THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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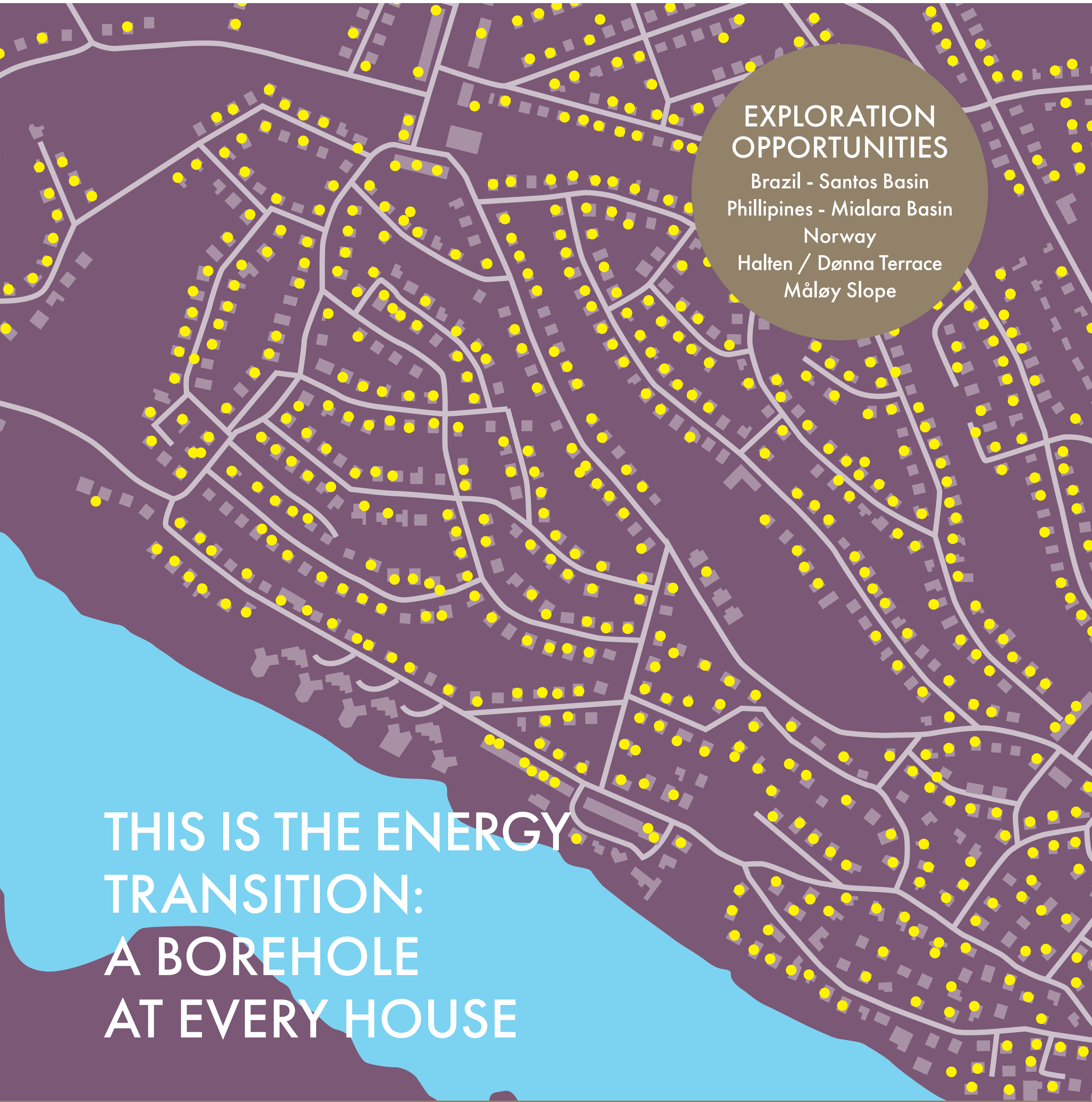

EXPLORATION OPPORTUNITIES

Brazil - Santos Basin

Phillipines - Mialara Basin

Norway

Halten / Dønna Terrace

Måløy Slope

THIS IS THE ENERGY TRANSITION: A BOREHOLE AT EVERY HOUSE

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COVER ILLUSTRATION: GEO EXPRO

Drillers have the future

SOME OF MY fellow geoscientists may not like this. Still, based on recent conversations with some key people in the shallow geothermal sector, the conclusion is that only a few geoscientists are needed when it comes to this critical element of the heating/cooling transition. Why?

As you can read in the cover story, shallow geothermal systems often rely on closed loops. The geology is still important, but not as critical as in oil and gas or deep geothermal. And believe me, that is only a good thing!

It is a good thing because the geological risk of shallow geothermal loops is basically lacking, except for the drilling stage. That is why these loops can be drilled anywhere, with the length of the loop determined by the conductivity of the rocks and the energy demand of the building it is connected to.

The speed with which boreholes are drilled is of the utmost importance to make shallow geothermal more competitive. In turn, this means that experienced drillers will be required in large numbers if this sector is to grow as much as in Sweden, to name a great example of a country where shallow geothermal is everywhere. Time for a job change?

Henk Kombrink

> **"The geology is still important, but not as critical as in oil and gas or deep geothermal. And believe me, that is only a good thing!"**

BEHIND THE COVER

Sweden is the third country in the world when it comes to geothermal energy production. And the surprising thing is, it is all from the shallow subsurface. Since the oil crisis in the 1970's, the country realized that independence from oil and gas is critical. It spearheaded the birth of an industry that has now resulted in shallow geothermal loops being present almost everywhere. The front cover illustration shows part of the city of Stockholm that perfectly illustrates this. The image was sourced from the Swedish Geological Survey, which keeps track of all boreholes drilled.

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Join us at IMAGE '24: Your Passport to Global Energy

The Society of Exploration Geophysicists (SEG) and the American Association of Petroleum Geologists (AAPG) in conjunction with the Society for Sedimentary Geology (SEPM) are excited to host the fourth annual International Meeting for Applied Geoscience and Energy (IMAGE), 26–29 August in Houston, Texas at the George R. Brown Convention Center

IMAGE '24 has been designed and built by industry experts to serve as a pivotal gathering for geoscientists, energy professionals, and visionaries to convene and to shape the trajectory of applied geosciences and energy. It will offer an influential platform for disseminating best practices, uncovering solutions, and cultivating fresh perspectives and strategies to confront and prepare for the challenges ahead.

Featuring a comprehensive and forward-thinking technical program comprised of over 1,000 presentations, IMAGE will inspire and foster collaboration across various key areas, including strategic market trends, the business of applied geoscience, energy markets and finance, near-surface geophysics, energy transition and sustainability, diversity, and inclusion, as well as government policies and regulation.

Save the date of 26–29 August and plan to be part of this transformative event in Houston.

Further information at: https://www.imageevent.org/

The Role of Geosciences in Shaping our Energy Future

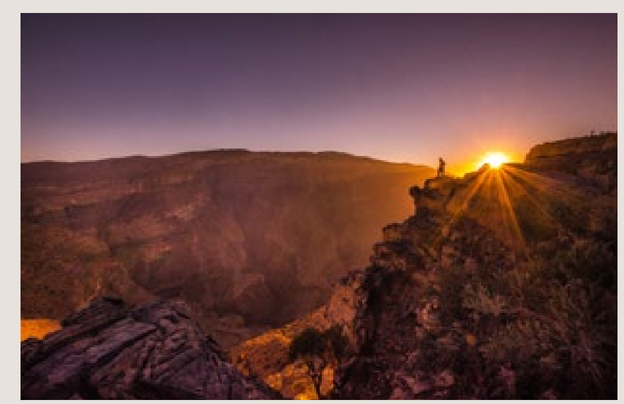
The 2024 AAPG International Conference and Exhibition (ICE) to be held in Muscat, Oman, aims to bring together geoscientists from all around the world, providing them with a unique platform to exchange and present their knowledge, insights, and research findings. It offers an unparalleled opportunity for collaboration, discussion, and networking among professionals in the geosciences field

THIS YEAR'S conference theme, "The role of geosciences in shaping our energy future", will showcase how the future of energy is being shaped through diversification and transformation of geological disciplines to address the evolving energy landscape and our adaptation as we strive to achieve carbon neutrality.

A key enabler is the advances in digitalization and technologies in transforming our ways of working to unlock the subsurface faster and more effectively. An equally important enabler is the repurposing of skills to cater for the requirements the evolving energy ecosystem will demand. As such, an outstanding technical program is being assembled, with global participation of abstracts, notable keynote speakers, panel discussions, and workshops promises to bring a global perspective that you will find diverse and enriching.

Overall, this gathering of geoscientists fosters a collaborative and inclusive environment where ideas can flourish, new solutions can be developed, and the geosciences community can collectively work towards a more sustainable and prosperous future.

Further information at: ICEevent.org



PHOTOGRAPHY: IMAGE; AAPG

Enhancing Reservoir Characterization Through MSI Workflow

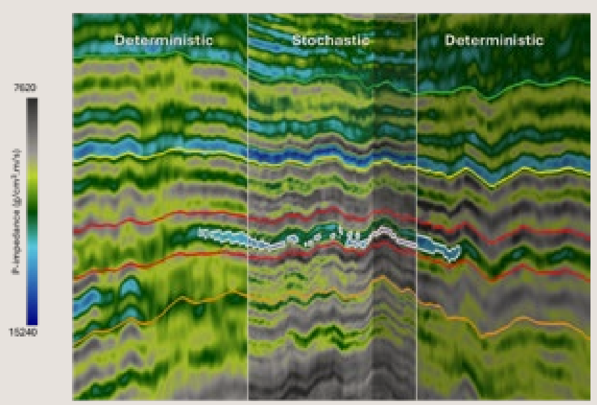
A THOROUGH geological understanding remains crucial for sustainable long-term production from unconventional assets. In the Midland Basin, a key challenge is navigating thin carbonate debris flows in the reservoir, which can impede drilling and create stress barriers, leading to increased rig time and costs if not properly identified and incorporated into the well planning process.

To identify these debris flows within the target area, deterministic inversion was applied using seismic amplitude data and geologic models of well log properties. Although effective in many ways, the inversion produced models limited by the seismic resolution, making it difficult to accurately estimate the thickness and map thin geological features.

Stochastic inversion can provide a more detailed view of the debris flows' position, thickness, and extent. By generating multiple high-resolution impedance volumes, all of which align with the seismic data, stochastic inversion modeled geological features as thin as 8 feet. This contrasts with deterministic inversion, which struggled to resolve debris flows thinner than 40 feet.

Multi-realization analysis of resultant high-resolution property volumes was used to produce thickness maps of the thin debris flows and highlight the uncertainty associated with these maps. This comprehensive view of potential drilling hazards allowed engineers and geologists to make more informed decisions, reducing the risk of encountering unexpected obstacles during drilling and minimizing additional costs and delays.

Author, Dominique Moulière
AspenTech - Sr. Product Manager



Comparative analysis of deterministic and stochastic inversion of a Midland Basin Dataset. Note the resolution of the debris flow unit.

Seismic Ocean Bottom Node Acquisition without ROV

Allton has developed an innovative Drop & Pop vehicle solution for cost-effective seismic node acquisition which enables the deployment and recovery of seismic ocean bottom node (OBN) without the use of remotely operated underwater vehicles (ROV).

GUIDED BY industry demand for improved efficiency and reduced costs for the acquisition of sparse node grid seismic and 2D transects, Allton was led to research and develop an innovative solution - a seismic OBN Drop & Pop vehicle.

The tool, which does not require the use of ROV, can be deployed at a speed of 5 knots and also be utilised with other environmental measurement tools designed for use on the sea floor, such as water temperature, pH and salinity.

The Drop & Pop unit can host any standard seismic OBN available on the market. The system was designed to be modular and containerised for logistical efficiency and easily fits on a standard back deck on a vessel of opportunity.

As one of Allton's cutting-edge Multiphysics Solutions, the Drop & Pop vehicle's mechanisms are based on the same laws of physics and similar technology to that used to build its Multiphysics Nodes (EM + Seismic OBN). Patents to protect the intellectual property were filed in early 2024.

Jillian D. Young-Lorenz
Allton

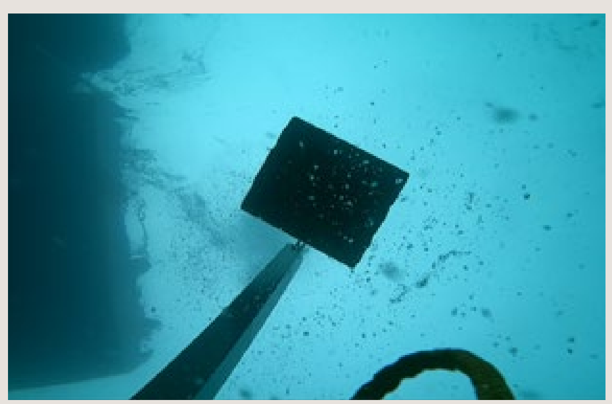


ILLUSTRATION: PROVIDED BY PERMIAN OPERATOR; PHOTOGRAPHY: ALLTON

FIRSTS

"...The world's fossil fuel supplies are depleting, we are having to drill deeper and find unconventional sources. The Permian is a great example, a wonderful example of energy innovation, but there is no grandparent rock"

Rodney Garrard – Arch Insurance

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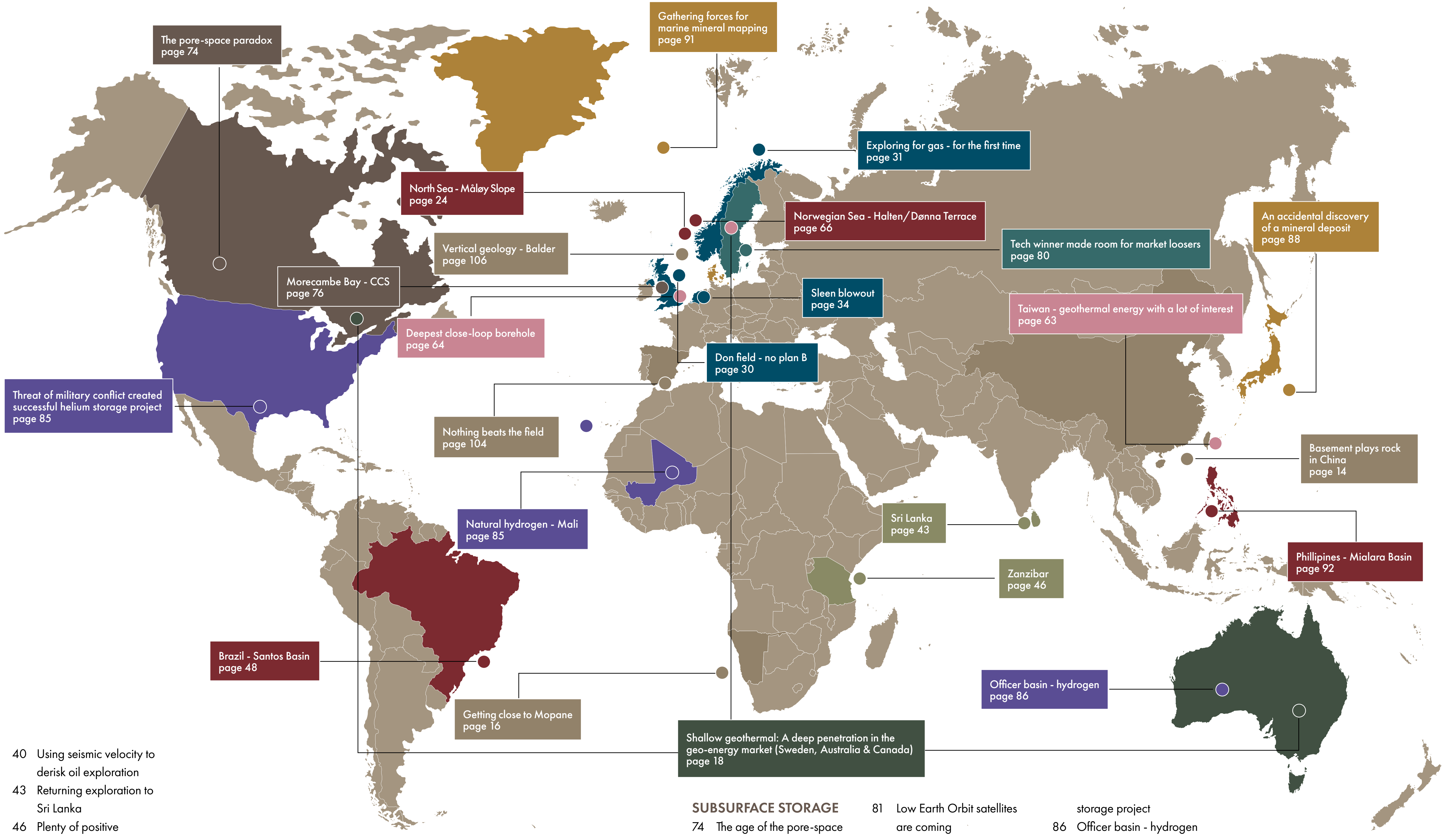

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The East Med – still the game changer it was branded as?

New petroleum provinces may increasingly experience competition from the energy transition, which only exposes above-ground fragility more

THE DISCOVERIES of the giant Tamar and Leviathan gas fields offshore Israel in 2009 and 2010 respectively were hailed as two of the largest finds of the decade. As such, the perception of the Eastern Mediterranean and its role in gas markets was redefined, with some describing the discoveries as game changers, both for the region and the broader gas markets, particularly in Europe.

However, international interest in the Eastern Mediterranean's offshore oil and gas resources has followed a cycle from widespread excitement to a stall in activity, to disappointment, and back to excitement again, and then disappointment and serious concerns, depending on local and global developments.

Following the energy crisis that Europe experienced in 2022 and the quest of the European Union (EU) to find alternative gas suppliers to Russia, Eastern Mediterranean gas re-gained attention. "Israel, Egypt and Cyprus, because of their significant offshore gas reserves, make the Eastern Mediterranean region a strategic partner for the EU in its effort to diversify its gas supply routes", the EU said. However, that enthusiasm was soon hit by a sad reality: The political fragmentation of the region.

The war in Gaza is a reminder of the above-ground fragility of the region, which translates into a very high risk of doing business. In an era where there are no shortages of gas reserves around the world, companies would be easily forgiven if they decided to look elsewhere to allocate their limited capital and resources, especially as the energy transition accelerates.

In 2022, the IEA announced that the golden age of gas may soon be reaching an end before it had the chance to fully materialise as competition from green energy intensifies. While on a global level, this may be questionable. However, when it comes to the most eastern region of the Mediterranean, it may well be the case under existing circumstances which are unlikely to be reversed any time soon. ■

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.

Net energy matters

Modern societies are completely dependent on a functioning reliable energy production. So why we are trying, unsuccessfully, to negotiate with physics and economics by forcing low-density, high mining-intensity solar, wind and battery products?

WHILST THESE sources have a supporting role to play in the energy system, the majority of energy sources for powering the world should be high density, low emissions, low land use, low mining-intensity, reliable baseload fuel sources including natural gas, hydrogen, and nuclear. That's the physics.

Before we talk about net energy and how skilled geoscientists fit into a reliable and clean energy system and why electrification by use of nuclear is the most economical clean energy source, we need full disclosure. I have nothing to sell. After working in E&P for 18 years I pivoted into nuclear waste disposal in 2018. I was generally curious about the energy source and how spent nuclear fuel would be safely disposed of. Nowadays I work in the global insurance industry. What I am implying is that my identity is not wrapped up in my conclusions.

To understand net energy is to understand biology. Put simply, it revolves around knowing where your next meal (energy) is coming from. However, today our relationship with energy starts to become vague anywhere past the fuelling station and/or the plug socket. As geoscientists we should find this concerning.

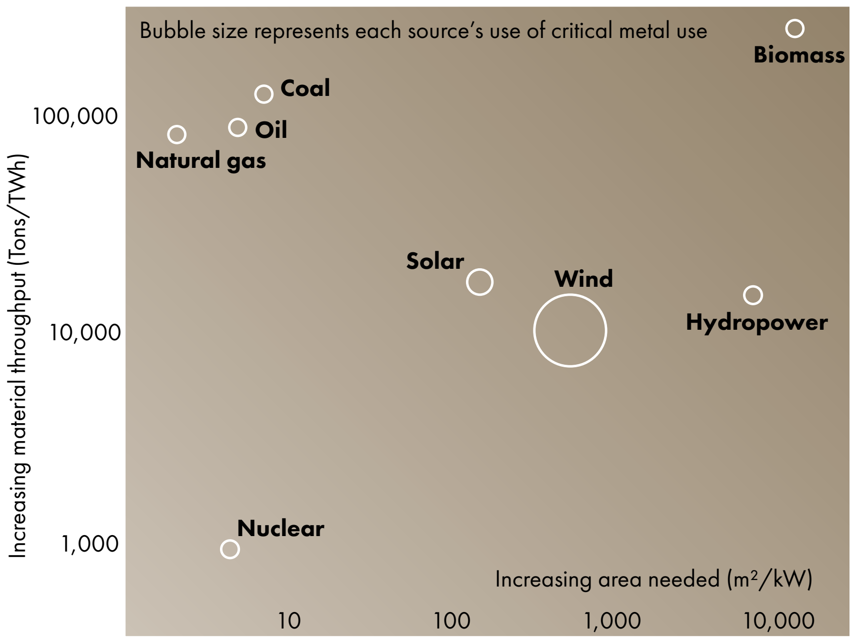
The world's fossil fuel supplies are depleting, we are having to drill deeper and find unconventional sources. The Permian is a great example, a wonderful example of energy innovation, but there is no grandparent rock. To understand the true nature of our predicament is to understand net energy. Instead, we are told we need to move away from fossil fuels to prevent climate change. I am not a climate change denier, but what should be on the forefront of everyone's mind is that fossil fuels are transitioning away from us, and we don't seem to be focused on a solution.

Today's wind turbines and solar panels, modern renewables, are really extensions of the fossil fuel industry. Currently, these devices can only be made, built, repaired and rebuilt using fossil fuels, which is a high net-energy source, to produce solar panels and wind turbines that provide a lower net energy. With a population of around 8.1 billion today, there is no way that energy derived from modern renewables can support the energy needs of today's population or the future, as these industries do not produce high enough net energy to be sustainable on thier own.

In the coming months, I will write a few periodicals that attempt to explain net energy. Why are the current energy policies of many countries so contentious? Why has nuclear power become such a sensitive political issue? What are the strengths and weaknesses of wind power and solar energy and what needs to be done to secure the reliable energy supply of the future? ■

Rodney Garrard - Arch Insurance

Spatial and material requirements by energy source



SOURCE FIGURE: GLEX ENERGY

Basement plays rock in China

CNOOC's recent exploration results for the offshore is yielding positive results

OVER RECENT years, a number of significant oil and gas offshore discoveries and successful appraisal programmes have been reported in China, even though it is often unclear if the "discoveries" are part of an already producing complex or new standalone success. Press releases need unravelling to understand whether volumes are recoverable or in-place. Nevertheless, the results offshore China seem to be impressive, especially the success in basement plays.

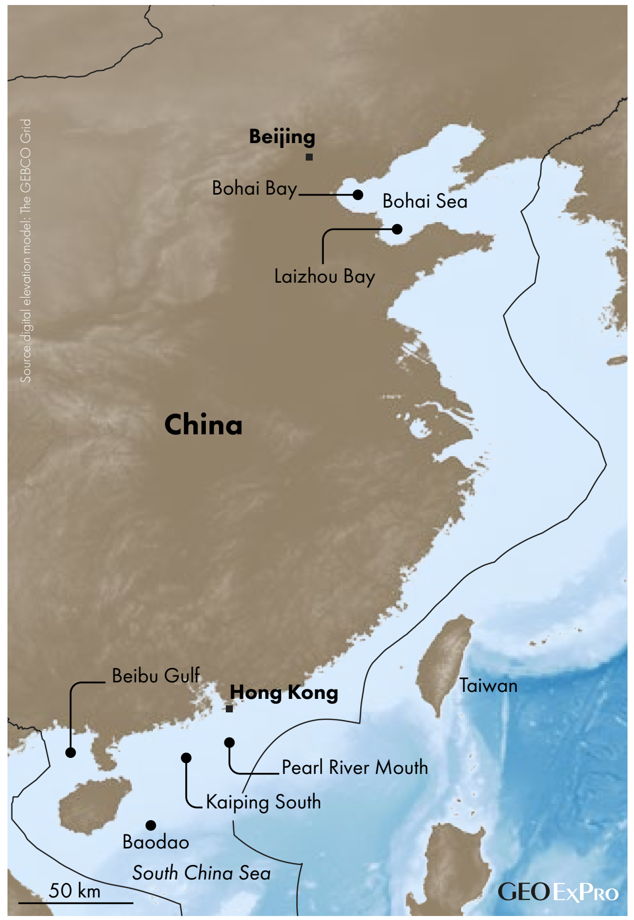
In 2017, CNOOC announced the Bozhong 19-6 oil and gas discovery in Bohai Bay, one of three major bays in the Bohai Sea. Exploration well 19-6-1 discovered resources in the range of over one billion barrels of light oil and 6 TCF of gas in Pre-Cambrian basement in a buried hill play. The discovery represents one of China's biggest hydrocarbon offshore discoveries and first significant gas discovery in the Bohai Bay. In 2020 CNOOC announced the Kenli 6-1 oil discovery in Bohai Sea. Well KL6-1-3 proved up the Mio-Pliocene potential of the Laibei Lower Uplift in Laizhou Bay.

During the same year CNOOC made the Huizhou 26-6 discovery in the Pearl River Mouth in the South China Sea. The discovery well HZ26-6-1 tested oil and gas, and this is the first time that CNOOC has achieved commercial and highly productive flows in a buried hill play in the Pearl River Mouth Basin.

Following the Bozhong 19-6 discovery in basement in the Bohai Bay success continued in early 2021 with the Bozhong 13-2 oil and gas discovery. Later in 2021, CNOOC declared that the Kenli 10-2 was a heavy oil discovery in Laizhou Bay in the Bohai Sea. The Kenli 10-2-4 well encountered oil in Mio-Pliocene sediments.

The following year CNOOC announced the Baodao 21-1-1 deepwater gas discovery located in the South China Sea. Baodao 21-1 is reported to have certified proven in-place gas of over 1.8 TCF plus light oil in Oligocene reservoirs.

Early 2023, CNOOC announced that the Bozhong 26-6 oil and gas discovery and been re-appraised in the Bohai Sea. Total proved in-place volumes increased to 1.2 billion barrels of oil equivalent. CNOOC consider Bozhong 26-6 to be the largest metamorphic buried hill oilfield in the world. Later in 2023, CNOOC announced its first offshore unconventional discovery in the Beibu Gulf. The operator's Weiye-1 wildcat well had a modest flow rate but is considered to have opened the door for more significant unconventional exploration in the Beibuwan Basin.

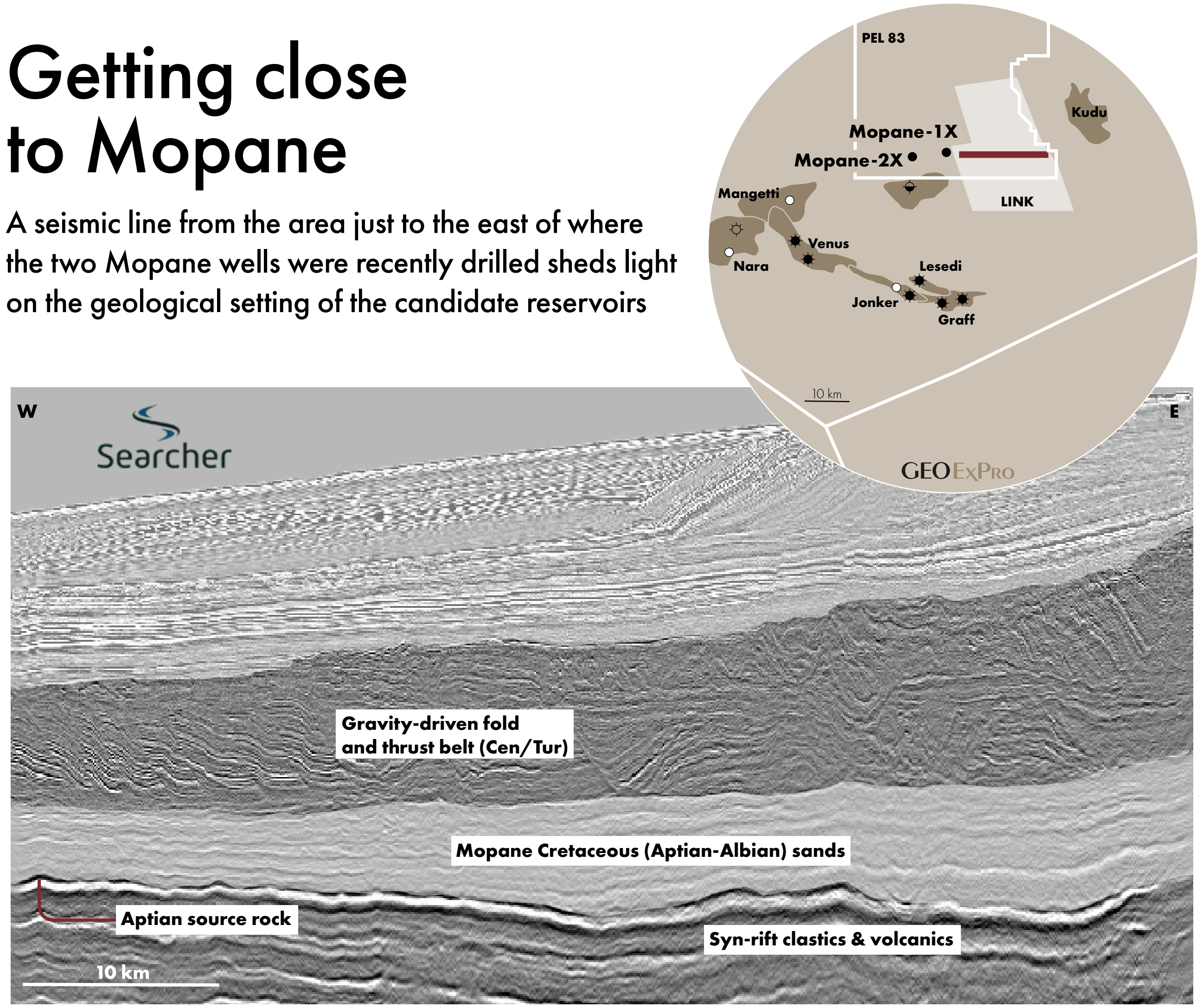


In March 2024 CNOOC's QHD27-3-3 made an oil discovery in the northern Bohai Sea. The main oil-bearing Mio-Pliocene reservoirs at Qinhuangdao 27-3 tested medium to heavy crude. During the same month CNOOC announced an oil discovery designated Kaiping South in the deepwater of the eastern part of the South China Sea. The KP18-1-1d discovery well encountered oil-bearing Eocene and Oligocene reservoirs. ■

Ian Cross - Moyes & Co

Getting close to Mopane

A seismic line from the area just to the east of where the two Mopane wells were recently drilled sheds light on the geological setting of the candidate reservoirs



SOURCE: SEARCHER SEISMIC

FOR OBVIOUS reasons, there has been a lot of recent media coverage on the test results of the Mopane 1X well in Namibian waters. The well flowed at 14 kboepd at maximum capacity, which has subsequently contributed to the consortium of companies – Galp, operator at 80 %, and NAMCOR and Custos at 10 % each – to announce that the Mopane complex could hold 10 billion barrels of oil equivalent or higher.

An interesting observation is that Mopane is thought to host hydrocarbons in both Venus and Graff types of reservoirs, as Peter Elliott from NVentures wrote in a recent GEO EXPRO article. He wrote: "The Mopane complex (ed.) appears to hold both the Late Cretaceous Cenomanian – Turonian (CT) play seen at Graff, and the Lower Cretaceous Albian-Aptian play seen at Venus. A major detachment at Cenomanian level appears to underlie high-energy clastics, forming combination stratigraphic/structural traps in the Cenomanian/Turonian. Further large build-ups at the base Cretaceous show strong similarities to the basin floor fan play in the Albian. Galp announced major light oil columns at two depths, suggesting perhaps both plays are active."

The seismic section shows both the Cenomanian and Turonian gravity-driven fold and thrust belt as well as the underlying Aptian-Albian more parallel-layered strata. It is in both these intervals that the wells have supposedly found hydrocarbon-bearing reservoirs, and going by the names of the reservoirs used by the consortium (AVO 1-3), AVO anomalies likely formed the leading factors in drilling these wells. The source rock of the discovery is probably the Aptian interval as noted in the seismic. ■

Henk Kombrink

A DELICIOUS MEAL

Neil Hodgson from Searcher, when he sent us the seismic line, further mentioned that Galp describes the Aptian/Albian succession above the source rock as a "complex of channels". Is that a reference to the local delicacy named Mopane? Mopanes are big and fat worms that are said to be full of meat, so using this name for this new discovery is quite fitting as it seems to be quite full of meat!

COVER STORY

"The cost of drilling has basically stayed the same over the last decades thanks to the upscaling of the sector, the innovations when it comes to drilling and thus the time it takes to complete a borehole"

Signhild Gehlin – The Swedish Geoenergy Center

COVER STORY

SHALLOW GEOTHERMAL:

A DEEP PENETRATION IN THE GEO-ENERGY MARKET

In contrast to what many people may expect, shallow geothermal is bigger than deep geothermal when looking at the total installed capacity worldwide. Here, we talk to three experts from the shallow geothermal space in Sweden, Australia and Canada to hear how the market is evolving, what the role of the subsurface is, and how technological development is making even more advances

HENK KOMBRINK

Geothermal drilling in Sweden, just before drilling started.

THE TOP THREE countries in terms of geothermal energy production are China, the US and Sweden. In total, these countries produced around 200 TWh in 2020. Of that figure, ground-source heat pumps account for 126 TWh, so 63 % of the total energy produced. So, it is the shallow geothermal systems that are responsible for most geo-energy produced in these places. In Sweden, it is even at 100 % of the share.

Yet, in the media, there is a lot of attention for deep geothermal drilling projects: At the end of the day, a borehole that terminates at 100 m below the surface is not as spectacular as one that makes it to 7 kilometers. A lot more geoscience is associated with deeper boreholes as well, whilst logging or well testing is something that is rarely done in the shallow drilling business. But given the amount of energy produced from ground-source heating systems, it is still very useful to also look at these projects a bit more and learn about the role of the subsurface.

What I took away from the three conversations I had, was that the costs of drilling shallow boreholes in most countries are still relatively high for many homeowners to opt for ground-source heating. That is why there ▸

HOW THE IDEA OF GROUND-SOURCE HEATING CAME ABOUT

At first, people took up the idea of storing summer heat in a borehole, which was trialled near Stockholm. "However, in the light of the conductive nature of the rocks", Signhild continues, "the heat dissipated quickly. So that didn't work. Then, somebody came up with the idea that if the rocks could not be used as a heat store, they could instead be used as a heat source, with a heat pump on top. It was the start of the industry."

is such pressure on developing technology to make drilling faster, as all three people I talked to addressed.

The geology is also of great importance and not only drives the design of every system, it is also determining the way the boreholes are being drilled. A thermally conductive lithology means that shallower boreholes will do, and groundwater flow is another major factor influencing the design of loops.

"The potential for deep geothermal in Sweden is very limited, but the contrary is true for shallow geothermal"

Also, because the subsurface is essentially treated as a battery, the geological setting including the heat capacity needs to be integrated into the design of the building to prevent a long-term energy imbalance. As Edward Wiarda tells us during his interview (p 58), the energy transition is about the integration of above-ground as well as below-ground factors. The shallow geothermal space is a perfect example for that.

