are reported to have up to 5 wells planned to test the central and southern Orange Basin, and the government in South Africa is quickly putting into place new institutions and regulations to encourage future development of resources.

ExxonMobil is set to drill the Namibe Basin offshore southern Angola; a successful campaign here could open another oil and gas front in neighbouring Namibia. Junior explorers are picking up momentum as well; Petrodel and Octant plan to drill large targets in the Pemba coast in Tanzania, Conjugate Energy are planning two wildcats in southern Uganda, and all eyes are on Guinea Bissau as Apus gear up to drill the long-awaited Atum well.

So, it is fair to say that after having weathered the perfect storm of low oil prices, investor boycotts and global lockdowns over the last few years, high-impact exploration in Africa is back on the map. ■







Should you rely on geothermal gradients?

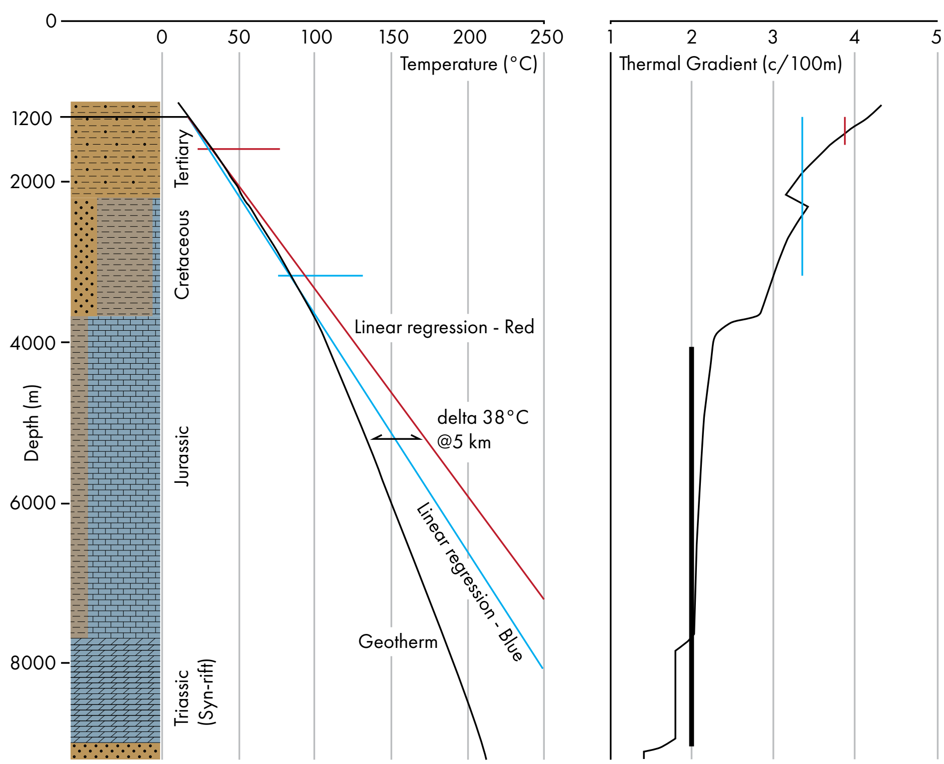
David Rajmon

A constant geothermal gradient is not a good rule of thumb to extrapolate temperatures - not even close

DAVID RAMJON

When I start a new project, I commonly get this question: "What is the geothermal gradient in this area?" The question stems from an underlying assumption that the gradient provides information about the temperature down deep at the source rock level. I don't particularly care. Why? Well…, what gradient are we talking about? At what depth range?

Geothermal gradient is a rate of temperature change with depth - the slope of a line in a temperature-depth (T-D) plot between two temperature measurements in a well. Using a single gradient implies a linear geotherm.



Let's consider a North Sea 1D model and focus purely on the present-day temperature, ignoring transient effects over geologic history. Looking at the model plot we can immediately notice that the temperature does not increase with depth in a linear manner, i.e. at a constant rate. The geotherm is a curve in the T-D plot and the gradient generally decreases with depth. Why? Because the rocks are less porous and therefore more conductive with increasing depth. This is only partly balanced by the opposite effect of thermal conductivity decreasing with increasing temperature.

