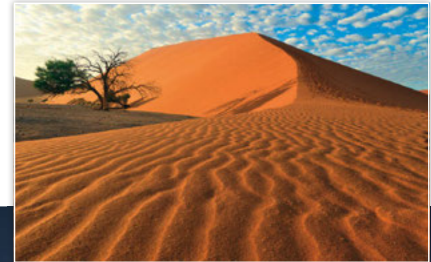
VOL. 18, NO. 5 – 2021

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



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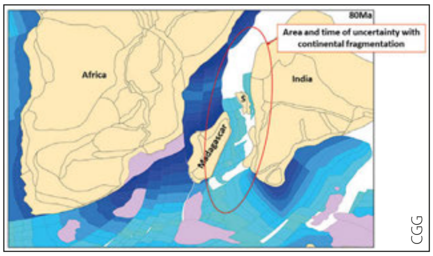

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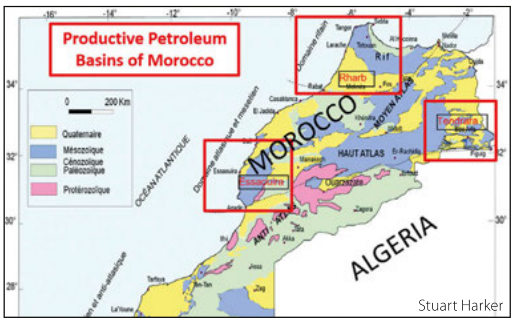

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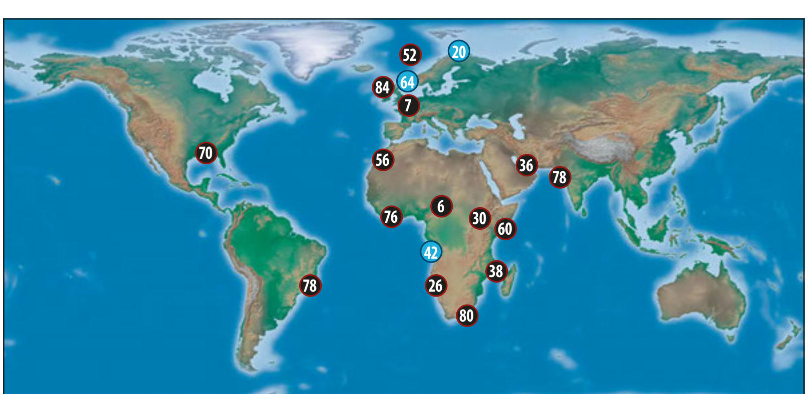
Growing recognition of the untapped value of legacy well cuttings is changing the attitude towards these important samples and there is now real momentum behind the concept of digitalising entire national archives.



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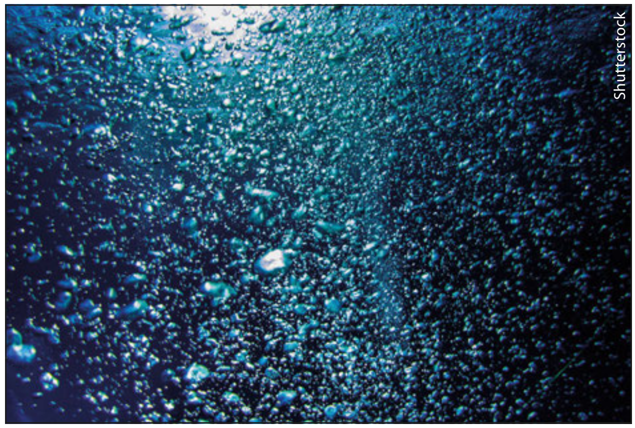
This issue of *GEO ExPro* focuses on Northwest Europe; Africa; Seismic Interpretation and Increasing Efficiency in E&P.

Real Rocks and Explosive Lakes



A limnic eruption could include methane, CO_2 and H_2S.

The well-known British geologist and Dean of the Royal School of Mines (Imperial College) in the 1940s is credited with the quote: "I suggest the best geologist is he who has seen the most rocks." Unfortunately, these days students and practitioners of geology do not get out into the field to study outcrop as much as they did in times past. Even contact with real physical samples seems to be in decline in this virtual world of ours.

Two of the articles in this issue address physical rock samples, though very differently. Kirstie Wright and Henk Kombrink have been rescuing unwanted North Sea core and saving it from landfill. It seems tragic that this resource that has cost UK operators vast sums over many decades to acquire, is now superfluous to requirements. I have no doubt much of it still has huge value as a teaching resource and for future activities such as carbon capture and storage evaluation. The industry should credit and support this endeavour.

The second article details how physical samples are being made more accessible to users by making them 'virtual'. Well cuttings have been the last frontier of subsurface rock digitalisation and now governments who take responsibility for national rock archives are working with a UK-based company to add incremental value to the samples in their custody. With renewed interest in their suitability for new machine learning methodologies and a greater focus on bringing all data types into a seamless digital environment, it is likely that more large-scale cuttings digitalisation projects will commence worldwide.

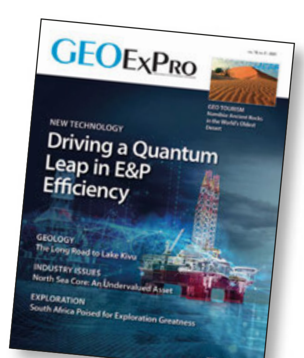
I was ignorant of the magnitude of the dangers posed by lake overturns or limnic eruptions until I learnt about a decades-long effort to develop the methane resource in Lake Kivu, in the African rift. Although these events are relatively rare, they can be truly catastrophic, as witnessed in 1986 when Lake Nyos in Cameroon released around 80 million m^3 of CO_2 and killed over 1,800 people. Philip Morkel's article about the danger lurking in the highest of Africa's Great Lakes provides a fascinating insight into how providing energy to the settlements around this beautiful lake could also protect the inhabitants from future catastrophe. A win-win situation not commonly attributed to natural resource development. ■

Iain Brown
Editor in Chief

DRIVING A QUANTUM LEAP IN E&P EFFICIENCY

As the energy industry grapples with the task of navigating the new business environment to deliver security of supply, environmental sustainability and affordability, the need for a step-change in efficiency becomes paramount. The biggest impact can be realised by evaluating workflows and operations from a holistic perspective.

Inset: The 85m-tall Dune 45 is a popular roadside climb at the Sossusvlei sand dunes.



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Rebound in Africa?

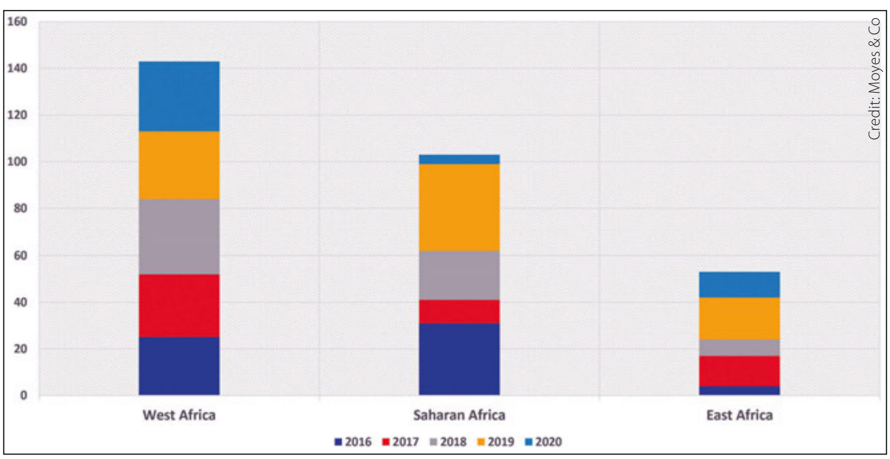
The lack of in-person conferences and ability to have face-to-face meetings has certainly slowed down deal-making globally. However, there is encouragement that we may see a modest rebound in Africa as we go into the final quarter of 2021 with Egypt and Angola leading the charge.

There are different ways to measure M&A activity and we have used individual block count from the Moyes transaction database for the period 2016 to 2020. As can be seen on the graph, West Africa dominates and generally activity has been quite steady in this sub-region. Saharan African saw a significant drop in 2020 after a blockbuster 2019. This spike in 2019 can be explained by several deals done in Egypt. Buyers of the Egypt assets include Pharos Energy, Dragon Oil, Noble Energy, BP and United Oil & Gas. Activity in East Africa, the quietest of the sub-regions in this period, was also boosted by a busy 2019 with Kenya and Mozambique seeing deals going over the line.

A word of caution! It should be noted that while deals are recorded as being completed in 2019, the incubation period may have been over the prior years, when much of the hard work and decisions would have taken place. There is a time lag that will give the impression of certain years being busier than they actually are, or vice versa.

Looking in more detail at the period 2016 to 2020 (and to date in 2021), most M&A activity reported has taken place in Egypt, which can be considered the region's hot spot. This is followed by the hydrocarbon-producing countries of Angola, Nigeria, Tunisia and Gabon. Most of the transactions seen in Africa involve production, development, or low risk appraisal assets.

Africa: Transactions by Block: 2016–2020.



Exploration M&A activity has been slow, although the Orange Sub-basin, which straddles the Namibia – South Africa border, will play host to three high-impact exploration wells within the next nine months. These are TotalEnergies' Venus-1, Shell's Graaf-1 and Azinam's Gazania-1. All the upcoming wells will test different plays within the frontier province. Success in any of these will encourage M&A activity within the Late Jurassic to present-day sub-basin where several partnering opportunities are currently open.

By some distance, TotalEnergies has been the biggest investor in the African region as its focus has shifted from other parts of the world such as Asia-Pacific. Other players that continue to move forward in the continent include Eni and Qatar Petroleum (QP). State-owned QP is a partner in almost all the upcoming high-impact wells in Africa through partnerships with Eni, ExxonMobil, TotalEnergies and Shell.

Private Equity (PE) firms have largely focused on countries where they are comfortable with above-ground risk such as the UK, USA, Canada and Australia. In Saharan Africa, Egypt has attracted private equity investment such as the Carlyle and CVC Capital-backed Neptune Energy, which acquired assets from Engie E&P. While in West Africa, the Carlyle-backed Assala Energy acquired Shell's onshore assets in Gabon, and the Warburg Pincus-backed Trident Energy acquired Hess's offshore interests in Equatorial Guinea. ■

Ian Cross, Moyes & Co

ABBREVIATIONS

Numbers
(US and scientific community)

M: thousand = 1×10^3
MM: million = 1×10^6
B: billion = 1×10^9
T: trillion = 1×10^{12}

Liquids

barrel = bbl = 159 litre
boe: barrels of oil equivalent
bopd: barrels (bbls) of oil per day
bcpd: bbls of condensate per day
bwpd: bbls of water per day
stoiip: stock-tank oil initially in place

Gas

MMscfg: million ft^3 gas
MMscmg: million m^3 gas
Tcfg: trillion cubic feet of gas

Ma: Million years ago

LNG

Liquified Natural Gas (LNG) is natural gas (primarily methane) cooled to a temperature of approximately -260 °C.

NGL

Natural gas liquids (NGL) include propane, butane, pentane, hexane and heptane, but not methane and ethane.

Reserves and resources

P1 reserves:
Quantity of hydrocarbons believed recoverable with a 90% probability

P2 reserves:
Quantity of hydrocarbons believed recoverable with a 50% probability

P3 reserves:
Quantity of hydrocarbons believed recoverable with a 10% probability

Oilfield glossary:
www.glossary.oilfield.slb.com

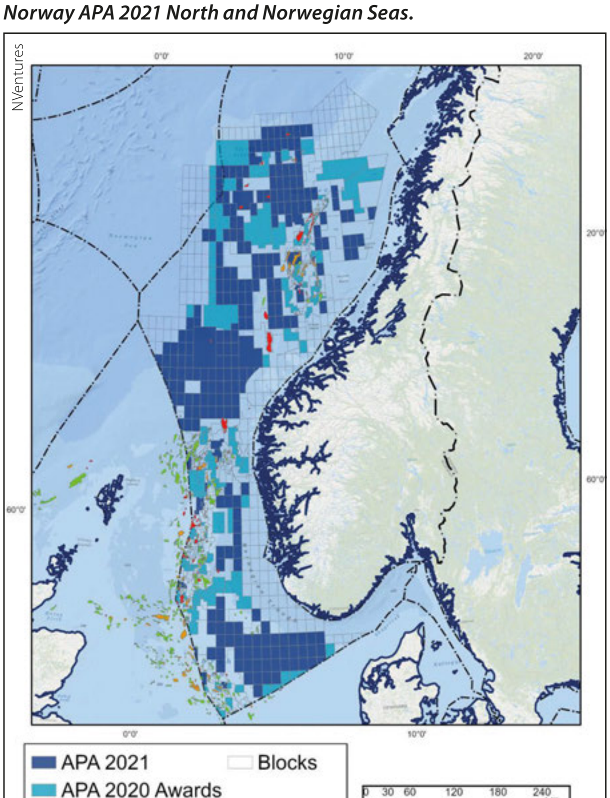
Future of European Oil and Gas Licensing

The two major northern European oil and gas producers appear to be on slightly different trajectories when it comes to their approach to future exploitation of their continental shelves.

APA 2021

In Norway this year, the Ministry of Petroleum and Energy launched the annual licensing round, seeking bids for mature areas in the Norwegian Continental Shelf (NCS). The country's Awards in Predefined Areas 2021 (APA 2021) licensing round offers oil companies a total of 84 blocks located in the North Sea and the Norwegian and Barents Seas. The round included new blocks south-east of Bear Island, halfway between the Arctic Svalbard Archipelago and mainland Norway. Norway introduced the predefined area rounds in 2003 to promote exploration in the most geologically known parts of the Norwegian continental shelf and has expanded the predefined areas with each round.

Norway APA 2021 North and Norwegian Seas.



The deadline for interested companies to submit their applications was 8 September 2021, with the government aiming to award new production licences during the first quarter of 2022. Although the expected size of discoveries from the mature areas is smaller, they could be feasible and profitable when developed in conjunction with other discoveries and by utilising the existing, or planned infrastructure. This latest round has attracted bids from 31 oil companies including Equinor, Aker BP, ConocoPhillips, and Lundin Energy among others.

The Norwegian government is under harsh attack from environmental organisations, as well as a growing number of foreign countries, for its continued drilling in Arctic waters. 70 of the 84 blocks are in the northern Barents Sea. At the end of 2020, Norway's supreme court approved government plans for oil exploration in the Barents, rejecting a lawsuit by environmental groups who claimed the oil licences breached an article in the Norwegian constitution and would also be contrary to the 2015 Paris climate accord.

Despite the increasingly vocal environmental lobby in Norway, it remains the case that the government's expected total net cash flow from the petroleum industry in 2021 is huge, estimated at NOK 154 billion. (US$18 billion). Total employment in the petroleum sector was around 200,000 in 2019, which, for a population of around 4.5 million, remains significant. The export value of hydrocarbons in 2020 was 42% of the total of Norway's exported goods, which highlights the continuing importance of the industry.

Recent parliamentary elections in Norway resulted in a decisive victory for the centre-left opposition and Labour is now expected to lead the next government, which is likely to be formed in mid-October. It is therefore likely that they would be responsible for making the eventual awards of acreage early next year. The Labour Party has said that any transition away from oil will be gradual and that in the meantime exploration for oil and gas will continue.

In the United Kingdom, the other major player in this industry, the Government in September last year carried out a review of the policy on oil and gas licensing to ensure it was compatible with its climate change objectives. Accepting the continuing role of oil and gas on its path to net zero, the British Government will introduce a new Climate Compatibility Checkpoint on future oil and gas licensing rounds to ensure they are compatible with wider climate objectives, including net zero emissions by 2050. This checkpoint will use the current evidence at the time, considering the UK's demand for oil and gas, projected production levels, increasing prevalence of cleaner technologies such as offshore wind and carbon capture, and the sector's continued progress against its emissions reduction targets. The Department for Business, Energy and Industrial Strategy (BEIS) has stated that design of this checkpoint will be completed by the end of 2021.

In parallel, the Offshore Petroleum Regulator for Environment and Decommissioning is conducting a new Offshore Energy Strategic Environmental Assessment which will underpin future licensing rounds. The Oil and Gas Authority (OGA) will run another licensing round for oil and gas exploration on the completion of this assessment.

32nd Offshore Licensing Round

In the meantime, the 32nd Offshore Licensing Round, launched in July 2019, resulted in the OGA offering for award

113 licence areas over 260 blocks or part-blocks. This round offered blocks in mature, producing areas close to existing infrastructure, under the flexible terms of the Innovate Licence which enables applicants to define a licence duration and phasing that will allow them to execute the optimal work programme.

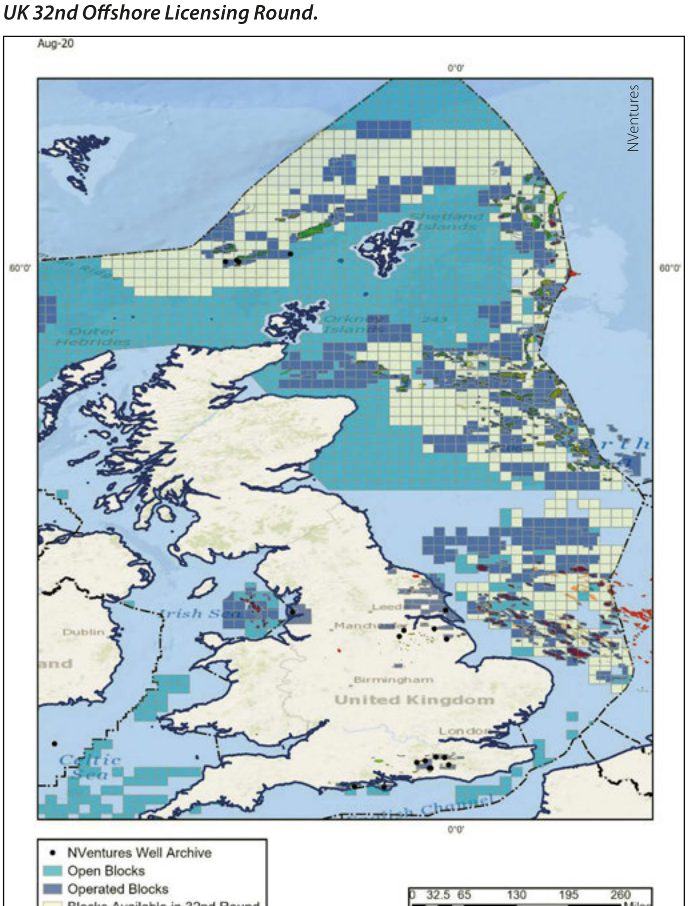
There were 104 from 71 companies ranging from multinationals to new country entrants. Most of the licences will enter the Initial Term (Phase A or Phase B exploration stage), and 16 of the awards are for licences that will proceed straight to Second Term, either for potential developments, or redevelopments of fields where production had ceased, and the acreage had been relinquished.