Despite the larger upfront costs, ground-source heat pumps tend to work longer and more economically than air-source heat pumps, so in the long run it pays off. All in all, with technology advancing and more pressure and incentives to source energy for domestic heating locally, I see a bright future for shallow geothermal. And let's not forget the statistics – shallow geothermal has already proven to be the most important player in the geothermal space!

SWEDEN

"The potential for deep geothermal in Sweden is very limited, but the contrary is true for shallow geothermal", says Signhild Gehlin from The Swedish Geoenergy Center. Signhild is one of the very few people who works full-time in the shallow geothermal space, and as the only employee of the Geoenergy Center she is probably the best person to talk to about this sector. She is also the editor of a magazine on geo-energy and provides courses for those wanting to enter the industry. As such, she is very aware of everything that is happening in Sweden when it comes to ground-source heating.

Why is Sweden a country that has such a high density of shallow geothermal boreholes? "Our geology, which mostly consists of old crystalline bedrock, is characterised by a high quartz content, which makes for good thermal conductors", says Signhild. That is a good starting point. "In addition,", she says, "Sweden has never had a gas network, so there has not been the competition with cheap gas as we tend to see in other countries."

But it still took an oil crisis to really make people aware of the fact that energy dependency is a critical thing. It was in the late 1970's and the decades after that shallow geothermal drilling gained in importance.

"And the costs of drilling have basically stayed the same over the last decades", says Signhild. "It is thanks to the upscaling of the sector, the innovations when it comes to drilling and thus the time in which we can complete a borehole that the costs have been able to stay relatively flat. When I started in 1995, I asked about the cost of drilling per meter: Around 20 €/m. Twenty years later it was still the same price!"

Most boreholes in Sweden are drilled using percussion hammer drilling. "That's what basement rocks are best for; you can drill very deep, and the borehole does not collapse either. We can now drill 300 m in a single day," Signhild adds, "which is more than deep enough for a single-family home."

INCREASED ENERGY EXTRACTION

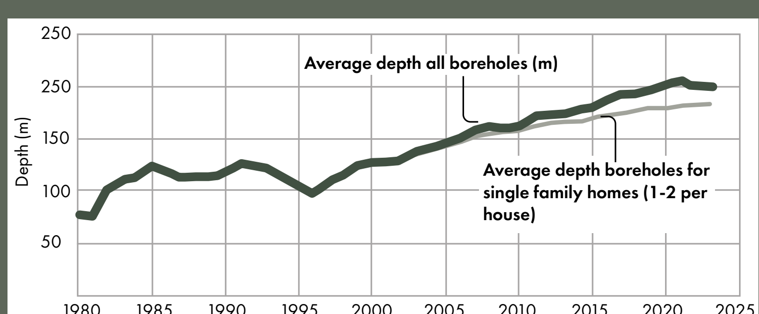
In some ways, Sweden is already in a second cycle of ground-source heating development, thanks to advances in heat pump technology. As the ability to extract energy from the geothermal loops has increased - a Co-efficient of Production (COP) of 2.5 was the norm back in the days; now many heat pumps will run on a COP of 4 - 5: Twice as much energy will be extracted from the ground", explains Signhild.

"This means if you take more energy from the ground, your boreholes will need to be deeper in order to recharge sufficiently", she continues. "That is why a shallow borehole of 100 m depth that was ok in 1995 won't do nowadays. In turn, this means you will need more or deeper boreholes to retrieve the same amount of energy from the borehole again as the heat pump extracted."

This has led to an odd development. "You can now buy a heat pump that is very high spec, but it has a button to says it works just like the old one!", laughs Signhild. "It is absolutely not the way to go if you'd like to benefit from your new machine. It is much better to drill a second borehole instead."

THE EXPENSIVE TOP HOLE

Drilling costs and the way projects are completed is clearly reflected in the graph below. The top line shows the average depth of all geothermal boreholes drilled in Sweden. The lower one, which indicates the wells drilled for single-family homes, starts to deviate from 2003, when single-borehole projects record a slightly lower average depth. "The reason for that", says Signhild, "is that the cost of drilling the top hole is four to five times as much as the rest of the hole, because of the casing required for the first few meters. That's why projects where multiple boreholes are needed, the preference is to drill fewer but deeper holes to prevent additional casing costs."



Average depth of all shallow geothermal boreholes drilled in Sweden (thick line) versus average depth of all boreholes drilled for singe family houses.

PHOTOGRAPHY PREVIOUS PAGE: ORNUNGA, SWEDEN; SOURCE: SWEDISH GEOENERGY CENTER

AUSTRALIA

"I only got into drilling because I could not get the drillers to the site when I wanted them to come. If there is a drought in Australia, they are all out drilling water wells, so I won't get them when I need to drill my geothermal holes", says Marcus Wearing-Smith when I talk to him from his home in Perth, Western Australia.

Marcus is the managing director of Direct Energy Australia. His company is specialized in the integration of geothermal systems with other renewable technologies to create net zero homes, carrying out both the entire design and installation. One of the unique things he does is directional drilling, such that from only a small pad, multiple boreholes can be drilling in various directions. This is especially useful when the available surface area is limited.

HOW IS THE MARKET?

"I've got four directional drilling rigs", says Marcus, "and I just had an inquiry from someone in Canada who is interested in buying one of them. It is a situation I have not seen for a while and ▸

"I only got into drilling because I could not get the drillers to the site when I wanted them to come.

PHOTOGRAPHY: ORNUNGA, SWEDEN

The most used type of bit for drilling shallow geothermal boreholes in Sweden: the hammer bit.

THE GEOLOGY DRIVES EVERYTHING

"The subsurface is extremely important", says Marcus, "with the combination of both the geology and groundwater(flow) determining productivity in terms of thermal heat transfer." It can vary around 45 W to 64 W per lineal meter of borehole, utilising a 32 mm thick pipe. We have achieved up to 100 W per lineal meter using hybrid systems and smart controls. These figures are taken from southern states with ground temperatures of 18 to 21 °C."

The Sydney sandstone is the highest-performing geothermal unit in Australia as it is a clean sand, and it is quite straightforward to hammer through. Melbourne is about half as productive because of the presence of more clay layers that are not as conductive. At the same time, Melbourne's climate needs more energy to heat in winter. That's why it is almost twice as costly to drill a geothermal loop of the same energy output in Melbourne than in Sydney.

"Unexpected subsurface conditions are every driller's worst enemy, such as cavities and excess water", continues Marcus. "Very hard rock can take a long time to drill, which also is an impediment. This is another reason why upscaling the market is key, because the more knowledge is gained on how to drill the local geology, the more efficient the process gets."

"We keep a record of the geology we drill through", says Marcus. "In general, we record the cuttings profiles and take photographs of the soil at 5 m intervals. This is for our own database."

is a testament to the market for these rigs heating up, at least in Canada."

Is the same happening in Australia though?

"I wouldn't say there is a strong demand; it is too early to conclude that the same is happening here in Australia", Marcus continues. "At the moment, the prices of geothermal heat pumps are still too high to really compete against air source heat pumps. The payback times can be around 20 years, which is generally considered too long for many people. That's why I think we need a massive upscaling, especially when it comes to geothermal heat pumps that allow for both heating and cooling. Until that arrives, the costs will remain prohibitive in many cases, especially when there is no government incentive."

At the same time, the focus on Net Zero by 2050 has put things into motion. "The major engineering firms are recognizing geothermal as an option, even though a lack of experience in these firms does restrict progress. It is key to do accurate upfront costing and design to understand the validity of the ground source," Marcus says. "There seems a tendency to overdesign systems, which can have a detrimental effect on the price tag."

"If they would have had geo-energy back in the Middle Ages, these loops would still be in operation today."

CANADA

As we saw earlier, the absence of a gas network in Sweden was instrumental in the rapid progress shallow geothermal made in that country, especially after the price hikes in the 1970's. However, in many other countries, gas distribution networks do exist, creating a very different starting point for the shallow geothermal sector.

"These gas distribution companies obviously see us as competitors", says Stan Reitsma, president of Geosource Energy in Toronto, Canada. "However,", he continues, "that there is now some growing interest from these companies, possibly because the scale at which shallow geothermal loops are now being implemented is starting to make a difference."

Stan got into the shallow geothermal business because of a natural interest in energy, and a growing awareness that hydrocarbon resources are finite. "As a kid, I went through the oil embargo in the 1970s, and the concept of resources being finite stuck with me", he said.

"In 2002, when conventional gas production peaked in the US, I decided it was time to start looking at other sources of energy and geothermal appeared on my radar. I also knew that air-source heat pumps were not always that great at the temperatures we sometimes experience here in Canada. That made me decide to go to geothermal and I bought a rig."

"It was all before shale gas started to kick in in the US, and by the time it was 2008, the gas price was indeed much higher than in 2002, so I thought I was on the right track", Stan continues. "Then the shale revolution changed the picture completely. It pushed gas prices back down, which was not of much help for us."

"All these loops do is to move some heat around"

"I still monitor gas prices closely and let's be honest, shale is also finite", he says. "There will be a point where the market will become a lot more buoyant for us. Saying that, recent history has also taught us that we cannot predict the market – there are so many unknows!"

But despite the unknowns, the fact is that shallow geothermal loops already have a close to 30 % market penetration in the Toronto area new builds currently. And because of that, developers are not so concerned about the reliability of these systems. "We don't get asked anymore how it works", Stan says," they just assume it does because there are so many that already do. It's becoming standard technology. We will probably never get to 100 % but 90 % is certainly possible by 2030."

TECHNOLOGY AND DRILLING COSTS

We already saw that drilling costs have remained stable in Sweden over the past decades. The same is true for Canada, and it is down to the same factors: More custom-made drilling rigs and faster drilling. "Back in the days", Stan says, "we thought we were rocking it when we did 200 feet per day, now we get frustrated if we don't do 600 feet."

"The biggest change we have seen unfolding is getting our loops into more spaces", Stan says. He especially alludes to the more crowded city centres, where retrofitting a building with ground-source heating can be a challenge. And like Australia, where Marcus is drilling boreholes at an angle, Stan is doing the same with Geosource Energy.

"Geosteering is the next thing for our sector", Stan continues. Taking advantage of the technology used in oil and gas, he thinks that within a year from now, his company will be able to drill at a 45° angle first, and then vertical from there. "Being able to exactly locate the bit will be a great advantage for this industry, especially in city centres where there will be competition for rock volume."

Another advantage of geosteering will be the prevention of boreholes accidently cross-cutting each other. Especially are hard rocks, such as the metamorphic rocks of New York, the trajectory of the drill string is rarely vertical even when it is supposed to be so. ■

The 240 Markland project, Toronto, Canada, is a retrofit of a 10-storey multi-residential building with angled boreholes. See how tight some of these boreholes are at surface.

PHOTOGRAPHY: GEOSOURCE ENERGY

INNOVATION IN DRILLING TECHNOLOGY

Marcus started with drilling vertical boreholes only, but he then experienced that some jobs were unable to support vertical loop geothermal systems due to a lack of ground area available.

The radial drilling concept has overcome some of the limitations of vertical drilling. "We have drilled in the basement of a high rise in inner city Melbourne whilst the building was under construction without impacting the construction timetable", Marcus says.

"Thanks to the radial drilling capability, we can place a drill chamber and drill up to 2,100 meters in a single spot. And as space is often restricted on many sites, we do prefer this way of drilling because it limits moving the rig around."

Geosource Energy rigs on Java Street, Brooklyn, New York. This 321-borehole project is the largest geothermal residential development in New York State.

PHOTOGRAPHY: GEOSOURCE ENERGY

RECORDING THE GEOLOGY

The way states deal with geothermal drilling activity is very different in North America. "Ontario does not require logging of boreholes, but in Newfoundland, we had to submit a geological report for all 350 holes boreholes we drilled on a single project", says Stan. In contrast, the city of New York does not require to administer anything, so there is no archive at all. At the same time, we found that Las Vegas had a lot of drilling records at hand, which is possibly a testament to their interest in water", Stan suggests.

ADDRESSING THE IMBALANCE

Shallow geothermal energy production can be compared with the use of a battery. As long as buildings are not too close and the loops are at a reasonable distance from each other, the battery will be able to recharge, whether you cool it or put heat in it. "However, in urban centres where boreholes will be competing for space, we need to think carefully about how to drill those loops and possibly coordinate with neighbours to make sure that there is no overloading happening", Stan says.

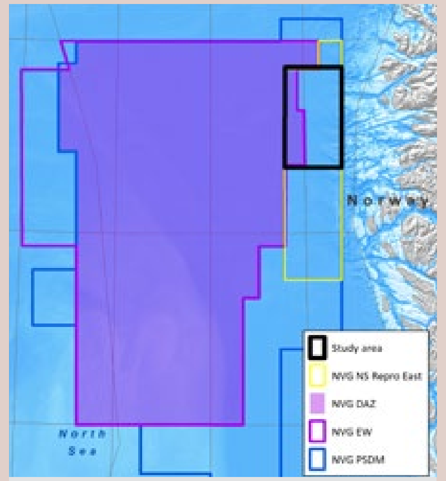
One thing that can be done to help solve the long-term imbalance of a system is to retrieve energy from the sewer system. "This is already happening in places", says Stan. Yet again, it shows that engineering and subsurface and construction go much more hand in hand in the geothermal energy space.

COVER STORY

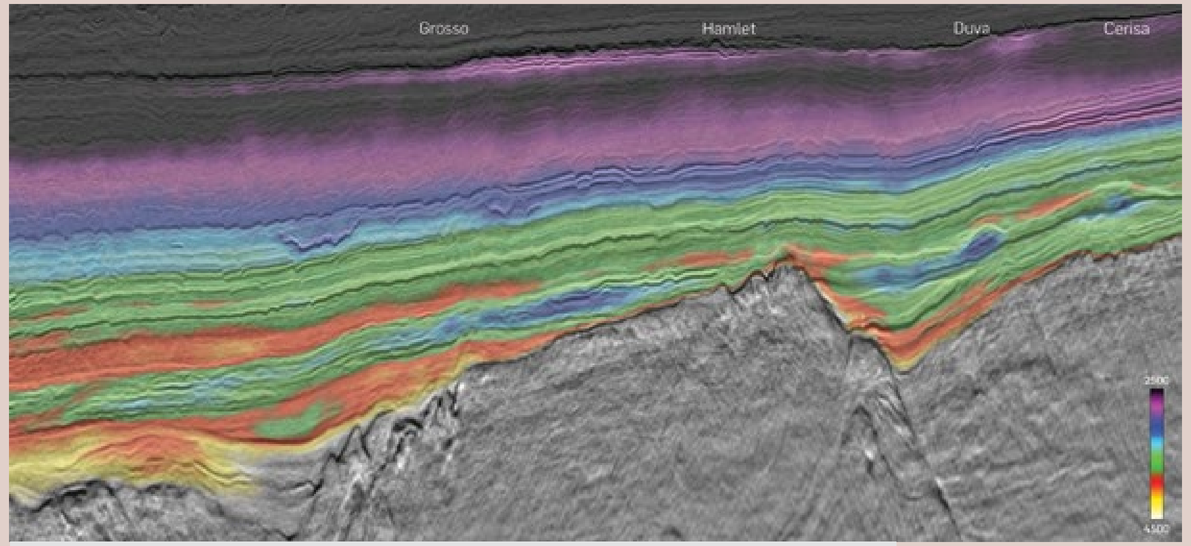
Norwegian North Sea: Identifying details of Lower Cretaceous sand fairways on the Måløy Slope

The composite seismic line is taken from the newly re-imaged 'Northern Viking Graben N-S East' dataset. The line passes through a number of wells on the Måløy Slope where the Agat Formation is relatively thick. These include the producing Duva Field, the new Hamlet discovery and the Cerisa prospect, which is currently being drilled (May 2024).

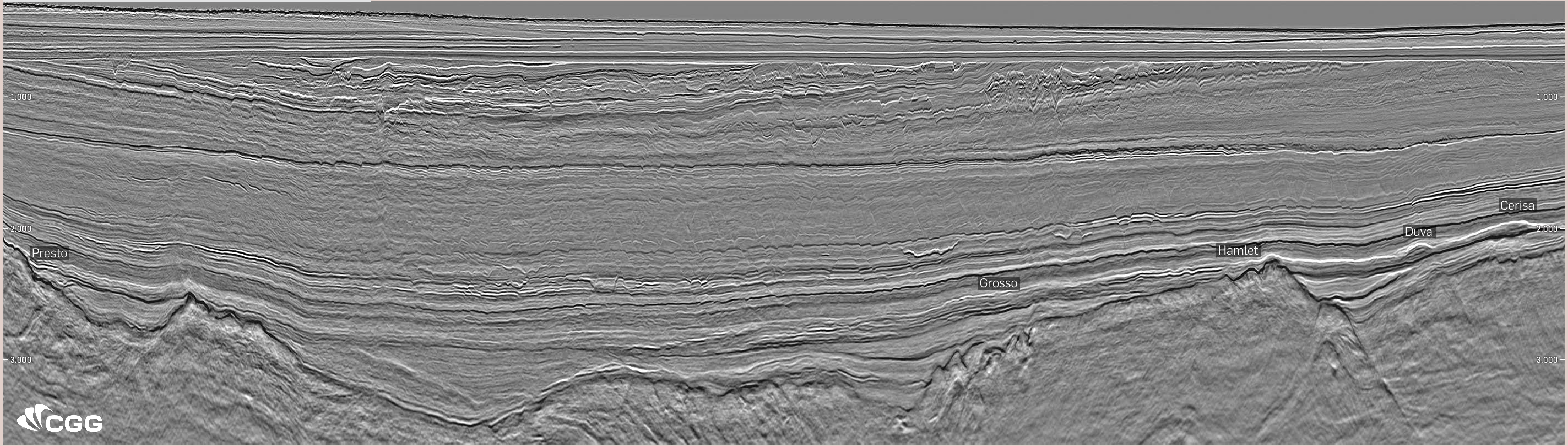
The northern North Sea is a highly active oil and gas exploration region, where several commercial discoveries have been made over recent years. The Lower Cretaceous sands within the Agat Formation represents an important reservoir play that has been targeted for decades. The quality and spatial distribution of the sand within the Agat Formation varies over the area, making it challenging to map the Agat play. This high-quality regional dataset is a valuable tool for interpretation and attribute generation to map out and correlate the different Agat sand packages and fairways.



Map showing location of CGG's Northern Viking Graben (NVG) datasets. Single-azimuth re-imaging was performed on the NVG data in the area outlined by the yellow polygon. The seismic section below is from within the black polygon.



TL-FWI velocities with frequencies up to 14 Hz, draped over the re-imaged 'Northern Viking Graben N-S East' dataset. Areas of low velocity can be seen throughout the Agat interval, especially at the Duva Field.



Imaging uplift overcomes mapping challenges of Lower Cretaceous Agat Play

CGG's re-imaged 3D seismic data set on the Måløy Slope brings a new understanding of the Agat sand fairway systems

IRINA PENE, SILJE ROGNE, JASWINDER MANN-KALIL AND MARIT STOKKE BAUCK, CGG

HYDROCARBON exploration targeting the Lower Cretaceous Agat sands began in 1980 after a serendipitous discovery by well 35/3-2. As a result, additional wells targeting the Agat Formation were drilled, but none of these were economic. This changed in 2016 when the Duva Field was discovered. Combined with the success of Neptune Energy's Hamlet and Ofelia discoveries in 2022, there has never been a greater need to understand the complexities of the deposition and distribution of the Agat sands.

To better understand the play extent and decrease risk, CGG re-imaged the eastern extent of the 3D Northern Viking Graben (NVG) seismic survey in 2023. The uplift in data quality, due to improved signal-to-noise and velocity model building, enables better mapping of the spatial distribution of the Lower Cretaceous units. We demonstrate that integrating high-quality regional seismic with well data and seismic attributes is best suited for describing the geometry, shape, and extent of the Agat sand deposits.

IDENTIFICATION OF THE AGAT SANDS

The Agat sands on the north-south trending Måløy slope were deposited during repeated turbidity currents in a prograding submarine system, from a narrow shelf in the east, to the deep marine basin in the west. Deposition was partly controlled by underlying north-south trending fault blocks and Jurassic east-west oriented canyons, which has resulted in variable sand thickness and quality.

This is further illustrated in Figure 1, where log data show a number of clean sand units, interbedded with siltstones and mudstones. We can identify sand units corresponding to a decrease in impedance which appears stronger where the sand is cleaner, as seen in well 36/1-3 (Figure 1b). By correlating the sand at the well locations with their seismic response, we can begin to map the sand units away from the wells, and then assess lateral and vertical heterogeneities and reservoir complexity.

MAPPING OF SAND FAIRWAYS

To map the different sand units in the basin, we need to understand the differences in the depositional geometry of the feeding systems. Figure 2 shows seismic sections across east-west feeding systems. We can observe how the thickness of the unit varies not only across the different systems but also within each fairway.

The detailed maps, shown in Figure 3, indicate individual Agat sand pulses. The isochore map of the Agat Formation in Figure 3a shows the thickness variations identified in Figure 2 but at a regional scale. We see strong differences in the presence of the Agat Formation, with its thickness ranging from absent, due to bypass and non-sediment deposition in the east, to more than 350 meters in the basins.

The RMS amplitude extraction of an intra-Agat horizon (Figure 3b) reveals distinct stratigraphic features. Several elongated and linear geometries observed can be interpreted as potential sediment fairways extending into the basin, marked with SF in Figures 2 and 3. The amplitude variation can be explained by the difference in sand content, with better-quality sands giving a strong amplitude response, as seen at the Duva discovery well in Figure 1a.

To support this further, the RGB colour blend in Figure 3c shows good correlation with the bright amplitude features identified on the RMS map. A combination of the two attributes highlights the intricacies of the fairways on the Måløy Slope.

SF1 passes through the Duva Field and Hamlet discovery, and the shape and orientation of the fairway imply multiple sedimentary input directions from the south and southeast. The amplitudes vary over the entire fairway. Brighter amplitudes seem to correlate with a sandy channel-like feature as seen at the location of the Duva discovery. Dimming of amplitudes in some areas can be explained by the sands pinching-out or by the presence of mud-filled channels, which tend to form a seal, as seen with the interbedded sandstones and mudstones in Figure 1. This can explain the lack of hydrocarbons in well 36/7-3 despite encountering good-quality sands.

SF2 is east-west oriented crossing the Ofelia discovery and the Grosso dry well. Input of sediments from the east would suggest the fairway being more sand-rich at Ofelia and in a more heterolithic part of the system at Grosso well, where the Agat Formation consists of thin sand-shale intercalations.

SF3 and SF4 are north-east-southwest oriented, suggesting sediment input from the northeast. These two fairways appear to contribute with sediment input in SF2, a possible explanation for the thicker Agat Formation encountered by the Grosso well, but no wells have penetrated the sediments inside SF3 and SF4 to confirm this.

UNLOCKING FURTHER POTENTIAL

Clearly, there are many feeder systems across the Måløy slope and here we show just one of the intra-Agat horizons. Further mapping of the Agat interval has the potential to reveal more complexities of the individual sand pulses. This, combined with leveraging additional insights from well data, can provide a full analysis of the provenance and depositional architecture of sand units and, thereby, the reservoir thickness and quality, offering the potential to further unlock the exploration potential of the Lower Cretaceous on the Måløy Slope.

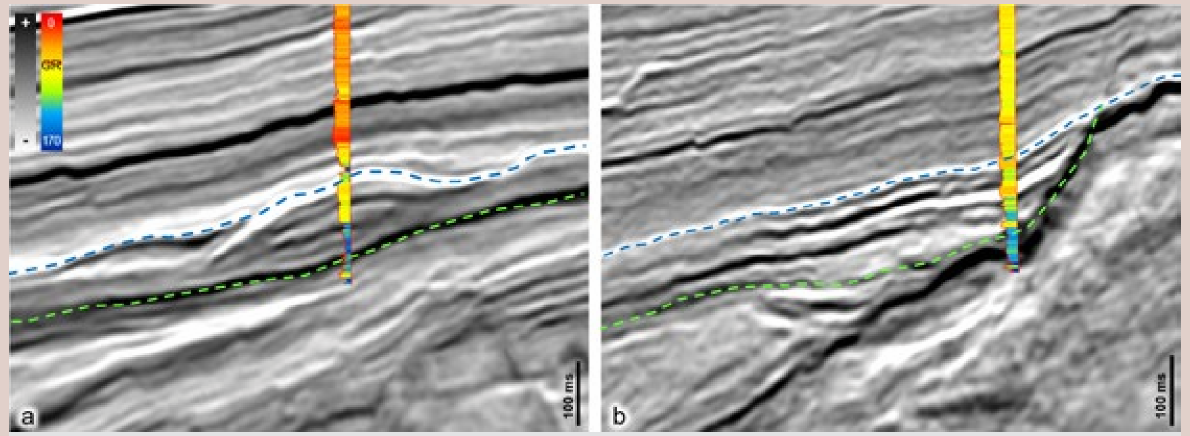


Figure 1: Seismic sections with the Gamma Ray log overlain through the 36/7-4 Duva discovery well (a) and the 36/1-3 Presto prospect well (b). The blue and green dashed lines represent the top and base of the Agat Formation, respectively.

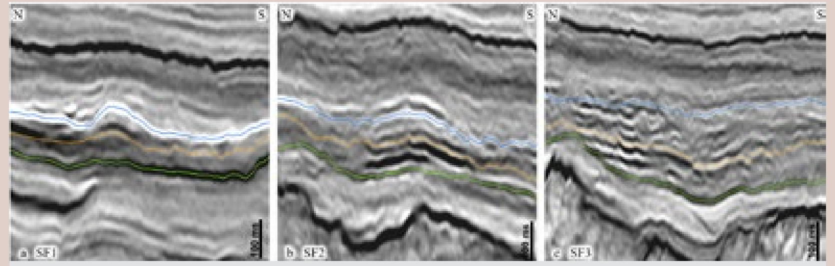


Figure 2: N-S oriented seismic sections through three different sediment fairways (SF1, SF2, SF3). The locations of the seismic lines are seen in Figure 3b. The blue and green lines represent the top and base of the Agat Formation, respectively. The orange line represents an intra-Agat surface used to extract the attribute maps displayed in Figure 3.

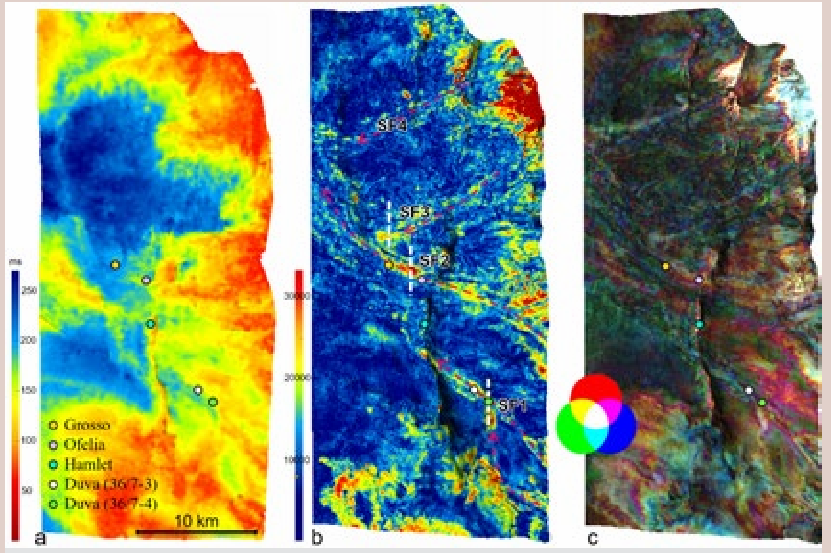


Figure 3: Isochore map of the Agat Formation (a). RMS attribute map at intra Agat (b). RGB-blend at intra Agat (c). The red, green and blue colors on (c) represent 10, 15 and 20 hertz respectively. The red dashed lines on (b) illustrate potential sand fairway systems. The white dashed lines on (b) are the locations of the seismic lines in Figure 2.

NORTHWEST EUROPE

"And this team worked up the geology of the field, which is situated along the northern margins of the Middle Jurassic Brent delta system, in such a way that the Dons even became one of the top producers across the entire UKCS for a while"

Peter Buchanan – former CEO of Valiant

"The best recipe for a business adventure to succeed is not to have a plan B"

Peter Buchanan and Phil Crookall reflect on Valiant's success in re-developing the Don field in the UK Northern North Sea

WOULD YOU re-mortgage your house to invest in an oilfield development because you simply believe in it? Yes, good on you. Would you still do it when a major says there is no future in it? There will probably not be many who would still go for that. But Peter Buchanan did, and he has never regretted it.

This short story is about the Dons, a cluster of oil compartments named West Don, Don SW and NE Don in the UK Northern North Sea.

Why was it a success? "We had a great team of people who were solely dedicated to this single field", says Peter when I spoke to him over the phone. "And this team worked up the geology of the field, which is situated along the northern margins of the Middle Jurassic Brent delta system, in such a way that the Dons even became one of the top producers across the entire UKCS for a while."

But how did this opportunity arise? It started at a time when the UK government realized that something needed to be done about marginal fields, around 2005. Before infrastructure would go, it was time to get satellites developed. BP put forward the Dons. It ended up in the hands of First Oil, Petrofac and RBS – the bank where Peter worked at the time. But even though RBS was interested in financing oil and gas developments, it was not keen to have an operating share.

"That's why RBS wanted out, but I had seen the opportunity", says Peter. "It was at that time that I decided to leave RBS, remortgage my house, and buy the RBS share in the Dons." That was the start of the company Valiant.

And even though Valiant was not the operator of the field - that was Petrofac which later became Enquest - it was the team in Valiant that did the subsurface legwork to plan the wells. "It is a simple thing", Peter says, "when you have got a dedicated team working on a single project, and there is a real push to make it a success, you've got the incentive to do so. It is a good thing not to have a plan B."

Phil Crookall, who was the Technical Director at the time, adds: "The field size was too small for BP, it was just not part of their main portfolio and they never put a dedicated team to it in the same way as we did."

"As an example", Phil said, "we had identified a fault panel in the field that had previously been interpreted by BP as being a downfaulted block. Our geophysicist, after careful examination, was convinced it was an upthrown block. So, you can imagine the excitement when the well came in to prognosis. It became one of the best producers of the field and you can imagine the upside that fault block brought with it."

Ultimately the Don area produced more than 50 million barrels of oil before being successfully decommissioned, with the originally envisioned field extents being added to with some near field extensions.

Is there room for another Don adventure in the North Sea? "I haven't been in Aberdeen since 2012", says Peter, "but it must have changed a lot since." That is certainly true. ■

Henk Kombrink

Exploring for gas - for the first time

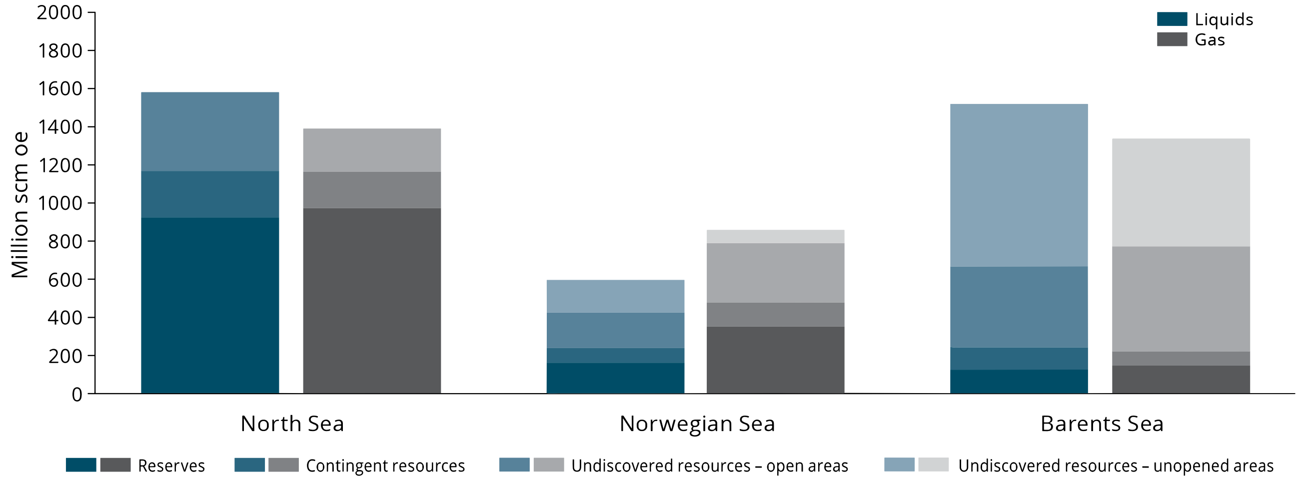
Three companies are joining forces to solve one of the Barents Sea's biggest challenges – limited export capacity for gas. And to justify investment in new capacity, they have set out to find new gas resources

"WE HAVE practically never looked for gas in the Barents Sea. All exploration wells have had oil as their target, and all discoveries of gas have been accidental", said Dag Mustad, Asset Manager at Aker BP when he gave a lecture during the conference NCS Exploration - Recent Discoveries at Fornebu in May.

Snøhvit is the only gas field in operation in the Barents Sea, but the Goliat, Johan Castberg and Wisting oil fields also have associated gas volumes. Goliat is in operation, Johan Castberg is scheduled to start extraction in the fourth quarter of 2024, and Wisting could be the next major development.

The partners behind the major oil discovery are working towards an investment decision by the end of 2026.

With the exception of Snøhvit, the gas resources that have so far been proven in the Barents Sea are considered worthless. The reason is the lack of export infrastructure; there is ►



The Norwegian Offshore Directorate expects large undiscovered gas (and oil) resources in the Barents Sea. Many of these are admittedly located in the northern Barents Sea, which is not open to petroleum activities.

only one pipeline in the Barents Sea and it runs from Snøhvit to the Hammerfest LNG plant on Melkøya. From the plant, gas is exported as LNG.

It is expected that the gas from Snøhvit alone will cover the LNG plant's capacity until 2040. If the Goliat partners proceed with plans for a gas pipeline from the Goliat field, the capacity may remain full for a few more years.

Mustad explained that the current limitations in gas capacity not only contribute to turning existing gas discoveries into stranded assets – a lack of infrastructure also deters companies from looking for gas.

Today's situation represents poor resource management, especially when realising that the Norwegian Offshore Directorate (NOD) earmarked the Barents Sea as the area where half of the undiscovered gas resources on the Norwegian continental shelf reside.

EXPLORATION FOR GAS TO START IN 2025/2026

The obvious solution to the problem is to increase export capacity, and although this has been discussed over several years, little has been done. Until recently.

"In 2023, the industry was challenged by Energy Minister Terje Aasland to start looking for gas, and also work on developing a solution for increased export capacity", Mustad said.

This was perhaps the necessary nudge that the companies needed. They had been stuck in a chicken-or-the-egg situation. The solution will be to work on the challenges in parallel.

"For the first time, we will start looking for gas", Mustad stated. The Aker BP representative was able to say that the largest players in the Barents Sea have now joined together in a trilateral collaboration where the aim is to discover new gas resources to justify potential future investments in increased export capacity. The three companies are Equinor, Vår Energi and Aker BP.

During the APA (allocation in predefined areas) round in 2023, the three companies collaborated to secure new exploration permits in the Barents Sea, and they now collectively hold four licenses that focus on areas prospective for gas.

Mustad expects that the companies will start drilling in 2025 or 2026. In autumn 2023, Vår Energi announced that together with Equinor they had secured a drilling rig earmarked for drilling in the Barents Sea in the period 2024 – 2026. The agreement included an option for another three years, such that exploratory drilling can continue until 2029.