Further, lithology contrasts induce substantial variation in the geotherm slope (the gradient). And we don't even consider the extreme case of salt here. Notice the sharp change in the geotherm slope at the top of Jurassic carbonates. That is because carbonates are more conductive than shales. Shales act as insulators, slowing the upward heat flow and therefore temperature increases below. That translates to a) higher T gradient within the shaly section and b) the geotherm within the conductive carbonates being shifted to higher temperature and slightly steepened. The effect is further supported by a substantial shale radioactive heat generation.

Consider two linear temperature regressions starting at 1,200 m depth bsl (200 m bsf). The red one fits through the temperature 600 m deeper, the blue one fits through the temperature 1,800 m deeper. The corresponding average gradients over those depth ranges are indicated in the gradient plot. Interpolated temperatures over those intervals are close to the geotherm, although the blue line is up to several °C lower than the geotherm. Extrapolations look entirely different though. At 5,000 m bsl (4,000 m bsf), the red line overestimates the geotherm by 38°C, let alone deeper down.

A constant geothermal gradient is not a good rule of thumb to extrapolate temperatures - not even close. At best, it can be used for temperature interpolation over a short depth range at a reservoir scale. A simple 1D thermal model is needed to get a meaningful temperature estimate at depth. ■

Riedel shears, my favorite kinematic indicator

Dr. Molly Turko

Riedel shear fractures and faults are quite common in brittle deformation, however, they are frequently either misinterpreted, misused, or overlooked altogether

MOLLY TURKO, DEVON ENERGY

RIEDEL SHEARS are commonly the first set of subsidiary faults we see prior to the breakthrough of a master fault. They form systematically at an acute angle (~10-20°) to the main fault in an en echelon pattern. Although they are commonly mentioned when discussing strike-slip tectonics, Riedel shears also develop along normal faults and reverse faults. However, we commonly refer to them as the synthetic or antithetic sets in those cases.

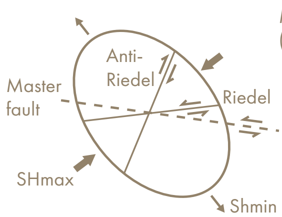
It can often be difficult to determine the sense of slip along a strike-slip fault in the subsurface due to a lack of piercing points. Additionally, it may be difficult to determine slip sense at an outcrop that lacks bedding, such as a homogenous granite. However, the Riedel shears are great for determining slip sense, regardless of piercing points.

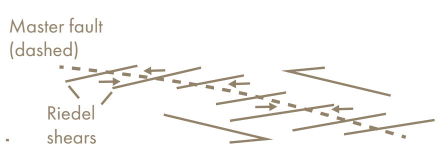
THE TRICK

One trick to determining the sense of slip using Riedel shears is to draw a line through the en echelon set of faults that develop prior to fault breakthrough. The acute angle between the Riedel shears and the line you drew - which would represent the master fault - creates an arrow shape that "points" in the direction of slip. This can be done on an outcrop or on a seismic time slice.

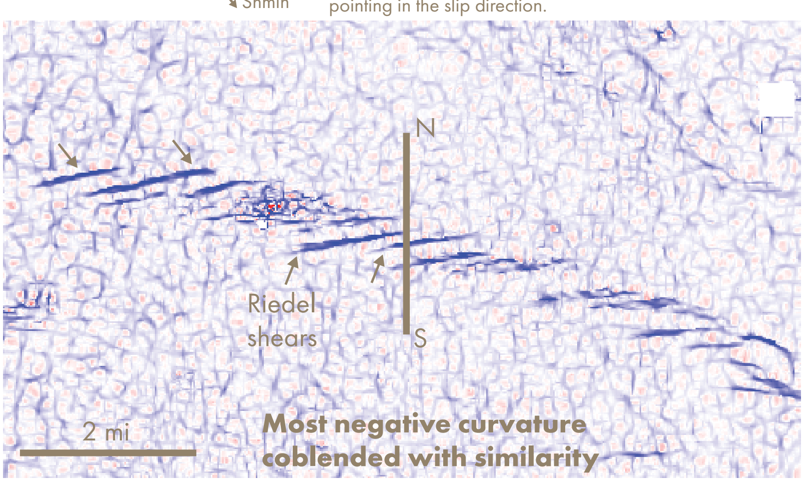
Since Riedel shears also commonly have a sense of normal slip associated with them, they can often be resolved on 3D seismic data. The illustration shows a time slice through a left-lateral strike-slip fault where an en echelon pattern of Riedel shears can be observed. The cross-section shows the slight normal slip along one of these faults. Furthermore, Riedel shears will have the same sense of slip as the master fault. Anti-Riedel shears, however, will have the opposite sense of slip.