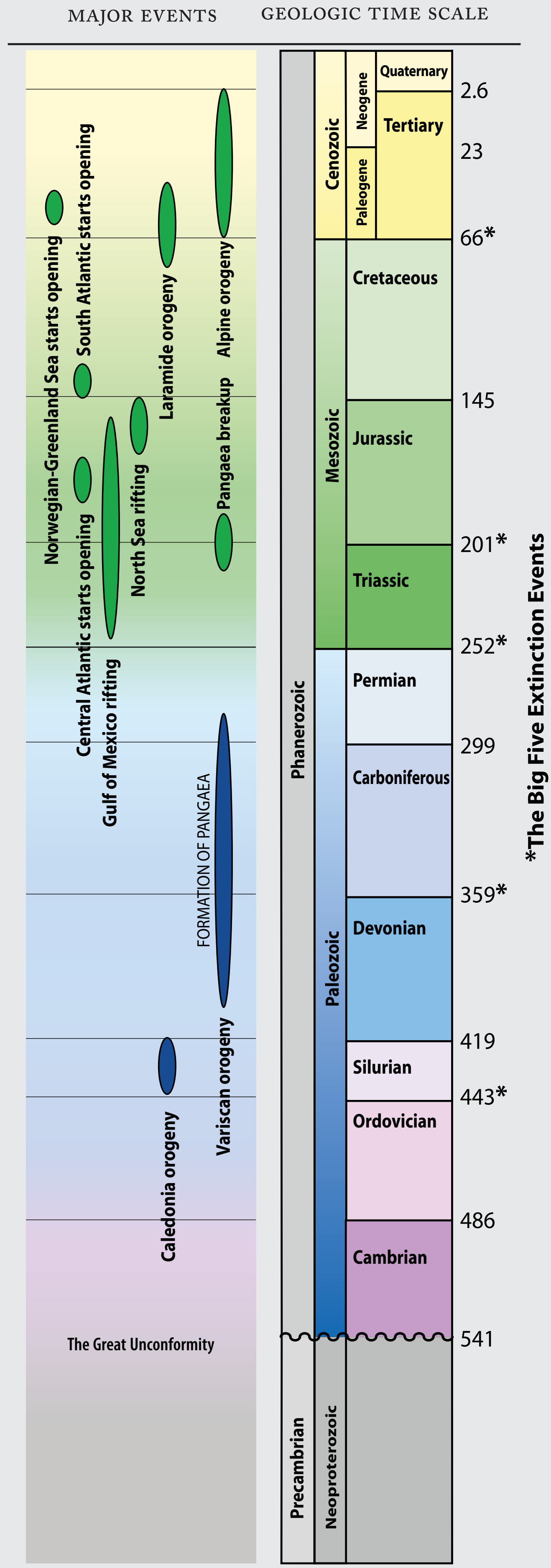
No Further Licensing Rounds in Denmark

At the other end of the spectrum, Denmark (a producer since 1972) has introduced a cut-off date of 2050 for oil and gas extraction in the North Sea and has cancelled all future licensing rounds. Last year a broad majority in the Danish Parliament reached a deal on the future of oil and gas production in its waters, leading to the cancellation of the 8th licensing round and all future rounds. The deal also establishes a final phase-out date for hydrocarbon extraction by 2050, outlining plans for a transition of impacted workers. Denmark is currently the largest oil producer in the EU and will now become the biggest producer worldwide to establish a final phase-out date. Other countries to have done so all produce significantly less oil and gas than Denmark.

Denmark is a long-time leader in wind energy and a prominent exporter of wind turbines, with wind now producing over 40% of Denmark's total electricity consumption. Their direction of travel is clear. ■

UK 32nd Offshore Licensing Round.





Namibia – Time to Shine?

There has been mounting excitement about the petroleum potential of Namibia's onshore Kavango Basin in the Kalahari Desert of north-eastern Namibia and north-western Botswana. The basin, which contains a thick Permian sequence, sits on the southern portion of the Southern Trans-African Rift and Shear system which controlled the basin development and the potential for hydrocarbon accumulations.

Canadian explorer, ReconAfrica, is targeting conventional hydrocarbon reservoirs with source rocks within the Karoo Group. Interpretation of high-resolution aero-magnetic data revealed a very deep untested basin with optimal conditions for preserving thick organic-rich marine source rocks in the lower portion of the Karoo. Maximum depth to basement has been estimated at over 9,000m and preliminary analyses indicate source rock intervals with thermal maturation levels supportive of oil and gas.

A petrophysical study, the first in the Kavango Basin, has identified five potential conventional reservoir zones in the 6-2 well, of which three are clastic zones and two are carbonate zones (limestone, dolomite) based on the first set of core analysis and mineralogical data from Core Lab. This study, which brings together wireline log data, core data, and sample and hydrocarbon show data from the 6-2 well, confirms 198m (650 feet) of net reservoir over five separate intervals.

A new 2D seismic programme of some 450 km is progressing well with acquisition showing good initial data quality. The programme is on schedule for completion by the end of October 2021. The new 2D data will provide the critical insight for the second phase of drilling into seismically defined structures or traps.

ReconAfrica and its joint venture partner NAMCOR (the state oil company of Namibia) confirmed in late September that the Ministry of Mines and Energy granted approval of a one-year extension for their 6.3 million acre (PEL) 73 exploration licence, due to the Covid-19 pandemic impacting progress. This now extends the First Renewal Period to 29 January 2023 and gives the company time to fully evaluate the new seismic data and plan its next drilling campaign.

Meanwhile offshore Namibia, long seen as a potential new source of oil, has been hampered by a lack of exploration to firm up the extent of its reserves. Its offshore geology is similar to Brazil, which has seen a boom in oil exploration.

Gas has already been discovered offshore Namibia by Chevron in 1974. Since then, various operators, including Shell and Tullow Oil, have drilled a further seven appraisal wells on the Kudu field before withdrawing from the concession after failing to secure a commercial outlet for the gas. The field is estimated to contain resources of 750–2,300 Bscfg. Oil was found in May 2017 at the Wingat-1 well in the Walvis Basin, drilled by Brazil's HRT, but not in commercial volumes.

The Venus-1 exploration well in Block 2913B in the far south, operated by TotalEnergies is expected to spud in December 2021, and will target a large, DHI-supported, basin floor fan system of Albian age. Shell's Namibia Graff-1 well will also spud in the same timeframe and targets a Late Aptian/Albian sandy turbidite channel system.

Ambitions for the offshore are now high with investors and explorers waiting to hear the results of these new wells with bated breath. Should a major find in 2022 be made to confirm this area as a major new oil and gas hub, other major oil companies will no doubt enter the fray, and some will also look further south to the Southern Orange Basin. ■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Galen Cobb Talks About the 23rd Edition of the World Petroleum Congress

Tell me more about the US National Committee of the WPC?

The World Petroleum Council (WPC) has nearly 65 member countries, representing over 96% of global oil and gas production and consumption. Each member country, the US included, has a National Committee. I serve as the Chair of the US National Committee, which is comprised of individuals and companies that represent the industry in the United States and lead the efforts of the US and its involvement in the triennial World Petroleum Congresses and other Council activities.

What is your hope for the 23rd World Petroleum Congress?

We are looking forward to hosting the 23rd edition of the World Petroleum Congress here in Houston, the energy capital of the world. There have been a lot of positive developments within the industry since Houston last hosted the World Petroleum Congress in 1987, including the shale revolution in the US. Our hope is that we're able to convene key global energy leaders and provide a place to host meaningful and forward-looking conversations that will benefit generations to come.

Why should people attend the Congress?

The Congress gives attendees an all-in-one event where they can hear from influential leaders and expert speakers on current industry topics; connect with industry professionals from all over the world; and be part of influential conversations that will impact the future of energy. This is a 'can't-miss' event for oil and gas professionals looking to participate in a prestigious conference with renowned participants before the end of the year.

What programming should delegates expect?

Our program will cover all levels, from the Strategic Program featuring plenary sessions, CEO panels, ministerial sessions and round tables, with insights from some of the highest-level international energy leaders and stakeholders, to our Technical Program made up of in-depth forums, round tables and expert workshops.

The US National Committee is responsible for putting together the US Program that will include several US-focused sessions and industry insight luncheons, including recently announced speakers Tim Leach from ConocoPhillips, Scott Sheffield from Pioneer Natural Resources Company and Travis Stice from Diamondback Energy, who will participate in the luncheon session on the US shale revolution.

Galen Cobb: Vice President of Industry Relations for Halliburton and Chair of the US National Committee for the WPC.

Beyond programming, what other events or activities will there be?

The Congress will host several special events such as the Dewhurst Award that will be awarded to Dr Daniel Yergin, the WPC Excellence Awards and USA Night that will celebrate the culture of the host country and City of Houston. We will also have several special features on the exhibition floor that will be a chance for delegates to learn and interact, such as the Innovation Zone by ConocoPhillips, Social Responsibility booth, NASA and more. ■

The UK OGA Launches £1 Million Decarbonisation Competition

In September 2021, the Oil and Gas Authority (OGA) announced that a competition has been launched to help decarbonise offshore oil and gas production. The competition, managed by the OGA, is designed to advance the widespread electrification of offshore installations on the UK Continental Shelf, which are currently powered by gas or diesel.

Organisers are looking for studies (technical, engineering, and/or commercial) that will bring electrification projects a step closer to reality. The winning ideas will be allocated a share of the £1 million prize fund, to complete the proposed work by 31 March 2022.

This competition follows the Government's commitment in the North Sea Transition Deal to support funding for early-stage offshore electrification studies by the end of 2021. Key results from the studies will be published for others to benefit from and build on the ideas generated.

The OGA's Energy Integration Report found that the UK Continental Shelf could (through a mix of platform electrification, carbon capture and storage, offshore wind, and hydrogen) absorb up to 60% of the UK's entire CO_2 abatement needed to achieve net zero emissions by 2050. ■

Energy Companies Partner Up for Low Emission Aviation

TotalEnergies and technology group Safran have partnered to accelerate the reduction of the CO_2 emissions of the aviation industry. Sustainable aviation fuel (SAF) plays a key role in this approach.

The collaboration will leverage Safran and TotalEnergies' respective areas of expertise for the development and deployment of sustainable aviation fuels and develop an informed understanding of the overall value chain. In the short term, the partnership aims to make current jet engines compatible with fuel containing up to 100% SAF. Longer term, it will then work to optimise fuel energy efficiency and environmental performance. This collaboration may extend to other fields, such as adapting fuel systems to SAF or developing new-generation battery systems for electric motors.

Sustainable aviation fuels are an immediately available option for significantly reducing CO_2 emissions from air transportation, as they can currently be used in blends of up to 50% without modifying existing supply chain infrastructure, aircraft or engines. Safran is a key player in projects that will allow the use of 100% SAF in existing aircraft.

French legislation calls for aircraft to use at least 1% SAF by 2022 for all flights originating in France, while the European Commission calls for an increase to 2% by 2025 and 5% by 2030 as part of the European Green Deal. ■

UK Gas Shock – It Shouldn't Be

The UK has little to no gas storage capacity and is at risk of becoming overly reliant on renewable energy to keep the lights on this winter, according to John Underhill, a Professor of Geoscience and Energy Transition at Heriot-Watt University.

Without addressing the need to replenish sources, have secure and reliable supplies and storage, the current crisis is simply a warning of what is to come over the coming winter and beyond.

His comments come as the UK faces steep rises in domestic energy bills as global gas prices soar and several energy suppliers go to the wall.

John Underhill reminds us that as the current energy crisis demonstrates that gas remains an essential part of the energy mix in the UK for at least the medium term. He has voiced his concerns on the run-up to COP26 when world leaders gather in Glasgow to discuss climate change. He said: "Our current energy crisis is a result of a perfect storm of factors including a complete lack of subsurface storage for renewable energy, local supply issues due in part to maintenance of North Sea facilities and a significant decline in our indigenous resources that means we now have a reliance on imports. The current situation underlines why the move to greener, renewable energy is a transition and must not be a cliff edge. At present, the UK's energy needs are challenged. In fact, we are so stretched right now that the UK even had to restart a coal-fired power station, which is not the best optic in the lead-up to COP26. When that is decommissioned and offline, we will no longer have that safety net."

The failure of smaller UK energy providers, caught out by the rapid raise in gas process, has affected almost 1.5 million UK customers, bringing the issue of secure energy firmly back into public debate.

Professor John Underhill.

"Short of the lights going out, cookers failing to light and radiators going cold, this may be as close as we get to the 'black swan' moment where people realise where our energy comes from and our need to ensure there is sufficient home-grown supply, reliable import sources and backup in the form of subsurface storage to avoid shutdowns and other unintended consequences for food supply chains and the like. Until such time that we have a reliable and robust renewable base that more than covers our energy needs, oil and gas has a continued and vital role to play in our energy transition goals and to alleviate fuel poverty. While it's clear society's continued reliance on fossil fuels is untenable given climate change predictions, this demand will need to be phased out gradually and emphasises the need for a managed energy transition rather than a hard stop, as we move towards a sustainable, renewable energy future."

At Heriot-Watt University in Edinburgh, Scotland, John Underhill runs a research programme that is addressing these issues, assessing the critical technical risks, producing a road map of subsurface options and seeking long-term solutions to guarantee energy security for the UK. "We are leading in the effort to train and educate the next generation of Earth Scientists through the UK's Centre for Doctoral Training (CDT) GeoNetZero programme. The CDT students have a pivotal role to play in finding solutions to our energy needs in the years ahead. Those who study with us before working in this field will be crucial in enabling society to decarbonise, address the United Nation Sustainability goals and move towards a low-carbon sustainable future." ■

Kenya Retains Oil Focus while Looking to Energy Transition

The **Kenya Vision 2030** project is aiming to transform Kenya into a newly industrialised, middle-income country which can provide a high quality of life to all its citizens by 2030, in a clean and secure environment. Development projects which are part of the vision's blueprint are expected to significantly increase the population of Kenya over the next decade, creating a strain on the country's energy requirements.

Up to this point, Kenya has been a country dependent on the consumption of oil. In 2012, British oil company **Tullow** discovered an oil reservoir which promises to yield roughly one billion barrels of crude oil. However, due to multiple roadblocks in development, oil discoveries in the northern Kenyan region have yet to be bought to market, and Tullow have since attempted to reduce their stake in the investment.

The Covid-19 pandemic has also meant a significant amount of disruption to oil demand, causing oil prices to deflate further than had been seen previously because of oversupply. Major oil companies have reduced their capital expenditure in upstream oil exploration and production, making it difficult to attract investment.

Focus on Lamu Basin

In the immediate future, it is key that Kenya does everything it can to continue to attract investors in its oil infrastructure. To that end, investment in oil prospects has now turned its attention to the Lamu Basin, where Italian firm Eni are set to begin drilling an oil exploration well to seek the presence of commercially viable oil and gas accumulations.

Although a commercial oil discovery has not yet been made in the area, a discovery at the Lamu Basin would add credence to the prospective success of Kenya's oil industry. Kenya has only exported a singular consignment of 240,000 barrels of crude oil thus far, obtained from the **Early Oil Pilot Scheme** which was used to test Kenya's product in the global oil market before plans for mass production would be put in place.

Mounting pressure from Western governments, climate lobbies, and financiers has also made companies think twice about investing in oil projects such as **Turkana** in Kenya.


Kenyan Ministry of Energy and Petroleum

Charles Keter – Kenyan Cabinet Secretary for Energy & Petroleum.

Kenya's energy transition

With regard to renewable energy, however, Kenya has already made significant strides forward, and there is ample potential for power generation from **renewable energy** sources in the country. The government has sought the expansion of renewable energy generation in its overall power development plan for the period **2017 to 2037**, projecting that, by the year 2037, renewable energy sources will provide just over 60 per cent of the installed power capacity in the country.

Geothermal, hydro, wind and **solar** are all in contention to be a part of the renewable energy mix in Kenya going forward. In recent years, measures to promote investment in the renewable sector have been passed by the Kenyan Government, including the enactment of a **new energy act in 2019**, which aims to develop the renewable energy sector in Kenya, and the establishment of new authorities to regulate the production, conversion, distribution, supply, marketing and use of renewables.

Incentives for renewable energy generation have also been employed, including certain stamp duty exemptions, tax benefits, and the development of public–private partnerships between the government and renewables companies. This has helped increase investment in renewables in Kenya.

Challenges Ahead

This is not to say that there are no challenges in this area. In procuring geothermal power, Kenya must allow for the fact that there is expected to be a long lead time from concept to production – between five and seven years, the upfront investment costs will be high, along with a heavy investment in transmission and other support infrastructure to existing load centres, and there will be significant resource exploration and development risk.

In hydropower generation too, the challenges are many and varied. Variation in hydrology and climate change, leading to reduction of water levels in reservoirs; relocation and resettlement of affected persons to create room for the construction of reservoirs; the long lead time; and the absence of synergies and competing interests in hydropower management, are all obstacles which must be overcome.

More generally, investment and exploitation of renewable energy in Kenya is impeded by a low awareness of the potential opportunities and economic benefits, limited local capacity to manufacture power components and equipment, inadequate credit and financing mechanisms, and insufficient storage capacity in existing power generating reservoirs.

While the challenges of securing Kenya's energy future may seem enormous, with innovative thinking and attractive investment opportunities presented by the regulators, Kenya can achieve its 2030 vision. ■

The Hard Truth About Realistic Energy Transition

MIKE LAKIN, Envoi

Since the last commodity price crash in 2015–2016, a fraction of the exploration needed to guarantee supply has occurred due to the lack of funding. The reasons for this are linked with global oversupply (arguably linked to unconventionals in North America). There is also some evidence that Saudi Arabia's new ruler used this period to reassert control of OPEC by turning on the taps and pressuring its members until they could be relied upon to work as a unit to control supply. This was followed by prices rising back to a sustainable level of around US$50–60/bbl in 2018/19, which would previously have been enough to revive exploration activity, but the evidence for climate change caused by rapidly growing emissions in 2017/18 led to Environmental, Social and Governance (ESG) investment controls which has since stalled Western investment. The global Covid-19 pandemic in late 2019 has only made the problem worse with reduced global demand for fuel with lockdown. It is interesting to note that the net effect was that global emissions reduced by the 30% that the experts say is needed by 2050 to prevent temperatures rising more than 2°C and a possible climate change tipping point.

The Western world's decision makers appear to think that a realistic energy transition can be achieved by simply switching off all fossil fuels including the hydrocarbons on which the global economy is arguably built and has become entirely dependent. The net result is a potentially unfillable hole in global energy supply.

The evidence is clear from an increasing number of respected and trusted intelligence sources. The following graph released by Rystad illustrates clearly to even the most sceptical, that there are simply insufficient existing hydrocarbons resources for the world to transition without additional sources of oil and particularly gas.