REQUIRES TIME

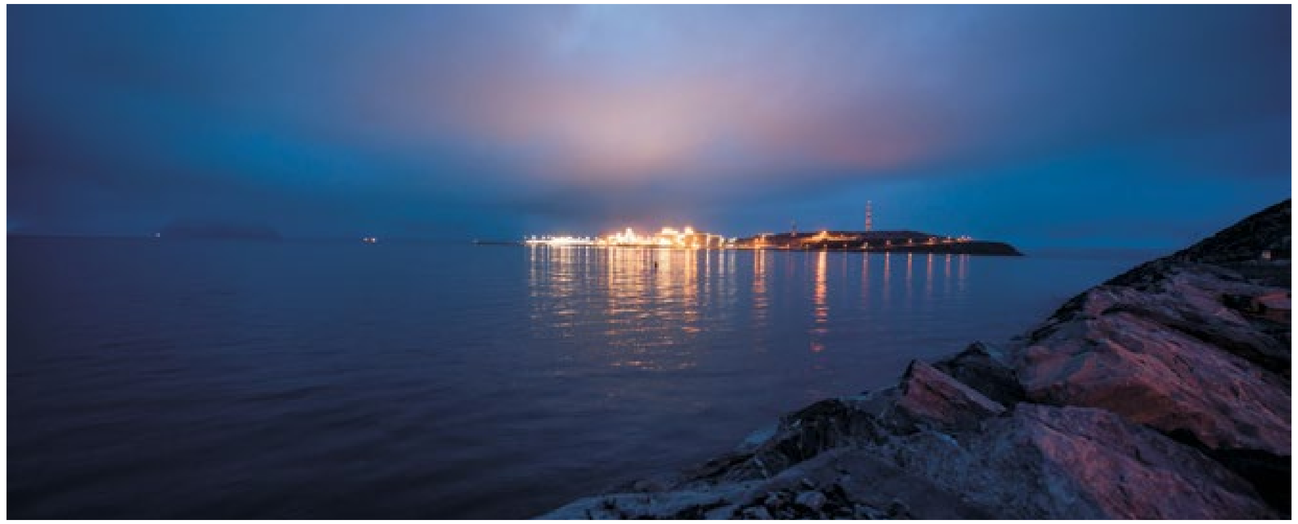
It is an ambitious goal that the companies have set themselves. Because they must find large gas resources to enable the development of transport infrastructure.

Mustad also emphasized that distance to infrastructure is crucial for profitability – new gas discoveries should be made near developed fields or upcoming developments. The Lupa gas discovery, made by Vår Energi and partner Aker BP in 2022, is a good example in this respect.

The occurrence was detected on the Finnmark platform and was the largest discovery on the NCS in 2022 with 57 – 132 million barrels of oil equivalent.

Mustad could not give a concrete figure on how many discoveries must be made and what the minimum size should be, but he was clear that today's known gas resources are far from sufficient. "We must therefore find more "Lupas" in the coming years", he said. ■

Ronny Setså

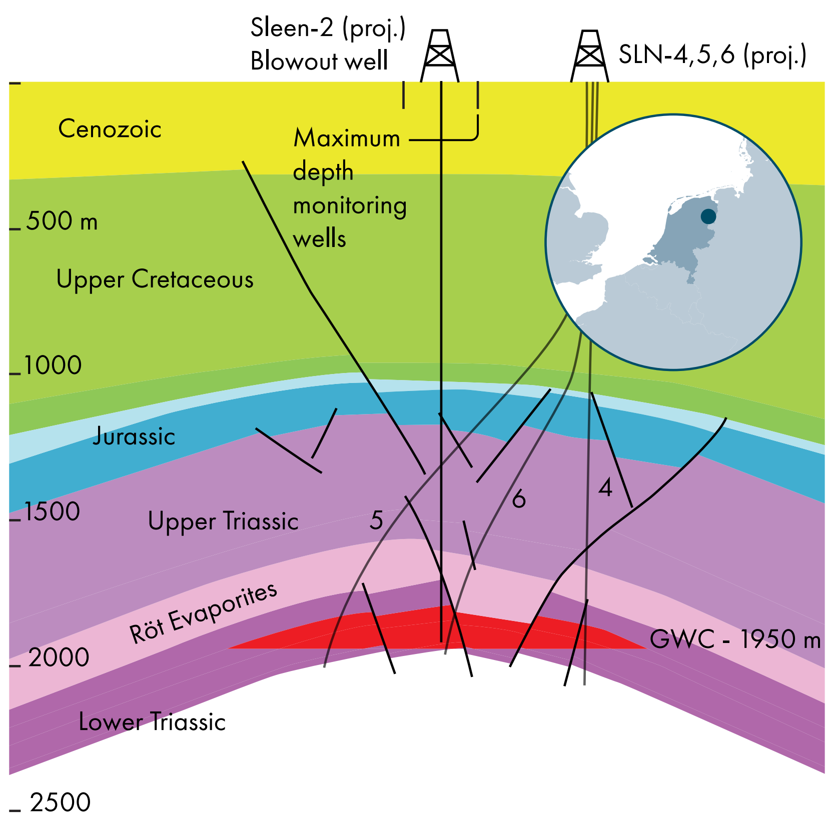


The Hammerfest LNG plant receives natural gas from Snøhvit and operates at full capacity. If Norway is to extract more gas from the Barents Sea, export capacity must therefore be increased. The most economical solution is considered to be a pipeline that can be connected to Polarled in the Norwegian Sea.

SOURCE: NOD'S RESOURCE REPORT 2023; PHOTOGRAPHY: OLE JØRGEN BRATLAND, EQUINOR

The gas blowout that continues to have an effect even after almost 60 years

Researchers show that methane leakage from a Triassic reservoir in the Netherlands is still taking place following a blowout that made the entire rig disappear



Cross-section through the Sleen field illustrating the closure and the depth of the monitoring wells. Redrawn after a cross-section published by NAM.

THE DISCOVERY of the Groningen gas field in 1959 led to a flurry of drilling activity in the Netherlands and surrounding countries in a quest for more gas. It is therefore not a surprise that a few things went wrong. And something did go wrong near the village of Sleen in the northern part of the country in 1965. Whilst drilling well SLN-02, operator NAM experienced sudden well control issues at a depth of 1,944 m after hitting overpressured gas. Soon after this happened, a crater formed a few tens of meters away from the rig where gas started to escape. Within an hour, many similar eruptions appeared within a 350 m radius from the well only to form a large crater shortly after in which the entire rig eventually disappeared.

A relief well was drilled approximately 600 m to the northwest of the initial well, which successfully connected to the SLN-02 well at a depth of 1,924 m. Only after pumping 390 tonnes of cement into the well, the release of methane eventually ceased. But did it cease completely?

STILL ONGOING

Even though this all happened almost six decades ago, the effects of the blowout continue to manifest themselves until today, a team of researchers wrote in PNAS in 2017. Based on measurements performed using a network of groundwater monitoring wells, the researchers demonstrated that methane concentrations are highest in the monitoring well that is situated closest to the blowout site - 43.8 mg/L.

This methane concentration was not abnormally high, however. Naturally occurring concentrations of up to 100 mg/L have been shown in groundwater in the Netherlands. That's why another methodology had to be applied to link the local peak in methane concentration to the gas field deeper down. This was subsequently shown by isotopic analysis, which suggested a thermogenic origin of the gas.

On that basis, the researchers concluded that after all these years and the injection of a lot of cement in the relief well, gas is still leaking from the Triassic reservoir at a depth of around 1,900 m and is making its way all the way up. But is it making its way to the atmosphere?

Visually recognizable methane seepage at surface was not observed by the researchers. The explanation for that is anoxic oxidation of the methane, coupled to the reduction of iron and manganese. The shallow subsurface therefore forms a natural buffer, limited by the availability of iron and manganese oxides.

In summary, the study cited here clearly shows that once the subsurface has been disturbed in a way as took place in Sleen in 1965, a long period of fluid leakage is to be expected even when the reservoir is kilometers deep. ■

Henk Kombrink

FEATURES

"We now have an effective approach for early identification of oil in a prospect, based on Swi values calculated from seismic velocities..."

Martin Essenfeld and Rafael Sandrea

How careful core description and detailed biostratigraphic analysis can delineate sub-seismic reservoir zones in a highly mud-prone system

A multi-disciplinary, multi-well appraisal of reservoir development in the mid-Cretaceous, offshore mid-Norway

JOHN CATER, PETROSTRAT

This study was undertaken by PetroStrat staff in collaboration with Stratum AS (QEMSCAN), Barnwell Parker Geoscience Limited (seismic interpretation) and HM Research Associates (heavy mineral provenance analysis). Together, we have completed a year-long multi-client appraisal of approximately 765 m of mid-Cretaceous core in 20 study wells across the Halten and Dønna Terraces, to quantify and map reservoir presence and reservoir quality in deep-water Aptian to Coniacian sediments.

Sand fairways were mapped within a high-resolution biostratigraphic framework, based on new analysis of 625 samples from 29 wells, refining existing NOD/Diskos-sourced paper data to generate PetroStrat 'K-sequences'. The latter range from the late Aptian K24 sequence through 10+ Turonian K40-K58 time slices, to early, middle and late Coniacian K60, K62 and K64 sequences.

Subsidence patterns, guided by seismic interpretation commissioned for the study and isopach mapping of individual time slices, reveal the development of local depocenters and unconformities as the area extended and subsided through mid-Cretaceous times. Sand fairway provenance was constrained by heavy mineral analysis, QEMSCAN data, conventional petrographic analysis and detailed records of biostratigraphic reworking. Fairway mapping was constrained by process-based sedimentological analysis of core.

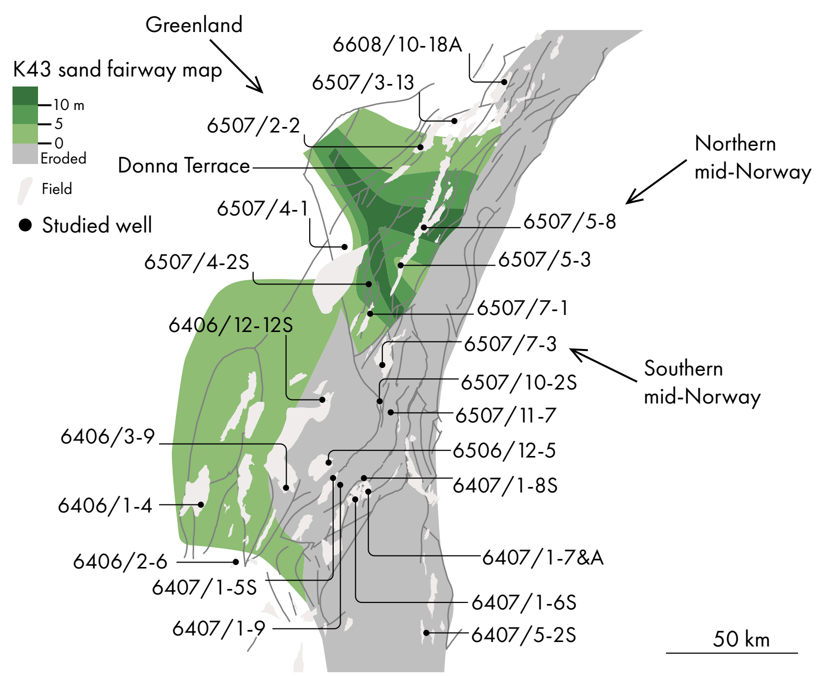


Figure 1: Example time slice of the K43 sand fairway.

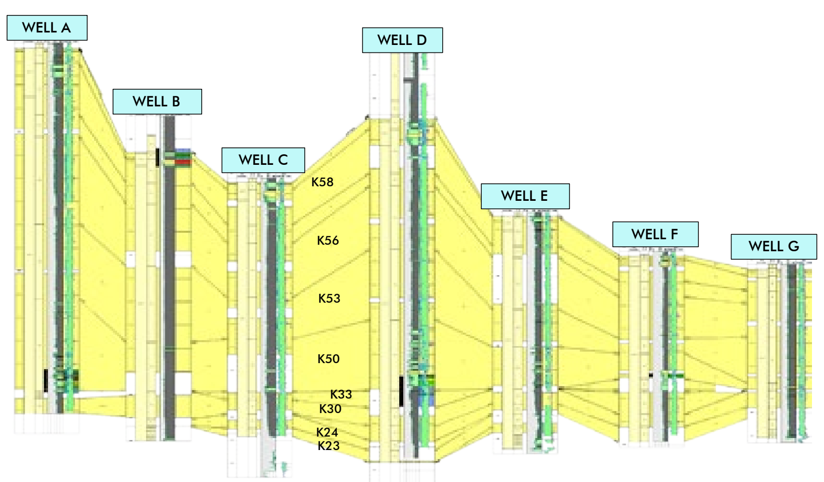


Figure 2: Erosion of earlier Cretaceous time-slices to the south and east of the K43 fairway resulted in a major unconformity, illustrated by this correlation panel that shows a separation of K33 (mid-Albian) from K50 (early Turonian) sediments, with the Cenomanian Stage missing.

NARROW FAIRWAYS

The thicknesses of clean to slightly silty sandstone within each time-slice define 'optimal' sand fairways, which were hand-contoured between wells, guided by seismic data. The system is sand-poor, with accumulated thicknesses of less than 10 m of 'optimal' sand present in any one time slice. Only five of the time slices encountered in the analysed wells contain metre-scale 'clean' sand accumulations. Fairways in the other time slices happen not to include 'optimal' sand in the analysed wells. The fairways are narrow, bounded by sea-floor highs, and are generally below seismic resolution.

Gravity-driven sands were deposited mainly within subsiding zones between active tectonic highs. These highs were generally elongated parallel to the Dønna Terrace trend (SW-NE), but the influence of cross-cutting NW-SE trending lineaments (e.g., the Gleipne and Jan Mayen Fracture Zones) is evident on the isopach map of one example time slice (Figure 1). Sand provenance data suggest dominant sand supply was from Greenland at that time, with northern Norway also supplying sediment in this and other time slices. Southern mid-Norway was apparently not a common source of sediment. Biostratigraphic data record reworking of Palaeozoic to Cretaceous sediments into many of the fairways, consistent with sand supply via river systems draining areas of complex palaeo-geology.

A MAJOR UNCONFORMITY

Erosion of earlier Cretaceous time-slices to the south and east of the K43 fairway resulted in a major unconformity, illustrated by the correlation panel in Figure 2, separating K33 (mid-Albian) from K50 (early Turonian) sediments, with the Cenomanian Stage missing. In the Egyptian Vulture (6407/1-9) well, the highly bioturbated Albian marls are reddened below the unconformity and are overlain by softer, dark grey, weakly bioturbated shales that were deposited in a poorly circulated intra-shelf basin after the collapse of the eroded uplift.

Turbidite sands overlying this hiatus accumulated in a subsiding mini-basin, within weakly confined channel systems that were supplied by hyperpycnal, sustained flows (Figure 3). Multi-metre thickness of sustained flow deposits suggests the input of large volumes of sediment in single flood events, likely from major river systems (rather than by erosion of local islands). Debrites intercalated with the turbidites comprise large clasts of weakly lithified mud and sand floating in a 'starry night' matrix of poorly-sorted sand and mud; these are interpreted to record bank collapse events that reworked poorly-consolidated sediment into the channels, together with remobilisation of sediments from the margins of the mini-basins shortly after their initial deposition.

The dominant turbidite sandstones are replaced locally (mainly across the Dønna Terrace) by the deposits of episodic tractional flows, loosely termed 'contourites' in this study (although their flow orientation is uncertain in the absence of image log data).

CONTOURITE FACIES

Figure 4 illustrates the range of 'contourite' facies encountered. These ▸

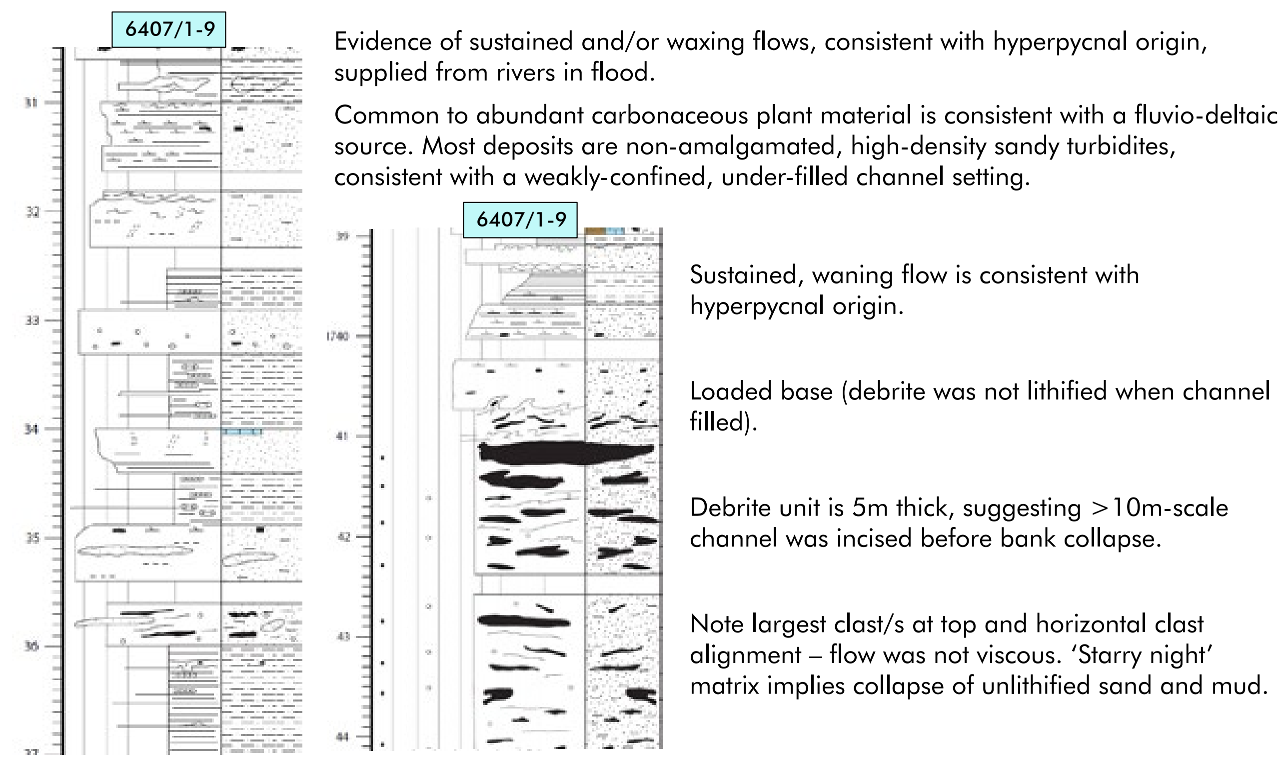
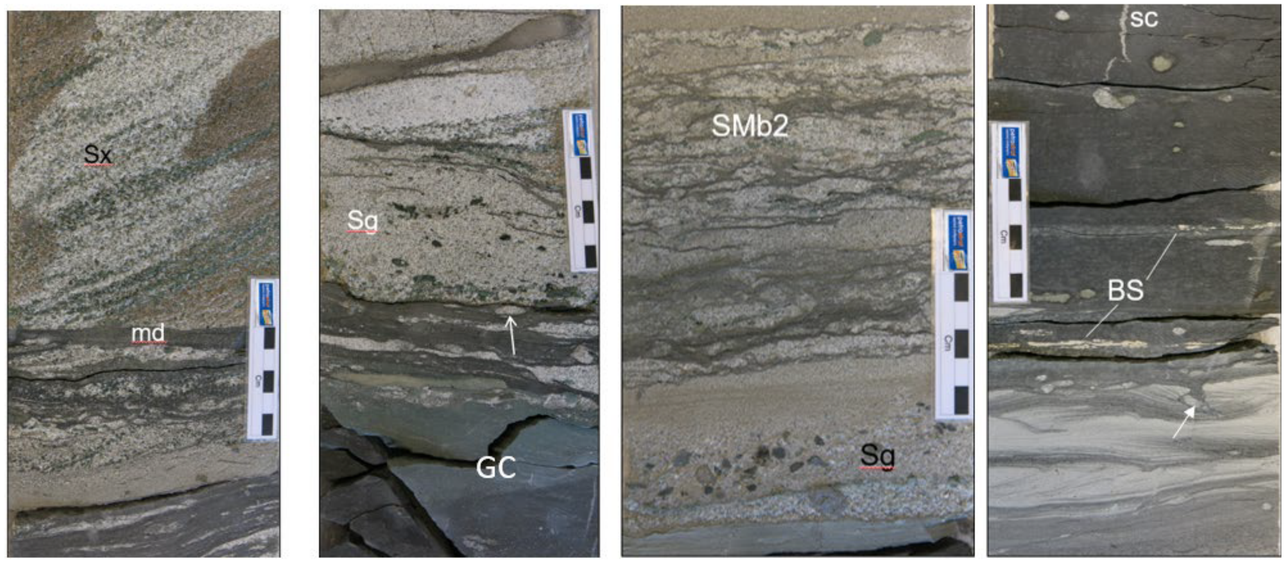


Figure 3: Turbidite sands accumulated in a subsiding mini-basin show evidence of weakly confined channel systems that were supplied by hyperpycnal, sustained flows.



Sx = cross-bedded clean sand (note common green mud grains); md = mud drape (recording episodic hiatuses, with time for minor colonisation by sand-filled burrows, arrowed); Sg = clean sand with green mud granules and pebbles; GC = green, chloritic clay formed on the seafloor; SMb2 = highly bioturbated sandstone; sc = synaeresis crack (suggesting fluctuating salinity); BS = broken shells; fractured firmground surface is arrowed.

Figure 4: Bottom-current facies; Lysing Member in well 6507/5-8, Ærfugl.

sandstones can be highly permeable and are generally somewhat coarser grained and better sorted than the associated turbidites, perhaps due to winnowing of the latter on the seafloor before they were consolidated. Green, chloritic grains, granules and pebbles of mud are common in these sandstones, evidently having been reworked from seafloor muds. The latter appear to have been formed by seafloor alteration of originally grey, smectitic muds and ash-falls that were then eroded by the contour currents.

Episodic tractional flows, transporting dunes or mega-ripples of medium and coarse sand across the seafloor, were punctuated by accumulation of grey mud drapes that were then colonised by sand-filled Planolites and Sabularia burrows, together with common muddy Arenicolites and local Zoophycos. The prolonged hiatuses recorded by this colonisation suggests highly episodic contour current activity, perhaps modulated by storms or tides and focused between seafloor highs.

The reservoir quality of these sandstones is mainly a function of their grain size and grain composition, with ductile materials (mainly mica, mudstone grains and detrital clay) enhancing the impact of deep burial compaction. Post-compactional cementation is less important, particularly in shallower wells. The contourite sandstones, representing winnowed turbidite deposits, tend to be coarser grained, better sorted and less ductile-rich than their predecessor facies (although ductile mud grains can be common – as seen in Figure 4 - and are associated with later calcite cements).

The impact of thin contourite beds on the reservoir performance of the dominant turbidite systems is cryptic, since some beds are highly permeable 'thief' zones whereas others form pervasively-cemented baffles to fluid flow.

One driver for this study was to assess the potential impact of local erosion of clean sand from uplifted Garn Formation intervals, forming high-permeability turbidite systems (e.g. in the area around Dvalin North, Block 6507/7). The cored examples of this play type comprise multi-Darcy Lysing Member sandstones deposited on eroded Garn highs. The Lysing units (probably of mid-Coniacian, K62 age) are submarine fan-delta deposits containing large clasts of mud, coal and sand reworked from the nearby mid-Jurassic hinterland. Muddy K62 facies in the surrounding wells suggest these high-quality sands are of limited extent, probably forming small footwall turbidite systems attached to active highs. More extensive deposits can be expected in hanging-wall systems of similar age.

DELINEATING SUB-SEISMIC RESERVOIR ZONES

This study shows how careful core description and detailed biostratigraphic analysis can delineate sub-seismic reservoir zones in a highly mud-prone system. The application and integration of heavy mineral analysis, QEMSCAN data and biostratigraphic reworking signals is clearly vital to understanding the transport directions of the sand fairways, with process-based sedimentology of cored intervals indicating the types and thus geometries of the geobodies. ■

Using seismic velocity to derisk oil exploration

An effective approach for early identification of oil in a prospect, based on initial water saturation values calculated from seismic velocities

MARTIN ESSENFELD AND RAFAEL SANDREA

In a recent GEO EXPRO article, we developed a field-based approach to identify natural gas prospects directly from seismic surveys. The gas fields are straight up. If the p-wave velocities (Vp) calculated from the seismic are below 11,000 ft/s, gas is the option. Reservoir fluid saturated rock Vp values greater than this gas threshold indicate liquids, oil or water, both of which have similar Vp values. The explorationist's enigma is how to distinguish the ones that contain oil.

The purpose of this study is to develop a method that could identify an oil prospect directly from the seismic. Our approach is to determine the rock's water saturation by analyzing the behaviour of 20 major oil fields around the world. Water saturation is an important reservoir parameter that determines reserves and well productivities.

Morris and Biggs (1967) developed the following proven equation that relates permeability (k), porosity (Ø) and irreducible water saturation in sandstones.

$$Swirr = C \times Ø^3 / k^{1/2}$$

C is a constant whose value depends on the density of the hydrocarbons in the formation. C is 250 for medium gravity oils, and C = 79 for dry gas at shallow depths. The irreducible water saturation, Swirr, is a laboratory-obtained value calculated from capillary pressure data on cores; its value is normally less than the reservoir's initial water saturation, Swi, when the field is first discovered. Swi is also known as connate water saturation and is the value used to calculate the STOIP of oil fields. Figure 1 shows the above algorithm as a graphical expression for oil fields.

We expanded the database of Morris and Biggs´ work, using laboratory data obtained from a number of giants and world-class oil-producing fields, concentrating in the usual producing sandstone range of porosities (10 - 35 %), irreducible water saturations (0 - 35 %), and the corresponding range of absolute permeabilities (10 - 2,000 mD).

As part of the same project, a comprehensive review of the permeability–porosity–water saturation data was undertaken to determine the relationship of the pore size distribution to the resulting permeability values. The result of this 'expanded' database in the range of values of interest for producing sandstones and shaly sandstones is shown in Figure 1.

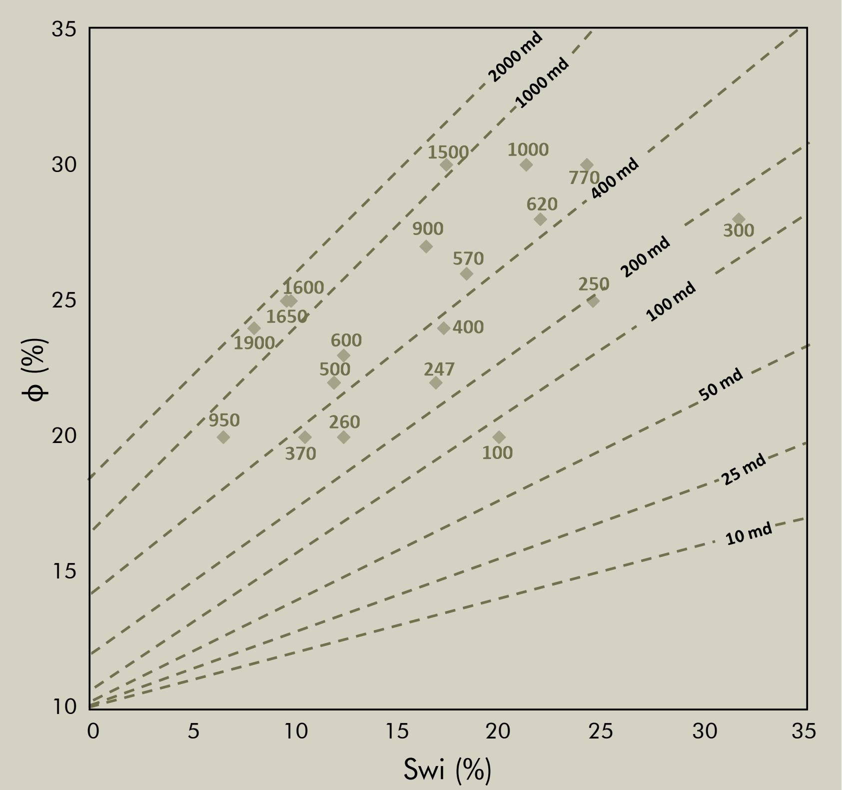


Figure 1: Expression of the equation mentioned in the text with oil fields in this study.

MECHANISTIC REVIEW FOR THE LEAP FROM SWIRR TO SWI

As part of the in-depth review, three major aspects were reviewed to 'scale' the Morris and Biggs approach (laboratory core data) to the physical conditions in oil reservoirs when they are first discovered and after development. The three aspects reviewed extensively were; the difference in linear pressure gradients overcoming the capillary forces, the difference in time-scale, and finally mercury displacing water in the lab versus migrating oil displacing water from a sand originally 100 % saturated by water until the 'reduced' water saturation values we find today – Swi.

After these three considerations, there is no doubt that the k–Ø–Swirr laboratory concept can be scaled to the oilfields as we now find them, where Swi is the result from the migration into the trap, under the real geologic and timeframe conditions. It should be no surprise that Swi must be higher than Swirr, as the latter would be obtained in the laboratory. Therefore, for this project, and from here onwards, we shift to the approach where Swi ▸

Field, Disc. Yr., Country	Age	Depth TVD (ft)	Net Thick (ft)	Ø %	k (mD)	Pg (psi/ft)	Swi %
Thunder Horse, 1999, USA	Miocene	27000	520	20	370	0.72	10.5
Prudhoe Bay, 1967, USA	Triassic	8800	500	22	500	0.49	11.9
Hibernia, 1979, Canadá	Cretaceous	11900	450	20	950	0.44	6.5
Safaniya, 1951, Saudi Arabia	Cretaceous	5100	136	26	570	0.45	18.4
Burgan, 1938, Kuwait	Cretaceous	5900	100	25	1600	0.65	9.8
Kirkuk, 1927, Iraq	Oligocene	2600	1000	20	100	0.42	20.0
Girassol, 1996, Angola	Oligocene	9400	360	30	1000	0.43	21.3
Bonga, 1996, Nigeria	Miocene	8640	110	30	770	0.44	24.3
Agbami, 1998, Nigeria	Miocene	11100	470	25	1650	0.43	9.6
Forties, 1970, North Sea	Paleocene	7000	830	24	400	0.46	17.3
ACG, 1958, Caspian Sea	Pliocene	11980	150	22	500	0.53	11.9
Lula, 2006, Brazil	Cretaceous	24600	1040	20	260	0.46	12.4
Marlim, 1985, Brazil	Oligocene	15060	560	30	1500	0.53	17.4
Chayvo, 1979, Russia	Miocene	7400	490	22	247	0.44	16.9
Daqing, 1959, China	Cretaceous	2600	400	25	250	0.44	24.6
Minas, 1944, Indonesia	Miocene	2340	438	27	900	0.42	16.4
El Furrial, 1986, Venezuela	Oiligocene	14770	905	23	600	0.74	12.4
Lama, 1957, Venezuela	Eocene	9300	700	28	300	0.45	31.7
Guafita, 1984, Venezuela	Mio-Oligocene	6000	90	28	620	0.45	22.0
Valdivia, 1949, Colombia	Pennsylvanian	4500	230	24	1900	0.37	8.0

Table 1: Geologic and reservoir attributes of sandstone oil fields in this study.

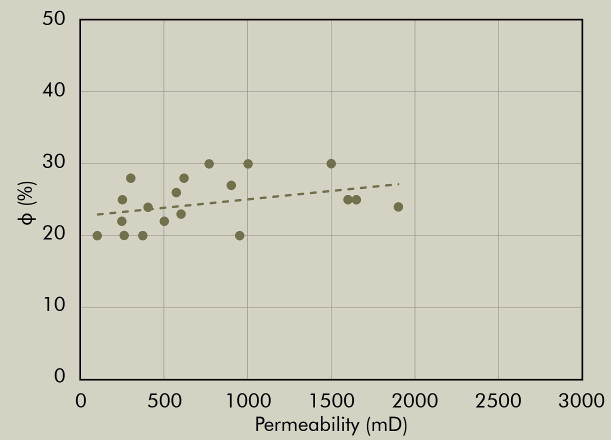


Figure 2: Porosity vs Permeability for oil fields in this study.

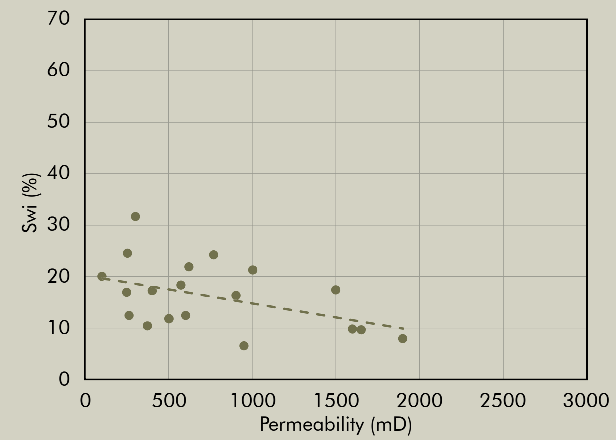


Figure 3: Swi vs Permeability for oil fields in this study.

in today's oil reservoirs substitutes the Swirr concept.

As a next step, the above-mentioned equation was used to calculate the 'Swirr' values – now corresponding to Swi at initial field conditions – for the 20 giant and world-class sandstone oil fields of this study, using their listed average reservoir porosity and permeability values. These field values, with their permeabilities highlighted, are displayed as orange dots in Figure 1 and are listed in Table 1, which also includes other relevant geologic and reservoir attributes of the selected fields. The Swi values range from 6 to 32 %, in the typical range for most oil reservoirs that extend to 37 %. We can safely assume that Swi values below a conservative level of 40 % would be comparable to oil-saturated reservoir rocks.

Let us now look at a 2D plot of the parameters in the studied equation. Figure 2 shows a strong correlation between permeability and porosity for the oil fields in this study. Figure 3 shows the relationship between Swi and permeability for the oil fields in this study. As expected, the lower the permeability the higher the initial water saturation. Work by Amado provides a similar correlation for oil fields with a wide range of Swi and permeability values corresponding to Mid Miocene and Lower Pliocene sands in the deepwater Gulf of Mexico (GOM).

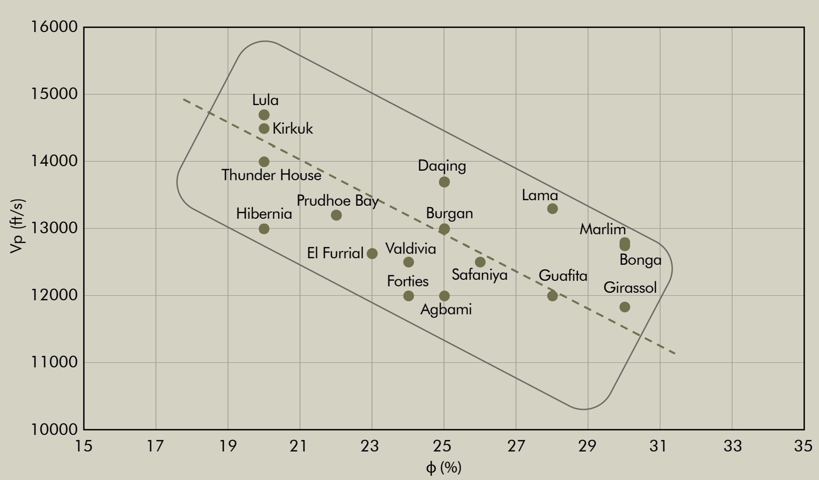


Figure 4: Vp vs Porosity correlation for oil fields in this study. If your Vp falls in the rectangular box shown here, your chances of hitting black gold are very high.

The GOM trend also indicates a similar Swi threshold – below 40 % – for the majority of its oil reservoirs.