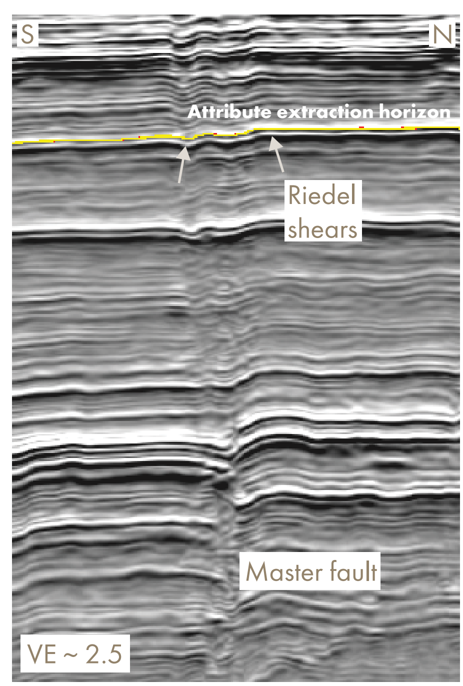
Riedel shears can occur at a variety of scales but it should be noted that they are subsidiary faults to a master fault and should not be used to describe regional fault patterns that occur at various orientations. This means that the timing of the Riedels will be the same as the master fault. Too often, geoscientists will see regional fault patterns at various orientations and apply a "Riedel model", but this is incorrect to the true meaning of the word and why it's also important to understand the tectonic history. ■





Determine the slip sense by drawing a line through the Riedel shears. The acute angle creates an arrow shape pointing in the slip direction.





Data courtesy of Contango.


Limestone

A geomechanics approach for natural fracture prediction

Natural fractures can provide the essential permeability in hydrocarbon and geothermal reservoirs. However, they exist in the sub-seismic domain and although they can be detected by well logs and cores, we are reliant upon outcrop analogues to understand their distribution and connectivity in 3D. We can use a simple geomechanics approach to predict their distribution and intensity as a basis for our conceptual model.

In general, thicker beds tend to have less and more widely spaced fractures than thinner beds. This concept of bedding-related mechanical stratigraphy can often be observed in carbonate sedimentary multilayers. This outcrop example, highlighting Upper Cretaceous interbedded limestones and cherts from the Majella anticline in the foreland fold-and-thrust belt of the Central Apennines in Italy, shows a major contrast in the distribution of fracture density within the nicely layered interval.

It can be observed that each layer interface represents a sharp discontinuity that marks a lithological change acting as a mechanical boundary for fracture propagation. In such a mechanical pattern, fractures are prone to be bed-confined and the fracture density and distribution are a function of the mechanical properties of the different carbonate layers.

Thicker coarse-grained limestone beds have a lower fracture density than thinner fine-grained limestone beds. This is particularly the case when these beds are adjacent or interbedded with chert layers or lenses. Also indicated is a meso-scale throughgoing fault, which is hereby interpreted as a tilted syn-sedimentary normal fault: Note stratal thickening to the right.

Paolo Pace, Pace Geoscience, and Steven Ogilvie, Ogilvie Geoscience

FEATURE YOUR OUTCROP

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

How to explain these rates?