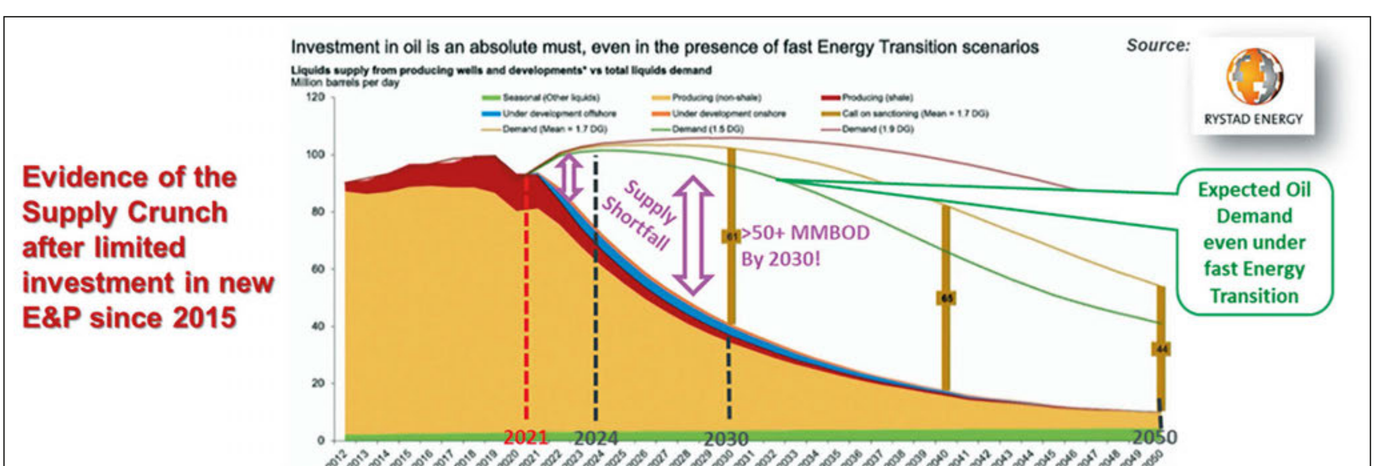
All the evidence is that however fast the world builds wind and solar farms, it simply cannot replace hydrocarbons in the near, if not medium or perhaps even longer term. The blackouts in California in summer 2020, and in Texas in the early 2021 winter freeze, show what happens when there is insufficient switchable generation or spare capacity to ensure security of supply. New Zealand is another reminder of what a ban on all new exploration and production can do in just four years. This has led to them considering re-importing coal to ensure enough power, which is significantly more emissive than the oil and particularly gas it will be replacing.

Gas is rarely compared to other fossil fuels and clearly needs to be recognised as a vital 'fuel of transition' that satisfies the 3 As (i.e., achievable, affordable, and acceptable) due to its low emissions compared to oil and particularly coal. The recent and dramatic global gas price rises are perhaps the early signs of this undersupply biting and just a taster of what is to come.

By comparison, it is interesting how the medical experts were wholly involved by the politicians in their decision making in managing the terrible impact that Covid-19 was having on their voting population. As with the global financial crisis in 2008, the signs of a pending crash were equally evident.

The investment community's current eschewal of E&P now appears equally short-sighted and only likely to increase, not decrease emissions. It is not too late to instigate a realistic approach to a new cycle of exploration, with ESG compliance, to help restore global supplies over the next five years. Currently, 20 years are estimated to be needed for alternative technologies, infrastructure and the changes in lifestyles required for transition to be achievable, affordable, and therefore acceptable. Perhaps the massive commodity price rises that are likely to accompany the supply shortfall will be enough for investors to wake up and see a way of making profits, but sustainably with clear ESG compliance.

The challenge is that after nearly six years of almost zero E&P investment and subsequent loss of experienced geoscience and engineering teams, few established E&P companies can now grow their exploration capability sufficiently fast, if at all. With a limited pool of experienced geologists and geophysicists who know where to locate the 6" holes to achieve even the historical 1:20 chance of exploration success, it will be challenging to say the least. New exploration techniques and technologies such as AI may advance and improve success rates and cycle times. Time will tell, but a rocky road is predicted. ■



Driving a Quantum Leap in E&P Efficiency

Dr JAMES L. ETIENNE, Halliburton

As the E&P sector undergoes structural change to adapt to the new business environment, the need for disruptive gains in E&P efficiencies has never been greater.

The E&P industry is experiencing an unprecedented level of change as strategies shift from growth to returns, business models diversify, and the need for action on sustainability initiatives accelerates. This coincides with an increasingly complex (and rapidly evolving) political, economic, social, technological, legal and environmental backdrop (PESTLE factors). The industry is tasked with navigating this business environment to deliver security of supply, environmental sustainability and affordability – this is where efficiency across-the-board becomes absolutely critical.

Efficiency is not just about saving time: its about maximising return on investment through deployed capital, portfolio optimisation, continuous improvement through removal of waste, and improved quality, consistency, and predictability of business outcomes. Operations also need to be as carbon-efficient as possible, reducing the CO_2 footprint and providing the means to offset remaining emissions to achieve net zero targets. As such, efficiency requires system-level optimisation to maximise gains for each E&P asset across its investment lifecycle, and across the portfolio of assets in which it sits.

Unprecedented Change

Efficiency must contemplate the horizon in respect of the PESTLE factors mentioned above – for example, what is the impact of Net Present Value (NPV) erosion because of increased carbon taxation and legislative pressures on Scope 1 and 2 emissions in the future? Can this erosion be mitigated by recycling the asset as a viable carbon sequestration site? Are there adjacencies that can be leveraged, such as the production of lithium from produced formation water to meet supply demands for electrification? How do these things impact the full lifecycle economics?

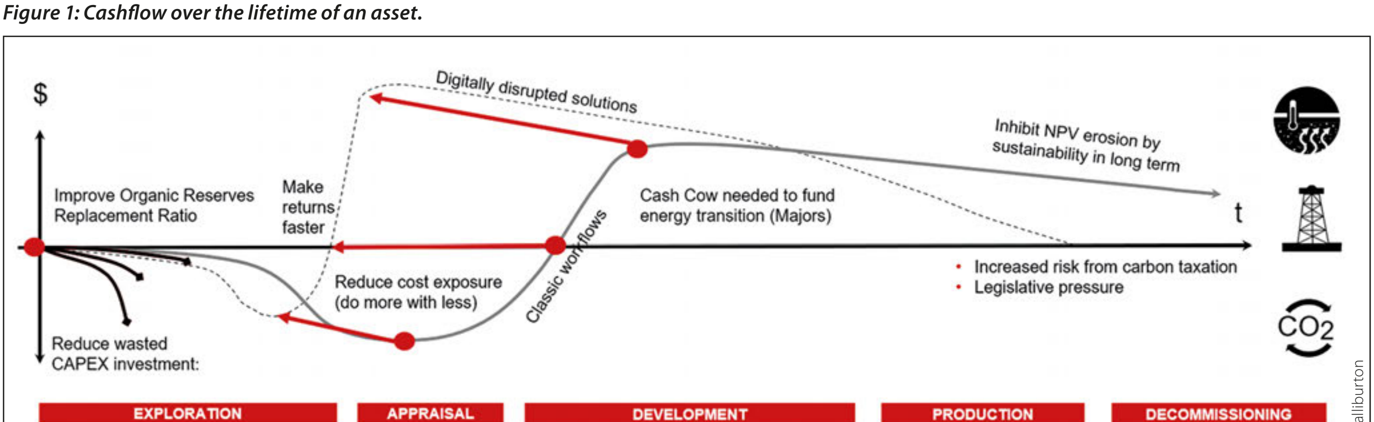
Since oil, and particularly gas, will remain an important part of the energy mix for the foreseeable future, there is a need to ensure security of supply through continued exploration and production activity, while maximising returns from *all* investments across the E&P asset lifecycle.

From Figure 1, we can see that cashflows start negative as investment in exploration is made and well and seismic commitments are executed early in the lifecycle. Cashflows turn positive after production commences. The NPV is significantly impacted by exploration successes that lead to discoveries that can be economically developed, and by time to first production. If the exploration investment does not lead to an economic discovery, then there is no return. Major efficiencies can be realised by reducing wasted CAPEX investments across the lifecycle, reducing OPEX while concurrently increasing capacity, enhancing returns through technology adoption and leveraging of insights to reduce time to first production and maximise recoverable reserves. Digital solutions are a must-have requirement to enable this step-change (Figure 2). So where are these efficiencies going to come from?

Disruptive Digital Technologies are Changing the Game

The technology landscape is going through a complete revolution. Secure private, public and hybrid cloud environments are being implemented that enable unprecedented levels of integration at the system level through connected and collaborative workflows, marrying front- and back-office tasks with information across the enterprise, including Real-Time operations at the edge. The effective delivery of efficient integrated workflows requires a common platform (see for example the OpenEarth® Community), ensuring consistency and availability of data without the traditional barriers imposed by data transfer

Figure 1: Cashflow over the lifetime of an asset.



between different specialist software applications. Common data standards are also highly desirable to enable fluidity across vendors and between joint venture partners (as exhibited by investments in the Open Subsurface Data Universe™).

The availability and affordability of cloud infrastructure enables solutions for Big Data handling, such that massive workflow efficiencies can be realised, with scalability, consistency and reproducibility. This includes the ability to deploy applications with optimum computational resources for job execution, applications that can take advantage of scalable resource allocation (e.g., microservices), and automation pipelines for classic physics-based techniques integrated with new Machine Learning capabilities to crunch large datasets or derive non-obvious insights.

With progress in IoT (Internet of Things), you can expect better Real-Time asset monitoring, optimised preventative and reactive maintenance, better availability of equipment, optimised production time, implementation of automation and remote management of assets. This Real-Time connectivity enables the E&P Digital Twin, and can positively impact risk and HSE, avoiding potential incidents, malfunctions and rationalising human interaction in operationally hazardous zones.

While adoption of cloud is an enabler, there is a need to embrace the opportunity by reviewing and refining workflow best practices (for example through value stream mapping) and by collaborating more to maximise business value. There is an important component of change management here too – efficiency through automation or assisted interpretation does not mean redundancy for the human taskforce. It means that we can focus more time on the highest value tasks, to create maximum business impact.

Well Construction

Some of the biggest gains to be made sit in the execution of well planning and drilling operations. Integrated digital solutions across the enterprise create a step-change in time savings

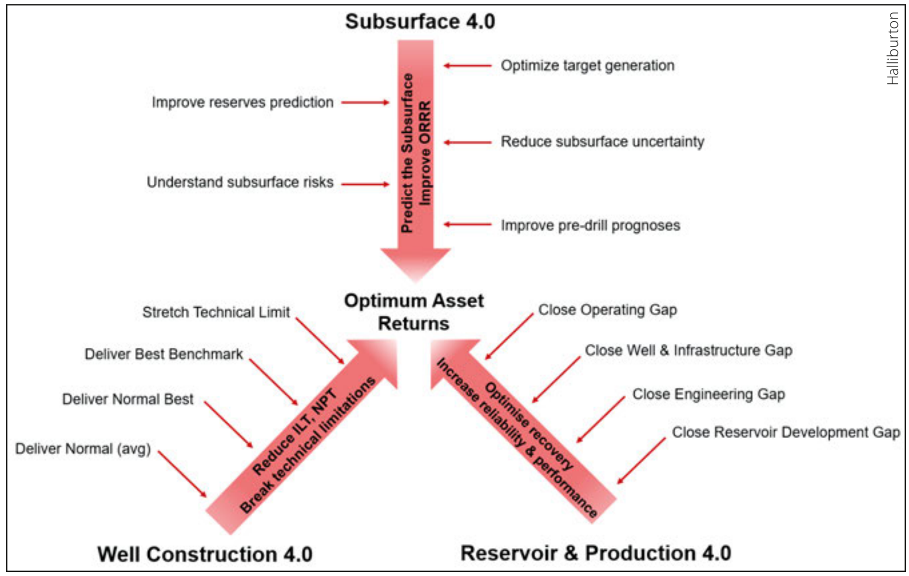
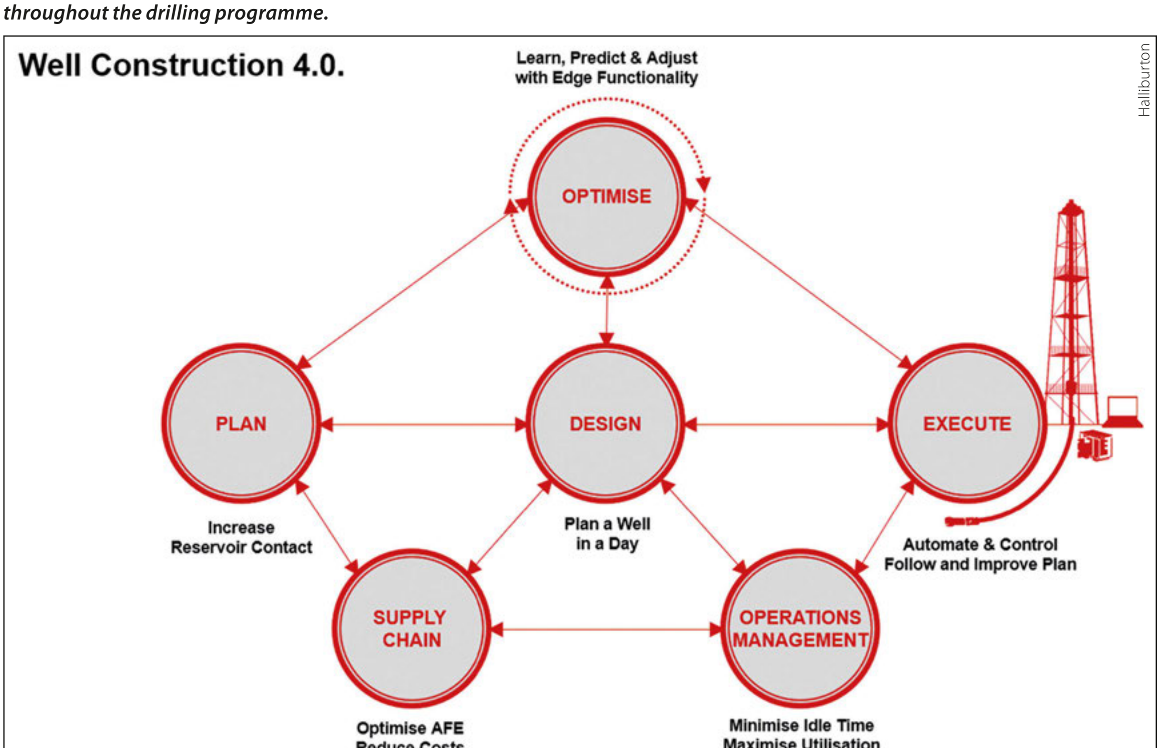


Figure 2: Different components of the asset lifecycle and targets for digital enhancement to create a step-change in realising asset returns. ORRR = Organic Reserves Replacement Ratio; ILT = Invisible Lost Time; NPT = Non-Productive Time.

Figure 3: Embracing digital transformation across the well construction lifecycle results in material improvements in efficiency for both operators and service companies. The entire workflow of planning, designing and executing the well can be optimised, reducing the time by an order of magnitude and keeping the well plan up-to-date in Real Time – in effect a live Digital Twin throughout the drilling programme.



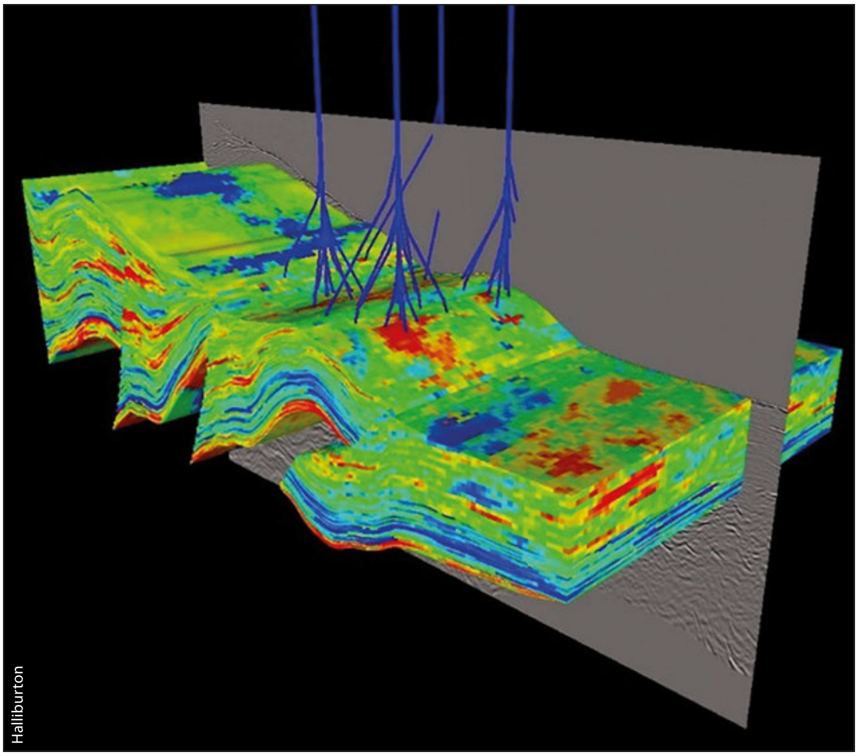


Figure 4: It is now possible to build and dynamically update very complex subsurface models, such as this piggy-back thrust system.

and reductions in CAPEX, OPEX, Non-Productive Time and Invisible Lost Time. These are achieved through performance improvements including streamlining the planning process with digital well programmes, drilling close to the limit with digital well operations, integrated production profiling, drilling performance management with Real-Time Services, technical improvements on trip time and rate of penetration and other factors including HSE and well integrity (Figure 3). By driving digital efficiency at the system level, savings on a single well can run to millions of dollars, with months of timesaving in the planning stage, materially impacting the Net Present Value of the asset.

Of course, the optimal execution of the well, and return on investment, even with all these gains is dependent on the well being drilled in the right place, completed with maximum reservoir contact and drilled in the right way to minimise well impairments. This requires a thorough understanding of the subsurface reservoir architecture and characteristics, any past production, and the nature of the overburden.

Subsurface Intelligence

The core petro-technical workflow is well established in subsurface interpretation, integrating well and seismic data to derive an interpretation of structure (Figure 4), stratigraphic relationships, and rock and fluid properties to assist in pre-drill prognosis in exploration, appraisal, development and production activities. Geology, geophysics, petrophysics, geomechanics and other disciplines are core to this effort, but the time involved to produce a portfolio of drillable prospects remains too long to meet current business expectations (often 18–24 months), with low overall probabilities of success in new ventures (wildcats leading to economically viable discoveries are typically <10%). In addition, significant rework and loss of knowledge between different stages of the asset lifecycle can negatively impact NPV. Data are often underutilised, and the wide array of different disciplines often leads to silos in knowledge which inhibit fully integrated workflows and value realisation through reduced uncertainty and better understanding of risk.

At the core, the primary challenge remains the same – how do we interpret and integrate direct and proxy observations of the subsurface and use all the power of the available predictive tools (subsurface insights, sequence stratigraphic principles, physics-based modelling and ML/AI) to drive the best possible fit-for-purpose interpretation of the subsurface to meet strategic and operational goals? How do we also ensure that prior knowledge is effectively leveraged across the asset lifecycle and all scales of modelling? A step-change in the approach to subsurface interpretation from initial data ingestion to the generation of actionable insights is required, one that allows for the development of seamless, dynamic and evergreen subsurface understanding.