ESTIMATING SWI WITH SEISMIC DATA

The Morris and Biggs algorithm has been demonstrated to be a suitable model to determine Swi, which is the key factor to determine oil in a reservoir rock. The model requires two parameters: Permeability and porosity. The Vp–porosity relationship is distinct, as demonstrated by Schon's correlation for 75 shaly sandstone cores of varying clay content. The porosity values obtained from this correlation then yield corresponding permeability values using Figure 4. Therefore, all of the requirements for an estimate of Swi for the prospect are now in place: It all begins with a reliable Vp value from the seismic (Figure 4).

On that basis, we now have an effective approach for early identification of oil in a prospect, based on Swi values calculated from seismic velocities. Swi values of less than 40 % are indicative of oil. It reduces drilling risk, which is advantageous for costly offshore drilling, and it is a great tool to fill the simulator as the new discovery is being appraised and developed.

ACKNOWLEDGMENT

We recognize the support received from Yeni Ferreira in handling and processing the data. ■

Returning exploration to Sri Lanka

An opportunity solving a crisis

THOMAS L. DAVIS AND AMILA SANDARUWAN RATNAYAKE

SRI LANKA is enduring the worst economic crisis since its independence in 1948. Its economy has been on a general downward trend since 2018, shrank by nearly 8 % in 2022 - 2023, and only posted growth in the final quarter of 2023.

At present, there is no in-country natural gas production or significant use and plans to build LNG storage and regasification facilities have stalled. Apart from hydroelectric, the country imports most of the energy it consumes, and imported oil and coal provide ~80 % of its power generation and transportation.

Geological research, exploration data, plus a 2012 USGS resource assessment indicate the offshore basins have significant petroleum potential with prospective plays lacking a single test well. Development of the discovered gas fields and returning exploration to the offshore offer Sri Lanka benefits: Alleviate its economic crisis, provide secure and inexpensive energy over decades and protect its independence in the geo-strategically important Indo-Pacific.

Here, we describe the potential of undiscovered, hydrocarbon resources in Sri Lanka's portion of the Cauvery and Mannar basins and the potential of the Lanka Basin.

Onshore, Sri Lanka consists mostly of high-grade metamorphic rocks with no obvious oil and gas potential. However, the country has three offshore sedimentary basins: Mannar, Cauvery, and Lanka (Figure 1). In 2012, the USGS published a geologically based assessment of undiscovered, technically recoverable, conventional petroleum resources that included the Cauvery and Mannar basins - the Lanka Basin was not assessed due to lack of geologic data.

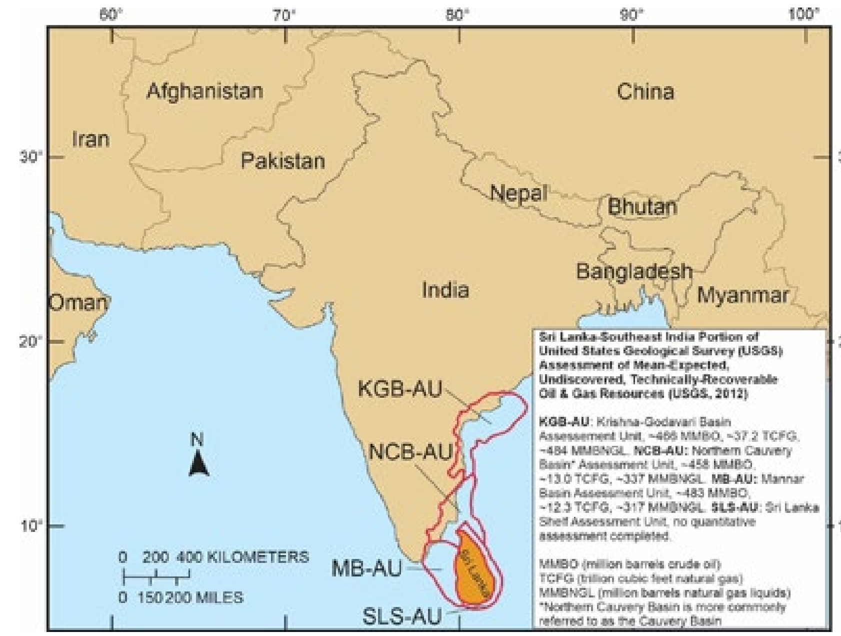


Figure 1: Map of the Indian subcontinent showing productive and potential oil and gas basins of Sri Lanka and the southeast continental margin area of India. Offshore Sri Lanka has considerable undiscovered, conventional NG, NGL, and oil potential that is estimated in the 2012 USGS Northern Cauvery and Mannar Assessment Units.

CAUVERY BASIN

Sri Lanka's portion of the Cauvery Basin remains underexplored with only seven, non-commercial test wells in a narrow, north-south-band along the northwest offshore. The PH-9-1 well, located in the Indian portion of the Ramnad-Palk depression (sub-basin) of the Cauvery Basin tested 1,488 BOPD and 570 MCFPD natural gas from a Cretaceous clastic reservoir.

India's portion of the Cauvery Basin is more explored than Sri Lanka's portion and India has production from a Cretaceous age source-reservoir rock petroleum-system couplet. It is likely that this couplet extends into the Sri Lankan waters based on proximity, mapping of depressions, and modeling and analyses of well data. Understanding the petroleum system of the Sri Lankan portion of the basin is constrained by the small number and older age of test wells, limited sampling, and other key data such as biomarker analyses of hydrocarbon shows.

MANNAR BASIN

The Sri Lankan portion of the Mannar Basin has proven petroleum resources but remains undeveloped and underexplored, with only five wells, all in the northern portion of the basin. The basin's undeveloped natural gas fields prove a productive petroleum system is present, and the basin's geology suggests additional systems. The stratigraphic and structural traps in the late Jurassic through Eocene section, in the central part of the basin have excellent conditions for hydrocarbon accumulations. ▸

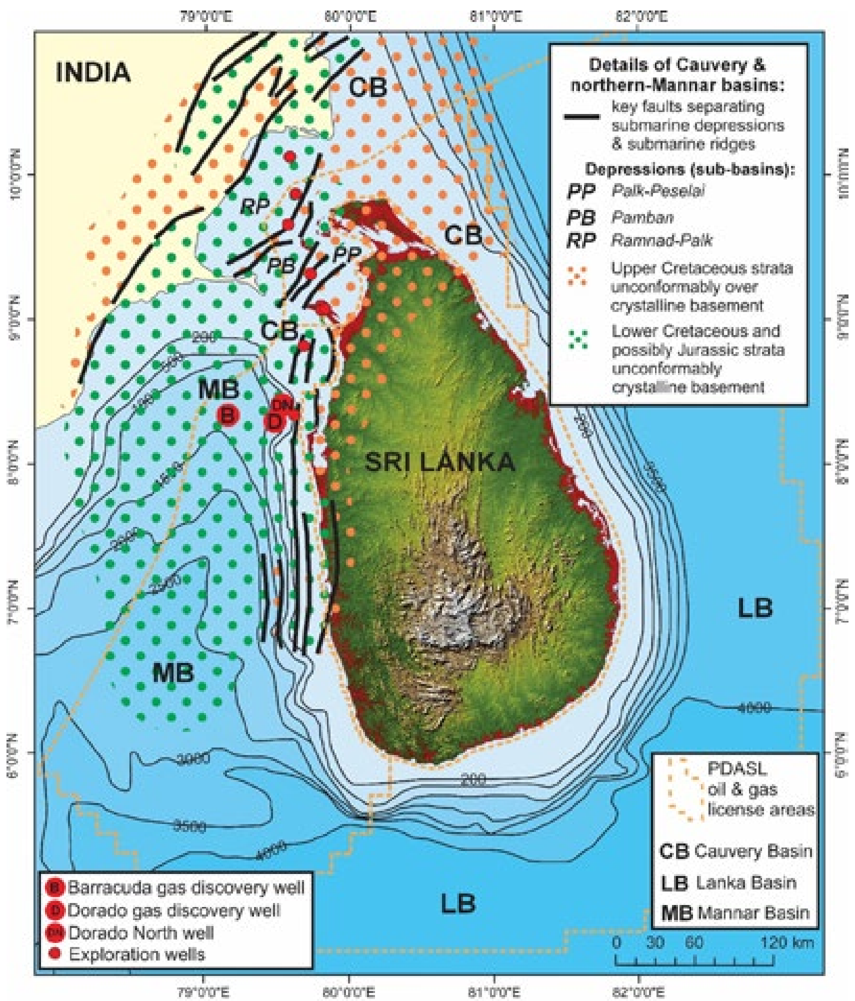


Figure 2: Map showing Sri Lanka's, and a portion of southeast India's, proven and potential hydrocarbon basins (Cauvery, Mannar, and Lanka). Shown are wells within and adjacent to PDASL license areas; map is modified from PRDS (2019) and PDASL (2023).

Analyses of Barracuda, Dorado, and Dorado North well samples confirm that the upper Cretaceous shale is a good to fair source rock (average TOCs are 1.37 % in Barracuda; 1.39 % in Dorado, and 1.64 % in Dorado North. An excellent Early Cretaceous source rock is likely present in the central part of the Mannar Basin given the basin's subsidence history, recognition of a major global anoxic event in the adjacent Cauvery Basin, but there are no well penetrations below the Upper Cretaceous in the Mannar Basin.

LANKA BASIN

The Lanka Basin is a frontier basin, lacking a single exploration well and source-rock analysis. However, the basin's oil and gas potential is promising based on its regional setting along the eastern passive margin of the Indian Ocean. North of the Lanka Basin, numerous offshore oil seeps have been mapped using synthetic aperture radar data, including four seeps in the adjacent Cauvery Basin.

The regional tectonic history of the continental margin suggests the Lanka Basin should have extensional traps formed in the Late Jurassic to Early Cretaceous, quickly followed by the development of transpressional traps due to the basin's position on the leeward side of the rotational-opening of the Mannar Basin and subsequent rifting of the Cauvery Basin during the Cretaceous. Recurring faulting during the Neogene, from collision of the Indian plate with Eurasia, steepened the Lankan Basin continental slope, and probably formed additional transpressional and convergent traps in the thick, deepwater prism.

COMMERCIAL QUANTITIES OF NATURAL GAS IN OFFSHORE SRI LANKA

In 2011, Cairn Lanka Private Limited's Dorado well made the first discovery of natural gas in Sri Lanka, followed by the Barracuda natural gas discovery, and proving a productive petroleum system in the Upper Cretaceous section of the northern Mannar Basin. The discoveries are estimated to have a combined midcase recoverable of 839 BCF of gas and 5.88 MMB of condensate. Cairn departed the undeveloped fields in 2015 stating that the fields would not be commercial, a decision made when the average international oil prices were below $40 USD.

OPPORTUNITY, CHALLENGES, AND PATHWAY

The two undeveloped gas fields (Barracuda and Dorado) prove there is a productive petroleum system involving the upper Cretaceous source rocks of the Sri Lankan portion of the Mannar Basin. In addition, in-depth geologic and geochemical studies of the Mannar and Cauvery basins show there are additional potential petroleum systems but are yet to be proven productive. Amongst energy experts, it is broadly recognized that the present-day, worldwide, underinvestment in oil and gas exploration will constrain future supplies and become a threat to economic global growth. Avoiding this will require far more than the present levels of investment despite claims that renewable energy will suffice for the energy transition. Sri Lanka will be no exception. ■

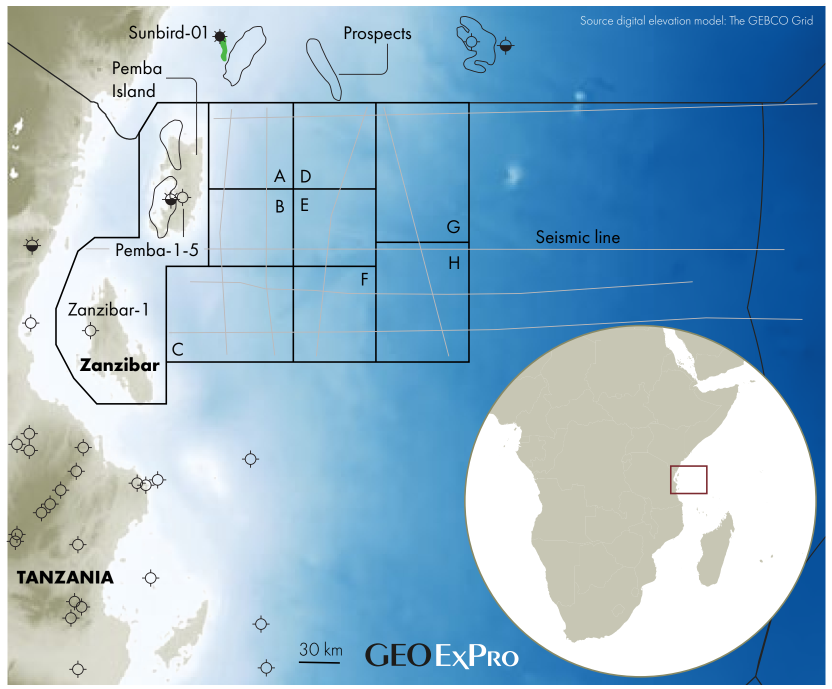
There are plenty of positive indications for hydrocarbons in Zanzibar, including oil

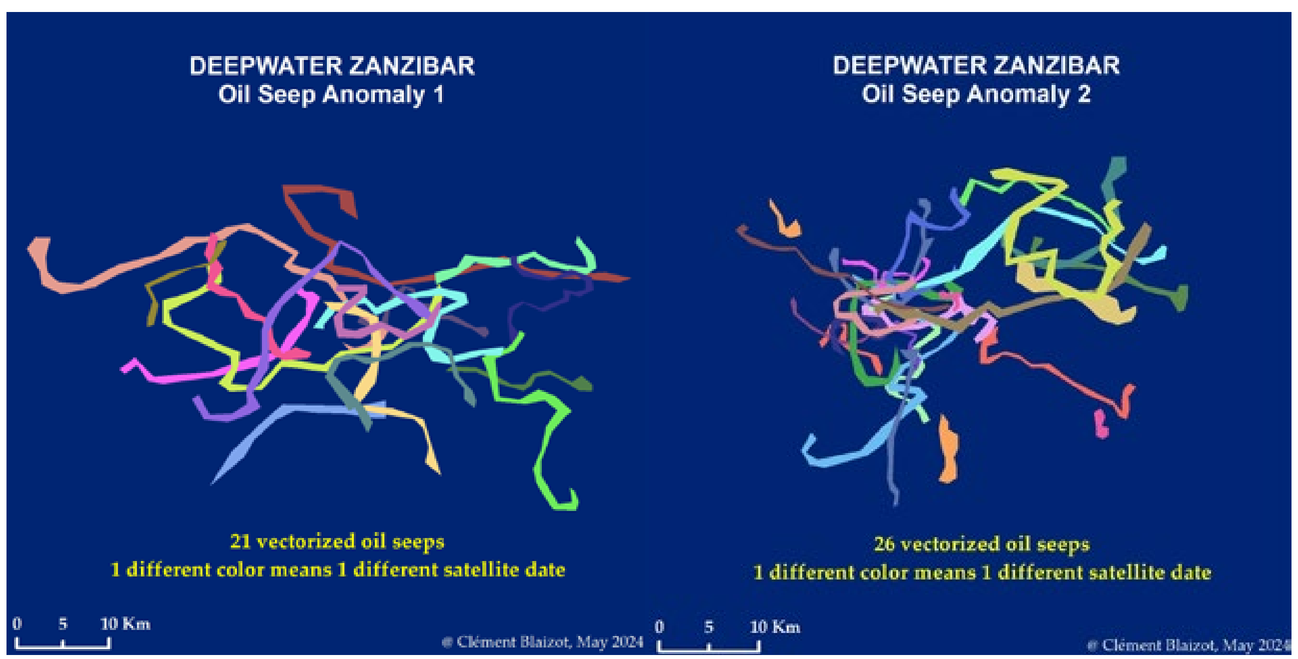
Hydrocarbon exploration in Zanzibar has never really taken off - the first licensing round now aims to re-ignite interest

LAUNCHED in March this year, the Zanzibar 1st Licensing Round offers a large frontier area with both oil and gas potential. There are 8 blocks available, named Block 1A to H, varying size between 2,846 km² to 5,666 km² and situated in water depths between 500 m and 3,000 m.

The fact that this is the first offshore licensing round does not mean that drilling for oil and gas never happened in the area though. In fact, exploration started quite some years ago. It was between 1952 and 1964 that bp and Shell started to drill the first wells in the area, including a few attempts on the Zanzibar and Pemba islands. Unfortunately, none of these wells discovered any commercial quantities of oil or gas. That said, a total of five wells were drilled on Pemba, one of which did result in oil shows, which is a first indication of an active petroleum system.

This is further supported by the presence of an oil seep on the same island. Further work on this seep has indicated that the oil can be traced to a marine source rock, which in turn can be correlated to an interval of Campanian – Maastrichtian Upper Cretaceous shales. The oil shows from the Pemba-5 well seem different though, which suggests that another source rock might be present in the area as well.





Two high repeat seep anomalies in Zanzibar waters, both in deep-water areas (> 1,500 m water depth).

THE EAST AFRICA MARGIN

The margin of East Africa has a complex geological history thanks to multiple phases of rifting with different stretching directions. The main phase of rifting, which led to the opening of the Indian Ocean, lasted from the Pliensbachian in the Early Jurassic to the Bajocian in Middle Jurassic times. Evaporites and marine shales were deposited during the Toarcian in the rift basins, marking the onset of the Indian Ocean marine incursion. This resulted in good-quality oil-prone source rocks. The giant gas discoveries in Tanzania and Mozambique are believed to be sourced from overmature Jurassic or, possibly, deeper Permian age Karoo shales.

SEEPS INDICATE A PETROLEUM SYSTEM

Offshore discoveries have yet to be made, and offshore wells have yet to be drilled too, but there are indications that an active petroleum system is also present in Zanzibar waters. Clément Blaizot, who runs an offshore satellite oil seep database of about 30 millions of km², performed an initial study to scan the area that is currently open for bids for the presence of oil seeps. The maps shown here are from the deep-water area in the east of the available acreage and illustrate two high repeat seep anomalies.

Seismic lines have previously been acquired across the area now open for bids, and SLB is supporting the Zanzibar government to make these lines available to any interested party. ■

Henk Kombrink

THE FIRST OFFSHORE OIL DISCOVERY IN EAST AFRICA

The map shown here, which provides a summary of the data available for the area in which the current licensing round is being held, shows an interesting discovery just north of Zanzibar in Kenyan waters. It is the so-called Sunbird discovery that was made by BG, with Australia-based Pancontinental as partner, in 2014.

The discovery was announced as being the first offshore oil discovery in East Africa, after intersecting a gross oil column of 14 m beneath a gross gas column of almost 30 m. The reservoir is not a very common one, being a Miocene pinnacle reef limestone. The depth at which the discovery was made is shallow: The hydrocarbons were found at around 900 m. Net reservoir thickness turned out to be 9.2 m in the oil zone and 28.3 m in the gas zone.

Press releases at the time mention that BG had difficulties analysing the well results due to the loss of drilling mud, seawater and remedial cement that had to be pumped in the reservoir accordingly. This is not a huge surprise given the fact that limestone reservoirs can have extremely porous sections.

The shallow depth of the Sunbird find and the planned TD at 3,000 m below sea-level suggests that the well also had a deeper target. It is unknown if anything was found below the Miocene, however. The commerciality of the oil accumulation in the reefal limestones probably turned out to be marginal, as no further drilling activity seems to have taken place in the area since.

New plays in Southern Santos Basin revealed by large-scale, high quality 3D Multi-Client seismic

The 17th Bidding Round for oil and gas exploration blocks in Brazil, held in 2021, included several offshore blocks located in the southern part of the prolific Santos Basin. Fourteen blocks were awarded during that round, sparking exploration momentum in Southern Santos. In a joint venture, TGS and PGS collaborated to develop a large-scale 3D Muli-Client (MC) program, called Santos Sul. The project aimed at acquiring high-quality data of the Southern Santos Basin (Figure 2) incorporating all awarded blocks. This program combines the knowledge and experience from TGS's extensive 2D library with PGS's industry-leading acquisition offerings. The seismic data processing was conducted in multiple East-West racetracks to provide industry access to interpretable depth products in record time. Both processing and depth-model building include a high-end Fast Track workflow, enabling early interpretation, quality assurance and better decision-making.

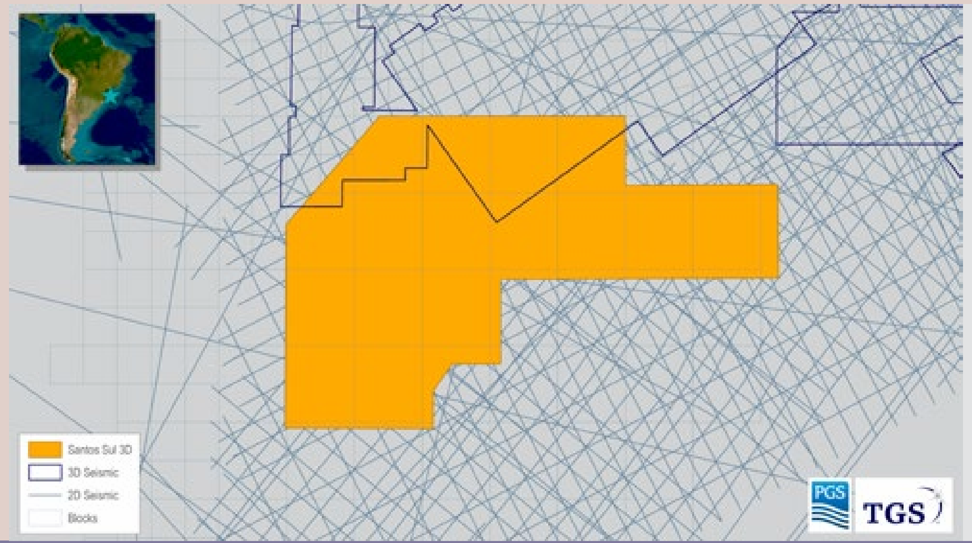


Figure 2: Map showing extent of Santos 3D Sul project in relationship with other TGS 2D and 3D programs.

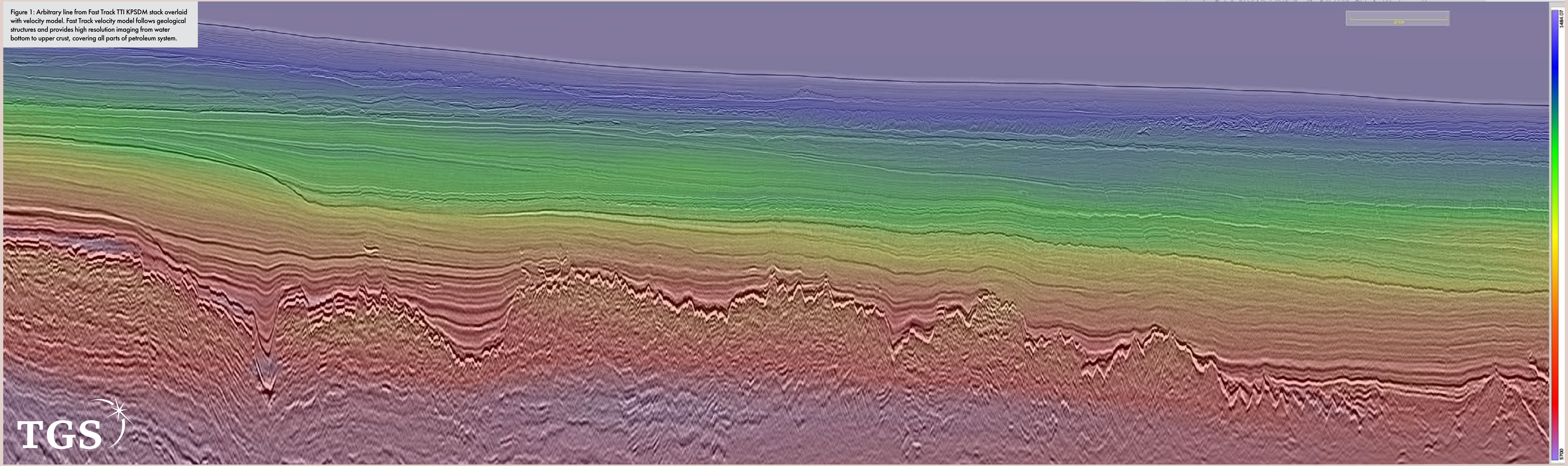


Figure 1: Arbitrary line from Fast Track TTI KPSDM stack overlaid with velocity model. Fast Track velocity model follows geological structures and provides high resolution imaging from water bottom to upper crust, covering all parts of petroleum system.

Leveraging integrated workflows and fast track data for prospect evaluation during acquisition

MILOS CVETKOVIC AND FRANCISCO COLINA, TGS

THE SANTOS SUL 3D MC program is situated near to a cluster of post-salt fields, such as Tubarao, Bauna, and Bauna Sul. Industry has expanded its exploration efforts in this region, now including Cretaceous to Oligocene clastic turbidites, departing from the Pre-Salt plays, which has been the dominant focus offshore for the past two decades.

Moreover, there has been a recent industry focus on exploration in the Santos and Pelotas Basins, which has intensified over the last couple of years due to several significant discoveries offshore Namibia. Both Brazilian offshore basins are still considered frontier areas, covered by 2D seismic data with only a few wells drilled in shallow waters. Therefore, acquiring higher-quality 3D data is essential to fully understand and de-risk the petroleum systems in these areas.

ACQUISITION

In a joint venture, PGS and TGS have conducted a high-density 3D survey (107-fold) over an area of approximately 12,290 km^2 using Geostreamers equipped with an 8 km cable length. By employing triple sources, we guarantee high fold and continuous recording of 15 seconds, allowing for uncompromised imaging. To ensure timely delivery of data to operators in the most promising areas of the basin, we divided the survey area into multiple racetracks. This allowed us to acquire seismic data throughout the season and deliver data subsets, for processing and model building along the way.

PRE-PROCESSING

We implemented modern broadband pre-processing with Fast Track and Full Integrity workflows. Fast Track wavefield separation is performed on-board and the data is transferred via satellite to the processing center onshore; subsequently, we perform robust de-noise and de-multiple sequences, followed by 3D Anti-leakage Fourier transform regularization. The pre-processed data undergoes quality control at every major stage and is reviewed with industry partners at key milestones.

The Full Integrity pre-processing is conducted entirely onshore, starting de-blending, de-noise, shot and channel amplitude scaling, receiver motion correction, tidal statics and dynamic water column correction. De-multiple is extended to both 3D SRME and shallow water de-multiple algorithms, followed by residual de-noise and 5D ALFT regularization.

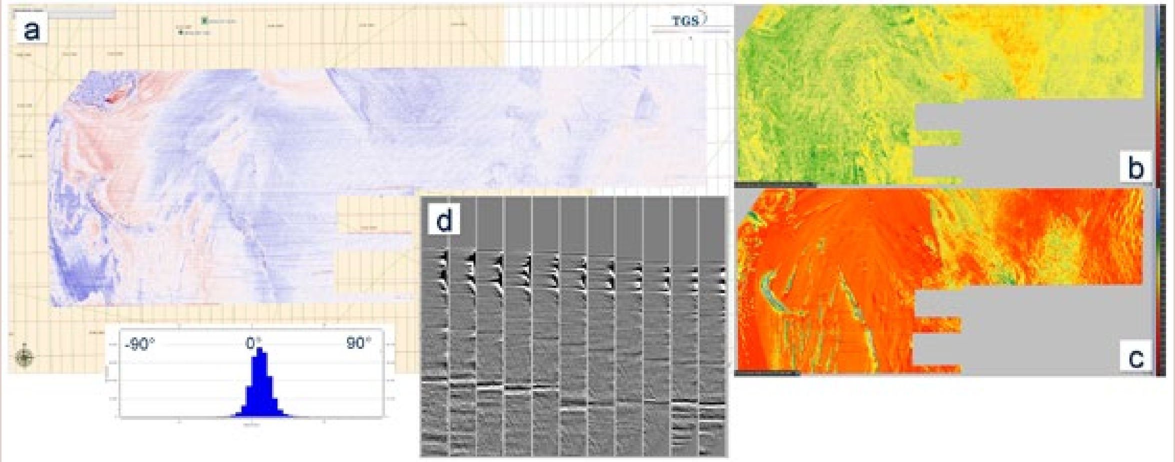


Figure 3: Rigorous QC during processing and model building stages. Different attributes extracted along the water bottom horizon: a) Instantaneous phase along far angle stack, b) bandwidth and c) signal to noise ratio from full stack. Note that the phase along water bottom is less than 10° off zero-phase on Fast Track products. d) Subset of Fast Track TTI KPSDM gathers.

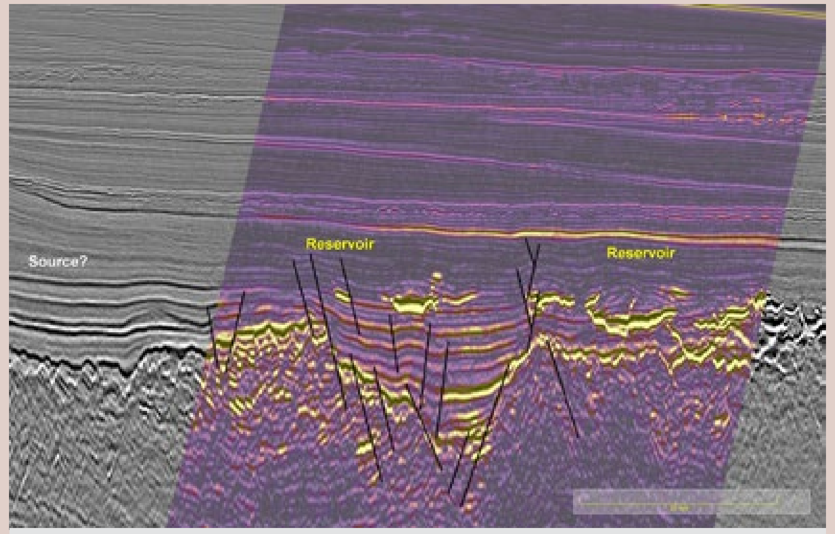


Figure 4: Identifying and mapping all parts of petroleum system while acquisition is still ongoing! Fast Track TTI KPSDM stack overlay with RMS amplitude attribute, highlighting potential source and reservoir rocks along with interpreted faults, possible migration pathways.

DEPTH MODEL BUILDING AND IMAGING

For depth model building and imaging we are using proven workflow TGS has applied on all recent MC programs and is widely accepted by industry. We use Tilted Traverse Isotropy Kirchhoff Pre-Stack Depth Migration (TTI KPSDM) as the main imaging algorithm for both Fast Track and Full Integrity.

We start with an initial 3D model created from grid of underlying 2D and data from three wells in the area. By integrating all available regional data, the value of regular grid of 2D data is amplified as we have a good starting VTI model that is following major regional horizons.

For Fast Track model building, we are updating Vp model with reflection-based tomography using non-parametric moveout picker and invert for global, dip-guided tomography solution. Since we were starting with very good velocity models, 3 passes of long wavelength tomography were performed to achieve overall flat gathers that will allow for good structural imaging as well as reliable angle stacks. Figure 1 shows velocity models overlay with TTI KPSDM stack for one of the central lines, where we can see that velocities are following structures and providing for a high-quality, high-frequency image from water bottom up to 10 km of section.

Even though we are at Fast Track stages, we do rigorous quality controls (QC) of the data in all domains, ensuring Amplitude Variation with Offset (AVO) fidelity. Figure 3 shows just a small subset of QCs that we typically run.

We are also generating geometrical and amplitude attributes that we use for further model building refinement, processing QCs and early prospects evaluation (Figure 4).

For Full integrity model building, we proceed with TGS' proprietary Dynamic Matching Full Waveform Inversion (DM FWI). DM FWI is a proven toolkit that works well for long-offset, full-azimuth data, 3D NAZ and even 2D datasets. For Santos Sul, we see that DM FWI is updating sediments not only in the shallow section but all the way to the expected source rock interval and SW-NE trending volcanic units (Figure 5). At deeper levels, volcanic features are also being delineated, such as volcanic cones that have slower seismic velocities, as well as sills and laccolites but at much faster velocities. The added details in the velocity model are further improving the flatness of the gathers and removing false undulating structures at Albian-Aptian level.

CONCLUSIONS

The Santos Sul 3D MC program is a crucial exploration program that will significantly enhance understanding of the petroleum system in the southern Santos Basin. This modern dataset is set to redefine geological plays in the region, offering an invaluable exploration tool for mitigating risks in future activities within the Southern Santos and Northern Pelotas Basin.

By employing high trace density broad-band acquisition and advanced DM FWI processing, the program aims to generate a drill-ready dataset.

The full range of TTI KPSDM Fast Track products for the area, covering approximately 12,290 km^2, will be available in early November 2024. The final KPSDM products for the entire area will be accessible by April 2025.

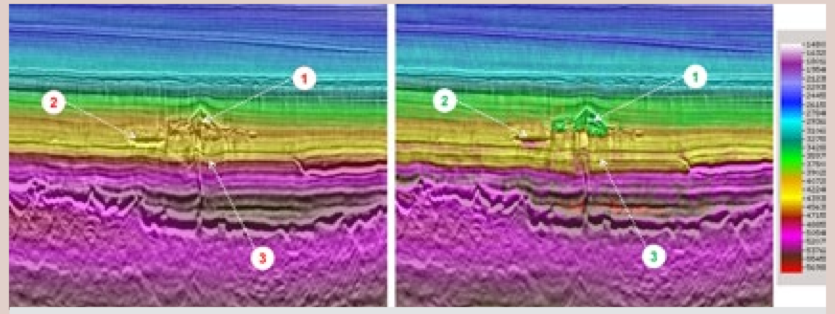


Figure 5: "Lithology interpretation" on DM FWI models. TTI KPSDM stack before and after DM FWI overlay with velocity model: a) Volcanic cone delineated with slower velocities then surrounding rocks, b) Faster velocity sill right next to volcanic cone and 3) DM FWI model removing artificial undulation and false structures underneath volcanic units.

PORTRAITS

"I had the luck of seeing how the sausage was made"

Bil Shea – Sharp Reflections

PORTRAITS

Bill Shea.

PLAYING WITH SEISMIC PROCESSING AS A PARAMETER DURING INVERSION

Bill Shea shares key moments in Sharp Reflection's journey and why it is important to always listen to what clients say

HENK KOMBRINK

"I HAD THE luck of seeing how the sausage was made", says Bill Shea at the start of our conversation, "and it made me feel uncomfortable." Bill is the CEO and founder of the Norwegian geophysical processing and interpretation company Sharp Reflections. He refers to the way seismic data was processed and made ready for interpreters to get stuck into. "Seeing the assumptions that were made during the process, with the final stacked result being labeled as data with a capital D convinced me that a bridge was needed between what seismic processors do and seismic interpreters see."

It was the seed that Bill needed to set up a company facilitating this very concept. And the timing was right.

"We entered the market when the wave of Multi-Client seismic surveys was taking off", tells Bill. This was around 2010. "The opportunity for communication between seismic processors and interpreters is limited with Multi-Client surveys, and that model only created more of a need for software along the lines of what we now do."

Secondly, around the same time, many smaller Norwegian oil and gas companies popped up that did not have the big tech facilities the bigger players used to have. "These companies were never going to license full-blown processing software because of budget and time constraints and would therefore benefit from a quick, fit-for-purpose solution."

These two factors combined had therefore created the niche that Bill identified through working in the industry as a seismic interpreter himself. And there was another reason why he wanted to get on with it.

THE HIGHEST VALUE

"The highest-value output of any new survey is the pre-stack data", says Bill. "Yet, until today, interpreters often lack the ability to interrogate these datasets because they are too large to handle for desktop machines. At the same time, every interpreter knows that an amplitude-driven prospect is more likely to be drilled, which creates a strong case for having access to the pre-stack data to further proof that."