A new depositional model for the Vaca Muerta

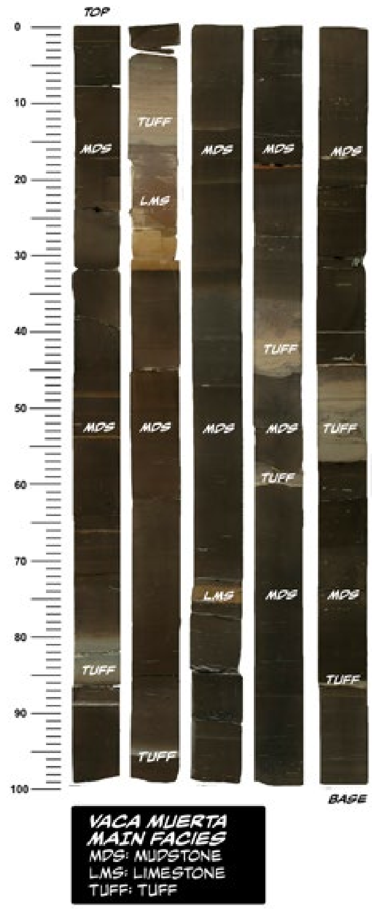
MARCOS ASENSIO

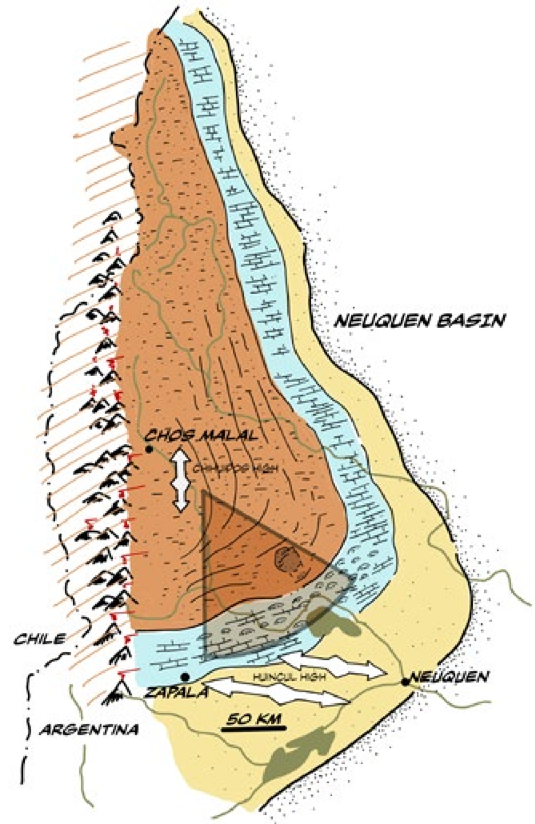
Marcos Asensio

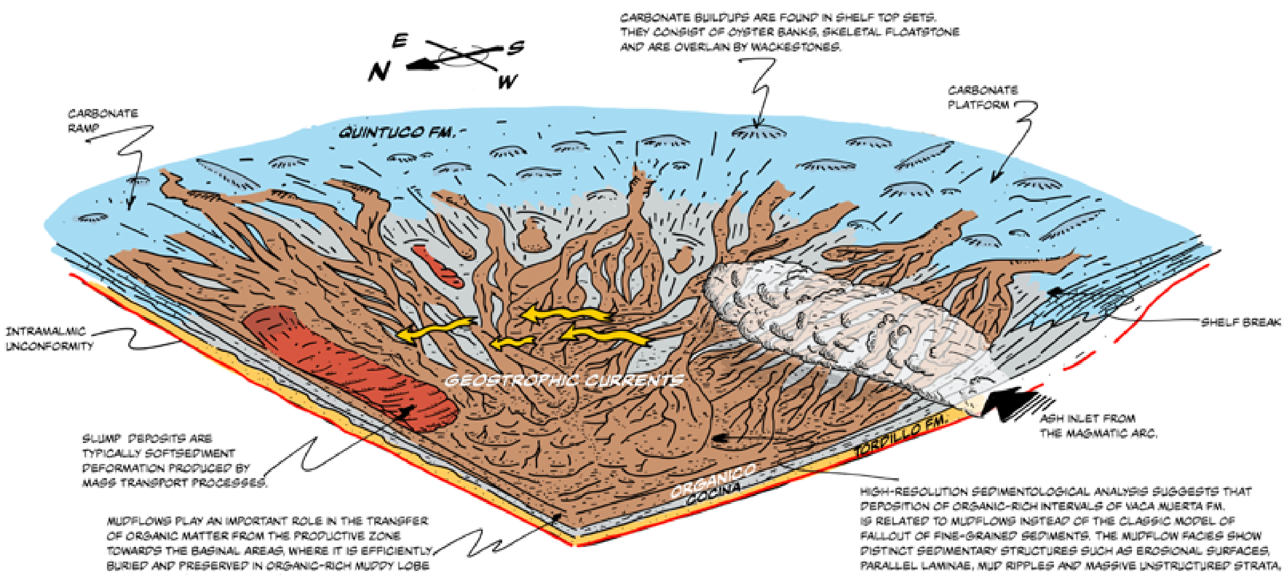
THE JURASSIC MARINE Vaca Muerta unit is a treasure trove with an estimated potential of 308 TCF of gas and 16.2 billion barrels of oil. While there are various types of facies like volcaniclastic, carbonate, and mixed siliciclastic-carbonate, it's the bituminous marls that steal the show.