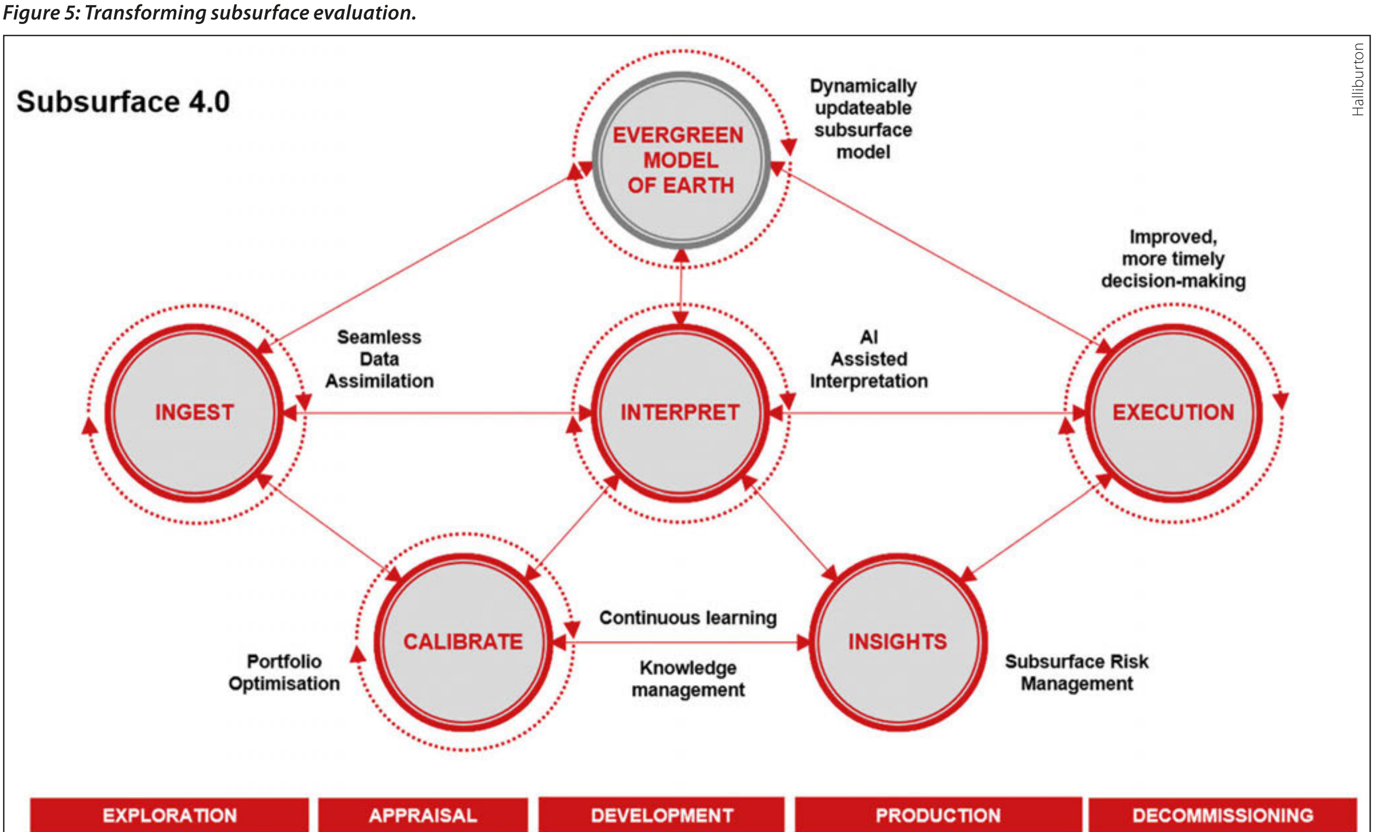
One critical element is to ensure that data are interpreted in context – how does the big picture geological framework condition our understanding of reservoir quality and architecture at the smaller scale? Insights from global paleoclimate, eustacy, geodynamics and source-to-sink analysis provide critical information on the behaviour of sediment routing systems over time for subsurface prediction and reduction of uncertainty (e.g., Neftex® Predictions). This context also serves as a reference for Machine Learning models.

Transforming subsurface evaluation requires a paradigm shift in the way data are ingested, interpreted and used to condition subsurface models to optimise operational decision-making (Figure 5).

It is necessary to access and connect structured and unstructured data, consume Real-Time data, adopt open platform and open data standards and leverage the elastic scaling of cloud for heavy-lifting jobs such as seismic processing. Interpretation requires assisted tooling, leveraging Machine Learning and predictive-physics-based tools, and regional petroleum geology understanding to provide the right context. Subsurface models need to be evergreen, dynamically updatable, able to handle complex geology (Figure 4), and be seamlessly scalable from the well bore, to the petroleum system and basin within which the asset sits (Figure 6).

This requires collaborative, multi-user workflows that are optimised for operations geology and commercial decision-making, with derived insights used to re-calibrate not only the subsurface understanding, but also the code underlying business process optimisation. This approach to subsurface interpretation helps to reduce uncertainty, and provides a better understanding of subsurface risk, to deliver the optimal

Figure 5: Transforming subsurface evaluation.



technical specification for every well, and to identify solutions required to close operating, well, infrastructure, engineering and reservoir development gaps (Figure 2). Additionally, with today's computing power, ML and AI supported design and planning can see a reduction time of up to 80%, which drastically improves the NPV by bringing in production months ahead of previously scheduled first oil.

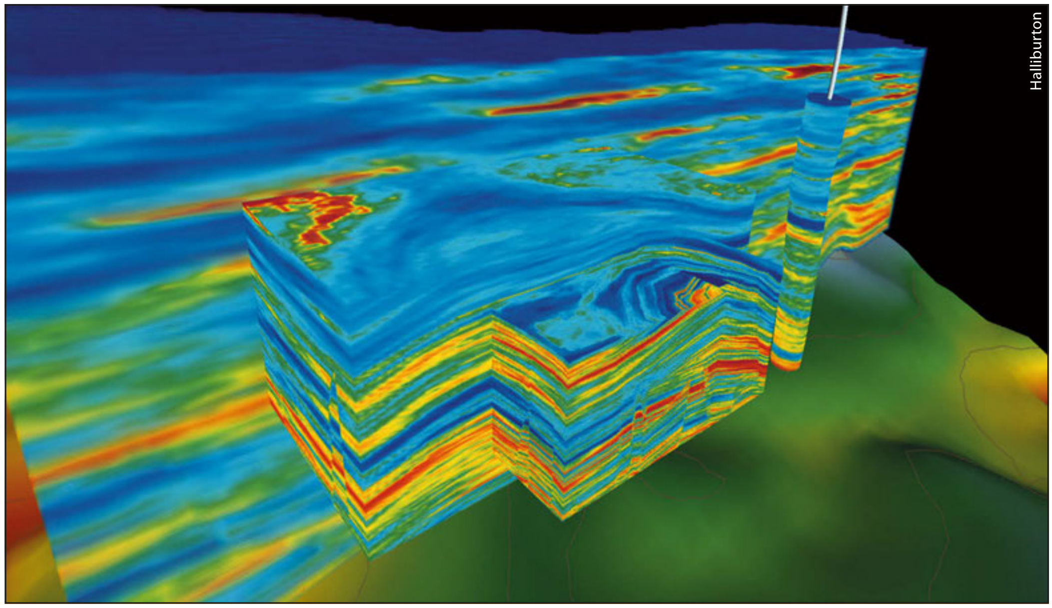


Figure 6: New Scalable Earth Modelling technology allows seamless, scalable models to be constructed and maintained that are self-consistent across all scales from the basin to the wellbore.

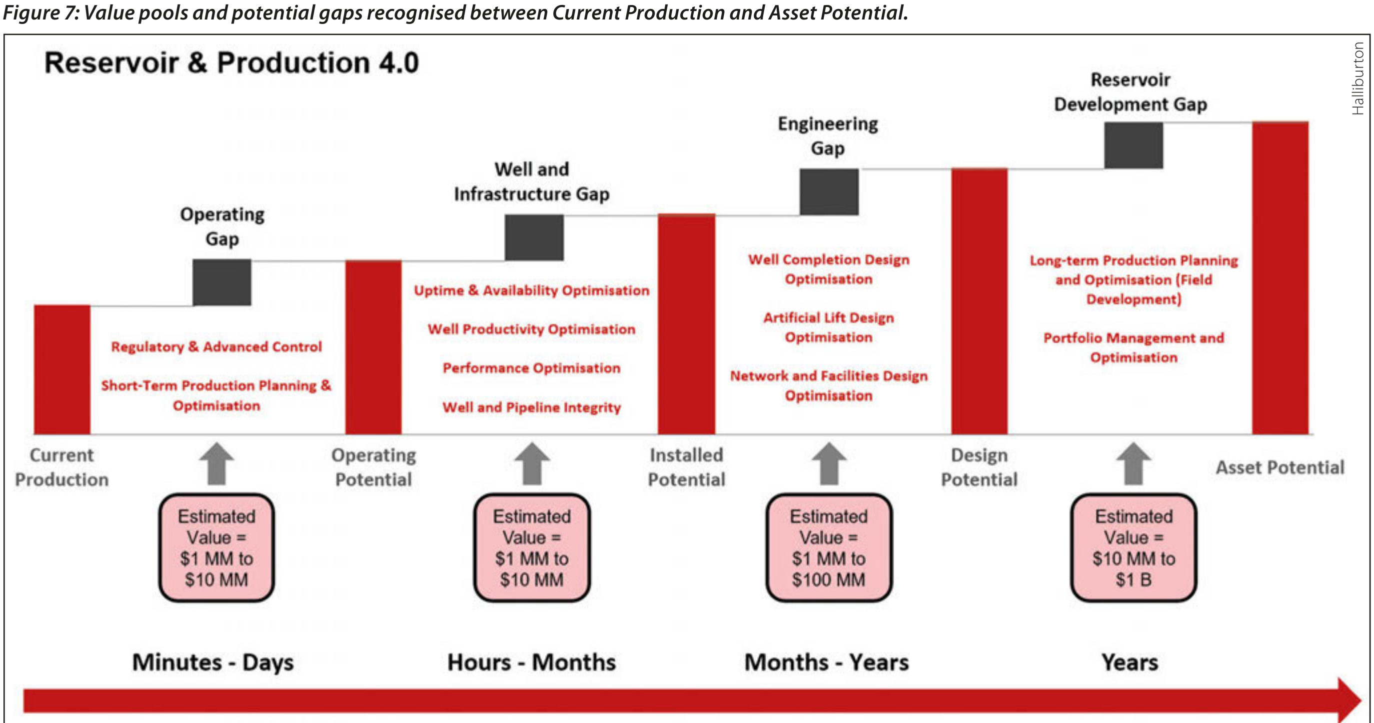
Reservoir and Production

The final piece is ensuring that all assets in the portfolio are delivering maximum value through return on investment, at the least amount of carbon intensity (Advantaged Hydrocarbons). Asset field development, management and production often hides the value pools (Figure 7). A system-level approach is required to identify and prioritise the investments required to close the operational, well, infrastructure, engineering and reservoir development gaps that have a material impact. Digital solutions are required across each of the value pools and their respective components. Capital allocation and OPEX should be optimised to target the gaps across this ecosystem that will drive the most efficiency in terms of returns, requiring a holistic analysis and understanding of the potential gains to make informed investment decisions.

Industrial Revolution 4.0

As the E&P sector continues to evolve, major efficiencies need to be realised by embracing the fourth industrial revolution, – driven by digital enablement, to maximise returns, reduce carbon intensity and ensure security of supply, affordability and long-term environmental sustainability. To do this requires adoption of the digital revolution at the system level, fully coupling subsurface insights with digital well construction to deliver superior reservoir and production performance. ■

Figure 7: Value pools and potential gaps recognised between Current Production and Asset Potential.



Barents Sea: New TopSeis Images Illuminate Near-field Opportunities

The development of the Johan Castberg field opens up new areas for near-field exploration. The Isflak discovery made earlier this year is estimated to hold 31 to 50 MMbbl of oil and is likely to be integrated with the field development at a later stage.

Advanced imaging of the new 3D TopSeis data has brought new insights to help identify additional prospectivity in the area, including in open acreage.

This west to east seismic line from the new Greater Castberg 3D TopSeis dataset passes through well 7219/9–1 as well as the Havis, Isflak, Drivis and Skrugard discoveries. The black arrow indicates the Base Cenozoic unconformity. Figure 2 in the bottom right corner shows an untested lead within the Bjørnøyrenna Fault Complex.

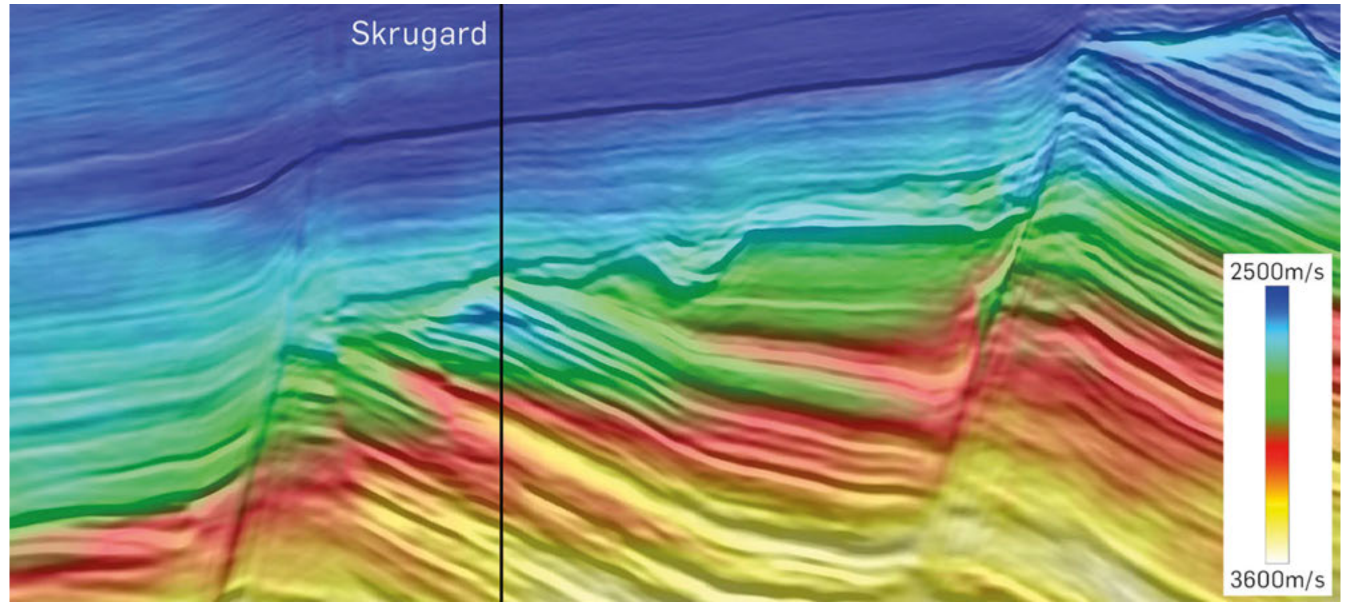
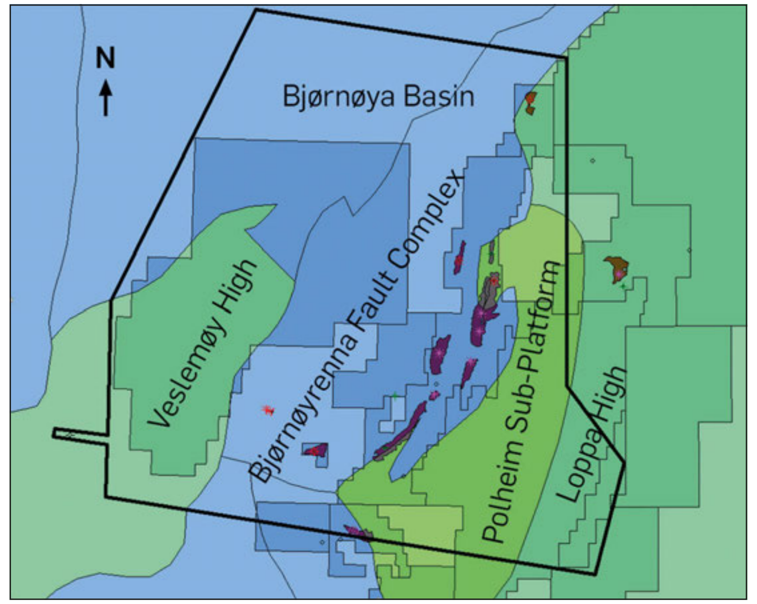
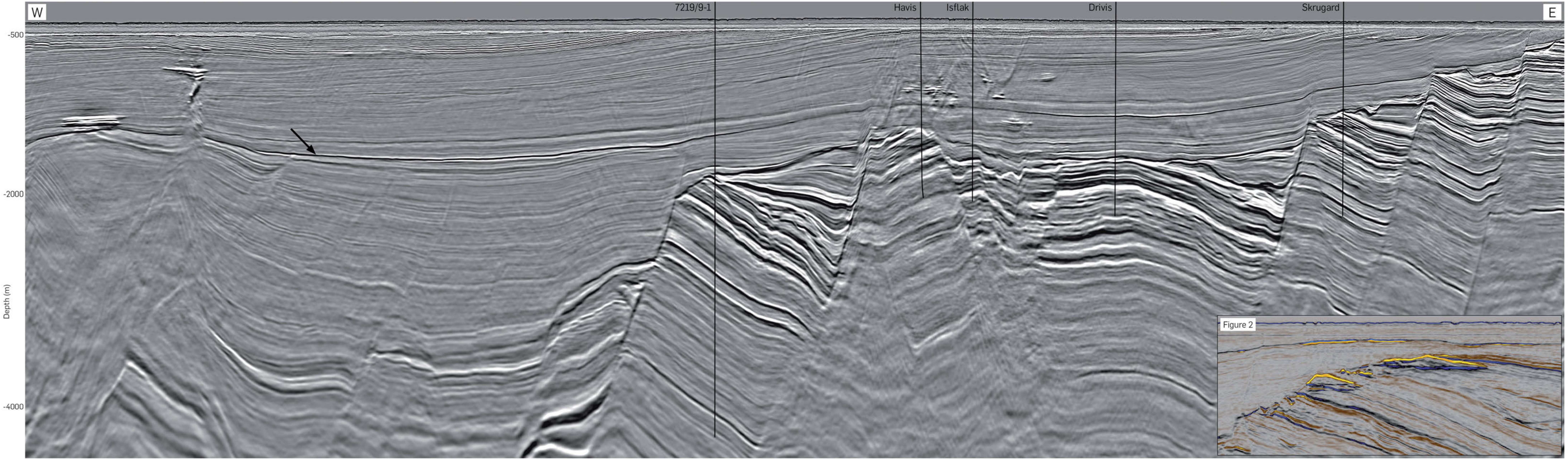


Figure 1: Seismic section overlain with the high-resolution velocity model using TL FWI.



Map showing location of CGG/TGS Greater Castberg TopSeis survey (5,168 km²) acquired in the Barents Sea in 2019, and the main structural elements.



Greater Castberg Survey – A Catalyst for Further Development

Advanced imaging of New TopSeis data addresses challenges in this complex area and provides crucial new insight in the hunt for additional hydrocarbon resources.