"I met scientists from the Fraunhofer Institute in Germany who were working on the visualization of big datasets from the automotive industry", explains Bill. Comparing the sizes of the datasets they were working with to what I was having access to made us conclude that there was scope to do it, provided that we could use the computing power of a cluster of machines rather than single desktops."

> "I had the luck of seeing how the sausage was made"

GETTING TO WORK

Bill and his small team got to work. "It all comes down to speed", he says. Using the technology we developed with Fraunhofer, through linking computing power, we could see how individual steps in the processing workflow affected the stacked reservoir image with just a few clicks of the mouse button. The inertia of the process had disappeared!"

Given the operator and seismic data landscape as described above, it is no surprise that Sharp Reflec- ▸

tions really took off in Norway. "In 2015, we had 20 to 25 Norwegian oil companies using the software", Bill says.

A SEISMIC FACTORY

Sharp Reflections did not only evolve around speed. Bill saw the need to challenge the classic processing workflows too.

"People in the processing industry are taught not to touch the primary energy and only apply a soft touch. But that leaves a lot of noise that gets in the interpreter's way", adds Bill. "With our software, we could, for example, remove multiples that survived the standard processing workflow."

Another thing we were able to do is analyse the gathers directly. All of the AVO and seismic inversion workflows assume that the gathers are perfectly flat, i.e. the velocities are 100 % correct. But in reality, we found that it is easy for 1-2 % deviations to creep in, leading to interpreters making the wrong assumptions about the quality of the data. Taking that level of precision on yourself is a solution that we provide.

Our clients appreciated that level of scrutiny, which enabled them to say to the seismic companies: "Give us the migrated data and we do the last mile ourselves."

That created a so-called seismic factory, with people taking the seismic data in, fixing the pre-stack gathers to subsequently send the data to a seismic interpretation platform. That was the first few years of Sharp Reflections.

"But how many software licences are you going to sell this way?", Bill asked rhetorically. "Maybe you sell one licence to every oil company."

A WIN-WIN

"An important next step in the development of our software came about when Statoil (now Equinor) came round and made us a good offer", Bill continues. "They wanted to increase capabilities in the geophysical inversion domain, which the software they used at the time did not cater for. However, instead of asking us to develop all this ourselves, they offered code that had been developed already internally but had never been further embedded in software."

The collaboration started in 2017 and continues until today. It is a really good example of how companies can work together and benefit from what both are good at.

> "Clients are smart and they do things with your software that you didn't anticipate and you'd better listen to what they say!"

"And don't get me wrong, we don't have exclusivity rights to use this Equinor code; any commercial party can use it, for a price", adds Bill.

The same happened to getting a foot in the door in the onshore seismic world in the US. "We knew that if you want to do inversion of land seismic data, you really have to look at the pre-stack data because the quality of the data is often at the margins of what can be achieved", Bill explains. Customers in the unconventional space told us: "If you are willing to invest in this, we know there is a market for your product."

The Sharp Reflections team subsequently developed a tool to work with full-azimuth pre-stack land data. "And guess what, there is a market for it", laughs Bill.

A BRILLIANT OBSERVATION

Sharp Reflection's 4D capability, a feature that is key to the software's development today, came about through a brilliant observation from the team of the Equinor Research Group. "One of them said: If you cheat and hack the full azimuth data model you can be much more efficient in the way you handle 4D data collections. It's because you guys have the capability to include all the monitoring surveys into one volume: The software thinks it is azimuthal data but in fact it is time lapse data."

"Clients are smart and they do things with your software that you didn't anticipate and you'd better listen to what they say!", reiterates Bill.

"So, the way we handle 4D was 100 % an Equinor idea at the start", Bill explains. "At the same time, we have always been clear that the investment required from our side to make the software work should enable us to use the final product in sales to other customers too. It needs honest conversations, but we have never run into issues this way. There is always a deal to be done."

The company has contracts with almost all majors now. "This 4D focus was a real catalyst. It is because our timelapse solution enables them to see interactively the 4D response at the reservoirs without the need to calculate the difference between each survey specifically. And the full-azimuth solution we built for onshore data now also provides for working with OBN data", adds Bill.

THE CHALLENGE OF MAINTAINING CONTROL

Could Bill ever foresee being where he is now? "After working in oil companies for 12 years, I concluded that I'm not the person to always seek internal agreement and consensus on everything that was needed to move forward", he says when I ask him about his learnings over the past decades. "Leading a start-up requires a very different approach, which suited me a lot better. However, now we are almost 50 people, the challenge in recent years has been to let go of some control. With the good people we have and continue to hire, I am confident that we can build this company further!" ■

PHOTOGRAPHY PREVIOUS PAGE: SHARP REFLECTIONS

PORTRAITS

NATURAL GAS, PLAYING CHICKEN ON THE ENERGY TRANSITION ROAD

Edward Wiarda after successfully climbing the Nevado Tolima in Colombia (5,300 m) in 2018. Edward and his family lived and worked in Colombia for a number of years before moving back to the Netherlands in 2021.

And more insights on how professional societies cope with the changing energy landscape during a conversation with Edward Wiarda – this year's EAGE president

HENK KOMBRINK

"IN THE WEST, many people are of the impression that a radical shift from oil and gas (red meat) to a rapid and complete phase-out of hydrocarbons (vegan) is the way to go, often without differentiating between oil and natural gas at all. But, I think we are now waking up to the realization that it is not so easy and that natural gas is the transition energy source that could help bridge the gap in hydrocarbon energy supply and the demand for net zero emissions", says Edward Wiarda, the current president of the European Association of Geoscientists and Engineers (EAGE).

This sets the scene of how Edward and his colleagues at the EAGE have been working on making the EAGE organization ready for the future. And now, as his year at the helm of the organization is drawing to a close, it is a good moment to reflect.

"The big change we have made is the shift from two relatively siloed divisions to a network of three circles – Oil & Gas, Sustainable Energy and Near-Surface Geoscience. And these circles are overlapping when we draw them in a diagram. As such, it embraces the simple fact that many people don't only work in one sector and that there are so many synergies and overlaps in terms of subsurface knowledge and workflows", Edward explains.

"THE PROBLEM IS NOT THE SUBSURFACE, IT IS WHAT IS (NOT) HAPPENING AT SURFACE"

"Traditionally, we have been very good at allowing geoscientists to engage with other geoscientists at the events we organize and through our journals", says Edward. "However, with the energy transition in mind and the much slimmer financial margins these sustainable energy technologies generate, it is key to see geoscience and all the above-ground factors in one integral system", he says. "Don't get me wrong, the EAGE's core focus and weight shall remain firmly placed on our member's needs, being the technical and subsurface aspects of the Energy Transition. However, if we want to remain relevant, we need to widen our scope."

> **"We can have a great panel lined up for a discussion, fantastic keynote speakers, and a strong strategic program, if there is no pivotable audience representing the non-technical stakeholders in the room to listen there is no point to organize these programs!"**

"From what I see and hear, there is a significant gap between sustainable energy technologies the global investor community is keen to invest in, and technologies currently focused on by EAGE members, for example geothermal and CCS, and subsurface energy storage. The only way to bridge this gap is to bring people from multiple sectors into one room to discuss these strategic, policy and investor perspectives."

But then the challenge is to fill the room with people from an equally wide variety of backgrounds. "So far, we have not been effective enough in this goal", admits Edward. ▸

"And why? Because we are not very good at targeting, inviting or attracting the 'pivotal audience', and effectively explaining that we need to accelerate the energy transition in clear non-technical terms. To do this better, the EAGE has started building relationships with non-technical stakeholder groups, in addition to offering a geoscience communication course in collaboration with well-known geoscience communicator Professor Iain Stewart to improve our non-technical communication to the world outside geosciences."

"It hopefully leads to a better turnout for our strategic sessions too. At the end of the day, the value of our events lies not only in the diversity of our panel members, it mainly lies at the value participants feel they get from these events! Only that is really behind our license to operate."

THE SEISMIC SERVICE SECTOR

We get to talk about the seismic service sector. It is an industry that is close to Edward's heart because he started his career as a processing geophysicist at WesternGeco. He currently works for EBN, the Dutch energy company that participates in many North Sea gas developments on behalf of the state, as well as being active in the geothermal, CCS and subsurface energy storage realms.

"From my perspective", says Edward, "the trend of a contracting seismic acquisition and imaging industry has not been a good starting point for the energy transition. Why? Because with fewer players in the field, prices are likely to go up, availability of vessels and imaging teams down, and innovation in seismic acquisition and imaging solutions to decline as R&D departments are downsized. And especially for the capital-intensive CCS, geothermal and hydrogen sectors, where margins are low and access to funds is not trivial, that is bad news."

But what drove the recent trend of a contraction in the seismic industry? At first hand, it seems straightforward to blame the oil price downturns for that, but Edward has another perspective.

"In my view, another important contributor to the decline in companies offering high-end seismic acquisition and processing solutions is how oil and gas operators have, contractually, slowly put more and more risks associated with the acquisition of surveys with the seismic service companies. That has caused some big projects to lose money because unexpected events frequently happen during acquisition", he says. "Moreover, oil and gas E&P operators appeared reluctant to pay a prime for high-end acquisition and imaging technologies that some innovation-driven seismic service companies brought to market, leading to low returns to their R&D investments."

> "I would have preferred a situation where we enter the energy transition with the seismic service landscape as we saw ten years ago."

"Of course, it is how a free market works, but I do feel that some introspection is required especially when the big oil and gas players are now complaining about the loss of diversity in the seismic acquisition space. And now it is the new players in the energy transition arena that are at the risk of paying the price for this, literally. A price they typically cannot pay due to aforementioned low margins and immature business models".

BACK TO GAS

"Coming back to the strategic sessions we tend to organize these days", Edward continues, "I am very pleased to see that energy poverty features as a theme during the EAGE Annual in Oslo this year. It reflects our desire to be a platform for discussing the broader range of issues and solutions needed to overcome this socio-economic issue and how geosciences can help with that."

"In that regard, the situation I find myself in when at work is a very interesting one. On one hand, there is the desire by a very vocal set of groups to move away from gas and become energy 'vegan' straight away, but the reality is that gas will be needed for quite a few years to come – if only to help keep energy prices at affordable levels and to provide the energy to drive the energy transition."

At the same time, the appetite for exploration is not what it used to be in the North Sea. It is getting increasingly busy as (future) wind farms, CCS, and subsurface hydrogen store developments are staking their claims through licensing rounds. "But, even though much of the easy and highly profitable and economically viable gas prospects have long been drilled, I think that some strategic decisions need to be made sooner than later to ensure that we tap into what is remaining before the infrastructure is gone and the gas exploration and production window is closed by a combination of public opinion, policy makers and investors moving away from the hydrocarbon sector."

"At the EAGE, there will always be a home for geoscientists and engineers of all three circles, including the Oil & Gas Circle", concludes Edward. "On the road of the Energy Transition, we should keep our foot on the gas for as long as needed rather than steer on a collision course with gas exploration and production. We need to accelerate through knowledge sharing, innovation in subsurface technologies and through removing above-surface obstacles by advising and engaging with the wider non-technical public domains. If the cross-discipline networking at our events help achieve this, even better!" ■

PHOTOGRAPHY PREVIOUS PAGE: PRIVATE

GEOTHERMAL ENERGY

"It is this subsurface energy storage facility that is unique in the Netherlands and possibly even in Europe"

Eva van der Voet – Ennatuurlijk Aardwarmte

The first high-temperature aquifer thermal energy storage project in Europe

Greenhouses in the Netherlands are buffered by storing excess geothermal heat at shallow depths in summertime

"WE HAVE A unique geothermal energy solution here", says geologist Eva van der Voet from Ennatuurlijk Aardwarmte in Middenmeer, the Netherlands. "The complex of greenhouses we deliver energy to is first of all supplied with geothermal heat from deep wells tapping into a Rotliegend aquifer at around 2,200 m depth, but at the end of the heat-grid sits a geothermal heat storage system in an aquifer at 360 m depth that can deliver or store energy per demand."

"It is this subsurface energy storage facility that is unique in the Netherlands and possibly even in Europe", says Eva.

This is how it works. "In summer, we tend to have an energy surplus from the deep geothermal sources. This enables us to store water of around 85° C into the shallow marine Maassluis Formation at 360 m depth. When winter comes, we produce the same water, which provides the bulk of the heat in one of the greenhouses", Eva explains. "We operate the system using three wells; a cold well, a hot well, and a monitoring well. The role of injector and producer wells swaps between the hot and cold well when the seasons turn."

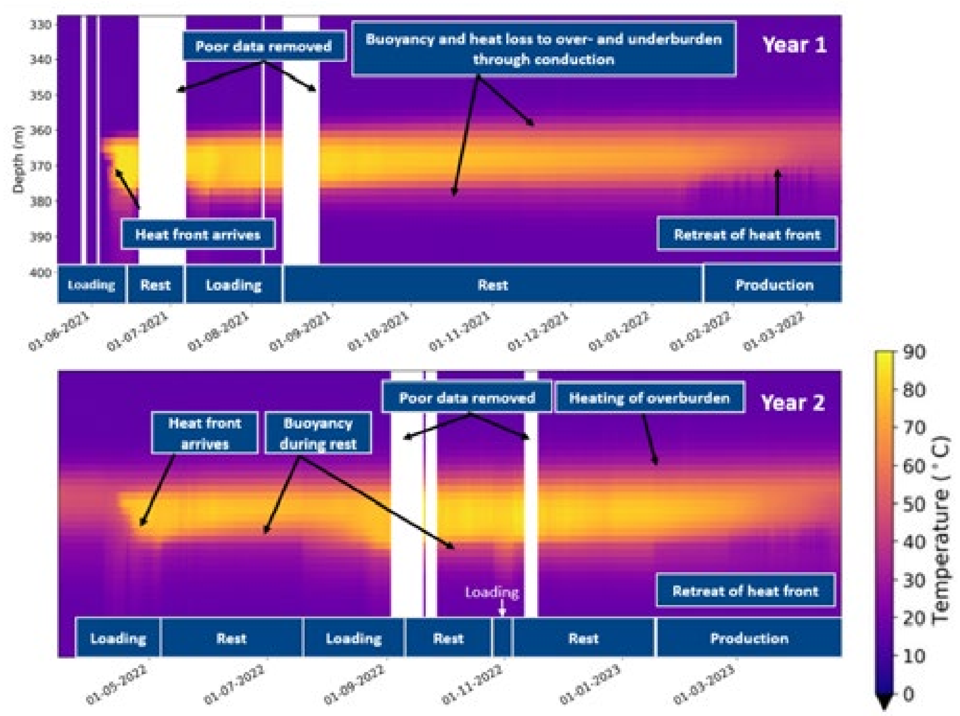
To accurately monitor subsurface temperatures, the three wells are fitted with fibre optic cables such that measurements are taken every 2 m at each 10-minute interval. "For instance, this allows us to see how the temperature gradient at the top and bottom of the hot-water plume becomes more dissipated over time, which is an effect of warming up of the aquifer", says Eva.

The initial temperature of the Maassluis Formation sands was around 15° C when injection started. "For that reason, we do not produce as much energy from the sands as we inject. In the first year, we had an efficiency of 27 %, and in the second year of 41 %. This is increasing to an expected efficiency of around 70 % in five years and 80 % in ten years. It just boils down to warming up the reservoir."

One of the requirements for an open energy storage system to work is not only to have a permeable reservoir at the right depth, it also requires an aquifer that is not characterised by high levels of groundwater flow. "That is not the case in Middenmeer, which makes it a suitable aquifer", confirms Eva.

Reservoir thickness is a crucial factor too. "When the sand layer is too thick, we tend to see buoyancy driven upward flow of warm water in the reservoir, which then results in the risk of cold water breakthrough when producing. At the same time, we don't want too thin a layer either, because this limits the possible flow capacity for each well." ■

Henk Kombrink



Two cycles of hot water injection (loading) and production (unloading) in the Middenmeer storage project. Measurements taken from fibre optic cables in the monitoring well, which is 30 m away from the hot well.

SOURCE: ENNATUURLIJK AARDWARMTE

Why Taiwan is looking at geothermal energy with a lot of interest

Above-ground and below-ground conditions are such that deep geothermal energy production in Taiwan seems the only way to go

"TAIWAN'S GEOTHERMAL heat gradient, ranging from 48 to 60° per kilometre, is a clear testament to the island's volcanic origin. This natural advantage has sparked significant interest in geothermal energy within the country", explains Kevin Gray, a geothermal energy expert and leader of a team at Black Reiver Consulting, who recently presented at a major geothermal conference in Taiwan.

There are also above-ground factors that favour deep geothermal energy production. "Most of the chips we use in our computers are made in Taiwan, and these plants are very power-hungry", says Kevin. "And while the country wants to retain this industry, it has also embarked on a clear pathway to achieve carbon neutrality. Geothermal energy plays a crucial role here, as the offshore wind sector cannot ensure the base load energy supply. Moreover, there is a firm commitment from the chipmakers to purchase any geothermal-produced MWh to power their operations, eliminating any uncertainty in demand. "This commitment is staggering, amounting to around 20 GW of power", says Kevin.

POLITICAL SENSITIVITIES

And why would Taiwan not build new nuclear power plants to replace the older generation? "That's due to regional political sensitivities", Kevin says. "This goes as far as the country not wanting any nuclear power generation on the island in the foreseeable future."

But there are challenges too. For instance, the island is very densely populated, and operational space is limited in many areas. In contrast, the less densely populated areas are very mountainous, which does not make a strong case for installing a rig either. "During the conference", Kevin adds, "we identified a number of former industrial sites that could well form the starting point for drilling operations. These places also have the benefit of good grid connectivity in place, which is always a major cost factor in integrating geothermal power into the energy system."

At the moment, there are a few geothermal pilot projects in the country that produce from reservoirs, but there is increasing momentum behind the idea of going deeper and reservoir-independent. "I think it is the way the country should go", says Kevin. "When I mentioned that during the conference, some people got a fright, and I saw them thinking – this means that there will be no geological input required" … "But that is not the case", said Kevin. "There is still the need to do your geomechanics, and you still need to understand the formation you are drilling through."

Kevin Gray (R) and Tony Pink (L) from Black Reiver Consulting with a member of the Taiwanese geothermal community.

PHOTOGRAPHY: BLACK REIVER CONSULTING

Given these factors, including favourable geology, a committed energy consumer, and a compelling argument against nuclear power, it becomes evident that Taiwan is a promising location for deep geothermal energy development. The country's potential in this field is certainly something to watch closely. ■

Henk Kombrink

The deepest closed-loop borehole drilled in the UK

Shallow geothermal closed-loop systems are not that shallow anymore

This is not the first time I write this, but I keep on saying it. If there is any sector in the geothermal drilling space that is active in the UK, without subsidies or extensive research frameworks, it is the shallow geothermal sector. These guys quietly complete borehole after borehole, slowly but steadily building a new energy system that sources most of its energy locally.

Recently, GTD Desco posted on LinkedIn that one of their rigs drilled the deepest closed loop borehole in the country. With the Central London Shard building in the background, the location was a challenge in itself given the very limited space to work. But with the mud system tucked away in a nearby underground car park, the borehole was drilled successfully nonetheless.

True, drilling to 420 m in London will not bring too many new geological surprises, but the geology is leading in how these boreholes are being drilled. The drilling crew used a 4-wing stepped PDC bit for the first part of the hole – which is in Cenozoic (unconsolidated) sands and muds – and then swapped to a rock roller after 75 m as the geology changed to hard Upper Cretaceous Chalk.

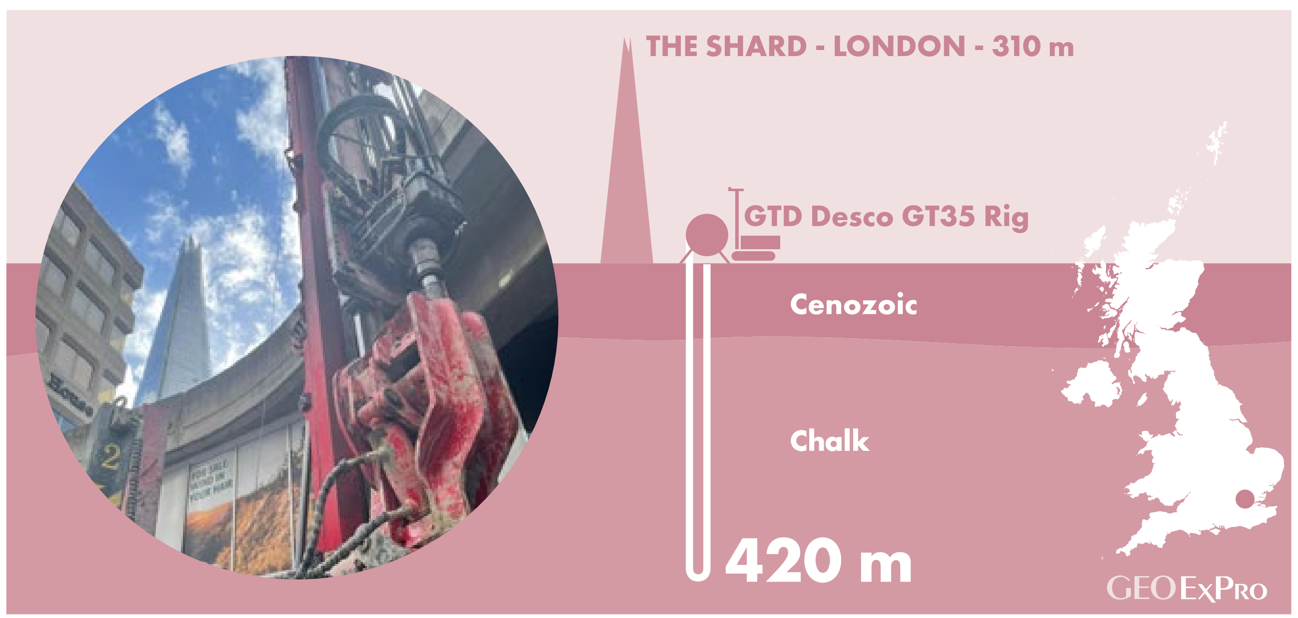
What is also interesting is the fact that the tubes of the closed-loop system were equipped with a fibre optic cable. As we recently wrote, this technology is making strides in monitoring deep oil and gas wells and in many other (subsurface) applications, but there is obviously a role for the shallow subsurface too when it comes to temperature measurements. I would be interested to see the temperature profile from this borehole at some point. ■

Henk Kombrink

ENERGY AND GEOLOGY

One of the factors determining the efficiency of a geothermal closed loop is how much groundwater flow takes place in the immediate vicinity of the tubes. The more groundwater flow, the higher the thermal exchange, and thus the higher the energy yield. Since the reservoir effectiveness of the Chalk in the London area relies heavily on fracture systems, the results of every borehole are different because it is hard to predict if a fracture zone is drilled or not.

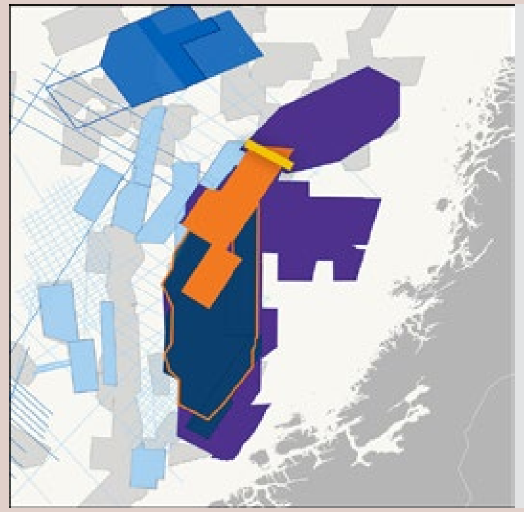
A loop of this kind will produce around 20 kW, which translates to 480 kWh per day. A detached house in Scotland consumes 80 kWh in gas per day on a cold winter's day, so this loop will be able to provide energy to a building that is significantly bigger than that!



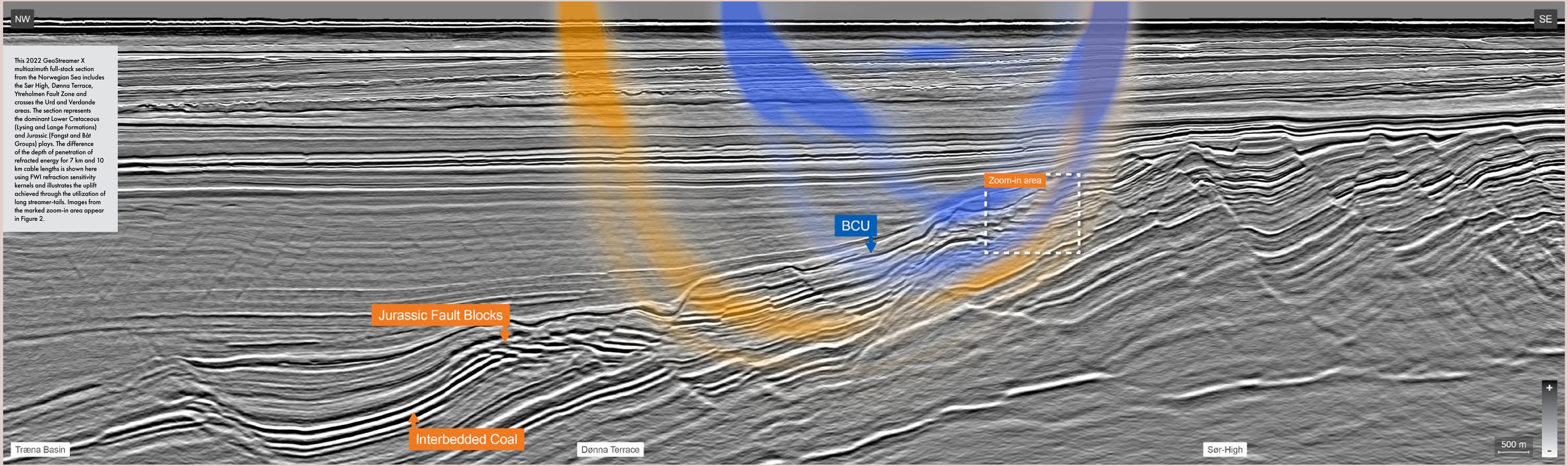
PHOTOGRAPHY: GTD DESCO

New GeoStreamer X multi-azimuth seismic dataset in the Norwegian Sea unlocks new prospectivity

GeoStreamer X combines multi-sensor towed streamer broadband seismic fidelity and wide-tow source efficiency, with multiazimuth illumination. Earlier this year, PGS added a new GeoStreamer X dataset to its already extensive Norwegian Sea data library. Through a continuous data rejuvenation strategy, utilizing acquisition innovations, imaging advancements and collaboration with industry operators in the area, significant improvement in terms of resolution and signal-to-noise ratio were achieved compared to legacy datasets. The pre-stack image quality is essential for the evaluation and derisking of prospects, and augments interest in the Cretaceous section. We reveal new prospectivity and exploration potential in undrilled structures demonstrating that the Norwegian Sea is still attractive for petroleum exploration.



The GeoStreamer X 2022 survey is shown in orange, highlighting the location of the line displayed. The survey area for the GeoStreamer X 2023 survey and the 2024 programs is also outlined in orange.



This 2022 GeoStreamer X multiazimuth full-stack section from the Norwegian Sea includes the Sør High, Dønna Terrace, Ytreholmen Fault Zone and crosses the Urd and Verdande areas. The section represents the dominant Lower Cretaceous (Lysing and Lange Formations) and Jurassic (Fangst and Båt Groups) plays. The difference of the depth of penetration of refracted energy for 7 km and 10 km cable lengths is shown here using FWI refraction sensitivity kernels and illustrates the uplift achieved through the utilization of long streamer-tails. Images from the marked zoom-in area appear in Figure 2.

GeoStreamer X innovative acquisition design and advanced processing

Key to enhanced subsurface imaging

MARCIN PRZYWARA, STEFAN MÖLLER AND JENS BEENFELDT, PGS

THE NORWEGIAN SEA is renowned for its high-quality hydrocarbon reservoirs situated within complex geological settings. Tilted fault blocks, formed during Late Jurassic rifting, host prolific pre-rift petroleum plays, characterized by high-quality Jurassic sandstone reservoirs located in structural traps. Recent advances in seismic processing deliver improved data quality and have redirected attention toward marine post-rift deep-water clastic systems and stratigraphic traps within the Cretaceous section. Efforts will continue to focus on more complex accumulations for both exploration opportunities and existing field extensions. A critical factor in evaluating these opportunities lies in high-resolution, AVO-friendly seismic data that provides comprehensive subsurface illumination beyond what single azimuth data can offer.

GEOSTREAMER X: FROM ACQUISITION INNOVATIONS TO SUPERIOR IMAGE

The 2022 GeoStreamer X acquisition program covers an area of approximately 6,777 km². The acquisition program was designed with an azimuth orientation perpendicular to the existing GeoStreamer datasets acquired between 2011 and 2016. Through a combination of reprocessing existing data and employing state-of-the-art depth imaging techniques, a large scale and uniform multi-azimuth dataset was created for the region.

The innovative GeoStreamer 2022 acquisition configuration employs a wide-tow triple source setup, allowing dense crossline sampling. The source array separation was 250 m between the outer arrays, and the data was recorded using 14 streamers spaced at 75 m intervals (12×7 km and 2×10 km long). The 2 long streamers, referred to as streamer-tails, were extended to achieve longer offsets, which provide greater depths during FWI-based velocity model building. The difference of the depth of penetration between the 7 and 10 km streamers is shown using FWI sensitivity kernels on the foldout line and illustrates the uplift from 10 km-long streamer-tails.

Additionally, the cables are towed as close as possible to the source arrays, allowing near offset reduction to 65 m. These near traces help to improve the de-multiple flow and led to an improved and detailed image in the very shallow overburden. The significantly enhanced near-offset distribution provides further comprehensive azimuthal coverage and together with the already existing GeoStreamer azimuth allows the utilization of all traces together in a regularization scheme.

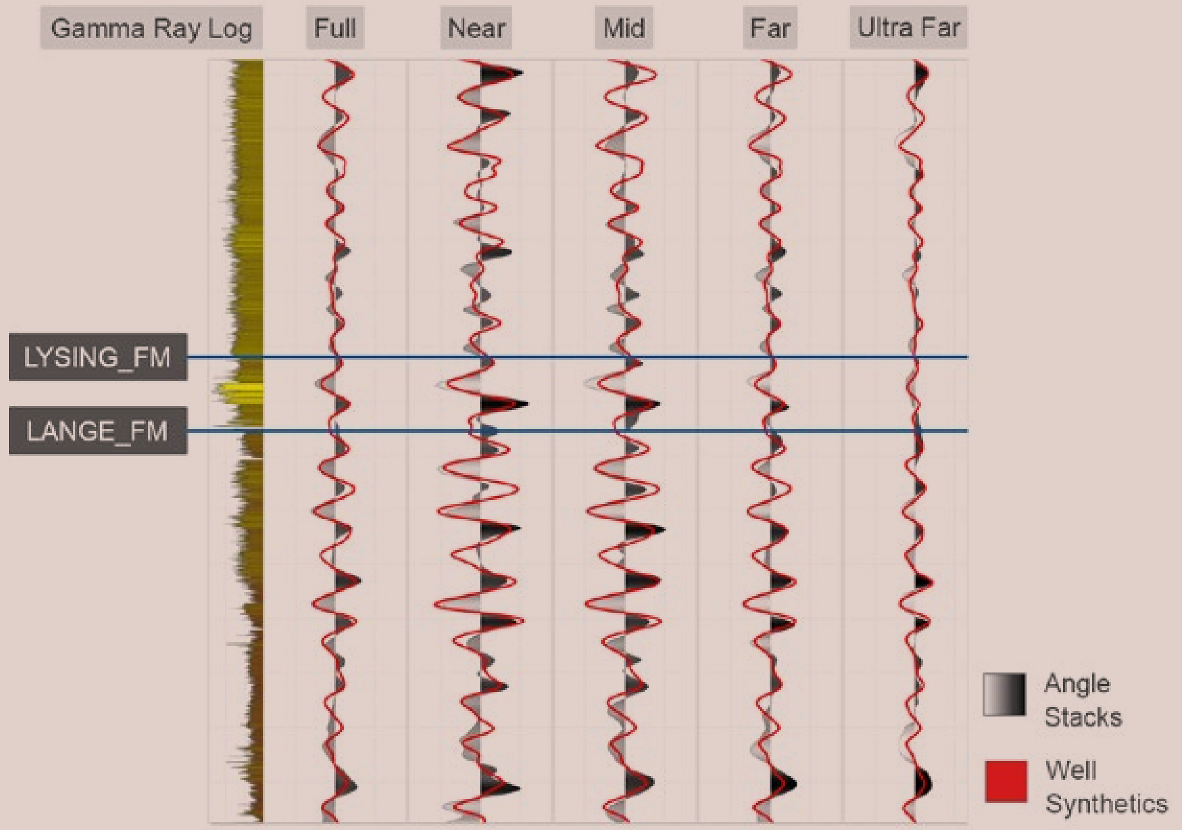


Figure 1: Representative well-to-seismic tie (well 6406/3-9; oil discoveries within Lysing Fm. and Lange Fm.) within the low reflectivity Cretaceous section. Consistent Amplitude-vs-offset (AVO) behavior through the partial stacks indicates high potential for successful seismic reservoir characterization.

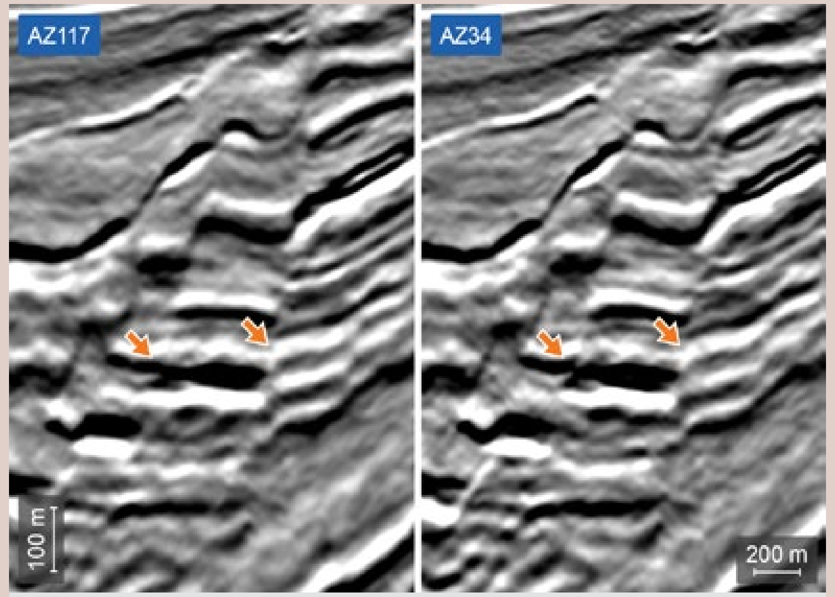


Figure 2: A comparison of Middle Jurassic depth sections of new azimuth (Azimuth 34; right) and reprocessed legacy (azimuth 117; left) downdip of the Svale field (area marked on foldout line) illustrates the dependency of structural imaging on illumination direction. While reflector termination against faults is improved, fault plane positioning and inferred fault zone width diverge. Interpretation of individual fault blocks would result in variable fault offset estimations between the two azimuths. Also, internal faulting of fault blocks and reflectivity within the blocks can show significant variations.