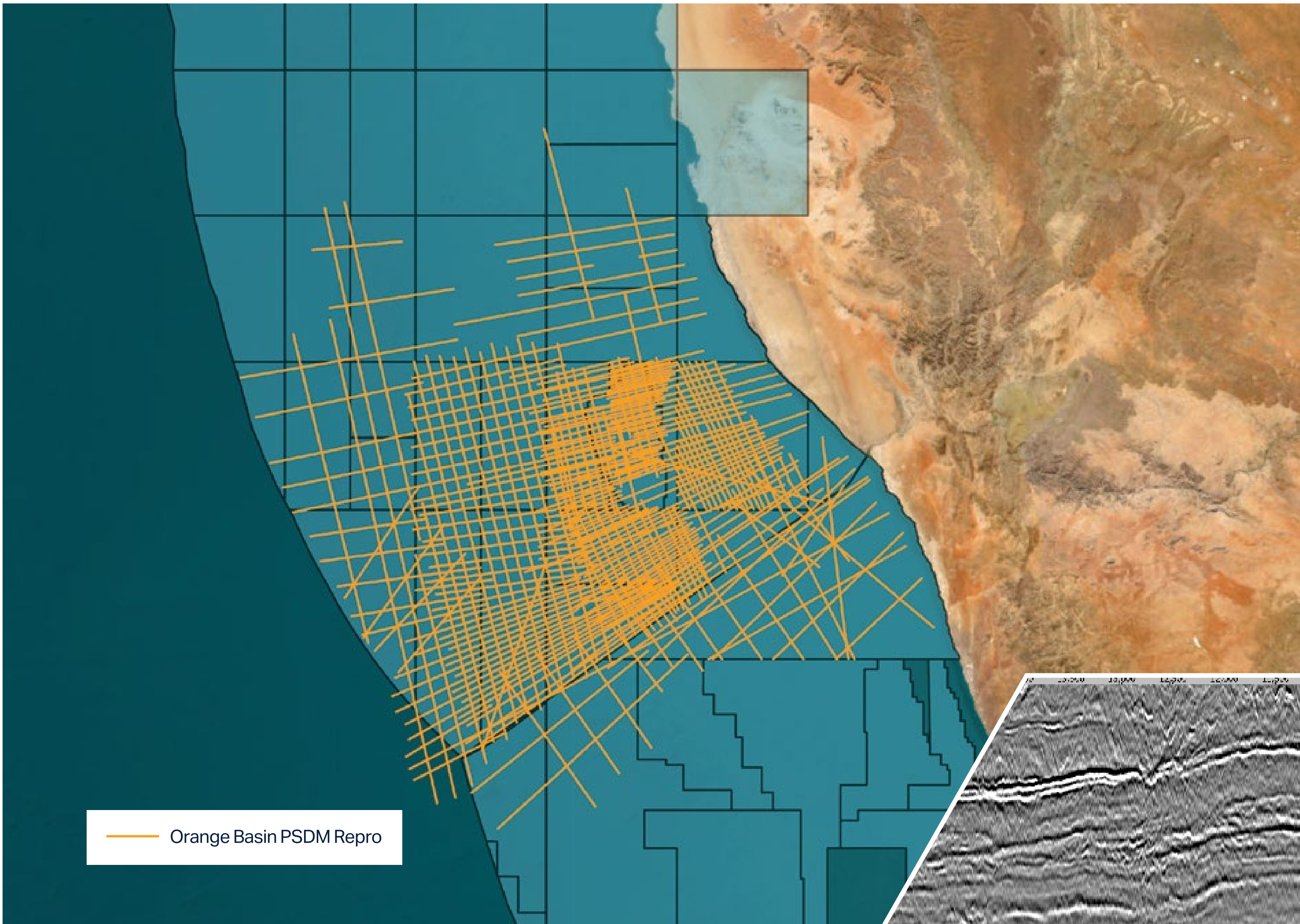
But there is a succession of 2,500 m (uncompacted, 1,000 m compacted) of fine-grained sediments, deposited in just 10 million years. That's almost double the usual rate for pelagic sedimentation, which is around 1-1.6 mm/year. So, how did this happen?

Well, recent high-resolution sedimentological studies suggest that the sedimentation of Vaca Muerta is actually due to fluid mud flows, not the traditional "normal fallout" model. The marlstone facies show tractive structures, suggesting that the sediments mainly piled up from gravitational mudflows, tuffaceous material and bioclastic detritus. These currents played a crucial role, transporting sediments from marginal environments to the heart of the basin. And this is what we illustrate here. ■








Orange Basin PSDM Repro