GUSTAV AAGENES ERSDAL and IDAR KJØRLAUG; CGG

Exploration activity in the Barents Sea has fluctuated considerably over the last 40 years, in line with the price of oil and general industry optimism. Today's high level of activity focused on ongoing and planned field developments and production may spur further exploration as infrastructure is developed. Exploration efforts in the vicinity of the producing Snøhvit and Goliat fields have been successful, and the ongoing development of the Johan Castberg field is opening up new areas for near-field exploration. An important tool in the search for additional resources is the recently processed Greater Castberg seismic survey, a CGG/TGS multi-client joint project. The survey was acquired with TopSeis™ technology, developed by CGG in collaboration with Lundin Energy Norway, which deploys wide-towed sources on top of the streamer spread in combination with a large front source (see Vinje et al., 2020). CGG processed the data, leveraging its unique experience of imaging TopSeis data and applying tailored proprietary high-end processing and imaging technologies, to deliver exceptional high-resolution depth-migrated seismic, a very detailed velocity model (see foldout Figure 1) and high quality AVO information (Salaun et al., 2020).

Exploration History

The main hydrocarbon discoveries in the Greater Castberg area have been made in the Early to Middle Jurassic Stø, Nordmela and Tubåen formations.

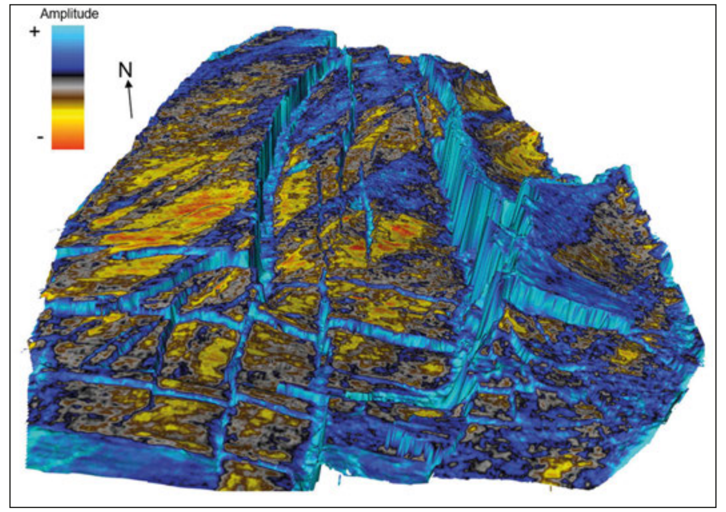


Figure 3: A 3D visualisation showing an amplitude extraction on the Top Snadd time structure map over the heavily faulted Polheim Sub-platform, revealing potential sand distribution through bright anomalies (yellow-red).

Significant resources are also confirmed within the Early Cretaceous Knurr and Kolmule formations.

Key wells in the exploration history of the Greater Castberg area are shown in the foldout seismic image. Norsk Hydro drilled the first well in the area in 1988 (7219/9–1), targeting a Jurassic rotated fault block, but unfortunately the well was dry. It was not until 2011 when Statoil drilled the Skrugard prospect (7220/8–1) that fortunes changed. The discovery is located on a rotated fault block where gas and oil were proven in Early to Middle Jurassic Stø and Nordmela sandstones. Skrugard opened up a new hydrocarbon province and was subsequently followed by a number of additional successful wells. Skrugard and the other two main discoveries, Havis and Drivis, are now being developed in the Johan Castberg field and are expected to hold 450–650 MMbbl of oil. The latest discovery, Isflak (7220/7–4), was made this year. Estimated to hold 31–50 MMbbl of recoverable oil it may be included in the field development at a later stage.

Hydrocarbon discoveries made outside the actual survey area are also relevant when evaluating the prospectivity of the Greater Castberg area. In the southern part of the Loppa High, the Gotha (7120/1–3) and Alta (7220/11–1) discoveries demonstrate reservoirs within Carboniferous to Permian carbonates and Permo-Triassic conglomerates in structural closures.

On the Loppa High in the east, the Neiden discovery (7220/6–2) proved oil and gas within carbonates of the Permian Ørn Formation.

In the Bjørnøya Basin, north of the survey, the Pingvin discovery (7319/12–1) proved gas stratigraphically trapped in a sandstone reservoir of the Paleocene Torsk Formation.

Prospectivity in the Greater Castberg Area

Within the survey area, erosion features and internal structuring can be seen within the paleo-Loppa basement ridge (Selis Ridge), indicating that weathering may have resulted in secondary porosity and possible productive reservoir properties (see Vinje et al., 2020). An appraisal well (7220/11–2) drilled at the Alta discovery indicates residual oil encountered in the basement. The weathered basement may potentially contribute with additional reservoir volumes if a discovery is made in the overlaying units.

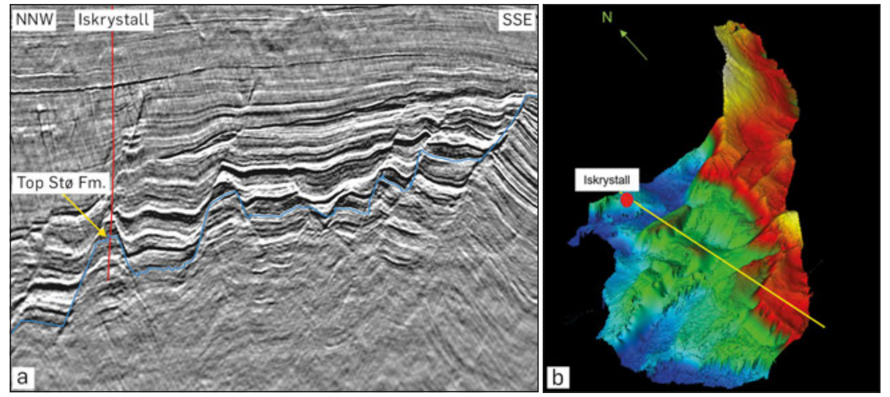


Figure 4: a) Seismic section showing high-amplitude reflections of Early to Middle Jurassic deposits within rotated fault blocks in open acreage near the Iskrystall gas discovery. b) Time-structure map revealing the geometry of the rotated fault blocks.

Dissolution and karstification of Carboniferous to Permian carbonates can be seen over the Loppa High, due to sub-aerial erosion during the Middle Permian. These features allow for improved reservoir properties within the carbonates, as seen in the Alta and Gotha discoveries.

On the Loppa High and the Polheim Sub-platform the Triassic is represented by the Snadd Formation with the Carnian sands deposited in fluvial channels or possibly in a coastal/nearshore environment. Figure 3 shows a number of bright anomalies that can be identified within open acreage on the Polheim Sub-platform. Interpretation of these potential sands benefits from the densely sampled high-resolution TopSeis data, allowing better prediction of reservoir quality and hydrocarbon presence.

In the Bjørnøyrenna Fault complex the high-resolution TopSeis data reveals untested leads that may bring additional resources to the Johan Castberg field in the future. Foldout figure 2 shows two bright spots on full-stack amplitude data that are located within Middle Jurassic and Lower Cretaceous strata with flat events underneath (direct hydrocarbon indicators).

Other leads are observed in rotated fault blocks located in open acreage east of the Iskrystall well (7219/8–2), with reservoir potential within the Early to Middle Jurassic sediments. The Iskrystall well encountered 132m of gas-filled sands but reservoir quality was limited due to quartz cementation. In Figure 4, a number of tilted fault-blocks can be seen up-dip from the well where the Jurassic targets may contain better reservoir properties and merit further investigation.

The Kayak (7219/9–2) and Nunatak (7220/5–2) wells represent significant discoveries within Early Cretaceous Kolmule and Knurr formations. The foldout image shows high-amplitude reflections in the Cretaceous strata, truncated by the Base Cenozoic unconformity (black arrow on foldout line) and with seismic indications of gas leakage above the truncations. The features are located in open acreage in the western part of the Bjørnøyrenna Fault Complex and interpreted as Early Cretaceous sand deposits possibly holding hydrocarbons.

In the Bjørnøya Basin the Pingvin discovery encountered 30m of gas within a Paleocene submarine fan reservoir with the most likely provenance of the reservoir sands from the north/north-west (Blaich et al., 2017). Within the TopSeis dataset, high-amplitude features near the base of the Cenozoic can be seen in what have been interpreted as similar sand deposits in locations further south into the basin.

A particular feature is observed on the flank of a salt diapir (Figure 5). The top reflector shows a polarity change from the lower part of the feature to the upper part and the soft event (red, negative) brightens considerably on the far-offset stacks and the shallow anomalies above the feature indicate gas leakage. The bright anomaly is interpreted as a sand-rich fan deposit with possible hydrocarbons, analogous to the Pingvin discovery.

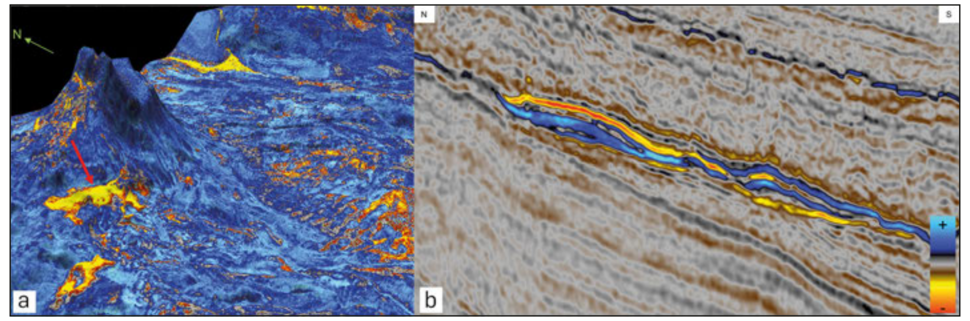
Future Plans

Looking forward, there is potential for further increased activity in the Barents Sea in the years to come. A Plan for Development and Operation (PDO) is expected for the Wisting Field in late 2022 and Lundin is still evaluating commercialisation of the Alta and Gotha discoveries. Lundin and partners in license PL1083 are investing heavily in the Nordkapp Basin by acquiring an advanced survey combining TopSeis technology and ocean-bottom nodes. In the 25th licensing round new acreage was awarded north of the Wisting Field. We therefore expect near-field, infrastructure-led exploration to play an important part in the search for new resources and believe that the imaging challenges in the Barents Sea require tailor-made technology solutions. In the Greater Castberg area the new TopSeis imaging results look set to be a catalyst for further development, providing the best data quality for revealing the remaining prospectivity.

All images courtesy of CGG Multi-Client and TGS.

References available online. ■

Figure 5: Located in the Bjørnøya Basin, on the flank of a salt diapir: a) A high-amplitude feature mapped near the base Cenozoic, highlighted by the red arrow. b) The same feature in section interpreted as a sand-rich fan deposit.



Namibia: Ancient Rocks in the World's Oldest Desert

Traverse diverse desert geomorphology, take a self-drive safari in a 4×4 camper truck, and examine rocks that narrate Africa's geologic and human history at your own pace.

LON ABBOTT and TERRI COOK

Namibia, with its long, complex geologic history on full display in magnificent outcrops, is a geologist's paradise. Combine this fascinating bedrock geology with the planet's tallest sand dunes, 6,000-year-old petroglyphs, and world-class game parks, and you have the ingredients for an unforgettable desert adventure.

Distances in Namibia are large, and many roads are gravel, so the most convenient way to tour is in a 4x4 camper (Figure 1). Our Namibian adventure began at the Windhoek airport, where we collected our fully equipped camper and were rolling down the highway enjoying the expansive vistas within an hour of our arrival.

Namibia's physiography is typical of an elevated passive continental margin: a 1,000–1,600m high inland plateau separated from a coastal plain by the 'Great Escarpment'. Namibia shares this morphology with other elevated passive margins, such as its 'twin' across the Atlantic – eastern Brazil. Brazil and Namibia were long-time neighbours in the supercontinent Gondwana until the opening of the South Atlantic Ocean sundered their bond about 130 Ma. That split was aided by hotspot volcanism, which produced Brazil's voluminous Paraná flood basalts and its eastern counterpart, Namibia's Etendeka volcanics.

Namibia is famous for the hyper-arid Namib coastal desert. Three factors conspire to create this hyper-aridity. The first is the country's 17–29°S latitude; many of Earth's great deserts lie within this belt, and because air on the sinking limb of the Hadley Cell atmospheric circulation is loathe to release its water vapour as rain. The second is that prevailing winds blow from the south-east, leaving Namibia's west coast in the rain shadow of the inland plateau. Lastly, the coastal Benguela ocean current delivers cold water from the Antarctic that cools the coastal air, reducing its capacity to hold water vapour. This same combination of factors has controlled Namibia's climate ever since Gondwana broke apart almost 130 Ma, making the Namib the world's oldest desert.

In addition to the break-up of Gondwana and its accompanying flood basalts, Namibia's beautifully exposed rocks highlight three additional marquee events: the Neoproterozoic 'Snowball Earth' episodes that occurred between 720–635 Ma, the Damara Orogeny, a mountain-building event that completed assembly of the Gondwana supercontinent between 560–550 Ma, and deposition of the Karoo Supergroup, a series of Late Carboniferous through Jurassic sediments that accumulated in basins that formed behind the rising mountains of South Africa's Cape Fold Belt.

Figure 1: A 4x4 camper is the ideal vehicle to explore Namibia.

Self-drive Safari: Etosha National Park

A must-see destination on any Namibian itinerary is the magnificent Etosha National Park. The park's east gate lies 500 km north of Windhoek on a sealed road. Tsumeb, the park's gateway town, is world famous among mineral collectors for exotic, gem-quality mineral specimens. Between 1905–1996, the Tsumeb copper-lead-zinc mine extracted 30 million tonnes of high-grade ore from an unusual pipe produced by karst collapse during the Damara Orogeny of the Neoproterozoic Otavi Limestone. The mine is the type locality for 56 different mineral species; many of its germanium minerals are found nowhere else.

Etosha is our favourite game park for two reasons. First, the sparse vegetation makes animal spotting comparatively simple. Second, Etosha can be seen on a self-drive safari; we chose how long to linger at each stop instead of being locked into a group timetable. The park surrounds the 120-km-long Etosha salt pan. Although the pan itself is desolate, springs to the south deliver groundwater to a series of waterholes that sustain scrubby vegetation and a diverse fauna that includes elephants, giraffes, rhinoceros, leopards, and lions.

Three lodges, which have campsites, lie along the self-drive route. Okaukuejo Camp is famed for night-time animal viewing at its floodlit waterhole; endangered black rhinos visit almost every night. Austral winter is the most popular time to visit; it's the dry season, so the animals cluster at the waterholes, making for better wildlife viewing. Although summer rains make driving the park's dirt roads trickier and wildlife spotting more difficult, as the animals spread out to take advantage of the abundant vegetation, it's the perfect time for bird watchers to spot some of the park's 340 different bird species.

Extraordinary Rocks and Ancient Peoples: Twyfelfontein

Namibia's Otavi Group, which was integral to validating the Snowball Earth hypothesis, displays outstanding exposures of glacial diamictite directly overlain by thick marine 'cap carbonates'. These record the dramatic climatic fluctuations Earth experienced between about 720–630 Ma, when the climate cycled from the 'icehouse' Sturtian glacial episode to a sweltering ocean in a 'hothouse' world, then back to an icehouse during the Marinoan glaciation, and finally back to a hothouse. We spent a delightful couple of hours surveying excellent diamictite and carbonate exposures riddled with 2-cm-diameter paleomagnetic sample holes in a small gorge traversed by a paved highway immediately north of Fransfontein, a 250 km drive from Etosha's south gate.

Our next destination was Twyfelfontein, which was designated a World Heritage Site because of its 5,000 petroglyphs carved by ancestors of today's San people (often called Bushmen) on desert-varnished red sandstone. The petroglyphs were outstanding, and we were equally captivated by this area's abundant lava-capped mesas underlain by red rock, which reminded us of Utah's famed Canyonlands, minus the crowds.

On the 120-km drive west from Fransfontein to Twyfelfontein, we traversed rocks representing all the major stages of Namibia's geologic history. We started in Neoproterozoic Snowball Earth rocks, which were deformed during the Damaran Orogeny. Farther west, isolated granite koppies (bedrock hills) rose above the desert floor (Figure 2). The koppies consist of post-tectonic Cambrian granite that

Figure 2: Lava-capped mesa and Cambrian granite.

Figure 3: Columnar Etendeka diabase dike.

Figure 4: Twyfelfontein petroglyphs.

Figure 5: Welwitschia mirabilis.

intruded as the Damaran Orogeny waned. Further west rose mesas consisting of Late Carboniferous and Permian Karoo Supergroup sediments capped by resistant basalt or rhyolite flows erupted 133–132 Ma from the Etendeka hotspot. Burnt Mountain, ten kilometres south-east of Twyfelfontein, is a prime example; its pastel slopes of Permian lake mudstone are capped by an Etendeka basalt flow. Nearby attractions include the Petrified Forest, which displays petrified logs washed by floods down a Permian river, and the Organ Pipes, consisting of columnar Etendeka diabase (Figure 3).

The Twyfelfontein petroglyphs were carved during the Late Stone Age, which spanned 6,000–2,000 years ago. Archaeologists think that successive generations of hunter-gatherers considered the local springs sacred and added ritual artwork to the panels over at least two millennia. The carvings, and a few paintings, depict human and animal footprints and hunting scenes replete with bow-and-arrow-toting hunters tracking stylised antelope, rhinos, zebras, giraffes, lions, and even seals (Figure 4). The red sandstone on which the petroglyphs are carved has its own fascinating geologic story. This Twyfelfontein Formation consists of aeolian sandstone that interfingers with the lowermost, 133–132 Ma Etendeka basalts. Here are seen preserved 133 Ma aeolian bedforms up to 100m tall that were passively buried and lithified by the basalt.

Desert Fogs: The Skeleton Coast

Our next stop was Namibia's famed Skeleton Coast. Heading west, the already sparse vegetation dwindled to nearly zero as we descended from the plateau and entered the coastal rain shadow. We were startled to see a lone oryx ambling across the barren gravel plain we were traversing. Shallow groundwater beneath ephemeral drainages does support vegetation, thus explaining how life thrives in this moonscape; travellers are advised to avoid these washes lest they become dinner for a desert lion.

Occasionally, we spotted an odd-looking plant with a metre-wide tangle of broad, leathery leaves sprawled across the otherwise barren plain. This extraordinary plant, *Welwitschia mirabilis*, is one of Earth's oldest living creatures; individual plants are as old as 1,500 years (Figure 5). The species, which grows only in the Namib Desert, is a living fossil, the only living representative of its ancient genus.

As we approached the coast, we entered a chilly fog bank. Fog seemed an incongruous sight in one of Earth's driest deserts. But such fog is commonplace on the Skeleton Coast, which has a cool 16°C mean annual temperature. These fogs occur because the Coriolis effect generates south-east winds that drive the northward flow of the cold Benguela current and another Coriolis-induced phenomenon, Ekman transport, further cools the water by causing flow perpendicular to the wind direction. This moves surface water west, away from the coast; the void is filled by cold, nutrient-rich water that upwells from depth. That upwelling cools the air, causing what little moisture it holds to condense as fog. It also delivers abundant nutrients to the marine ecosystem, sustaining kelp forests and massive schools of fish.