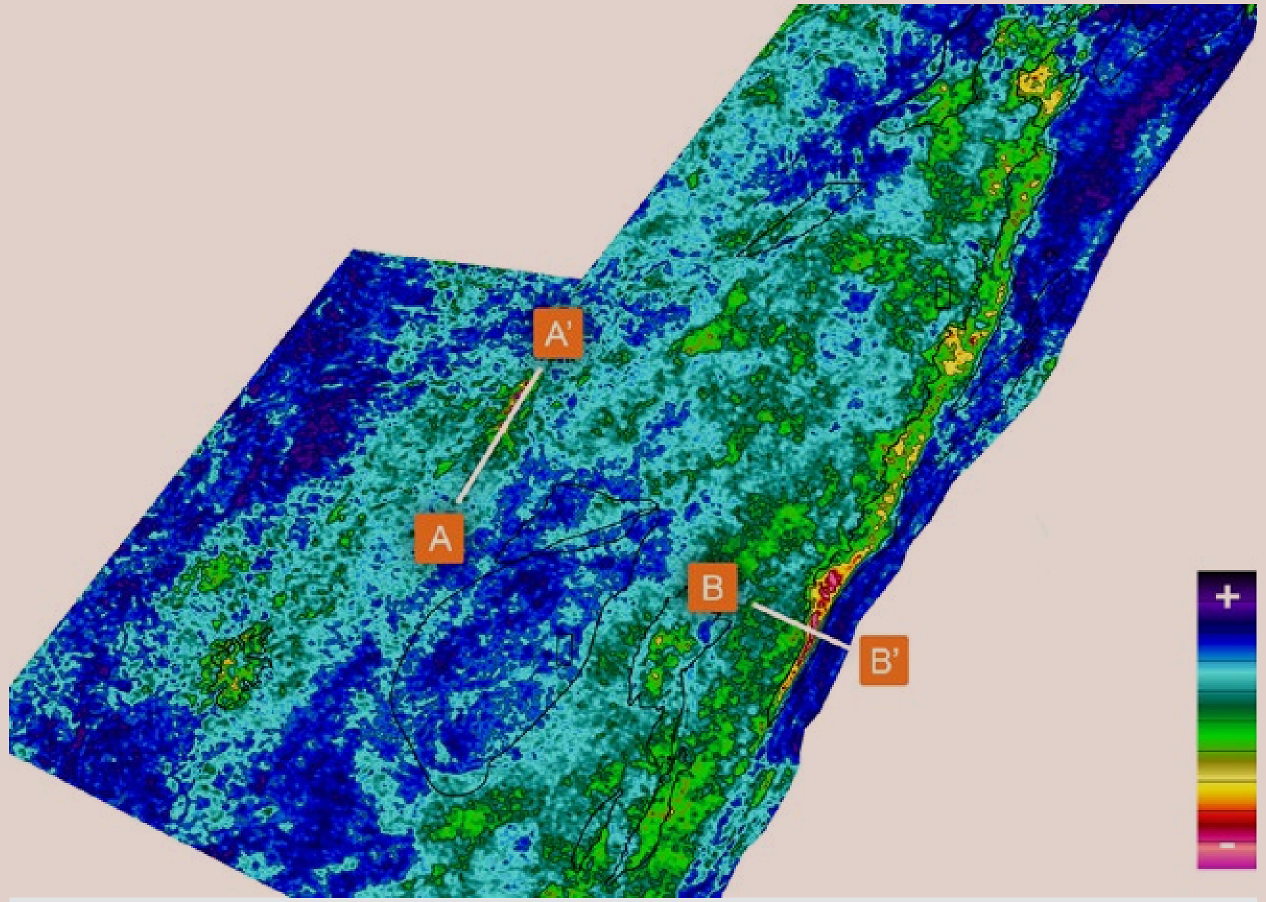


Figure 3: A map of inverted Vp/Vs ratio distribution within Lysing Fm, underlying existing Cretaceous fields and discoveries of Ærfugl, Ærfugl Nord, Marulk or Nidhogg, with the location of seismic lines through Ærfugl field (B - B') as well as the undrilled prospect (A – A') shown in Figure 4. Outlines of existing fields added for easier orientation.

IMPROVED SUBSURFACE RISK AND UNCERTAINTY ASSESSMENT

Rigorous control over the Amplitude vs Offset (AVO) behaviour throughout the entire processing sequence has yielded a dataset well-suited for exploration, near-field exploration, infrastructure-led exploration (ILX), and appraisal activities. The final dataset's quality has been quantitatively assessed by well to seismic ties across 43 wells in both the Cretaceous and Jurassic intervals. The cross-correlation coefficients, averaging over 0.7 on the multi-azimuth full stack, underscore a significant improvement in signal-to-noise ratio when compared with single azimuth legacy data. This uplift is particularly evident in low-reflectivity Cretaceous sections, as illustrated in the well-to-seismic tie panel for the 6406/3-9 well shown in Figure 1.

Improved GeoStreamer X multiazimuth illumination leads to significant enhancement in structural and stratigraphic imaging in both the Jurassic and Cretaceous sections. Fault plane imaging depends on illumination direction and in some cases, minor fault features that are not visible on the single azimuth data become apparent. The estimation of fault offset magnitudes can also depend on the illumination angle – one zoom-in example from the foldout line (marked with a rectangle) is presented here in Figure 2. Analysis of this new perspective can lead to better structural fidelity and structure uncertainty understanding, and consequently to improved appraisal of e.g. trap geometry, block compartmentalization, and fault property estimation.

The new data represents a significant advancement to unlock the full Cretaceous potential. It allows interpreters to investigate subtle structural features that constrain and compartmentalize prospects. The true value of this lies in enhanced trap geometry analysis and reservoir characterization, which accurately captures prospect segmentation and internal reservoir continuity.

GEOSTREAMER X HELPS UNLOCK REMAINING PROSPECTIVITY

To further assess the remaining prospectivity within the area, the dataset was inverted in a pre-stack simultane-

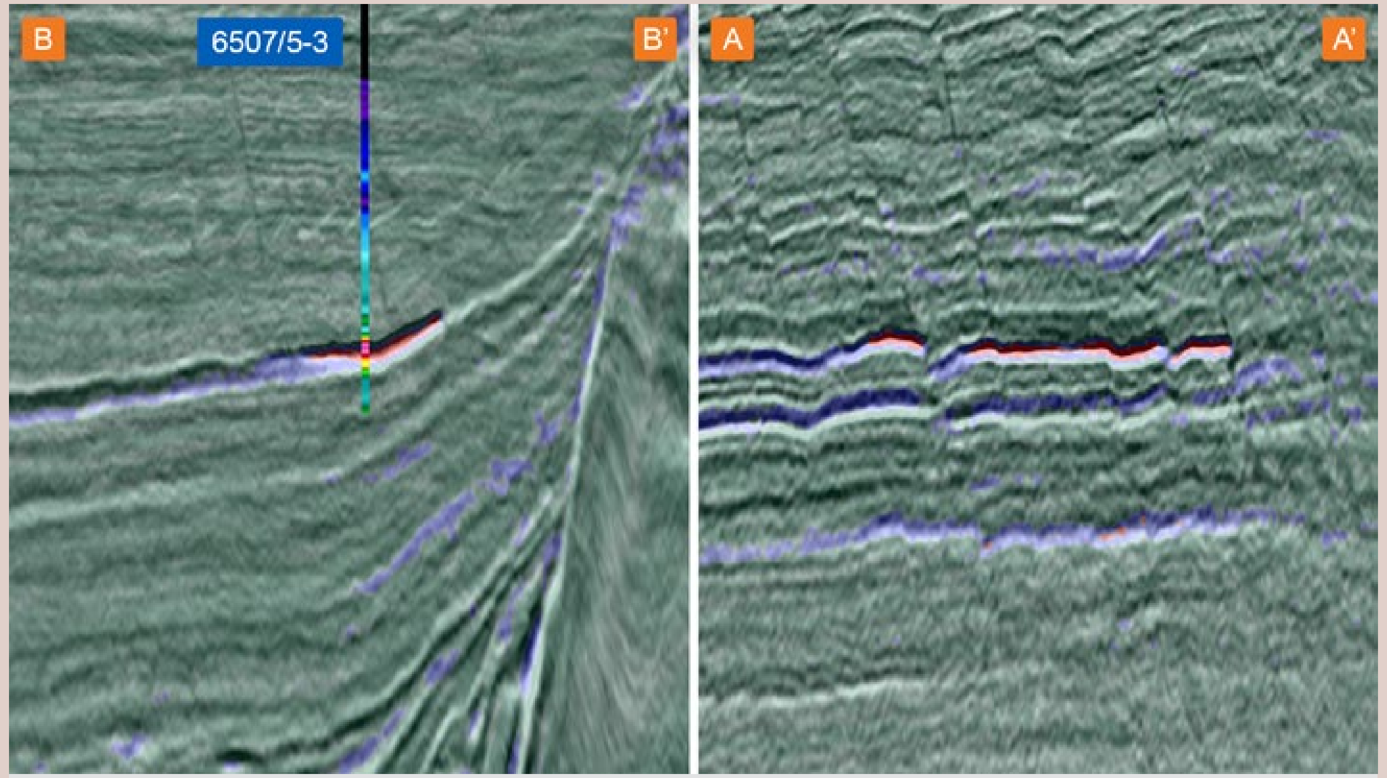


Figure 4: Example of stochastic litho-fluid classification of inversion results; Lysing Fm. known accumulation - Ærfugl line through discovery well 6507/5-3 (line B – B' shown in Figure 3); Vp/Vs log upscaled to seismic resolution displayed on the well track) and undrilled prospect (line A – A' shown in Figure 3; red – gas bearing sand, blue – water bearing sand, green – claystones.

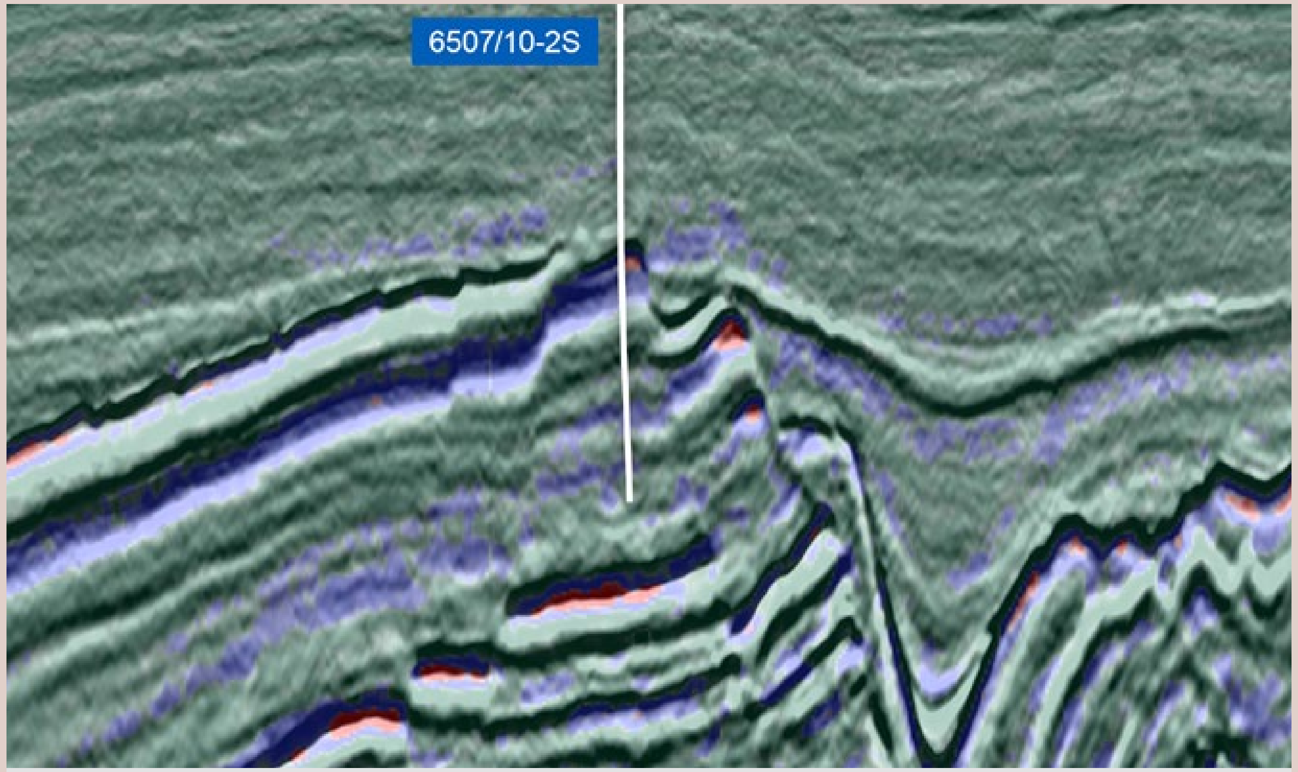


Figure 5: Line through Novus discovery well (6507/10-2S) litho-fluid classification result, highlighting the possibility of additional resources on a down-thrown fault block. Red – gas bearing sand, blue – water bearing sand, green – claystones.

ous inversion scheme to P-Impedance and Vp/Vs. Furthermore, by leveraging PGS' comprehensive petrophysics and rock physics rockAVO library, stochastic depth dependent rock physics modeling of Cretaceous and Jurassic intervals was conducted. The inversion results were subsequently classified using a Bayesian scheme in terms of the most likely lithology-fluid class.

The facies classification process integrates both seismic and well information, yielding a probabilistic description of the subsurface. These results correlate well with known accumulations, the Ærfugl litho-fluid classification line through discovery well 6507/5-3 is presented on Figures 3 and 4 (left), together with the identified prospect Figure 4 (right) - and provides further reassurance regarding hydrocarbon fill as a cause of the prospects anomalous seismic amplitude and AVO response.

In the Jurassic, there is potential for added reserves in existing developments and discoveries. Figure 5 shows Well 6507/10-2S (Novus discovery well) drilled by Faroe Petroleum Norge in 2014 about 13 km south of the Heidrun platform, which encountered oil and gas (24,5 m column total) in a reservoir with better-than-expected quality. After resources evaluation, the discovery was deemed non-commercial – despite easy tieback to Heidrun facilities.

After our analysis of the inversion results and litho-fluid classification, we reveal the possibility of added resources in a down-thrown fault block. The litho-fluid classification in the existing discovery agrees very well with hydrocarbon column height encountered in the well. If confirmed, a similar 50 m hydrocarbon column in the downthrown block within the Middle Jurassic Garn Fm. reservoir would affect subsurface volume estimation and the commercial assessment of the structure. A similar but small anomaly in an underlying section suggests the presence of additional reserves at deeper stratigraphic levels.

GEOSTREAMER X SOLVES EXPLORATION CHALLENGES

Through a small number of example extractions, we have demonstrated how an innovative acquisition set-up with wide-towed sources and a state-of-the-art depth imaging workflow, result in a high quality, multiazimuth broadband seismic dataset that has the potential to help overcome the main exploration challenges in the Norwegian Sea. Adding a second perspective/illumination direction allows for the assessment of the uncertainty in fine structural details and delivers a significantly improved understanding and characterization of shallow to deep reservoirs. Leads and opportunities suitable for near-field exploration have been mapped using an integrated quantitative interpretation workflow. There are many more to be unraveled!

SUBSURFACE STORAGE

"A poor site that fails to meet the criteria for safe subsurface storage"

Malcolm Butler - UKOGL and John Underhill - Aberdeen University

Are we moving into the age of the pore-space paradox?

A recent regulatory appeal in Canada has highlighted the tension between a potential carbon storage and lithium extraction project in what is supposed to be the same stratigraphic interval

Whilst the people at E3 Lithium in Canada will no doubt support the road to Net Zero, they were not very pleased to see the company Enhance receiving a permit to drill a CCS research well in the same acreage for which they hold a brine-hosted mineral licence. E3 Lithium feared that this "could directly and adversely affect the technical and economic feasibility of their lithium development." The well was drilled regardless, and the appeal was dismissed on the grounds that before Enhance can inject any CO_2, another application needs to be submitted first.

But it is an interesting case regardless, and it shows the increasing diversity of subsurface use that can sometimes lead to a conflict of interests.

FORMATIONS VERSUS GROUPS

The Formation that E3 Lithium is concerned about is the Leduc Formation, which is a well-known Devonian carbonate reservoir in Alberta from which a lot of oil has been produced. And even though E3 Lithium seems convinced that Enhance also targets the Leduc Fm, the decision document that can be found on the website of the Alberta Energy Regulator leaves some room for interpretation. Namely, the document says that with the newly drilled well, Enhance is testing the Woodbend Group formations. The document also says that "the operations conducted under the Well Licences have not impacted the brine-hosted minerals in the Leduc reservoir."

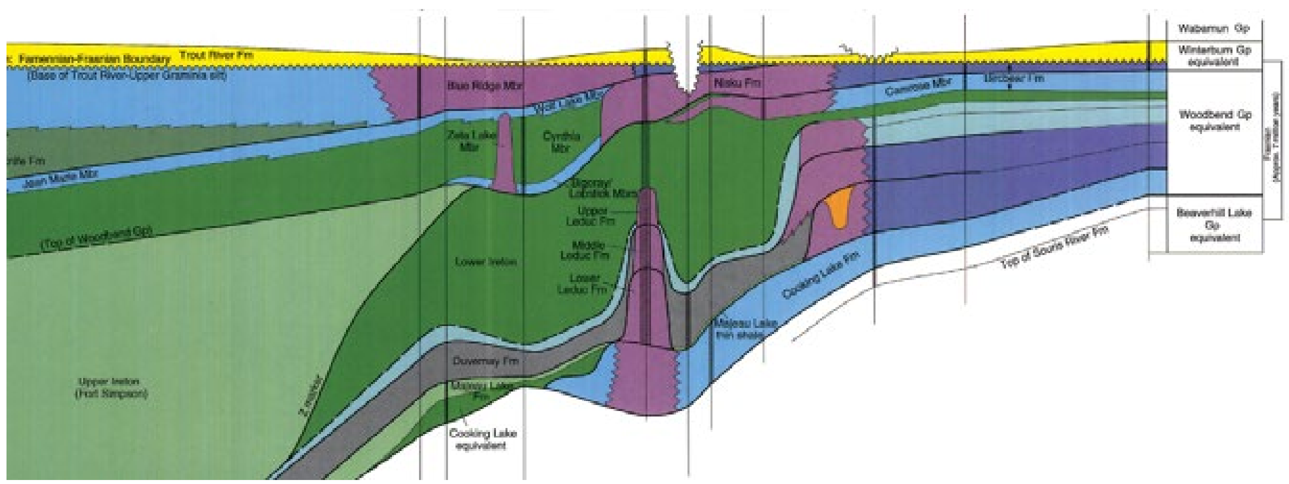
Enhance also responds that "E3's request for regulatory appeal is related to concerns that are subsurface in nature, and there is not yet enough information to evaluate and address these subsurface issues."

This response and the use of Group versus Formation names leaves room for interpretation. Does Enhance target another formation within the Woodbend Group, or is it saying that the testing it has done under the current licence is not impacting the Leduc because it is not injecting CO_2 yet? If the latter is true, the Leduc can still be the main target for CO_2 injection. This seems reasonable to assume, given that the Leduc Formation seems to be the interval displaying the most favourable reservoir properties. The use of Woodbend Group rather than Leduc Formation by Enhance still leaves room for speculation though and it should have been better to narrow that down more.

FURTHER COMMENTS

In a recent LinkedIn post on the matter by Bill Whitelaw, there is also some commentary on the attractiveness of lithium extraction from the Leduc Formation. Brendan Bishop noted that more research is required on the effects of CO_2 injection on Lithium concentration. He adds that these kinds of conflicts will probably become more frequent in the future. In turn, Bill Whitelaw responded to that concluding that "we're moving into the "Age of the Pore-Space Paradox." ■

Henk Kombrink



Stratigraphic diagram showing the Woodbend Group and the various formations that belong to this group.

SOURCE: FIGURE 12.7 IN THE ATLAS OF THE WESTERN CANADA SEDIMENTARY BASIN, THE ALBERTA ENERGY REGULATOR

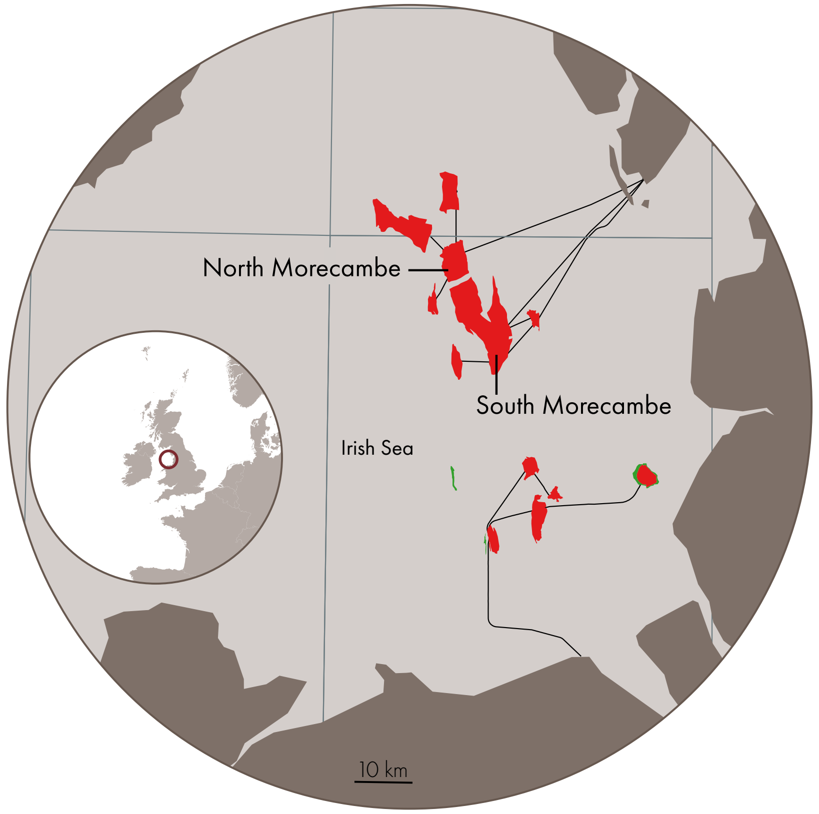
SUBSURFACE STORAGE

CO_2 storage in a tank

The Morecambe Bay fields in the East Irish Sea have been excellent gas producers. Operator Spirit Energy is now looking to re-use the fields for CO_2 storage

THE HOTEL hosting the Aberdeen evening lectures organised by the GESGB should have looked at the programme before deciding not to man the bar. The April talk was about CCS, and because of that, the turnout was about five times as high as normal. Callum Inglis and Tom Calder talked about Spirit's plans to reuse the Morecambe Bay gas fields for CO_2 storage.

The Morecambe Bay complex in the Irish Sea have an enormous storage potential of more than one billion tonnes of CO_2, amounting to about three years of the UK's total annual emissions. The reservoirs are not a major problem. The Triassic Ormskirk Formation can be considered a "tank" according to Callum, and especially at the top of the reservoir, which tends to be illite-free, reservoir characteristics are good (around 13 % porosity and 100-180 mD permeability). This also explains why around 6.6 Tcf of gas has so far been produced from Morecambe Bay, with a limited number of highly productive wells.



Because of gas production, pressures in the reservoirs have declined significantly, from 1,800 to around 100 psi today. For that reason, Spirit aims to inject CO_2 in the gas phase. In South Morecambe, the company will not even reach the point of being able to inject in supercritical phase during the 25 years of anticipated injection, given the size of the reservoir.

NATURAL CO_2

The Morecambe Bay fields are situated in an area where igneous activity during the Tertiary resulted in the emplacement of a series of dykes. This magmatic activity has probably resulted in the subsurface release of CO_2, to the point where the North Morecambe field contains around 6% CO_2 in the gas mix. This confirms that the overlying units prove the sealing capacity for CO_2 but at the same time, when asked about this during the Q&A, it also exposed the odd situation that the CO_2 that is currently produced from North Morecambe is being vented to the atmosphere.

MONITORING AND WIND

The Irish Sea is an area where wind farms are continuously being built. One of those is even planned to straddle the South Morecambe field. This has prioritised the need to acquire seismic data now before this cannot be done anymore. For that reason, a 3D seismic survey was recently acquired. The main aim of the survey is to better image the sealing units of the fields, as well as better map any faults.

4D seismic is not planned once injection will commence in 2030, partly because of lack of access due to wind farm developments, partly because of costs – OBN is seen as too expensive – and finally because of imaging – no 4D response is expected. Instead, Spirit has teamed up with company Reach Subsea that specialises in micro-gravity analysis to monitor reservoir dynamics. ■

Henk Kombrink

"A poor site that fails to meet the criteria for safe subsurface storage"

That is the conclusion two geologists arrived at when they further studied subsurface data from the proposed Cousland hydrogen store in Scotland

ONSHORE seismic is always more of a challenge to interpret than marine seismic data, and the seismic lines from the area around Cousland to the southeast of Edinburgh that Malcolm Butler (UK Onshore Geophysical Library, UKOGL) showed during his Aberdeen Energy Talk in March this year, proved that concept once more. The non-migrated seismic lines as available at UKOGL do not allow easy tracing of the horizons as found in the wells, which is further hampered by gaps in near-surface data resulting from the inability to shoot dynamite in some places.

Yet, based on data of this kind, the former Cousland gas field was proposed to be a candidate for storage of hydrogen in Scotland, probably driven by a desire from the government to come up with tangible candidates that make the energy transition more concrete. Unfortunately, the geology of onshore Scotland is not characterised by the presence of extensive layers of salt and associated caverns in which hydrogen storage is currently taking place further south in England. Neither are there many depleted gas fields that have a track record of storing gas.

SURROUNDED BY MINES

The Cousland former gas field is also particular because it is surrounded by former coal mines. This not only hampers any future seismic acquisition: The mines also form potential sites for the buildup of hydrogen in case of seal integrity issues.

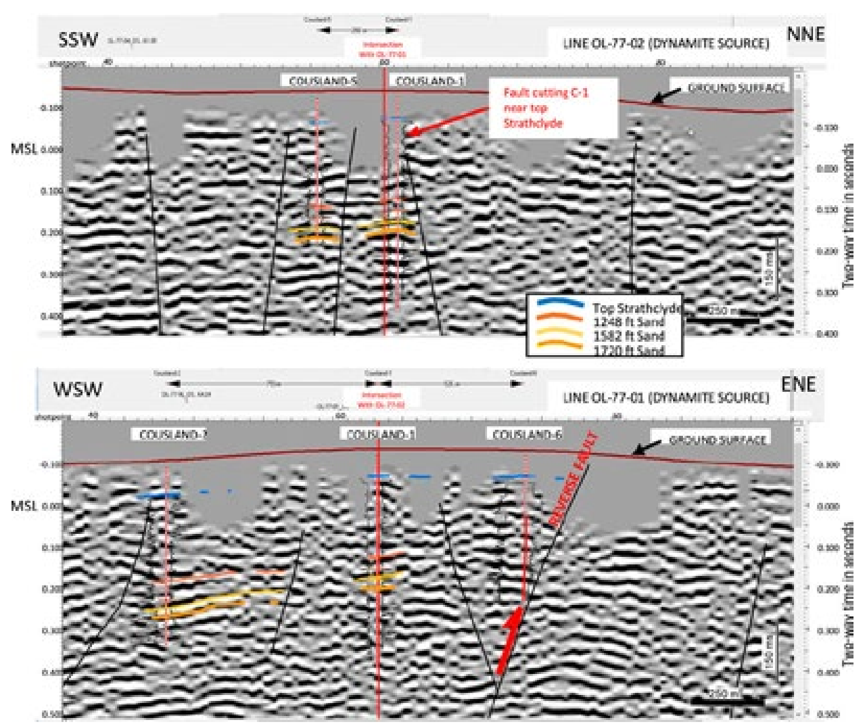
A TINY FIELD

But, Cousland is one of the few. Drilled in 1939, Cousland-1 found gas at around 310 m during a national campaign that had the purpose of finding oil. Even though five subsequent appraisal wells failed to prove more gas, Cousland was taken into production and around 0.25 billion standard cubic feet of gas was produced between 1939 and 1965.

The fact that none of the Cousland appraisal wells found gas is already a sign that mapping of the closure was impossible; the extent of the sealing units is another matter of concern. Especially in the light of storing a small molecule as hydrogen, it is unfortunate that no porosity logs were run in any of the wells to provide a better indication of the integrity of the seals. The lack of seismic data with sufficient resolution also prevents mapping the extent and thickness of the seal, in addition to better understanding the distribution of the reservoir itself.

Based on these and more findings, Malcolm Butler and John Underhill (Aberdeen University) therefore challenged the idea of using Cousland as a hydrogen store in a recent article in ES³ – Earth Science, Systems and Society. Based on this article, it seems unlikely that the go-ahead will be given for this project anytime soon. ■

Henk Kombrink



SOURCE: BUTLER AND UNDERHILL (2024), ES³

Seismic line across the Cousland-1 well illustrating the poor quality of the seismic data.

TECHNOLOGY

"Whilst back in the days, reservoirs were often relatively "clean", today we see increasingly complicated sections, especially more thinly-bedded successions"

Steve Rait – Reservoir Group

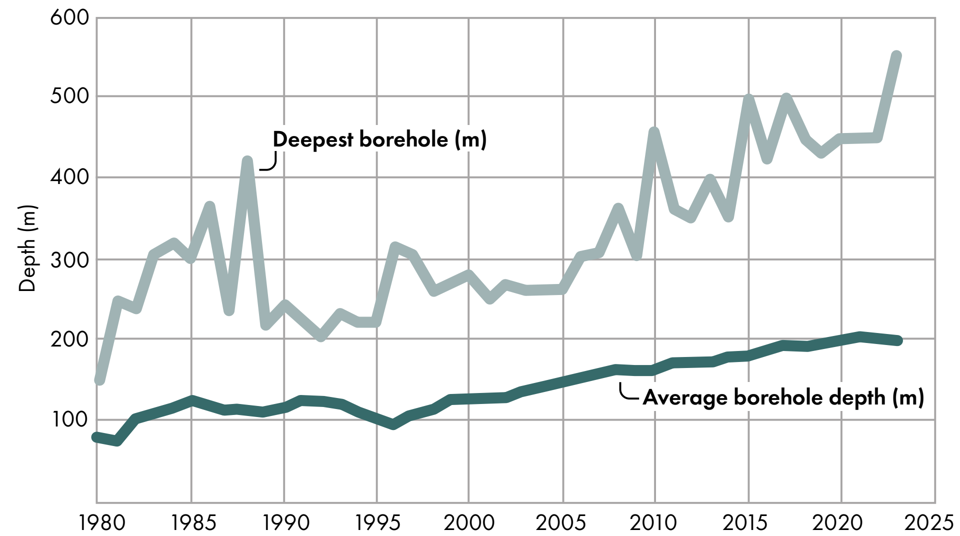
How the winner of a technology competition made room for the losers to take over the market

Two examples perfectly illustrate how the development of technology in Sweden's shallow geothermal space created a template for expansion

SWEDEN comes third in the list of countries using geothermal energy. But it is not deep geothermal energy, it is shallow geothermal – mostly sourced through closed loop systems of only a couple of hundred meters deep.

"Back in the 1980's and the early 1990's, each (ground source) heat pump was basically tailor-made to be fitted in somebody's basement", says Signhild Gehlin from the Swedish Geoenergy Center. Then, in 1995, and this is a key moment in the Swedish geo-energy history, the government decided to organise a competition to design a heat pump for a single family house with a borehole. The government also guaranteed the purchase of 10,000 heat pumps from the winning design."

"The winner of the competition, called the Markus 2500 Combi, was a complete disaster", says Signhild. "The refrigerant and the lubricating oil delivered by the supplier of the compressors in the heat pumps were incompatible for longer operations. The refrigerant reacted with the oil, slowly thinning it out until it stopped performing its lubricating



From around 1996, the average depth of shallow geothermal boreholes drilled in Sweden started to increase from around 100 m - limited by compressor capacity - to 200 m today – limited by energy demand.

SOURCE: FIGURE 12.7 IN THE ATLAS OF THE WESTERN CANADA SEDIMENTARY BASIN, THE ALBERTA ENERGY REGULATOR

function and the compressor malfunctioned", writes Petter Johansson in his book "A Silent Revolution".

But, instead of a market collapse following this debacle, it created the boost the companies that initially lost out needed. "The three biggest players in the Swedish ground source heat pump market at the present day were born during this competition", says Signhild.

INNOVATION IN DRILLING

The rapid development in ground source heat pump technology that started in 1995 subsequently ignited innovation in the drilling sector too. Until the mid 1990's, most shallow geothermal loops were drilled by rigs that were designed to complete water wells. These rigs could easily drill up to 100 m, which was mostly fine for groundwater purposes.

The compressor fitted on these rigs had a capacity of 20 bar, which meant that they could theoretically ensure upward circulation of the cuttings from around 200 m depth. "In practice", Signhild says, "it was more like 160 m." But then, thanks to the rapid evolution in heat pump COP and an increasing demand for a higher energy yield, it was soon realized that deeper wells were needed. This, in turn, created the momentum behind developing a more powerful compressor and a fleet of dedicated rigs for drilling shallow geothermal loops.

For that reason, it is no coincidence that from 1996, the average borehole depth for ground source heating purposes starts to increase, perfectly aligning with the moment at which heat pump technology is being developed fast. It is a perfect example of how the development of one part in the value chain spills over to adjacent ones. ■

Henk Kombrink

TECHNOLOGY

The Low Earth Orbit satellites are coming

Real-time transfer of marine seismic acquisition data has become a reality with the availability of a new network of satellites

UNTIL VERY recently, seismic acquisition companies only "saw" the data resulting from a marine survey when the vessel returned to shore. Of course, basic quality control of the data always takes place on board of the vessel, but any further processing had to wait until the data could literally be handed over to the onshore specialists.

Historically, satellite bandwidth was too limited to facilitate immediate transfer of the data. That has now changed with the arrival of so-called Low Earth Orbit (LEO) satellites. These satellites are a lot closer to the Earth than the more traditional geostationary satellites – 1,000 km versus almost 36,000 km respectively.

As PGS describes in a recent case study whereby full-integrity 4D seismic data from two surveys were directly transmitted to the cloud, the LEO satellites significantly reduce latency (delay), which enables a real-time data transfer between seismic vessels and onshore data centres.

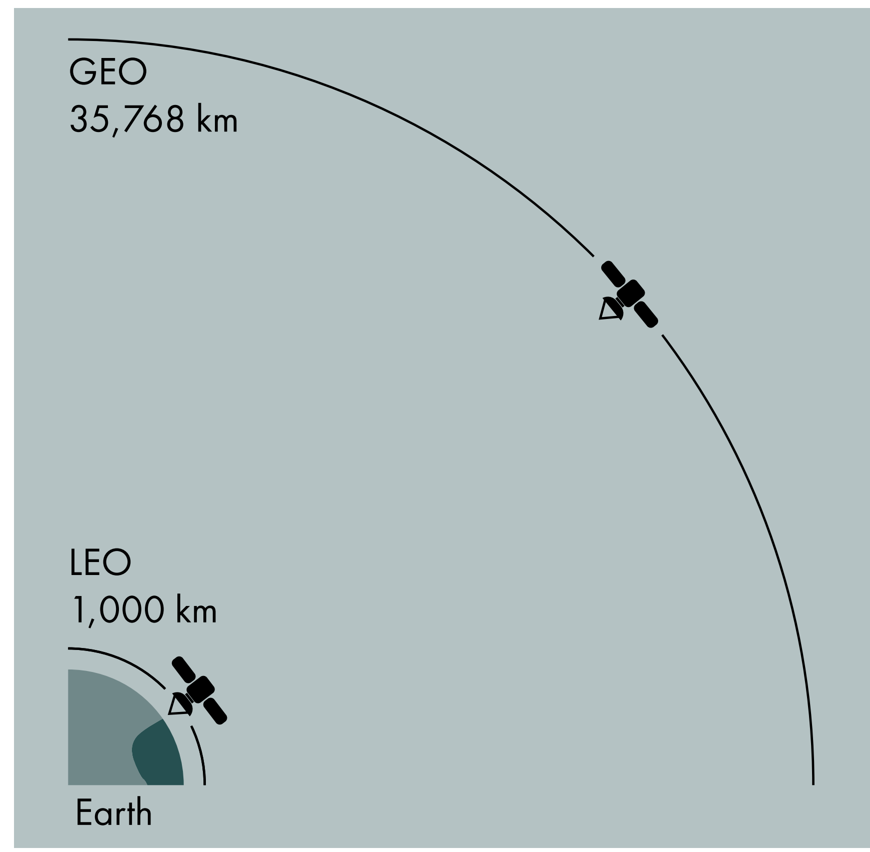
This enables much faster decision-making and also allows for optimizing the operational process whilst acquisition is still ongoing. The increase in bandwidth of LEO satellites also potentially reduces the operational costs as it reduces or even removes the need for on-board data processing.

As a result of the success of these trials, PGS took the strategic decision to implement a base Starlink (LEO) service level alongside the existing VSAT service (GEO).

"The only downside of the LEO system is that continued service is not yet guaranteed with LEO", says Erik Ewig from PGS. "That is the reason why we decided to run both systems on our vessels, even though we have not seen an issue with the availability of the LEO systems yet."

The successful validation of the new satellite technology provides a huge opportunity for the seismic industry, both regarding how clients are gaining access to the acquired data but also on how the project can be followed during the acquisition phase. ■

Henk Kombrink



LEO VERSUS GEO

Unlike satellites in the more distant GEO space that must always orbit along Earth's equator, LEO satellites do not always follow a particular path around Earth; their plane can be tilted. This means there are more available routes for satellites in LEO.

A satellite in LEO travels around the earth in 90 minutes, so they move across the sky very fast. To ensure constant coverage for telecommunication, a network of satellites in LEO is often used, creating a "net" around the Earth.

"We now see that the GEO network has also increased their commercially available bandwidth, probably as a result of the arrival of the LEO service", says Erik Ewig from PGS. "However, latency is still the key difference, which is not so much an issue for transfer of data but the more for things like remote quality control it is."

Getting increasingly complicated reservoirs to surface

Against a backdrop of a rapidly changing market, Steve Rait from Reservoir Group tells about the technology his company develops to keep coring challenging reservoirs successfully

One of Reservoir Group's coring bits showing an irregular placement of the blades to prevent whirling.

"IN A WAY, we have benefitted from the slowdown in drilling activity", says Steve Rait from Reservoir Group when we meet at the company's coring headquarters just north of Europe's oil and gas capital Aberdeen. Steve is Coring Manager at Reservoir Group – a position in which he ensures that the coring jobs his company is involved with run smoothly. Reservoir Group sends coring equipment all over the world - from the hotspots in Namibia and Guyana to smaller projects on the continent.

"Thirty years ago, in the North Sea, companies would cut core routinely to the point where even the reservoir sections in development wells were fully cored. This led to many service companies offering coring expertise. Increased pressure on rig rates and the dramatic effect of the recent downturns have all caused the landscape of coring contractors to shrink. The result is that we are now the biggest player in the region, along with gaining a much stronger foothold internationally", says Steve.

MORE COMPLICATED RESERVOIRS

Another thing that has changed is the types of reservoirs that are being cored. "Whilst back in the days, reservoirs were often relatively "clean", today we see increasingly complicated sections, especially more thinly-bedded successions", Steve explains. "And the risk of something going wrong in these strata is much higher, putting more pressure on selecting the right tools for the application."

One of these tools Reservoir Group further developed is the "Half Moon on Ice" concept. "It may sound a little cryptic", says Steve, "but it is basically a liner that consists of two halves that slot into our Thin Sleeve System Inner Tube. This enables quick inspection of the core when it is brought to surface. The Ice term originates from a treatment the liner receives before it is slotted in the core barrel to reduce jamming of the core."

"Another issue we try to prevent is bit balling", continues Steve, "which is a common phenomenon when drilling mudstones. We apply a coating to the bit that reduces sticking. In addition, our bits are asymmetric, such that whirling does not take place that easily. A high blade standoff further ensures that drilling fluids and the cuttings can easily migrate out of the bit."

"We have an innovation team that continuously works on improving our technology", concludes Steve, "but it is always the geology that determines how long of a core we cut per trip. In addition to that, let us not forget that a coring job always takes place at critical moments. We have to make absolutely sure that our kit arrives on time, works properly, and succeeds in having a good quality core recovered to surface." ■

Henk Kombrink

PHOTOGRAPHY: RESERVOIR GROUP

NEW GAS

"When I started looking at the data, I got more and more excited, to the point where my heart rate increase resulted in receiving some medication..."

Brian Evans – Curtin University

Natural hydrogen – as you may not have seen it before

A company based in Perth, Western Australia, believes that natural hydrogen has its origins at the start of the formation of the Earth – and that it is possible to produce it if explored properly

THE "MAINSTREAM" hydrogen community in the West leans towards multiple physical and chemical processes that lead to the formation of hydrogen in the crust, such as serpentinization, ferrolysis, nuclear decay or crushing of SiO_2 through shear in the presence of water. However, a team of scientists that previously established hydrogen's role in the Earth's formation postulates that these mechanisms suffer from substantial flaws. Vitaly Vidavskiy, Nikolay Larin and Vladimir Vidavskiy from Avalio point out that it is unrealistic to expect commercial volumes of hydrogen generated through crustal mechanisms due to several shortcomings.

Narrow operational pressure and temperature windows, the lack of water in crustal environments and the extremely slow rate of hydrogen generation all put question marks to the idea of stable generation of sufficient volumes of hydrogen in the crust. Serpentinization chemistry is still debated as well, and whether or not hydrogen is released during that process. Finally, hydrogen generation through shear in faults requires pure quartz, which is rarely seen in nature.

DEEP-SEATED HYDROGEN

Instead, the team believes that "deep-seated" hydrogen accumulated in the process of Earth's accretion, which keeps ascending in stream-like flows from the core through geologic time. Fundamental experimental research suggests the presence of hydrogen in the earth's core, and because hydrogen atoms share their electrons with metal atoms they can travel fast.

Implementing the results of scientific research, the first trials of soil gas detection in the field were started by Nikolay Larin and his father in 2006. Since then, this data acquisition method has become the natural hydrogen exploration industry standard around the world.

When using the theory postulated by the Avalio team, the presence of natural hydrogen is extremely universal and not limited to certain geological basins such as oil and gas. This may dramatically change the global geopolitical balance. However, it is still early days when it comes to answering the question where hydrogen can be produced economically, according to the researchers from Avalio. In Mali, hydrogen has been produced for over a decade at the same flow rates, apparently being recharged from a deeper source, whilst other finds such as in Kansas have recorded significant flow rates only for short periods. The latter suggests either insufficient or zero replenishment from the deep.

In order to more successfully explore hydrogen, the researchers argue that a dynamic component needs to be at the heart of any strategy, as proven by the Mali case that clearly demonstrates this through the immanent flow from a tiny reservoir for over a decade. ■

Henk Kombrink

Drilling for soil gas monitoring and soil sampling in Western Australia, August 2023.

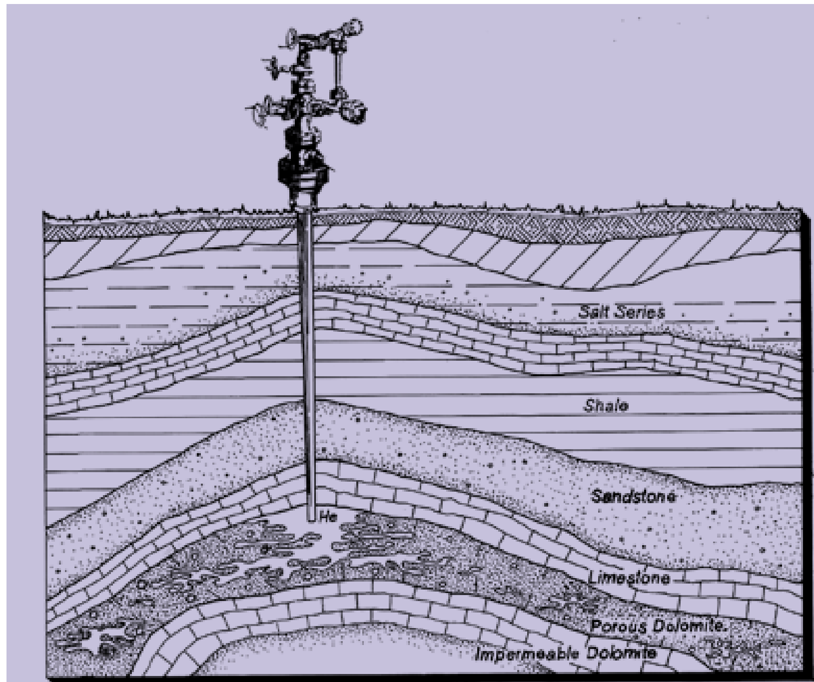
PHOTOGRAPHY: VITALY VIDAVSKIY

How the threat of military conflict created a successful helium storage project

Thanks to the typical American can-do attitude, a large subsurface helium storage project was initiated 70 years ago, which has heavily influenced the global market for decades

STORING non-hydrocarbon gas in depleted oil and gas fields is a hot topic, whether it is permanent storage of CO_2 or temporary storage of H_2 produced by excess wind energy. Yet, it is nothing new. The US government started to successfully store helium underground in 1945.

The Cliffside gas field in North Texas was discovered in 1924. The field consists of several anticlinal structures underlain by salt domes, of which the Bush Dome is the largest. The Brown dolomite reservoir, which also contained helium mixed in with natural gas, occurs at about 1 km depth and is sealed by anhydrite.



Historic American Engineering record, Library of Congress

PANIC

This helium was specifically targeted as early as 1929 and heavily relied upon during the Second World War. This depleted the reservoir to a large extent and caused panic in the US government. For that reason, the state started injecting excess pure helium into the crest of the Bush Dome in 1945 to build up reserves. When military operations during the Korean War and the 'space race' initiated by the Cold War demanded large quantities of helium, they produced it again and discovered that virtually all injected helium could be retrieved.

With reserves depleted again by 1959 and the success of the temporary helium storage under their belt, the US government decided to make the Bush Dome an official helium storage facility. The infrastructure was improved and private gas producers were incentivised to separate helium from their gas stream rather than letting it go to waste.

FLOODING THE MARKET

Injection of crude helium, consisting of ~ 65 % helium mixed with nitrogen, started in 1963. Over the next 30 years, > 35 BCF of gas was injected. However, over this time federal demand for helium declined while demand from the private sector steeply increased. The US government decided to start selling their reserves and flooded the market with cheap helium. The low price caused much of the private helium sector to shut down.

The Cliffside Helium System still supplies over 20 % of the domestic and 9 % of the global demand for helium and an estimated 1.8 BCF crude helium remains in the reservoir. However, the federal government is no longer interested in operating the helium facility and put it up for sale last year, with NBC news recently reporting that Messer Group emerged as the highest bidder.

It is likely that the aging facilities face a temporary shutdown for maintenance and upgrading when ownership is passed. The shutdown could last up to three years, putting additional pressure on the already tight helium market and further driving up the price of this unique noble gas. ■

Mariël Reitsma

Acquiring seismic data for oil exploration in 1980, but using it to find hydrogen now

Geophysicist who acquired seismic lines for Shell in 1980's in Australia's Officer Basin is now back to explore for hydrogen, using the same data

Brian Evans from Curtin University in Perth worked for Shell more than 40 years ago, and in that role he helped acquire seismic lines in the Officer Basin in Western Australia. At the time, nobody was interested in hydrogen, it was oil they were after in this Neoproterozoic basin that is characterised by an evaporitic succession of more than 700 million years old.

In those days, common belief was that the prospective strata were situated in the overburden of the evaporites, so the few wells that were drilled did not penetrate the salt. Pre-salt oil was unheard of and, in addition, it is unlikely that any source rock of more than 700 million years old would have survived anyway.

MORE AND MORE EXCITED

But times have changed, and in response to the increasing interest in hydrogen, Brian remembered the seismic lines he looked at more than 40 years ago. When he started looking at the data, he got more and more excited, to the point where his heart rate increase resulted in receiving some medication… The seismic namely shows some bright spots below the evaporites, in a succession that is supposed to host reservoir sands, as well as below the dolerite dykes in the overburden. He even interpreted gas chimneys in some of the lines.

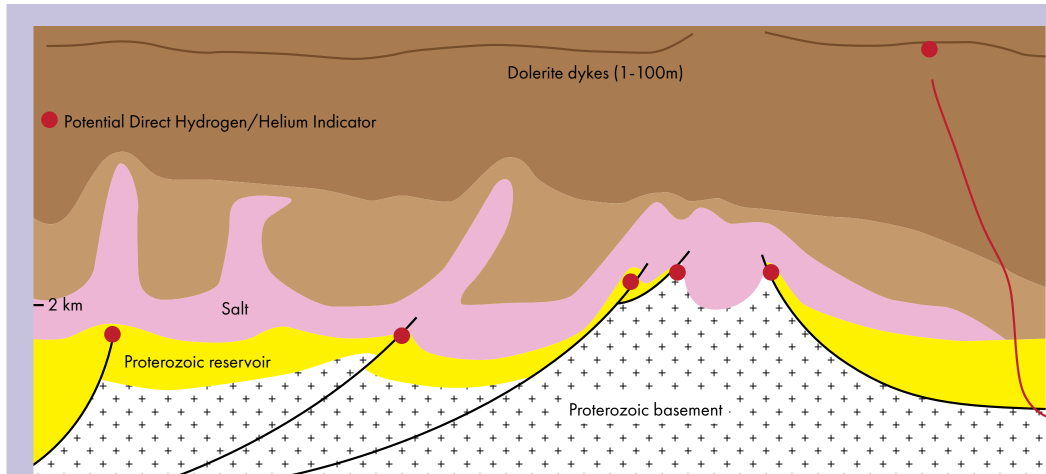
When combining these observations – the presence of fractured basement, a Proterozoic reservoir, sealing evaporites, dolerite dykes and indicators of gas migration, Brian concluded that there is surely potential for a hydrogen play in this basin.

Brian's work was picked up by a UK-based company called Georgina Energy Plc, which now aims to deepen one of the wells previously drilled in the Officer Basin – Hussar-1. The plan is to drill through the salt and test the Proterozoic sandstone below. According to

Georgina Energy, the sub-salt closure has the potential to hold up to 173 billion cubic feet of hydrogen, with Helium also being a likely gas to be found.

However, before drilling can take place, the closure would ideally require more of a mapping exercise, as the legacy seismic lines have a large spacing of between 30 and 50 km. But, if this still looks promising at the end, it will certainly be an exciting well to watch. ■

Henk Kombrink



Schematic cross-section through the Officer Basin in Western Australia, highlighting the places where bright spots can be seen in seismic data, potentially indicating the presence of hydrogen and helium. Dedrafted after a cross-section shown during Brian Evans' presentation at AAPG ICE Madrid.

DEEP SEA MINERALS

"We must also bear in mind that geology does not respect borders, and there is every reason to believe that Greenlandic waters can also hold mineral deposits"

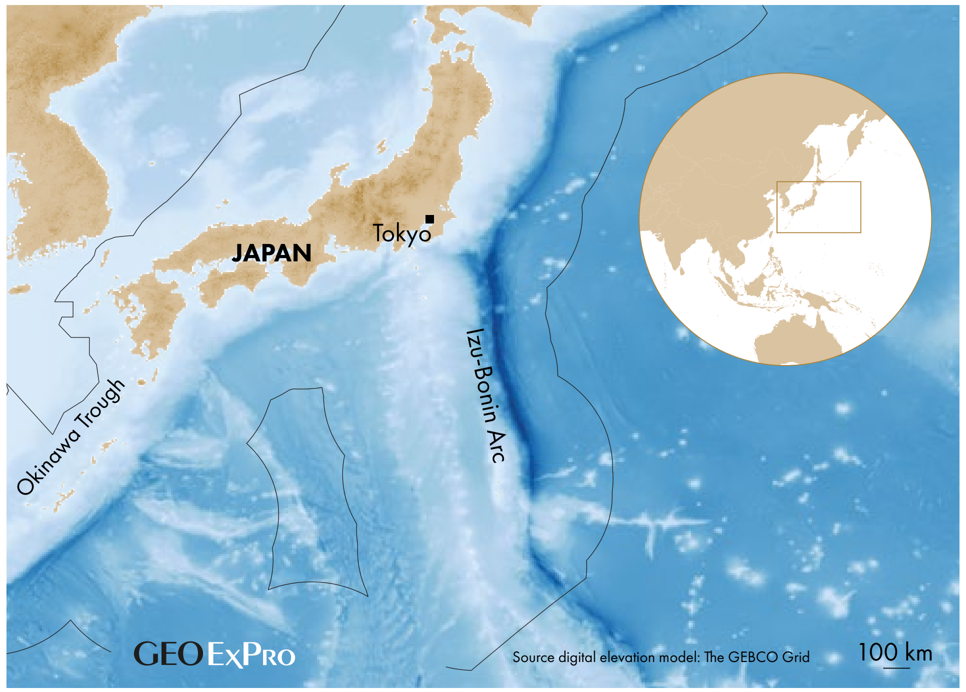
Ronny Setså - GeoPublishing

A frontrunner in deep-sea mineral production

Service and exploration companies can learn from the activities taking place in Japanese waters. JOGMEC has been searching for and trialled production of sulphide deposits in the deep sea for several years

THE NORWEGIAN deep-sea mineral community closely followed the talks from Nagase Kunpei and Kiyotaka Orita of the Japan Organization for Metals and Energy Security (JOGMEC) during the Deep Sea Minerals Conference in Bergen a few months ago. After Norway recently opened up seabed mineral operations on the Norwegian continental shelf, the experiences from Japan will be useful for this new industry.

Japan has conducted state-sponsored exploration for many years. The first surveys date back to 1985, while work on resource estimates has been ongoing since 2008. The presenters highlighted two areas where sulphide deposits have been detected; The Okinawa Trough southeast of the mainland, and the Izu-Bonin Arc south of Tokyo. In both areas, JOGMEC has carried out bathymetric measurements over larger areas. This has been followed up with smaller, more detailed investigations with remotely controlled robots (AUV and ROV), as well as with drilling boreholes.



JOGMEC has been exploring for sulphide deposits at the Okinawa Trough and the Izu-Bonin Arc.

NO LEGAL FRAMEWORK YET

Despite the fact that Japan is ahead of Norway in terms of mapping and test production of sulphide deposits, Kiyotaka reiterated that Japan does not currently have the same laws and regulations as Norway. That may be an explanation for why the country has not seen significant interest from mining companies so far. For the time being, it is primarily the state through JOGMEC that drives the Japanese deep sea mineral activities.

Perhaps it is JOGMEC that will one day initiate extraction, which may be sooner than some people think. The organization started trial production of sulphide deposits in 2017. Orita said that in 2018 they evaluated the test that was done in 2017 to improve the overall production system. Based on the evaluation, new research and development projects were carried out between 2019 and 2022.

One of the improvements JOGMEC has considered is changing from extraction machines that operate horizontally to machines that stand on top of or float over the sea floor and operate vertically through extraction from the top down.

The organization has also further developed the system that lifts the ore to the sea surface. The first test in 2017 showed enormous wear on the pump equipment (3 mm wear after an hour and a half of operation), as well as a great need for maintenance. A new and more intricate solution will help to avoid this, among other things by creating a closed pipe system which also consists of several parallel pipes.

However, Orita pointed out that these parts of the overall production system are still under development. The goal is a robust system that is both as cost-effective and environmentally friendly as possible. ■

Ronny Setså

USA looking to join the race

Several recent high-level initiatives in the US could give rise to American production and processing of marine minerals

THE METALS Company may be the first company - commercial or state-owned - in the world to start full-scale deep-sea mining. That makes their quarterly and annual reports a well-worth read, and while their latest did not disappoint in terms of operational highlights, it was equally interesting to read the "Industry Update" bullet points.

It was hard not to notice that several events have occurred in the US in the past few months, a country that has seemingly not played a major role in the fast-evolving deep-sea minerals space.

Three major developments have occurred at high political levels, which could ultimately enable American production and processing of marine minerals.

First, in March, legislation was introduced in the US House of Representatives, calling for the US to "support international governance of seafloor resource exploration and responsible polymetallic nodule collection by allied partners", and to "provide financial, diplomatic, or other forms of support for seafloor nodule collection, processing and refining."

The two congress members that introduced the bill, the Responsible Use of Seafloor Resources Act, stated that the legislation may reduce supply chain vulnerabilities, particularly concerning China's dominance of the global critical minerals supply chain, while bolstering American manufacturing and jobs.

Second, the 2024 National Defense Authorization Act with the inclusion of provisions directing the US Department of Defense to submit a report regarding the domestic processing of seafloor nodules, was passed into law in January. The Pentagon was expected to submit such a report on 1 March. No public announcement has been made after this date.

Third, in March, a large group of former US government officials and military officers urged US senators to ratify the United Nations Convention of the Law of the Sea (UNCLOS). While the US recognizes the treaty, they have yet to ratify it.

Until the US ratifies UNCLOS, they are not able to become a member of the International Seabed Authority (ISA), precluding them from taking an active role in developing and adopting regulations concerning the exploitation of mineral resources in international waters managed by ISA ("the Area").

Nor are they able to sponsor companies. Companies wanting to explore mineral resources in the Area may obtain licenses by forming partnerships with (being sponsored by) ISA member states. For instance, TMC has partnerships with The Republic of Nauru, The Kingdom of Tonga, and The Republic of Kiribati for its exploration licenses in the Clarion-Clipperton Zone in the Pacific Ocean. The Authority is expected to complete and adopt necessary mining regulations by 2025.

Even if the US decides against ratifying the UNCLOS, they may still move forward with plans for domestic exploitation of marine minerals, or build processing capacity to receive ore from international waters. ■

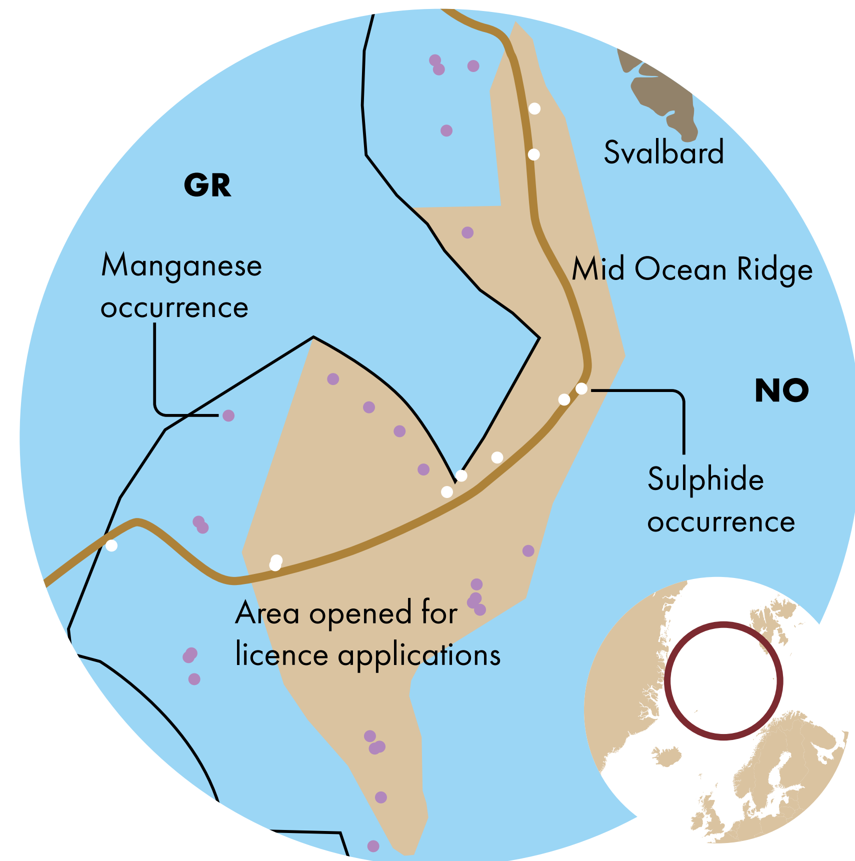
Ronny Setså

PHOTOGRAPHY: LISA FERDINANDO, DOD

The US Department of Defense is expected to address the national security implications of deep-sea nodule collection as part of its mandate to ensure the stability and strength of critical minerals used for defense and clean energy technologies like batteries and renewable energy infrastructure.

Gathering forces for marine mineral mapping

The Norwegian Offshore Directorate (NOD) enters into cooperation with Denmark and Greenland for increased knowledge and the possible establishment of a knowledge centre regarding deep-sea minerals



The NOD states that in February they entered into an agreement of intent with the National Geological Surveys for Denmark and Greenland (GEUS), the Greenlandic authorities and the Greenland Institute of Nature on a collaboration for increased knowledge of deep-sea minerals.

The plan is for the partners to submit a joint application to the Nordic Council of Ministers for support for the establishment of a new knowledge centre - Knowledge Centre for Responsible Sourcing of Deep-Sea Minerals in the Arctic Region.

This can contribute to the three countries building a joint knowledge base regarding deep-sea minerals in the sea areas between Norway and Greenland.

It was in January 2023 that the NOD presented its resource assessment for seabed minerals in the Norwegian economic zone (extended Norwegian shelf). Even though the estimate is so far based on relatively limited data, the directorate believes that there is significant scope.

The sulphide deposits occur in connection with the active spreading ridge (older sulphide deposits will have long since been buried by lava and thick sediment packs), while metal-rich crusts appear more scattered and are linked to seamounts.

The NOD and the universities in Bergen and Tromsø have carried out a number of expeditions in recent years and detected and sampled several marine mineral deposits. The map shows proven sulphide and manganese crust deposits.

Of course, the map does not show the deposits that are yet to be found. We must also bear in mind that geology does not respect borders, and there is every reason to believe that Greenlandic waters can also hold mineral deposits. It is likely that it will primarily be a question of crustal deposits because the spreading ridge, where we expect to find the sulphide deposits, is mainly located in the Norwegian economic zone.

Any future cooperation with the collection and sharing of seabed data can help to provide a more complete picture of the geology and resources in the sea areas that separate the countries. The NOD expects feedback from the Nordic Council of Ministers regarding support for the project closer to summer. The Nordic Council of Ministers has previously supported projects related to better utilization of Nordic mineral resources. ■

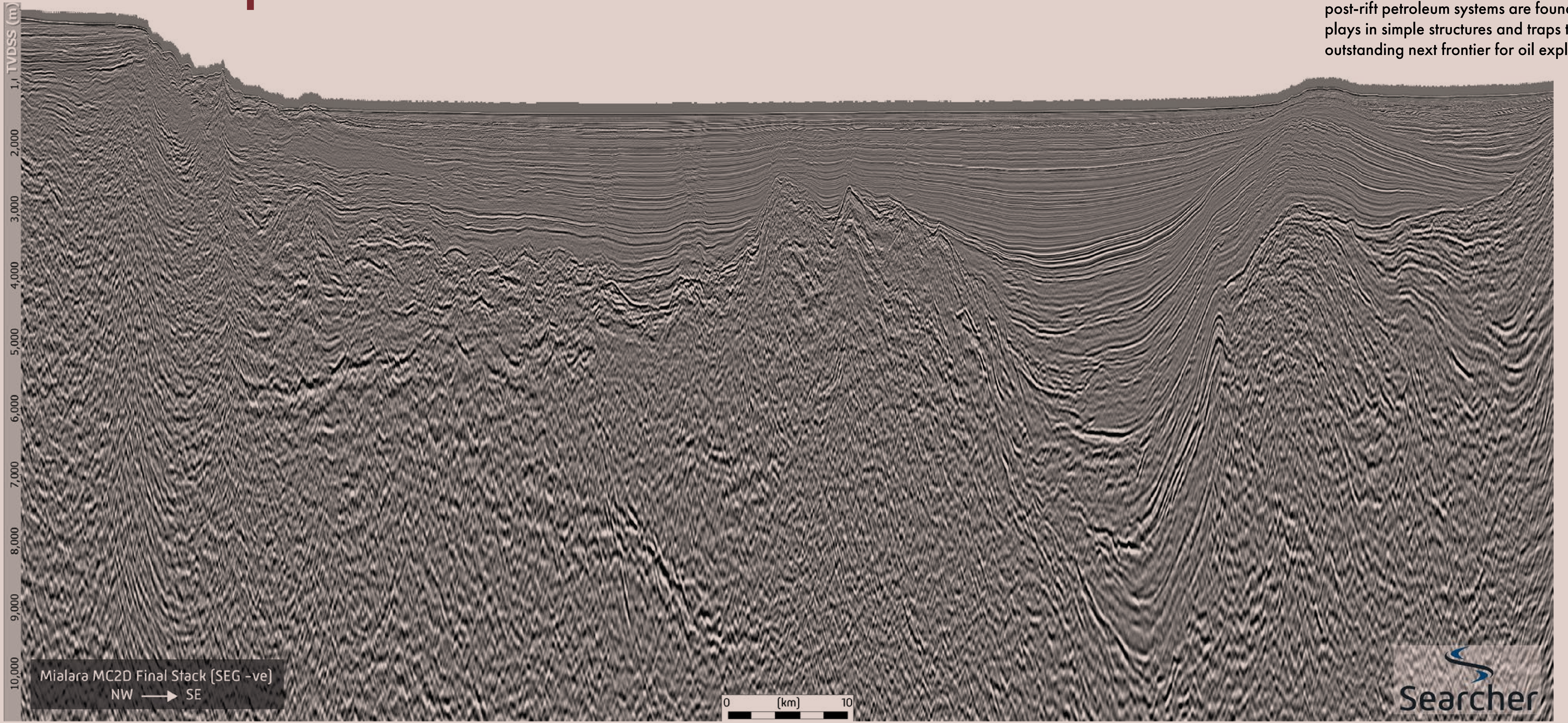
Ronny Setså

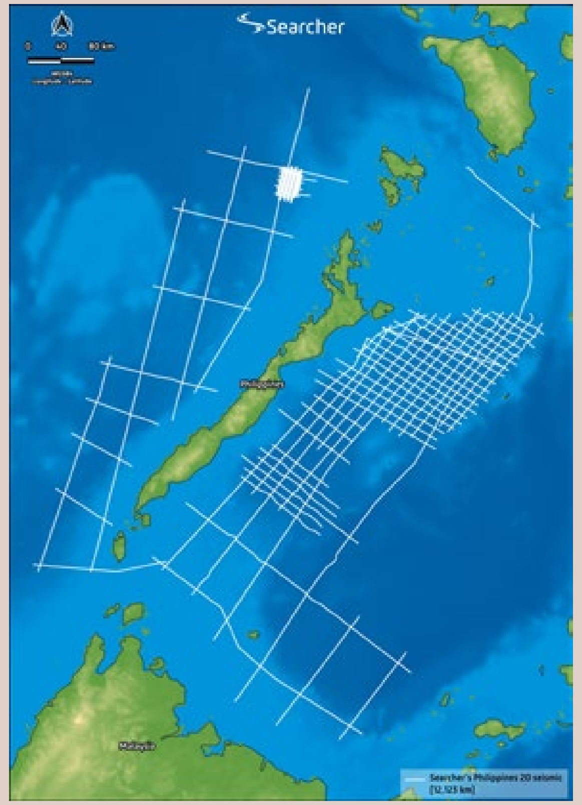
OPENED UP

On 15 April, the Norwegian Authorities formally decided to open an area in the Norwegian Sea and the Greenland Sea for mineral activities. It is expected that the first licensing round will start in 2024, with the award of exploration permits in the first half of 2025.

Orpheus in the Mialara Sub-Basin

The Philippines Big Oil Basin. In the East Palawan Basin, modern seismic data has revealed extensional horst-graben systems with more than 10 km of sedimentary fill in the Mialara Sub-Basin. Pre-rift, syn-rift and post-rift petroleum systems are found with large, carbonate and clastic plays in simple structures and traps that mark this basin out as the truly outstanding next frontier for oil exploration in the Philippines.





Searcher

East of Eden: The Mialara basin, the Philippines' last low-risk frontier for exploration greatness

KARYNA RODRIGUEZ, LAUREN FOUND AND NEIL HODGSON, SEARCHER

ARGUABLY THE first subterranean explorer to return from the untrodden lands below was the Argonaut Orpheus, descending to the Underworld to retrieve his wife Eurydice. Although the geology of this adventure is not recorded, it was a successful retrieval until just short of success, he looked behind him to check his wife was following and in doing so, Eurydice was lost forever. Doubt, a mixture of a lack of data and an imperfect model of the intentions of the gods crushed Orpheus's endeavour. Similarly, explorers in frontier basins must carry colossal uncertainties in the veracity of their earth vision, models, and of course the intentions of the gods of chance, to a degree that can overwhelm. One tool against these doubts is improved seismic imaging as this can not only give greater confidence in the subsurface understanding, but it can also reveal new insights that can stack the odds in the explorer's favour.

MIALARA SUB-BASIN SETTING

The multiphase tectonic evolution of the Philippines has resulted in a glittering array of complex structural settings including mobile arcs, accretionary terrains and spreading centres. The Palawan area of interest is primarily underlain by a sliver of micro-continental crust while the West Philippines (South China) and Sulu Sea basins are underlain by oceanic crust related to back arc spreading in the Early Miocene.

Previously unrecognised in the East Palawan Basin, modern seismic data has revealed a series of en-echelon grabens with over ten km of sedimentary fill. This area has been very little explored to date (see the fold out section) and is designated the Mialara Sub-Basin.

The Silangan-1 (Shell, 2011) was the most recent well drilled in the area in a basinal location west of the graben system and terminated in the Middle Miocene. This well targeted a stacked series of apparent flat spots (potential Direct Hydrocarbon Indicators), that Searchers more recent Mialara 2D dataset reveals to be just coincidental flat reflectors – the toes of slump faults, with no AVO support. However, the Maniguin-2 well was drilled in 1994 by PNOC to the west of the area on flank of the Mindoro-Cuyo Platform. This well tested 300 bopd of waxy oil from a Lower Miocene sandstone reservoir (the Semirara Formation). Indeed, the Lower to Middle Miocene sandstones in adjacent wells (Semirara-1 and Maniguin A-1X) also have high porosities (9 – 31 %) and permeabilities (< 1,070 mD). Samples from the basal Miocene section in Maniguin-2 exhibit good to excellent source potential. The Maniguin-2 well results have been used to calibrate temperature and heat flow data input into northern East Palawan burial history model (Figure 1).

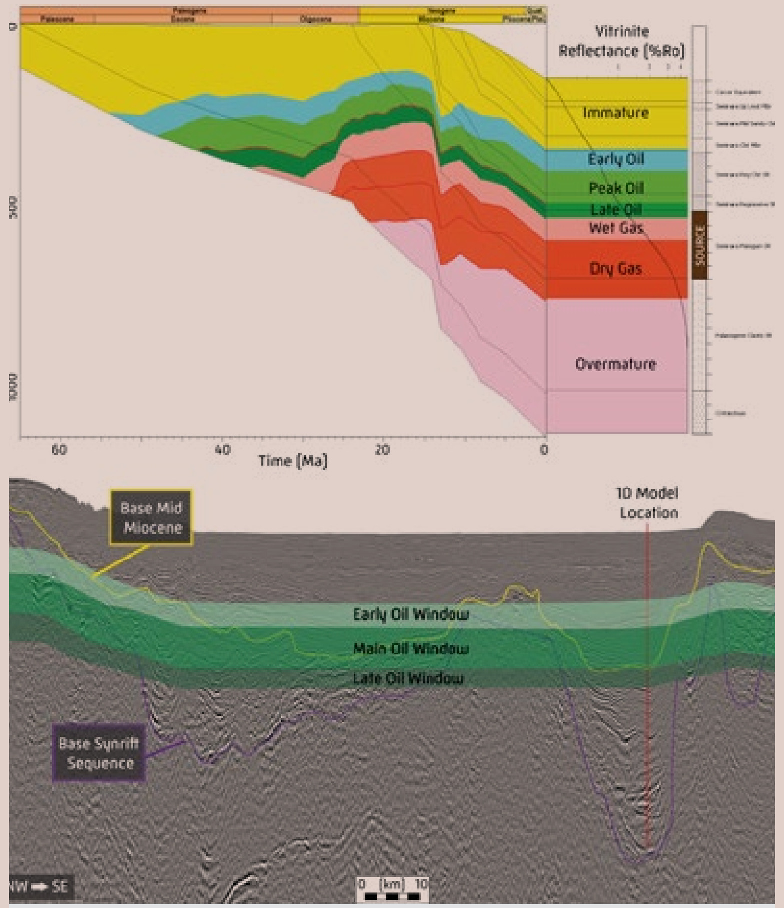


Figure 1: Basin model for the Mialara Sub-Basin, and seismic line indicating the current depth to oil window overlain. Early Miocene rocks, which are a source in Maniguin-2, are currently in the Late Oil-Early Gas window in the graben systems of the Mialara Sub-basin.