When we reached the coast, we registered for our mandatory day-trip permit to traverse the Skeleton Coast

Figure 6: Left: Skeleton Coast gate. Right: Shipwreck.

National Park. We then passed through a metal gate adorned with skull and crossbones and started down a long, straight road ploughed across the salt flats, stopping occasionally to explore one of the many shipwrecks that dot the coast (Figure 6). The omnipresent fog reduces the contrast between land, sea, and sky, adding yet another dimension to the surreal sensation of traversing this empty landscape.

The Matterhorn of Namibia

After traversing 219 km of empty coastline, we encountered the first major road junction since passing through the skull-and-crossbones gate. This inland road leads 100 km to the Brandberg, Namibia's highest mountain at 2,573m. This massive granite stock was emplaced 130 Ma, during the Etendeka large igneous event. It has been exhumed from a 5-km depth, with most erosion occurring between 80–60 Ma. Because the granite resisted that erosion better than the surrounding rocks, today it towers 1,800m above the surrounding coastal plain. The Tsisab Ravine on Brandberg's west flank has been sacred to the San for millennia; more than 45,000 painted pictographs have been found throughout the ravine's complex topography. The most famous is the so-called 'White Lady', which can be visited on a 1-hour guided hike.

Figure 7: The Spitzkoppe Cretaceous pluton.

The Spitzkoppe, which lies just north of the main highway connecting Windhoek to the scenic coastal cities of Swakopmund and Walvis Bay, is another exhumed Cretaceous pluton (Figure 7). Although less massive than the Brandberg, it is even more spectacular, hence its 'Matterhorn of Namibia' nickname. Its sheer, 600m high granite walls are a premier rock-climbing destination.

Guardians of the Coast: Sossusvlei Sand Dunes

The coast south of Swakopmund and Walvis Bay is every bit as arid as the Skeleton Coast, but its character is dramatically different. Abundant sand has drifted into huge dunes not found farther north. Dune 7, a short 13 km drive from Walvis Bay, is purported to be the tallest sand dune on Earth. Tourists flock to climb its impressive 383-metre face.

To be fully immersed in a sea of dunes, the destination of choice is Sossusvlei. A 49 km drive from the tourist base of Sesriem follows the ephemeral Tsauchab River as it plunges into a field of sand dunes that guard the coast. The 85m-tall Dune 45 is a popular roadside climb (Figure 8). Sossusvlei is a dune-encircled mud pan at the river's terminus. Vlei is an Afrikaans word meaning 'marsh'; Sossusvlei is undoubtedly a marsh in the aftermath of rare floods, but normally it is a silt- and camelthorn tree-covered plain surrounded by towering red dunes. Even more stunning is nearby Deadvlei: it was the river terminus 600–700 years ago, but a course change cut it off from moisture, leaving behind gaunt skeletons of camelthorn trees, undecomposed even after 600 years.

The final stop on our Namibian 4×4 adventure was nearby Sesriem Canyon. It combines gorgeous desert scenery with typical Namibian geologic and geomorphic diversity, making it a fitting finale. Here the (usually dry) Tsauchab River plunges off a resistant rim of Miocene conglomerate, carving a 30m deep canyon into the softer sandstone below. The coastal dunes to the west glowed red in the evening light, which also illuminated the dramatic Great Escarpment to the east. This view encapsulated for us Namibia's stark beauty and extraordinary geoheritage. We saw countless amazing sights in our travels, but we barely scratched the surface of what Namibia offers. ■

Figure 8: Above: Deadvlei mud pan with undecomposed camelthorn trees. Below: Dune 45.

A Long Route to Lake Kivu

A multi-decade marathon to develop a unique African resource.

PHILIP MORKEL

In Johannesburg in 1998, a Rwandan government delegation came looking for assistance to develop an energy supply for their country. They offered access to Lake Kivu, one of four lakes in Africa's Western Rift Valley, for development. They reported that it encompasses a unique trap for anoxic biogas formation and storage, providing enormous, dissolved gas reserves, notably methane. They explained how gas capture here had started in 1965, fuelling a local Heineken brewery. In short, they wanted to provide more energy to the country but were struggling to garner interest and commitments in the area. This is an incredible resource, with associated dangers, providing unique technical challenges to develop it effectively and safely.

Lake Kivu's Fiery Formation

The highest of Africa's Great Lakes, Kivu, straddles the border between the Democratic Republic of the Congo (DRC) and Rwanda (Figure 1). It lies in the Albertine Rift, the western branch of the East Africa Rift. The lake has a surface area of 2,400 km^2 with a surface elevation 1,463m above sea level. It is positioned over the rift's most active zone, where tectonic movement is gradually splitting the Somali Plate away from the rest of the continent. This rifting zone is underlain by shallow magma, a hot spot that has spawned a string of volcanoes. Two of the seven main peaks still lie above the hot zone and remain very active. Other peaks like Mt Karasimbi, 4600m high, have drifted up to 100 km east with tectonic movement.

Mt Nyiragongo had a flank spill on 22 May 2021, with lava flowing to within 5 km of Lake Kivu. Rifting action made the lake deep, despite sediments deposited on the lake floor. Surrounding hills plunge steeply into deep water, with a maximum depth of 486m and with an average of 220m. It is the world's eighteenth deepest and the ninth deepest lake by mean depth.

How Did It Get Full of Gas?

The Lake Kivu methane is biogenic in origin, formed by the acetate pathway which also produces CO_2. Anaerobic bio-digestion of dead organic matter (algae and fish) occurs on the floor of the lake. Other pathways such as methanogenesis

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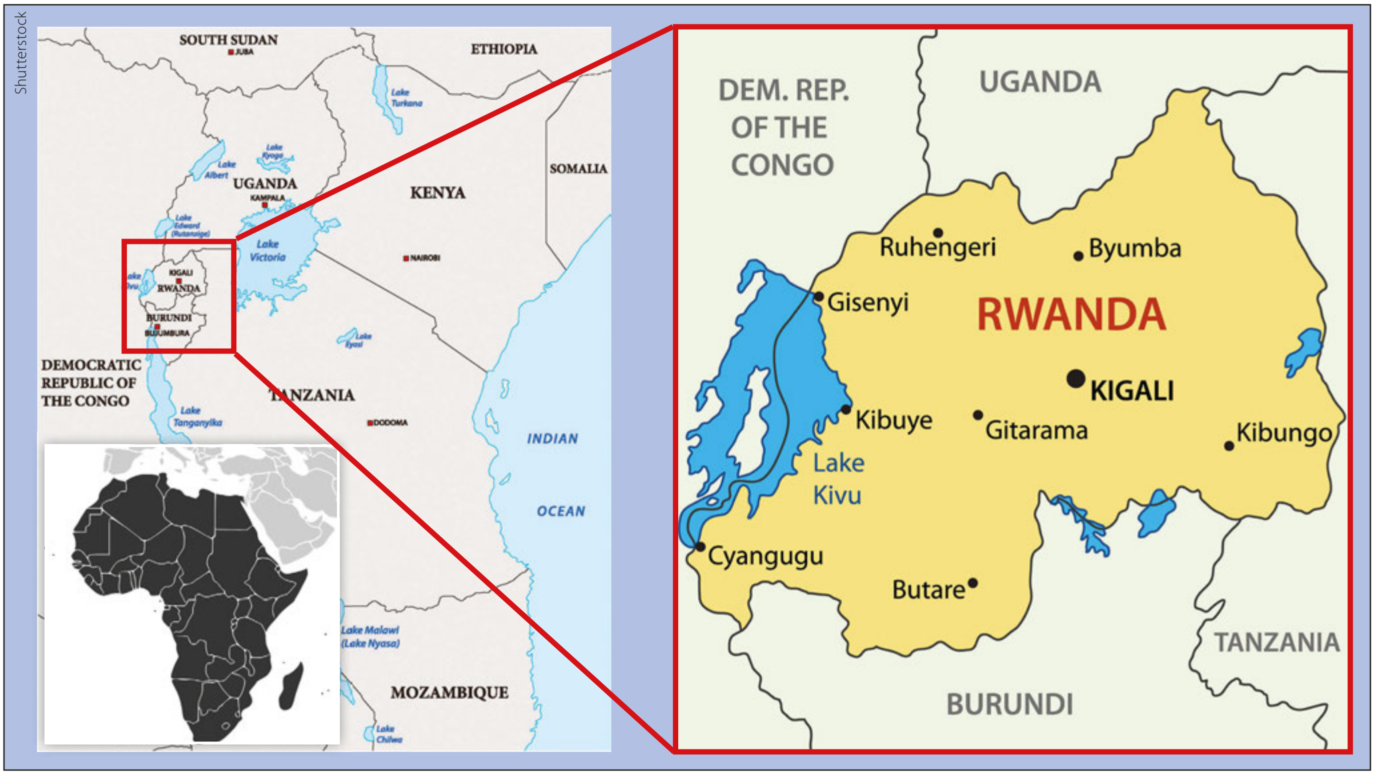


Figure 1: Location of Lake Kivu.

exist, where *archaeal methanogens* can convert some of the volcanic or biogenic CO_2 to methane. Most gas is renewable, with a current renewal rate averaging 0.5% per annum. Indications of a varying rate of renewal over recent decades may be due to the variety of measurement techniques, combined with a varying flux of nutrients from depth into the Biozone. Lake Kivu is estimated to contain approximately 55–60 billion m^3 (1.9–2.0 Tcf) of dissolved biomethane, mostly below a depth of 260m. It also contains roughly 300 billion m^3 of CO_2, similarly, distributed by depth.

Lake Kivu's extraordinary feature is stratification and resultant quiescence and stability of the deep waters. The vertical density profile is a key feature defining the lake's behaviour. No other lake is known to have five distinct strata. Unusually the deepest waters are the warmest, over 26°C. Oxygenated water persists in only the uppermost 60m Biozone layer. This Biozone supports aquatic life in the form of small, sardine-like fish called 'sambaza'. Seasonal wind-driven turnovers oxygenate the Biozone, occurring more strongly in the dry seasons. Oxygenation penetrates to a depth of up to 60m, but oxygenated water depletes seasonally to as shallow as 40m during the calmer, wet seasons.

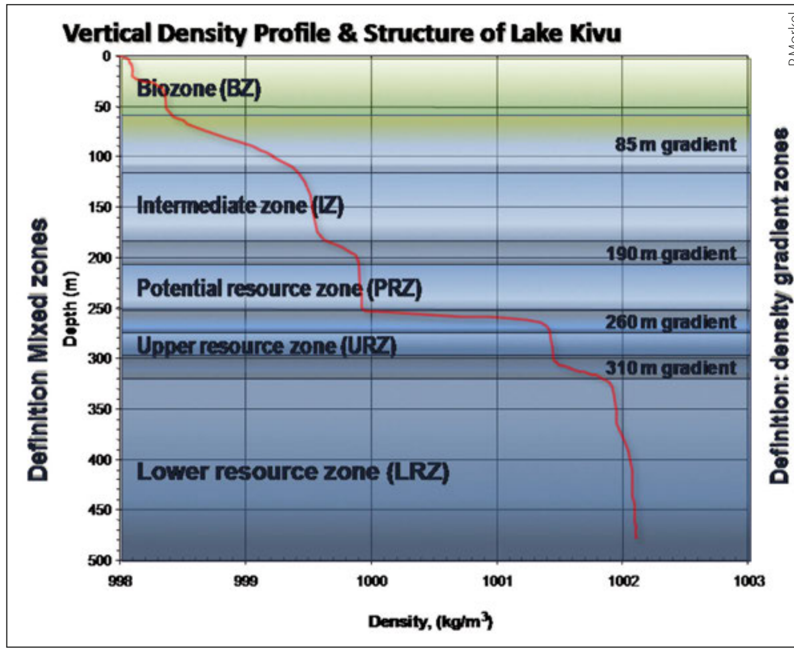


Figure 2: Vertical density profile in Lake Kivu (excluding pressure effect) and the associated definition of zones and of density gradients.

The deeper layers get progressively denser with depth, bearing increasing concentrations of salts (mainly of magnesium carbonates and sulphates) and nutrients. Sub-aquatic inflows of varying density create the density layers that separate the lake into definable strata. Figure 2 shows these density gradients, illustrating the defined zones. Gradient layers act as virtual traps, preventing significant vertical migration of gases out of the main gas resource zones.

A Resource and a Danger

Along with Cameroonian Lakes Nyos and Monoun, Kivu is one of three known to undergo limnic eruptions or lake overturns. The smaller crater lake events are rare, but more frequent. Dissolved CO_2 can catastrophically erupt from deep crater lake waters when triggered, i.e., by landslides. Eruptions similarly form a dense gas cloud, capable of suffocating wildlife and humans. This phenomenon has been observed in Cameroon at Lake Monoun in 1984, causing asphyxiation and death of 37 people and at neighbouring Lake Nyos in 1986, which released over 80 million m^3 of CO_2. This more destructive limnic eruption killed over 1,800 people.

At Lake Kivu, core samples from lake-bed sediment showed uneven strata, indicating disruptive events at time intervals of several millennia. Careful evaluation of data indicates few eruptions or 'turnovers' have occurred, one of which coincided with a prolonged drought period and a sharp drop in lake level 1,500 BC. These events emit 10,000 times more gas than crater lakes.

Limnic Eruptions from Lakes

For a limnic eruption to occur, there must be concentrations of dissolved gas (in Kivu's case, methane and CO_2) approaching saturation. It also needs an energetic trigger event, displacing a large volume of gas-saturated water upwards, to where pressure cannot keep the gases in solution. A rising column of degassing water initiates a surging gas-lift. Triggers are typically a volcanic eruption, or major seismic rift event. An alternate cause of limnic eruption is a gradual rise in gas saturation, which will take decades. Pressures peak at specific depths, such as 275m and 320m, which is where spontaneous gas eruption can trigger as 100% saturation occurs.

The active volcanoes are the 10,000-year-old Mounts Nyiragongo and Nyamulagira, lying 25 and 40 km to the lake's north. As recently as 22 May 2021 there was an eruption, with lava flows not quite reaching Lake Kivu to the south. A very similar flank spill in 2001 did reach the lake after streaming through the city of Goma, penetrating to 80m depth before solidifying.

The compositions of gas releases from lakes are unique to each, and Lake Kivu has a signature gas content in the anoxic zone of 20% methane and 80% carbon dioxide. Minor components include nitrogen, hydrogen sulphide and argon.

What the Eruption Process May Look Like

From the surface of the lake, if you were unlucky enough to be caught in an eruption's epicentre, the waters initially smooth out with fine, rising bubbles. The ferocity would rapidly escalate, appearing to boil. The odour of H_2S, like rotten eggs, would hit you strongly, but in seconds destroy your sense of smell. The rapidly rising waters would surge upwards and outwards, eventually causing tsunami-like concentric waves. Visibility would be clouded in fog.

The eruption's core could eventually grow wider than 1 km in diameter, from where a rapidly forming, low gas cloud would blast outwards. It is estimated that this eruptive 'storm' continues for 24 hours before it becomes depleted. At the surface, tsunami-like waves, metres high and a storm-surge in water level, would radiate rapidly outwards to all shores. Consequences for riparian populations living in settlements close by (Goma, Kabare, Kalehe, Bukavu and Sake in Congo, and Gisenyi, Kibuye, and Cyangugu in Rwanda) would be catastrophic. When the clouds finally clear, a muddy lake would reappear, as will a lifeless shore, smelly, and still deadly.

An Unexpected Opportunity

Following that first engagement, I was initially sceptical of the 1998, Rwandan delegation's mission to promote Lake Kivu as a gas resource. I called a chemical engineering expert in Cape Town, Gareth Shaw, who told me about his visit to the area in 1998. His reconnaissance report elicited little interest from his company, but he was able to share the technical findings with me. They were interesting and seemed plausible, though prompting further investigation.

A few years later in 2001, I was contacted by an ex-Fluor colleague, Mike Sterne. He worked for Murray & Roberts, a leading engineering and construction group based out of Johannesburg, and they were contemplating a trip to Rwanda. He asked if I would participate because of my African gas experience. I agreed and flew out to Rwanda just before Christmas 2001. At the Energy Ministry in Kigali, we worked through numerous reports on the feasibility of developing the Lake Kivu gas reserves, including an Egyptian study advocating a floating plant offshore. The following day we travelled north to Gisenyi, a city on the northern shore of Lake Kivu.

Gas Extraction

We were asked to look at the earlier venture to exploit the Kivu gas resource, a 1965 facility, UPEGAZ, built by UCB of Belgium. UPEGAZ was a land-based project for gas extraction on a Kivu peninsula close to deep water. When we visited the plant, it still limped along, though rusted and patched up. From the rotten-egg stench, it seemingly leaked as much gas as it piped to the brewery 2 km to the south. We were able to validate the still-working process, although in expanding the existing facilities there was not a viable onshore solution.

We later surveyed Kivu from the UPEGAZ facility, and in the process, I had formed the kernel of an idea: building an offshore facility in deep water with 400m risers, but with all processing modules submerged. This solution would be elegantly simple, continuously operable with minimal attention and maintenance. The concept was sketched out on the return flight and a recommendation made to Murray & Roberts to evaluate further.

Feasibility and Piloting

I worked with the Murray & Roberts projects team, leading the pre-feasibility study, comparing new and legacy ideas. The new concept was more promising, but unproven. The idea was to accelerate gas exsolution, and after months of research, including a visit to Boston to engage experts in underwater sonar, we found leading expertise just 10 km away in Johannesburg. We then designed a scaled-down pilot module, barge-mounted, on a shoe-string budget.

The pilot was a proof-of-concept and by November 2003, our expanded team mobilised to Rwanda. The pilot-rig (Figure 4) was procured, shipped and built on the lakeshore but once launched, getting it working was not easy. The new technology, though used for submarine detection, experienced leakage in cables and seals resulting in having to hand-haul the module out several times, over the small deck, to inspect and re-install. Several nights we were raided by fishermen, despite posting guards, with the raiders cutting anchor ropes and piping and then offering to sell them back to us.

Hard-won Success and Setback

On 26 January 2004, our gas-lift began working and gas flow started, igniting the flare. The government scheduled demonstrations of the technology while we collected data. The Minister of Energy enquired about operating it permanently by piping gas to shore, as it produced as much gas as the UPEGAZ facility. We advised not, but hosted potential investors, including South Africa's IDC, until southerly winds started blowing in May. We demobilised the rig to shore because the waves became too rough for safe operations. Data, confirming our earlier simulations, allowed carrying out full-scale designs. The barge fulfilled its purpose.

The completed test-work strongly supported full feasibility assessment and the results were presented to Rwandan investors and then to government leaders. But momentum by the early promoters slowed, outside factors interfered and a Murray & Roberts management reshuffle resulted in a decision not to participate, with focus shifting to the nuclear Pebble Bed Reactor (PBMR) project in 2005, a joint venture

Figure 3: Mt Nyiragongo alternately belches sulphurous smoke or steam from its molten caldera, two weeks before an eruption.

with SNC-Lavalin. I was asked to co-lead that project team, forcing a break from the Kivu project.