This basin model, when applied to the graben systems mapped across the Mialara Sub-Basin indicates that oil will currently be generating in the Graben systems perfectly situated to charge the overlying clastic turbidite systems and the Horst flank carbonate buildup plays. Abundant fluid migration features are observed on the new seismic data (DHIs and gas chimneys).

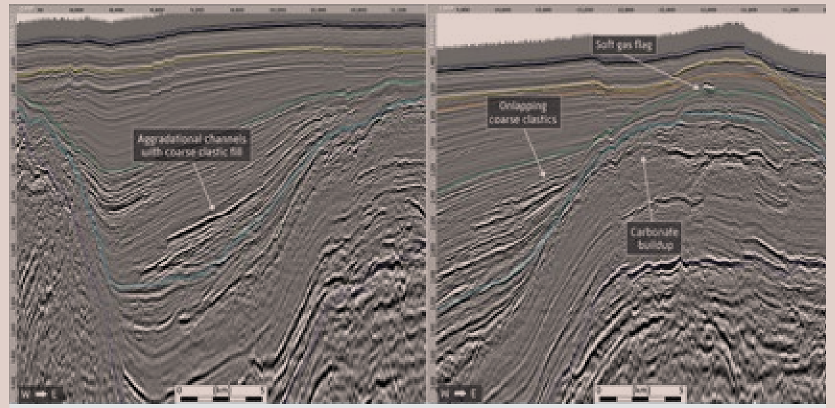


Figure 2: Seismic lines across the grabens in the Mialara sub basins beautifully indicating onlapping clastic plays and DHI's with the grabens, and carbonate buildups on the adjacent horsts.

The undrilled Miocene carbonate reef facies, analogous to the Nido Limestone targeted in fields across Northwest Palawan, are observed on Searchers 2D seismic dataset in the Mialara basin and provide targets with excellent reservoir quality. In this area however, the focus is shifting from the proven Philippine carbonate plays towards quartz rich coarse classic plays. The Mialara data uncovers several stratigraphic and structural leads including channels with differential compaction suggesting coarse clastic fill, Pre-Miocene horst blocks and tilted fault blocks. The exploration wells in the region have been drilled on the edges of the Basin and, although three of these encountered poor quality clastic reservoirs in the Early to Middle Miocene strata, these sediments were quartz-rich and appear to be of continental origin, likely shed from a provenance area on the adjacent Cuyo-Mindoro platform. The low permeability in these sediments is associated with very poorly sorted conglomerates, probably deposited as alluvial fans very close to the edge of the basin. It would seem likely that depositional environments elsewhere in the basin are highly likely to generate conditions more favourable to the development of good porosity and permeability.

The high quality of modern 2D seismic data in East Palawan provides a clearer image of the structural and stratigraphic framework and provides evidence of the existence of a viable petroleum system in the unexplored East Palawan Basin. Such data reduces uncertainty on the hydrocarbon systems and removes any lingering doubt that these basins will be both prolific and successful. Armed with such data the modern-day Orpheus, confident in their earth vision, indeed able to see the object of desire (DHI's) ahead of the drill bit, can return to the challenge of the Greek Myth, seeking to recover the prize from the depths without a shred of doubt. It is time to rewrite the story here and usher in a new age of exploration success to the Philippines.

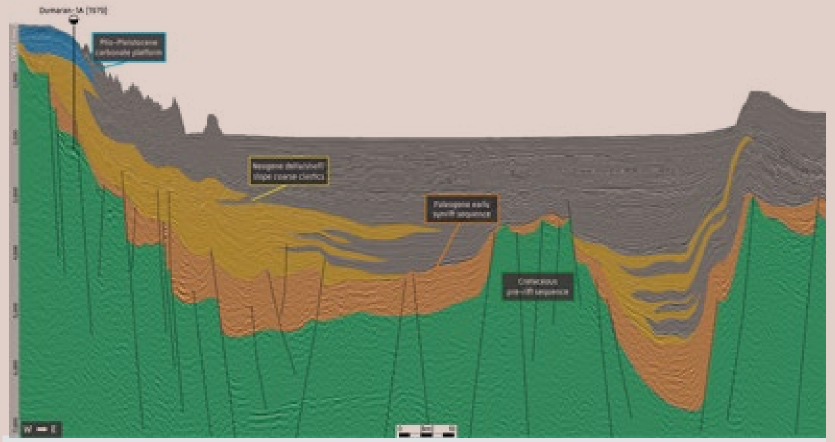


Figure 3: Facies distributions in the East Palawan Basin. Orange indicates sands. To the west (the shelf) these are interpreted as alluvial fan facies, poor quality and in the central and east graben of the Mialara sub basin these will be better sorted, early charged turbidites sourced from the North.

INSIGHTS

"Riedel shears are subsidiary faults to a master fault and should not be used to describe regional fault patterns that occur at various orientations. This is why it is important to understand the paleo-stresses and tectonic history"

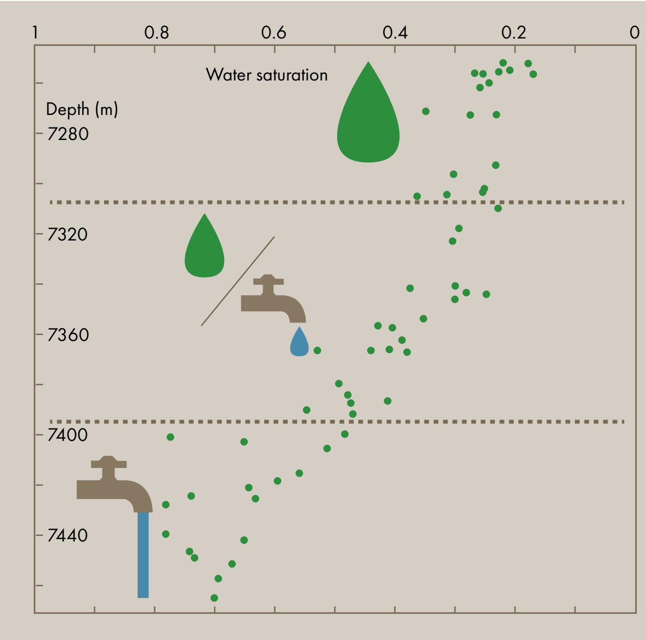
Molly Turko – Devon Energy

The rise of production geology

Developing an intricate understanding of a reservoir allows you to do more with less

RAFFIK LAZAR, GEOMODL INTERNATIONAL

BEFORE anything, let's clear the water: Production geology is not a cross-over between the cinema industry and our good ol' geology. Production geology refers to unravelling the geological intricacies in the reservoir using the classical subsurface workflows aided by the dynamic behaviour during hydrocarbon production.



Average water saturation versus depth for a group of producer wells correlated with production performance in a carbonate reservoir. The wells located higher compared to the FWL are characterized by low water saturation and dry oil production. The wells located at a moderate distance to the FWL produce oil with significant water cut. The wells located at the bottom of the oil column, close to the FWL, are characterized with high water saturation and excessive water production.

When the exploration geologist opens up the uncertainty spectrum by heavily leaning on geophysical data and broad geological concepts to map out prospective structures, the production geologist narrows down the possibilities to understand the connected hydrocarbon volumes by looking at the existing production performance at field level. Production geology connects the geology of the reservoir with the too often neglected physics of the reservoir.

Understanding connected volumes early can prove to be a game-changer for the asset team. Normally, critical subsurface uncertainties remain at the beginning of the field life and can only be unravelled by having more production data. A good example would be the sealing or leaking characteristic of a fault which can only be ascertained by comparing the connected volumes with the overall in place volumes… or drilling an additional well in the undrilled fault block.

Here are two examples where production geology expresses its might:

1) In a heavily faulted reservoir, the reconciliation between the overall static volume in place and the dynamically connected volumes from a P/Z plot observed at the producing wells during early production helped confirming undrained fault block. An infill well was successfully drilled. The asset team was instrumental to respond quickly because additional depletion would have rendered the infill well undrillable due to the excessive differential between virgin pressure (undrained scenario) and current pressure (depleted as per main block).

2) In a carbonate reservoir, cross plotting well test results versus depth against average Archie Saturation enabled the production geologist to distinguish three vertical levels: at the top with dry oil production, in the middle with a mix oil / water production and at the base largely dominated by water production. The initial FDP was steered toward focussing on the top level while zones with higher water production were sidelined until a surface water treatment facility is commissioned.

MORE WITH LESS

In our current era, where companies are reluctant to drill high-risk, high volumes exploration prospects, optimizing current reserves is the new way to go to arrest decline and in some cases replace reserves. Superior development of current reserves is also paramount to our push for carbone emission reduction. The rise of production geology will be a key enabler to do more with less. ■

Chasing Orange Basin Success on the South American Conjugate Margin

NVENTURES

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With the well-documented success achieved in the Namibian Orange Basin with the Venus and Graff discoveries in 2022, there has been an understandable interest in the South American conjugate margin and its potential to contain similar giant accumulations

JONATHAN LEATHER, NVENTURES

The basins of interest span from the Pelotas of southern Brazil and Uruguay, through the Punta del Este and into North Argentina. Historically, this has been an underexplored region, with relatively few exploration wells drilled in its extensive > 500,000 km² area. However, a number of international companies – including supermajors - have now established acreage positions, and with work programme commitments estimated to be well in excess of $ 500m, the area is going to see significant activity over the coming years.

GEOLOGY

The recent discoveries offshore Namibia have been made in Apto-Albian basin floor fans and Upper Cretaceous turbidites charged by a Lower Cretaceous Aptian source rock. Although there are differences between the Namibian and South American passive margins, with a noticeably thicker Tertiary section on the South American conjugate, the same Aptian-aged source interval that is present in the Namibian Orange Basin can be seismically correlated across to South America. With Cenomanian-Turonian source rocks also potentially developed and mature, and the identification on seismic of similar reservoirs to those encountered in the Venus and Graff discoveries, it is not surprising there has been so much recent interest.

PELOTAS BASIN, SOUTHERN BRAZIL

In December 2023, 44 Blocks were awarded in the Pelotas Basin in the 4th Cycle of Permanent Offers. The companies receiving awards included Petrobras, Shell, CNOOC, and Chevron. With signature bonuses exceeding $ 60m, and work programme commitments close to $ 400m, significant activity can clearly be expected there.

PELOTAS AND PUNTE DEL ESTE BASINS, URUGUAY

The entire available offshore acreage in Uruguay has now been licenced, with Shell, Apache, and YPF entering the country in 2022 and Challenger Energy most recently confirming award of the final licence, OFF-3, in 2024. Work commitments for the next 3 to 4 years include the acquisition of 2,500 km² of 3D seismic (Area OFF-4, Apache/Shell) and the drilling of an exploration well (Area OFF-6, Apache).

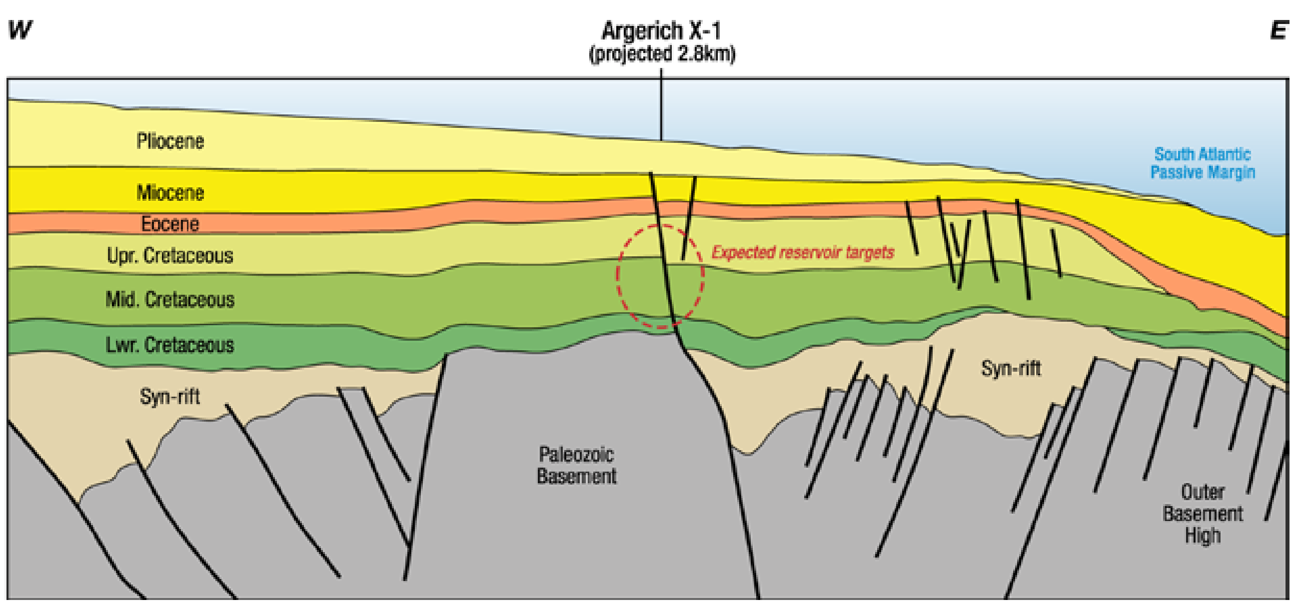
Chevron has also entered offshore Uruguay again after an absence of around 50 years, with a farm-in deal with Challenger on Block OFF-1 announced in March 2024. Under this agreement, Chevron will fund the acquisition of 3D seismic in 2024/25, with the intention of drilling a well in 2027. With a further nod to the potential ties to Namibian success, Charlestown Capital has taken a major investment in Challenger Energy. Charlestown are a major shareholder in Sintana Energy, already well-exposed to a number of exploration campaigns in the Namibian Orange Basin.

NORTH ARGENTINIAN BASIN, ARGENTINA

Moving further south along the continental margin and into Argentina, acreage holders include Equinor, YPF, Shell, TotalEnergies, and BP. Equinor and YPF are reported to be acquiring 3D seismic on Blocks CAN-102, CAN-108, and CAN-114 in 2024, with Shell and TotalEnergies also likely to be acquiring new seismic over their blocks this year. Argentina's first deepwater well, the Equinor-operated Argerich-1 in Block CAN-100, is understood to have spud. This is targeting Cretaceous-aged reservoirs and as an initial test of the conjugate margin will no doubt be closely watched by operators and acreage-holders on both sides of the Atlantic.

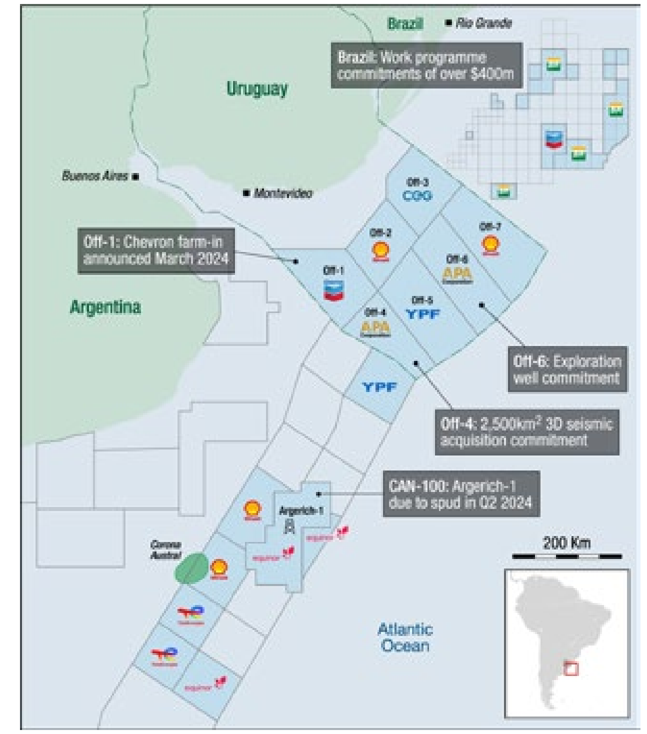
A SOUTH AMERICAN EXPLORATION HOTSPOT

The South Brazil-Uruguay-North Argentina conjugate margin to the Namibian offshore basins has very rapidly become a South American exploration hotspot. With supermajors now holding large acreage positions, extensive 3D seismic acquisition soon to get underway, and at least 3 wells planned to be drilled by 2027, this is definitely a region to watch – and could well be where the next basin-opening discovery of global impact is made. ■

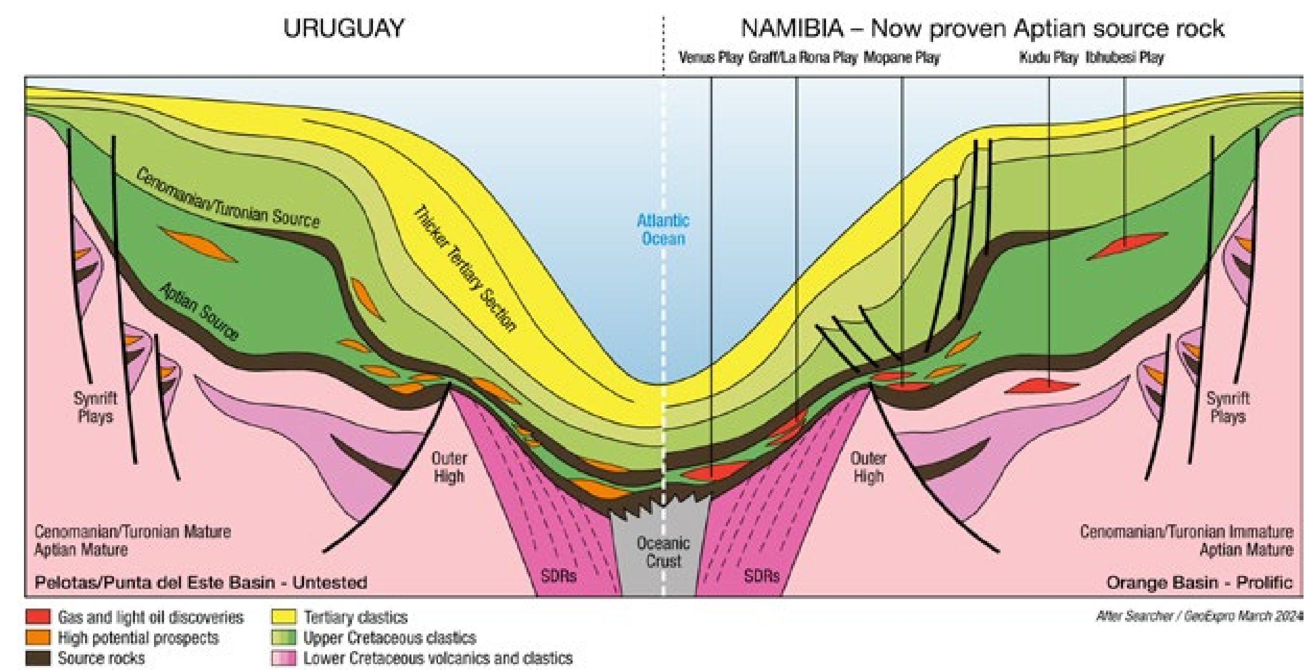


West-East trending cross-section showing the geology of the area where Equinor will spud the highly-anticipated Argerich X-1 well this year.

DRAFTED BY NVENTURES



The currently allocated offshore acreage in the Brazil-Uruguay-North Argentina area, clearly showing why the area is seen as the next frontier.



SOURCE: NVENTURES; SEARCHER SEISMIC

Aptian and Cenomanian/Turonian (C/T) source rock model across the conjugate Orange and Pelotas Basins. Due to a thicker Tertiary overburden offshore Uruguay, it is likely that not only the Aptian source rock is mature, but also the Cenomanian/Turonian.

Riedel shears as kinematic indicators

How Riedel shears express themselves in outcrop and seismic data

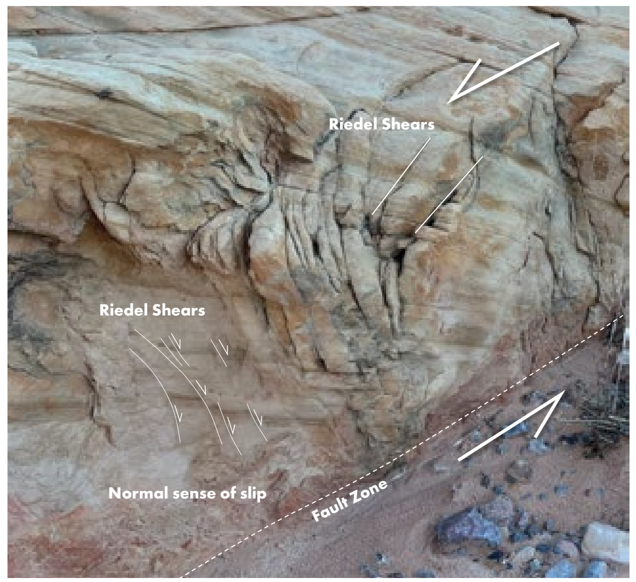
MOLLY TURKO, DEVON ENERGY

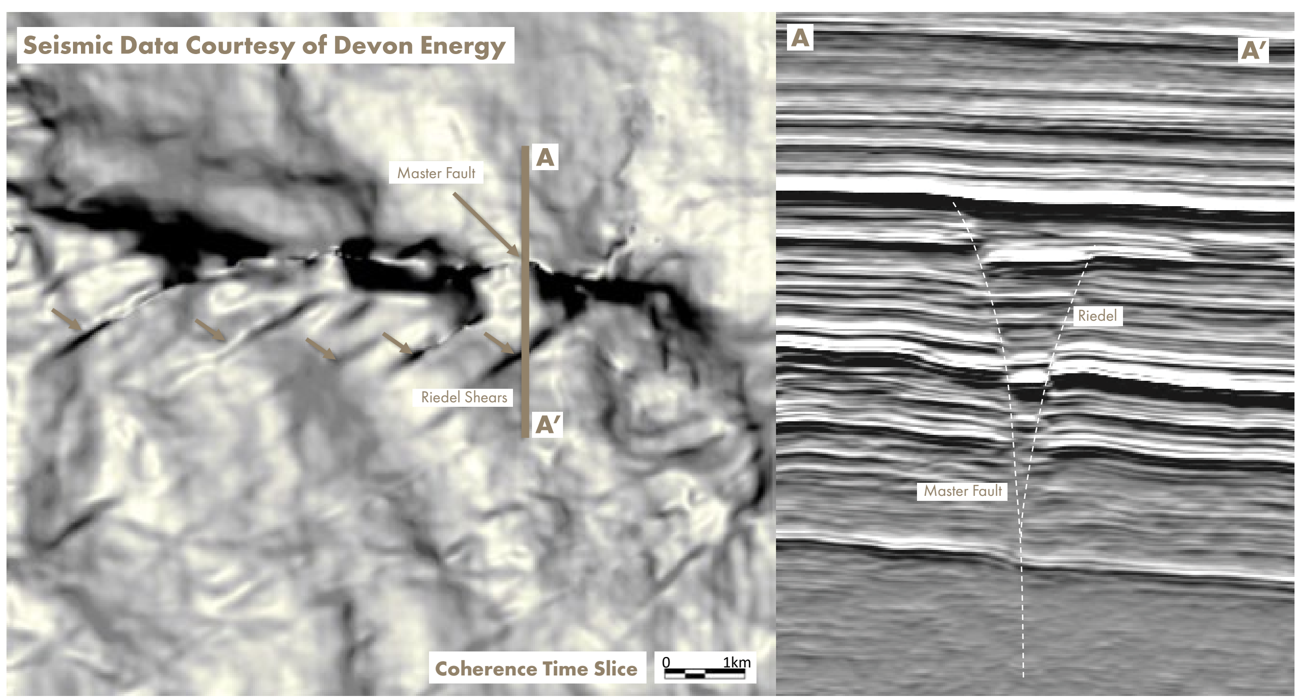
IN THE PREVIOUS article in this series, we discussed that Riedel shears are commonly the first set of subsidiary faults we see prior to the breakthrough of a master fault.

The photo shows a 3D outcrop view of a strike-slip fault (master fault) and associated Riedel shears. A cross-section view of the Riedel shears shows an extensional sense of offset linking down to the buried master fault in the wash. The orientation of the Riedel shears are about 20° to the master fault.

This slight offset frequently allows Riedel shear faults to be resolved in 3D seismic data where it may be difficult to determine piercing points in the subsurface, which would otherwise allow the interpreter to determine the slip sense. The seismic time slice shows where the en echelon pattern of Riedel shears can be observed and a cross-section where the faults show normal offset associated with the left-lateral strike-slip faulting.

By determining the slip sense along a strike-slip fault, an interpreter can decipher the paleo-stress history which can then aid in predicting additional faulting and fracturing patterns in a basin. It can also aid in predicting areas of enhanced secondary faulting/fracturing along a master fault. As previously noted, Riedel shears are subsidiary faults to a master fault and should not be used to describe regional fault patterns that occur at various orientations. This is why it is important to understand the paleo-stresses and tectonic history. ■





Heat flow as a basin model calibration? Not really

Surface heat flow "measurements" are not a useful thermal calibration for a basin model. It is a proxy for regional thermal regime variation and a local fluid flow indicator

DAVID RAJMON

MANY EXPLORATION geologists who work in data-lean basins or who do not have access to well data turn to published heat flow data as a calibration for basin models. More than one of my clients was surprised when I expressed my reservations. Basin models calculate heat flow so calibrating to published heat flow sounds reasonable. What's the issue?

Heat flow is not a measurement. It is a quantity calculated from measured temperatures and calculated thermal conductivity: HF = thermal conductivity x temperature gradient. Surface sediment heat flow is determined from temperatures measured with a probe - a rod fitted with an array of temperature sensors and a few others - that is dropped along side a piston or gravity corer, penetrating a few meters deep. Once in place, temperature is monitored over several minutes until it equilibrates. Measured temperatures are fitted with a regression line determining the sediment temperatures. These temperatures then provide the temperature gradient over a few meters depth interval.

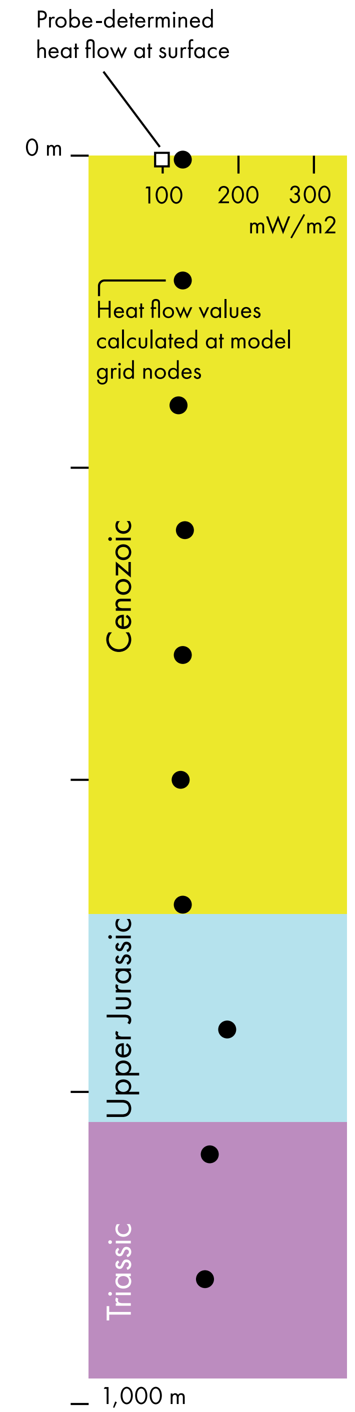
In the next step, heat pulses are sent into the sediment and temperatures are again monitored. Analysis of these measurements yields in situ thermal conductivity. It is important to note that the conductivity is measured in the horizontal radial direction from the probe and this can be significantly different (generally higher) from the vertical direction in anisotropic sediments (shales). Additionally, the quality of these measurements are dependent on the quality of the probe-sediment coupling.

While reported heat flow data may include a level of uncertainty, this is derived from the statistical assessment of the measurements, which may, to some extent, include the effect of the probe-sediment coupling. It cannot include the effect of anisotropy as it is unknown. Even so, these uncertainties can be significant. For example, measurements offshore Uruguay ranged between 31 and 75 mW/m^2 with 3 σ uncertainties mostly 1-7 and up to 13.5 mW/m^2.

> "More than one of my clients was surprised when I expressed my reservations."

Compared to that, a basin model calculates vertical heat flow on a much bigger spatial and temporal scale, based on vertical thermal conductivities assigned to the model from measured compacted sediments and extrapolated to high uncompacted porosities. Thus the heat flow calculated by the basin model can be a couple of tens of mW/m^2 different from the heat flow calculated from the surface in situ measurements.

So what is the surface heat flow good for? It is useful to compare trends and anomalies over large areas between in-situ derived and modelled heat flow. In this relative sense, it reflects the deep crust-lithosphere structure and local fluid flow along faults and other structures. ■



Schematic heat flow values calculated at model grid nodes vs. probe determined heat flow at surface 3-5 m. Diagram inspired by Harlé et al. (2019).

NOTHING BEATS THE FIELD

The cream of the outcrop

This panorama shows an Upper Miocene succession, la Rambla de Lanujar, in the Betic Cordillera, featuring in one of our field trips to Tabernas, Almería, Spain.

Apart from being a popular Hollywood Movies backdrop, this panorama helps participants assess and plan a petroleum development in a channelised turbidite system: Multiple erosive and infill phases that impact reservoir complexity through permeability contrasts. These are things that are not reconcilable in seismic or log data and a field visit is therefore very useful to fully appreciate this.

The field trip attendees are looking at a south-north-oriented cross-section of a channel complex which is encased in and onlapping onto hemipelagic fine-grained marlstones.

The channel is of Tortonian age (Upper Miocene) belonging to the Sartenella Formation. The turbidites are texturally and compositionally immature displaying a mixed load of fine-grained sand to gravel. At least five stacked channel units can be distinguished, with a progressively southward shift in the outcrop. The overall channel flow direction is eastward along the Tabernas basin axis away from the observer.

Arndt Peterhänsel and Maggie Murison, TRACS Training

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.

The geological record of a highly eruptive part of North Sea history

A unique core from the Balder Formation shines more light on how tuffs were deposited in Eocene times

MAX CASSON AND GEIR HELGESEN, EQUINOR

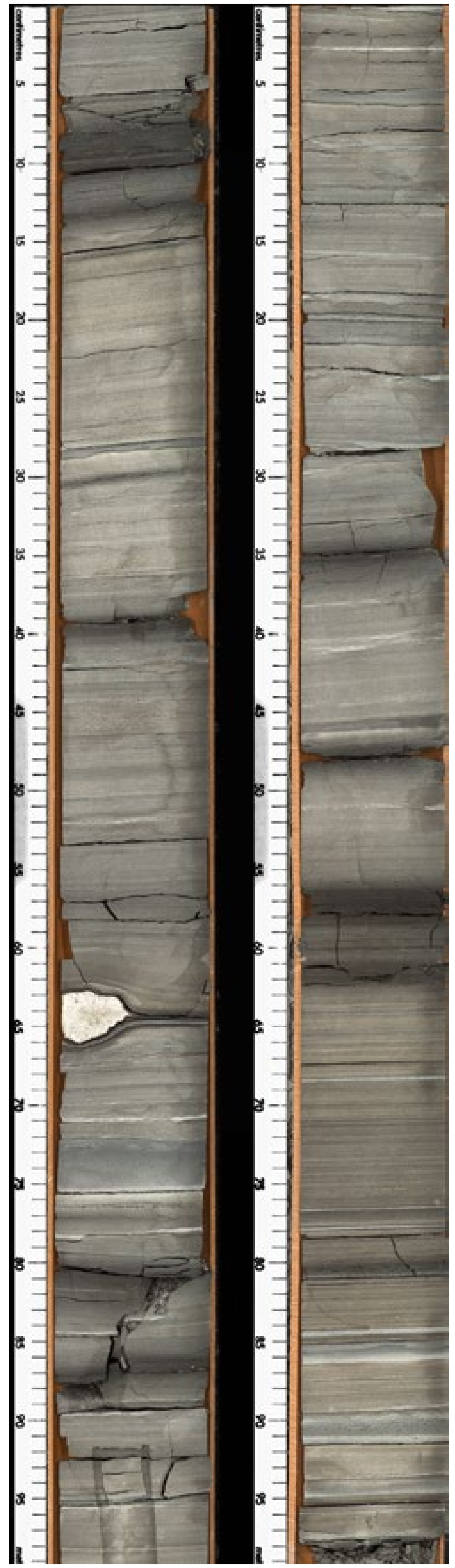
THE KVEIKJE discovery in the Norwegian North Sea was proven with a play-opening well in 2022, discovering a significant hydrocarbon accumulation in shallow Eocene-aged remobilised sands and injectites. These strata are traditionally considered as the overburden in this area.

Not only did the exploration well 35/10-8 S prove one of the largest discoveries in the Troll-Fram area in recent years, but a core was cut from the Lower Hordaland Group green claystones to near the base of the Balder Formation, covering the super-regional stratigraphic horizon, the 'top Balder Formation'. The 85 m long core therefore provides the opportunity to study the volcaniclastic sedimentology of one of the most mapped horizons in the North Sea.

The sandy Radøy Member representing the Kveikje reservoir is encased in the tuffaceous Balder Formation. Above and below the reservoir, the Balder Formation consists mainly of open marine hemipelagic and volcaniclastic sediments dropped out of suspension and deposited on an unstable slope. These deposits include centimeter to decimeter-thick graded calcareous tuff/ash beds that have no visible sedimentary traction structures associated with them.

Volcanic ash also occurs as very thin low-density turbidite beds (Bouma Tc-e), debrites and injectites as recognized in the Viking Graben core data. The latter may be related to syn-sedimentary remobilization and deformation of the substrate. Several scattered gravel to pebble-sized clasts can also be observed, deforming the surrounding strata. Bioturbation is only recognized in the hemipelagic black shales at the top of the Balder Formation as rare occurrences of Nereites, Chondrites and Planolites burrows, suggesting dysoxic to anoxic conditions.

The Balder Formation was deposited within a forced regressive phase. Tuff bed frequency within the core decreases upward, marking the waning and culmination of 0.5 million years of volcanic activity and a rise in sea-level that stretched from the Faroe Islands through the North Sea to Denmark. The volcanic activity is related to the final break-up phase of the North Atlantic margin and massive emplacement of volcanics in several Iceland-like igneous centres developed from the West of Shetland into the Møre and Vøring basins. ■



Lightly coloured calcareous tuff and ash beds of the Balder Formation, intercalated with darker coloured hemipelagic black shales from well 35/10-8 S, 1,170-1,172 m. In the left core a whitish clast can be seen with the associated deformation of the surrounding strata.

PHOTOGRAPHY: EQUINOR