Experts of the World Unite

In February 2007, a World Bank-sponsored conference was hosted in Gisenyi, with European diplomats, scientists, developers, and government delegations. The Kivu gas development experiences, theories and perspectives were presented, receiving new attention. But for the conference, consensus seemed distant with so many diverse opinions. After hearing of our gas extraction experience, the organisers co-opted me along with five scientists to 'quickly' confirm the 1986 rules for lake use.

Three years later our Expert Group published the lake management prescriptions, based on the workability of alternative extraction concepts. Designs based on the 1965 legacy approach would destroy the natural safety structure of a stratified lake structure. By May 2009, we also concluded that legacy approaches and ours were incompatible for simultaneous use. A legacy approach may be safe for 30–40 years, deteriorating thereafter to being a danger for centuries.

The Management Prescriptions for Lake Kivu Development (MPs) were issued in January 2010 in English and French, and both Rwanda and DRC adopted them through enabling legislation.

Figure 3: A leaking riser brought a gas-water mix to the 1965 extraction facility on Cap Rubone.

Renewed Investment Search

Later in 2007, the Rwandan Investment Group (RIG) engaged Hydragas, requesting a proposal for a feasibility study. We started the six-month study in 2008 but cancelled when payments were not forthcoming. We substantially completed our own feasibility study with contractors. RIG switched to backing a French team whose concept later failed. Another investor, from California, stepped in for us after RIG's pull-out. In 2008 we negotiated a $25 million investment with Kenyan co-investors, but with famously bad timing: the Global Financial Crisis hit on 1 August.

New Competition

In 2008, New York-based investors accompanied President Bush on Air-Force One to Kigali. They were introduced to Rwanda as the team who would resolve Rwanda's energy problems, producing 100 MW of clean power by 2010. Five years late, they had built a quarter of the promised capacity, using most of their capital. The unit still operates but remains unable to make a return on investment. In 2015, a copycat investor, also with investment and Presidential endorsement, embarked on the same road with the same engineers. But their feasibility study to secure an environmental and social impact assessment was rejected. Their study and rights were sold, and new owners were allowed to build a smaller demo facility, now in construction.

Taking a Break and Restarting

In 2011, I emigrated to Canada, working for eight years on large international resources projects, mainly gold and LNG. I remained aware of ongoing attempts to improve the performance and safety of Kivu's gas projects and in 2018, I registered a company to re-open development of Lake Kivu and commenced start-up fundraising. We believe we can develop this resource, so needed by the local communities, in a sustainable way that prevents disrupting the critical balance of the water layering at Kivu. With the right gas extraction method, the lake's risk of limnic eruption could drop by as much as 99% within 20 years – surely a worthwhile end game. ■

Figure 4: The test rig was cheap and ugly but was able to test gas separation to 70m depth.

UAE – Looking Outward

A cautious road to international participation in upstream exploration, with hydrogen in hot pursuit.

PETER ELLIOTT, NVentures Ltd

The Middle East is not a region associated with open international participation, since the nationalisation of resources in the 1970s, but strong trends are emerging to counter this isolationist policy. Since 2018, Sharjah, Ras Al Khaimah and Abu Dhabi have welcomed international bids on competitive licensing rounds, albeit in a selective manner designed to attract strategic partners and reward existing investors.

Eni in particular has played a dominant role across the Emirates, taking three blocks in Abu Dhabi, two in Sharjah and two in Ras Al Khaimah in the last two years, with companies from Japan and most recently Pakistan, participating. Meanwhile hydrogen and ammonia, its energy transport medium, is beginning to grab the limelight, as Abu Dhabi in particular builds major infrastructure for blue ammonia, with cargoes being sold to Japan in August 2021.

Abu Dhabi announced its very first Bid Round in 2018, with blocks outside the main producing areas. In support of this and further licensing in 2019, the state national oil company ADNOC, kicked off the world's largest contiguous 2D and 3D seismic survey to cover all underexplored areas. In January 2019 Eni and partner PTTEP were awarded Blocks 1 and 2 offshore, while INPEX took Block 4 straddling the coast. Occidental acquired onshore Block 3.

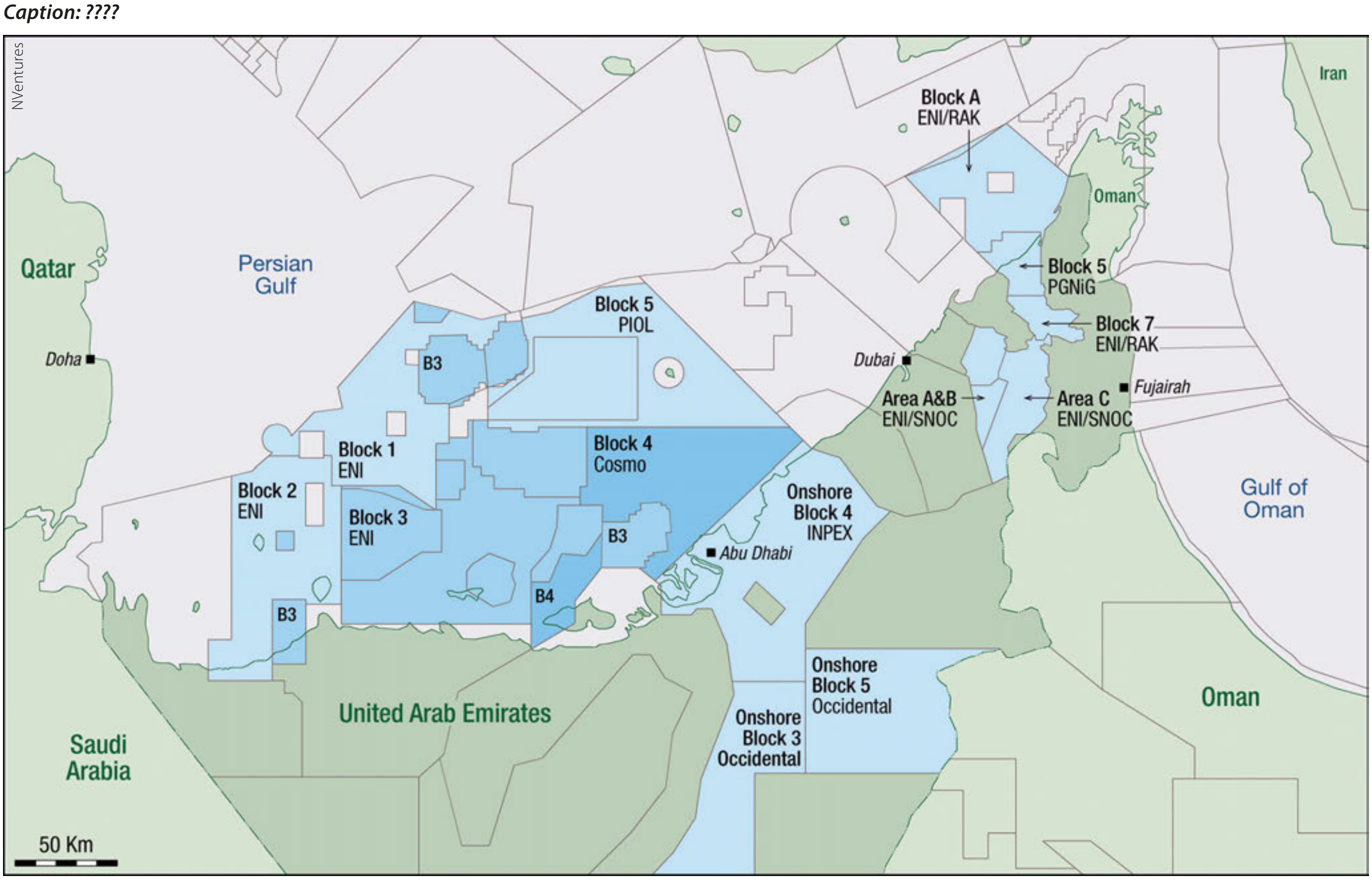
In opening investment to competitive bidding, ADNOC called for major E&P investment, a nine-year term for exploration, with a further 35 years for production, and an optional back-in for ADNOC of up to 60% on all production leases granted as a result. Eni committed US$230 million for the two offshore blocks and INPEX bid US$176 million. An Indian consortium took Block 1 onshore (Indian Oil Ltd and BPRL).

Before this first open Bid Round, ADNOC had sold small stakes in the main producing assets of the Lower Zakum and Umm Shaif projects to the likes of Eni, INPEX and CNOOC.

ADNOC announced a second Bid Round in May 2019. Whilst international interest was high, the award process was clearly based on firm criteria including strategic economic considerations (such as long-term offtake contracts with Japan and Asia) and long-term investment in existing projects in the Emirate. Terms remained similar with nine years for exploration, 35 years for exploitation and a possible 60% state back-in, along with signature bonuses and work programme commitments.

Occidental returned to win Block 5 onshore, adjacent to their existing

Caption: ????



block (bidding US$140 million). Cosmo, a Japanese consortium, already actively investing in the Mubarraz field offshore (as ADOC), were awarded offshore Block 4. US$145 million was bid, including signature bonus.

Block 3 offshore was awarded to the Eni / PTTEP consortium, adjacent to their First Round Blocks 1 and 2. Most recently in August 2021, a Pakistan consortium made up of OGDCL, Mari Petroleum, GHPL and PPL (25% each) were awarded the large offshore Block 5 concession. Block 5, with a US$305 million price tag, will be operated by Pakistan International Oil Limited (PIOL).

Interestingly ADNOC state they will not continue to offer Block 2 Onshore as part of the second round. The state firm announced a huge unconventional 'find' there in 2020, with volumes of 22 Bbo and 160 Tcf quoted at the time. ADNOC refer to the potential for licensing this to unconventional resource companies (Total was awarded 40% in a similar unconventional block, Ruwais Diyab, in 2018).

As a fascinating parallel to this surge in activity and investment in conventional and unconventional oil, Abu Dhabi is focusing heavily on hydrogen, ammonia, carbon capture utilisation and storge (CCUS) and renewables. Eni again is heavily involved, signing a memorandum of understanding (MoU) in September 2021 with Mubadala for hydrogen and ammonia joint ventures in the Emirate; the Italian firm already holds 20% in ADNOC Refining.

In 2021 alone, ADNOC has completed several agreements with international firms to push hydrogen and ammonia to the front of the energy agenda. In January, Japan and Abu Dhabi agreed headline terms to jointly develop ammonia and CCUS technology. In March, the Korean firm GS Energy invested in ammonia projects, whilst Petronas signed a broad MoU on upstream, downstream and ammonia investments. In April, the government of India signed a similar MoU for hydrogen and ammonia, whilst in May, ADNOC itself announced major plans for the production of Blue Ammonia (using blue hydrogen produced with CCUS) at its Fertil plant in the Ruwais Industrial Complex. In June, Fertiglobe announced it will join ADNOC and ADQ as a partner in a new, large-scale, 1 million tonnes per annum, blue ammonia project at TA'ZIZ industrial services zone in Ruwais. In July, companies from Japan (INPEX, JERA and JOGMEC) all agreed investments in hydrogen and renewables. Most recently ADNOC have announced first cargoes of blue hydrogen to Itochu, Idemitsu and INPEX.

Whilst oil and gas will continue to provide wealth and growth opportunities for the Emirates, for exports (and foreign currency reserves), domestic use and petrochemicals, there is a new kid on the block, with demand for hydrogen and ammonia already generating long-term revenues from major infrastructure projects. This is the reality of the energy transition in practice; the progress of hydrogen and ammonia will create conditions for low and net zero carbon energy, whilst oil, gas and petrochem will dominate global economic and industrial productivity for years to come. ■

The Outer Rovuma Fan

Hunting for Petroleum Systems in the Western Indian Ocean.

GREGOR DUVAL and MADHURIMA BHATTACHARYA, CGG

After decades of oil and gas exploration, large swathes of the globe remain unexplored. In frontier regions, such as the Western Indian Ocean, hydrocarbon exploration starts by delineating areas where continental crust may be present. This is usually where thick sedimentary basins may have developed, and the main elements of a working petroleum system may be present. At first glance, the Western Indian Ocean region may appear as barren oceanic crust with little potential, but there is tantalising evidence to suggest otherwise. The discovery of world-class gas fields in the Rovuma Basin of Northern Mozambique and Southern Tanzania in the last two decades have shed light on the prospectivity of the East African Region and the Western India Ocean islands at large. In recent years, International Oil Companies have started looking at new plays in hitherto uncharted territories such as Comoros, Seychelles and Mauritius. Exploration success in Mozambique in particular has renewed interest in the western blocks of the Comoros Archipelago on the part of independent companies such as Rhino Resources (Blocks 17 and 24), Western Energy and Safari Petroleum (Blocks 38, 39 and 40). The entry of Tullow Oil in 2019 (Blocks 35, 36 and 37 in partnership with Discover Exploration) has attracted further interest in Western Comoros to explore the Outer Rovuma Fan.

Re-evaluation of opportunities offshore East Africa and in the Western Indian Ocean has suggested that a new multi-client long-offset 2D regional seismic programme linking some of these recent discoveries along with additional potential fields data will provide better insight into the prospectivity of this region. This may be achieved using an advanced broadband imaging workflow to achieve deeper penetration for crustal imaging with low-frequency content, delivering better resolution of thin beds and stratigraphic traps to enhance the overall interpretation.

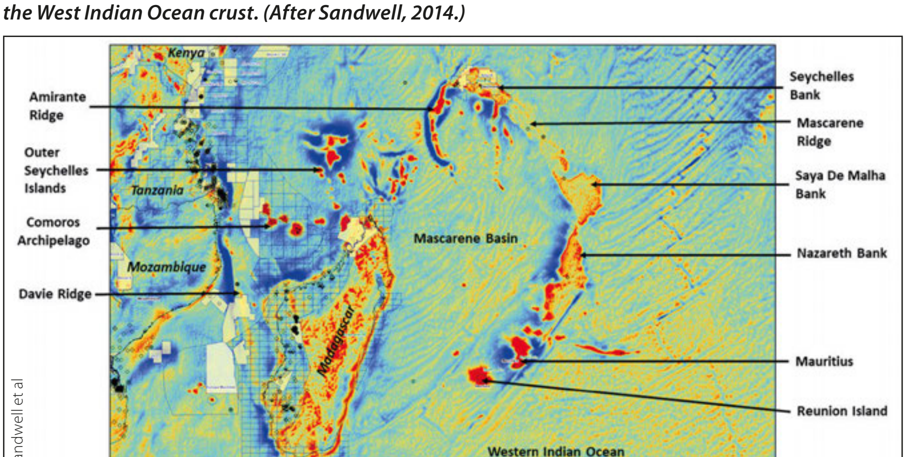
Knowledge Base and Common Understanding

Legacy geophysical and geological data suggest that oceanic crust is pervasive throughout the Western Indian Ocean, forming the Comoros Islands, the Glorioso Islands, Mauritius and much of the submarine ridge between Mauritius and the Seychelles (i.e., the Mascarene Ridge, Figure 1). This legacy information includes regional gravity and magnetics data, refraction and 2D reflection seismic, deep sea drilling project (DSDP) data and ocean drilling program (ODP) wells, and geological field studies. However, based on several recent studies, there is overwhelming evidence for the existence of slivers of continental crust in the Western Indian Ocean which were previously thought to be purely of intra-oceanic magmatic origin.

The obvious micro-continent in this region is the Seychelles Bank. This was proven in 1981 when Amoco drilled a series of three exploration wells about 120 km west of the main islands. These wells also proved the presence of a working petroleum system with oil and gas shows, and a mature source rock in the pre-rift Lower–Middle Jurassic sediments. A handful of DSDP wells were drilled around the Seychelles islands and two of them found oceanic crust to the north buried below a thin layer of Tertiary sediments. However, to the south, none were drilled deep enough to penetrate to the basement and prove/disprove whether pre-rift or syn-rift sediments could be present.

CGG's kinematic plate reconstruction models over the Western Indian Ocean region show the complexity of the poly-phased breakup of Gondwana. It suggests that there may be many more continental fragments like the Seychelles Bank scattered over the region (Figure 2). For example, the Mascarene Ridge fits exactly in the space and time of complex breakup between Madagascar and India. The Saya de Malha Bank is usually referred to as a sliver of continental crust, but the nature of the Nazareth Bank is often questioned. Several other promontories fitting in that space between Madagascar and India are indiscriminately mapped as part of the oceanic crust.

Figure 1: Satellite free air gravity anomaly map v29.1 highlighting the main geological features of the West Indian Ocean crust. (After Sandwell, 2014.)



New Evidence for the Presence of Continental Crust

Further to the west of the Seychelles Bank, refraction seismic and gravity data studied in 2013 by Hammond et al. show the potential continental nature of the Amirante Ridge (Figure 1). Gravity modelling and seismic receiver function analysis both suggest a crustal thickness of 24 km at Desroche Island, which is located on the northern half of the

Amirante Ridge, about 150 km away from the western edge of the Seychelles Bank. In comparison, oceanic crust rarely exceeds a thickness greater than 10 km. Furthermore, in 2012, Mukhopadhyay and Karisiddaiah suggested that the Amirante Ridge and its associated Trench Complex to the west are parts of a subduction zone. They noted the occurrence of calc-alkaline Eocene syenite covering some of the islands in the area. This type of rock is typically found in thick continental crustal areas and subduction zones. Also, the bathymetric profile, geometry and gravity signature are found to be very similar to other known subduction systems. These observations support the presence of continental crust at the heart of the Amirante Ridge. It is believed that the subduction zone was formed by rotational opening of the Mascarene Basin (Figure 1) with rapid accretion of oceanic crust in the south whilst a compressional front was temporarily formed in the north near the Seychelles Bank, analogous to the action-reaction principle of a lever.

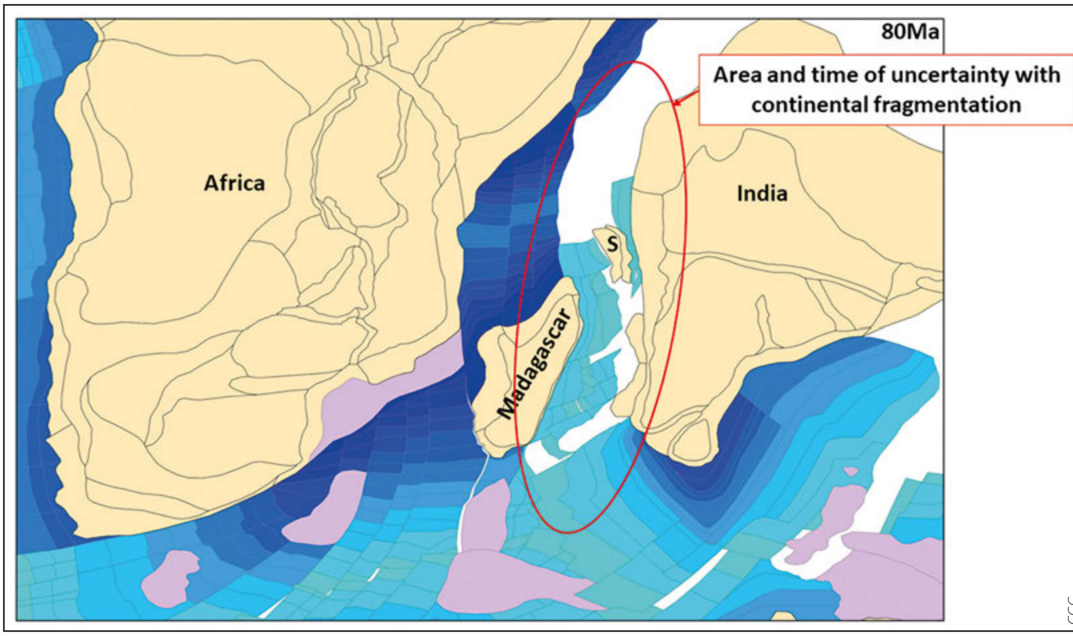


Figure 2: Plate Kinematics reconstruction at 80 Ma (Late Cretaceous–Campanian).

Further south, results published by Torsvik et al. (2013) from their field work and laboratory analyses showed that zircons found on Mauritius had varying ages of 660 Ma to 1971 Ma. Zircons are highly stable minerals that resist weathering and high heat. Torsvik et al. proposed that these zircons were assimilated from ancient fragments of continental crust brought to the surface by volcanic activity. The unanswered question remains: How far did those zircons travel to be found on the Mauritius island? Were they assimilated from nearby continental crust?

As we move westwards, the Comoros Archipelago, located to the west of Madagascar, is formed by four volcanic islands oriented in a WNW–ESE direction. From east to west, they are Mayotte, Anjouan, Mohéli and Grande Comore. The islands are generally of volcanic origin (Tertiary to Recent) formed by lithospheric deformation in the general context of the East African Rift system. However, various authors such as Esson et al. (1970), and Roach et al. (2017) have presented evidence of the presence of sandstone xenoliths on the island of Anjouan as well as sandstone inclusions in the lavas on Grande Comore and Mohéli, alluding to the continental nature of the underlying crust. These authors considered it as a critical piece of evidence to suggest that the western part of the Comoros Archipelago is underlain by continental crust or crustal fragments. Analysis of sedimentary rocks of the Anjouan islands by Roach et al. (2017) shows that they are derived from an alkali-granite source terrain and were deposited prior to the breakup of Gondwanaland. Zircon U-Pb dating indicates an age of ~533 Ma for sediment source terrain comparable to the ages found in the Pan-African belt of Madagascar.

Unproven Hydrocarbon Potential

Roach et al. (2017) also analysed tar balls collected from the island of Grand Comore and have proven them to be indigenous crude strandings derived from a carbonate-marl source rock system of Triassic to Early Jurassic age. The lack of heavy degradation is indicative of them being local in origin. These observations were combined with offshore seismic reflection data acquired west of the Comoros Islands and east of the commonly accepted Davie Fracture Zone that show tilted fault blocks with stratal growth at depth and suggest that there is a rifted continental section at depth. Based on geophysical data, Davison and Steel (2017) also observed that these grabens are small and probably situated on an extended continental crust. They also implied the possible presence of Jurassic source rocks buried in the oil window providing a case for hydrocarbon potential in the western blocks of the Comoros Archipelago. However, this interpretation has yet to be proven by drilling.

The Comoros Archipelago is separated from the East African margin by the Davie Fracture Zone (DFZ) considered for several years to be a simple transform margin. The DFZ accommodated the southward movement of Madagascar away from present-day Kenya and the Somalian coast during the Jurassic. In recent years, the crustal nature of the DFZ has been explored by several authors. The full crustal extent of the DFZ to the west of Comoros is questioned by Klimke and Franke (2016) in an abstract published for Terra Nova. Based on seismic data interpretation, they argue for a lack of evidence to interpret the presence of the

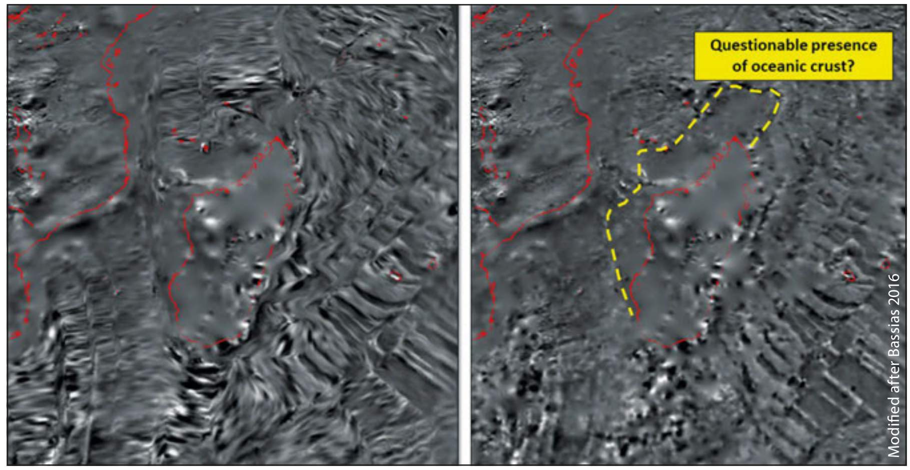


Figure 3: EMAG2 v3 regional magnetic data without directional gridding, highlighting the area of uncertainty north of Madagascar with regards to the presence of oceanic crust.

DFZ northwards beyond the Rovuma Delta. This suggests there was a larger expanse of continental shelf to fill the space between Madagascar and the African coast before rifting started. In turn, this would mean that the present-day Madagascan continental shelf may extend further north of the island and possibly as far as the Comoros Islands. The latest piece of evidence alluding to the idea of the larger extent of the Madagascan continental shelf was brought by Bassias et al. in 2016 [8]. They looked at the regional magnetic data available in the area (Figure 3). The presence of oceanic crust is typically inferred by the regular pattern of magnetic stripes. These are visible on the north-east side of the Comoros Islands but do not seem to be present on the south side in the space between Madagascar and Mayotte, casting doubt on the presence of oceanic crust there. Finally, Vormann and Jokat (2021) looked at five refraction lines along the Mozambique margin crossing the DFZ and attempted to refine the kinematic model for the East Africa margin. Based on their crustal interpretation, they identified the presence of continental fragment beneath the southern part of the Davie Ridge which concurs with observations made by Klimke and Franke (2016). They noted the presence of a wider continental–oceanic transition zone (COT) than previously stated along the south-west Madagascar and Tanzania/Kenya DFZ margin and that the COT gets broader from south to north along this margin. They also noted that the evolution of the northern DFZ as compared to the southern DFZ is more complex.

The Future Ahead

The East African margin has become a focus of exploration activity since the discovery of world-class gas fields in Mozambique, Tanzania and Kenya. This focus has brought with it a wealth of data, observations and models which highlight the likelihood that several isolated continental basins may exist and have been overlooked for hydrocarbon exploration along offshore East Africa and in the Western Indian Ocean. Based on our review of available data, there appears to be considerable hydrocarbon potential in these areas. We believe that a new long-offset 2D multi-client regional seismic programme spanning the Rovuma and West Somali Basin, the Comoros Archipelago, north-west Madagascar and extending out across the Indian Ocean in conjunction with gravity and magnetics data will give better insight into the prospectivity of the larger extent of the Western Indian Ocean. Hopefully, it will also provide answers to some of the enduring questions as to the nature of the crust, localised rifting history and eventually the evolution of the micro-continents of the Western Indian Ocean.

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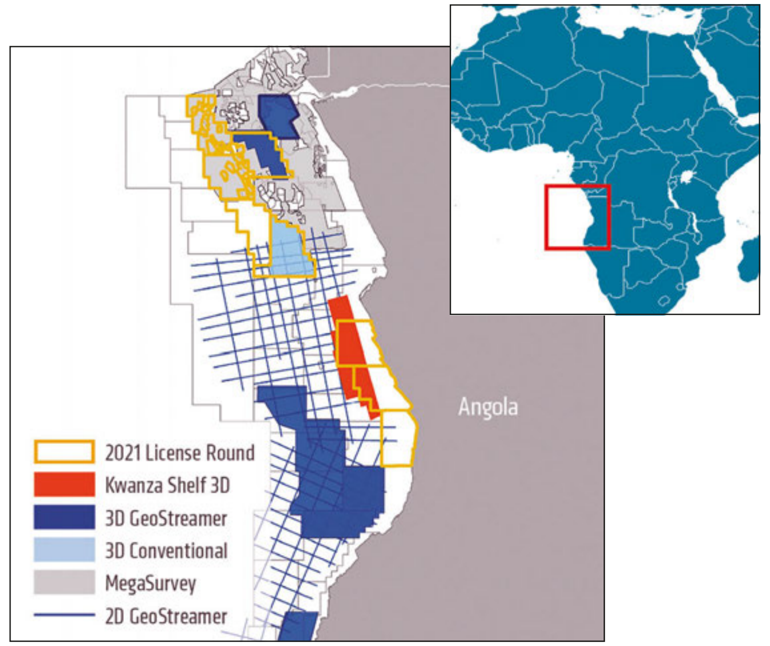
Quantitative Interpretation Reveals Prospectivity of the Kwanza Shelf, Offshore Angola

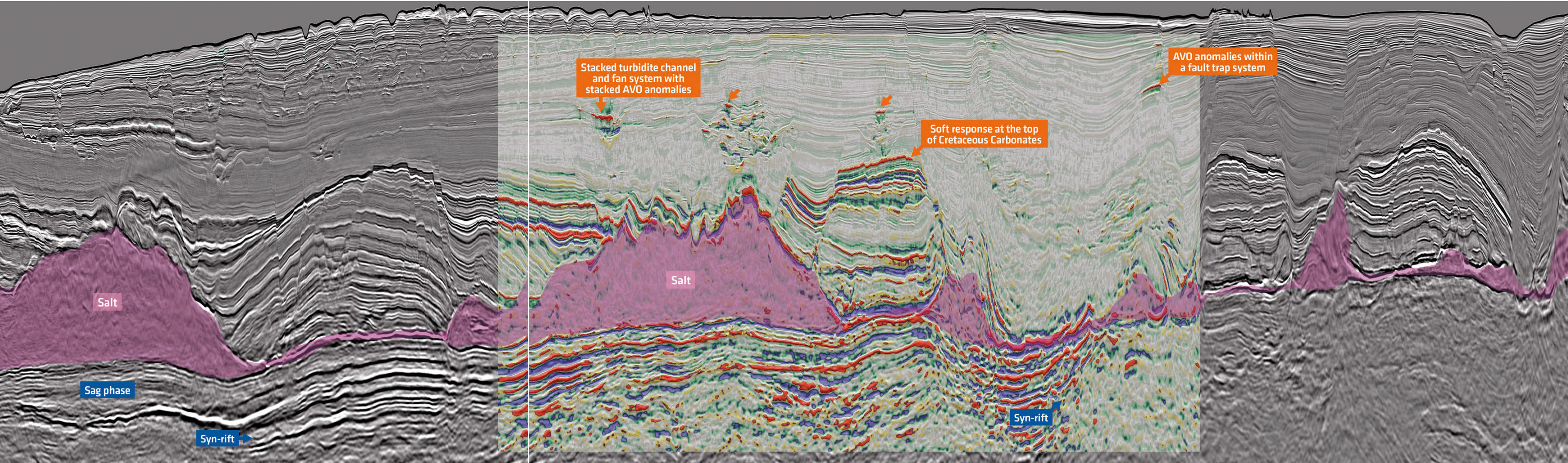
PGS in partnership with Agência Nacional de Petróleo, Gás e Biocombustíveis (ANPG) has recently acquired 8,304 sq. km of new multisensor GeoStreamer data over the Kwanza Shelf, 30 km off the central coast of Angola. This new 3D survey provides an unprecedented uplift in seismic imaging over the vintage 2D data. Modern processing workflows have been tailored to the unique imaging challenges of the presence of shallow water and subsurface salt. The new data unveils previously undetected pre-salt basins with many direct hydrocarbon indicators (DHIs) in both the syn-rift and post-rift sections, suggesting the presence of a working petroleum system in this underexplored area.

The Kwanza Shelf represents an enticing area for hydrocarbon exploration, as the Angolan continental margin contains substantial proven reserves and significant remaining untapped potential. This quantitative interpretation project takes advantage of newly available seismic data to examine some of the various post-salt and pre-salt reservoirs. Additionally, an interactive rock physics well atlas was integrated into this study and provides robust insights into the expected seismic response in the area, thus reducing the uncertainties associated with the observed seismic amplitudes.



Location of the new PGS multisensor GeoStreamer survey over the Kwanza Shelf, Offshore Angola (orange polygon). The 2021 licence round blocks are shown in yellow.

Figure 1: Final full-stack Kirchhoff Pre-Stack Depth Migrated (KPSDM) 3D line with relative acoustic impedance overlay. The relative acoustic impedance attribute has been generated using PGS's unique Prospect Scanner workflow. Numerous fluid and lithological anomalies are highlighted over pre-salt and post-salt targets. The complex network of turbidite channel and fan systems in the post-rift section (orange arrows) can now be confidently mapped in 3D across the area. Clear imaging of the pre-salt interval enables a detailed analysis of the stratigraphy and robust reservoir characterisation of these deposits.



Kwanza Shelf Potential Petroleum Systems

ROBERTO RUIZ, CYRILLE REISER and AVRIL BURRELL, PGS; JEAN AFONSO COLSOUL and NAIRE JUDITH RICARDO CAHUMBA QUENGE, ANPG

The Kwanza Shelf is situated within the Kwanza Basin, located in the southern part of the West African Aptian salt basin. The depocentre began to develop through rifting of the proto-Atlantic in the Late Jurassic to Early Cretaceous and represents the conjugate margin to the prolific hydrocarbon-bearing Santos and Campos Basins, offshore Brazil. The petroleum systems offshore Angola can be characterised in relation to the tectonic history of the margin.

The pre-/syn-rift was dominated by an extensional tectonic phase forming a series of horst and grabens perpendicular to the coastline where mixed continental facies were deposited. This included the deposition of the main syn-rift/pre-salt source rock: the Barremian-aged Bucomazi Formation. Three main reservoir units occur within the syn-rift/pre-salt sequence: the pre-rift Lucula Formation alluvial sandstones, the syn-rift Red Cuvo Formation alluvial sandstones, and the Grey Cuvo Formation (Chela Formation equivalent) fluvial to lacustrine sandstones and limestones.

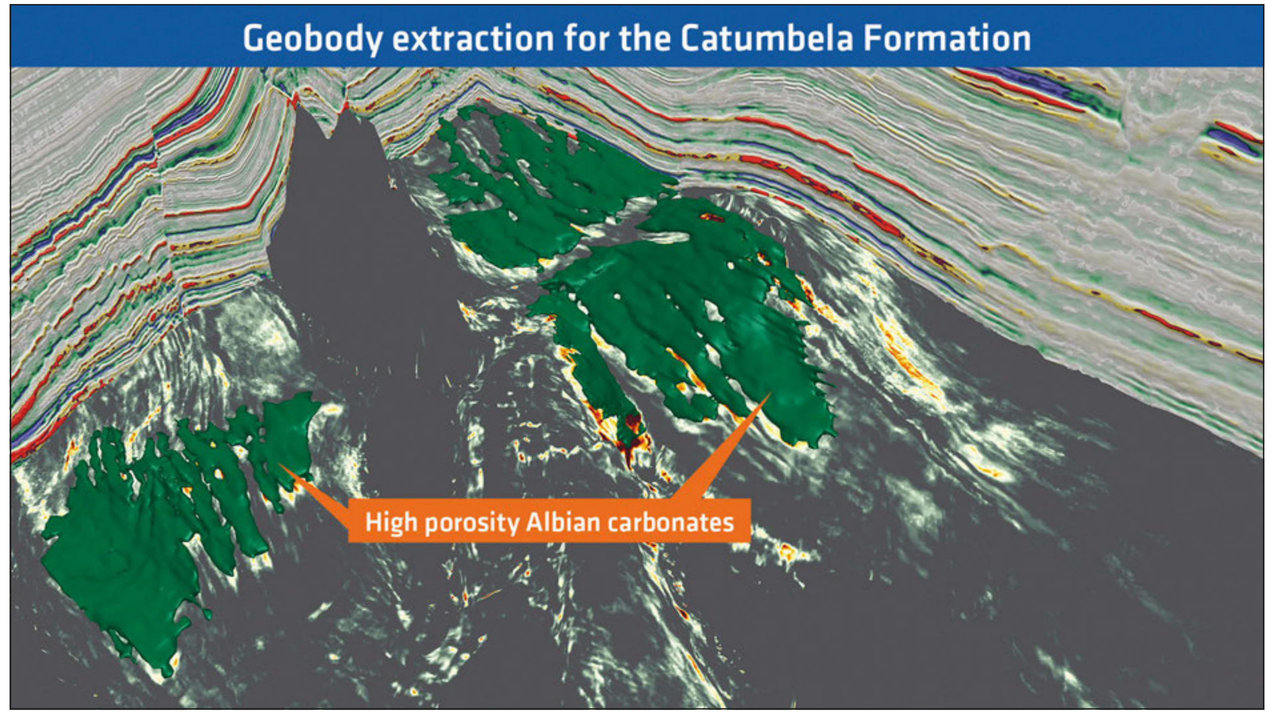
The post-rift is characterised by a shift from restricted evaporitic facies to open marine deposition and contains four main reservoir units: Albian Pinda Formation shelf carbonates; Late Cretaceous Iabe Formation progradational shallow marine sandstones; Palaeocene/Eocene Landana Formation sandstones; and Oligocene/Miocene Quifangondo Formation sandstones.

Exploration History: The Overlooked Kwanza Shelf

Of a total of 43 wells drilled on the Kwanza Shelf, 31 wells were drilled prior to 1993. Exploration moved to deeper water targets during the early 2000s following the rush to find analogues to the super-giant Lula oil field discovered in the Santos Basin, Brazil.

On the shelf, only two exploration wells have been drilled using early 1990s 3D seismic, with the remainder using 2D data of various 1980s vintages. Despite the limitations associated with mapping features using regional 2D seismic, drilling success rates have been encouragingly high. Between 1983 and 1990, of the seven wells drilled in shallow water, five made oil discoveries which were developed into the Cegonha, Mubafo, Denden, Pakubalu and Muamba fields. These

Figure 2: The Catumbela Formation (Albian), mainly composed of oolitic shoals, exhibits porosities in excess of 20% in the region, and well data has confirmed the presence of hydrocarbons. Integration of well and pre-stack seismic inversion results allowed the generation of a well-calibrated total porosity seismic volume over the Albian carbonates. High-porosity carbonate facies are observed as laterally continuous deposits across the shelfal area shown here in a 3D section display combined with Catumbela horizon sweetness and relative IP geobody extraction.



accumulations proved that both pre- and post-salt plays extend from the onshore to offshore, further helping to de-risk the prospectivity of the Kwanza Shelf.

The Mucua-1 well led to the discovery of the Denden field and proved the pre-salt play. Aptian pre-salt carbonate reservoirs formed in a lacustrine environment range from microbialites and oolites to coquinas, with primary porosities up to 15% and secondary macro-scale porosity enhancement due to dolomitisation.

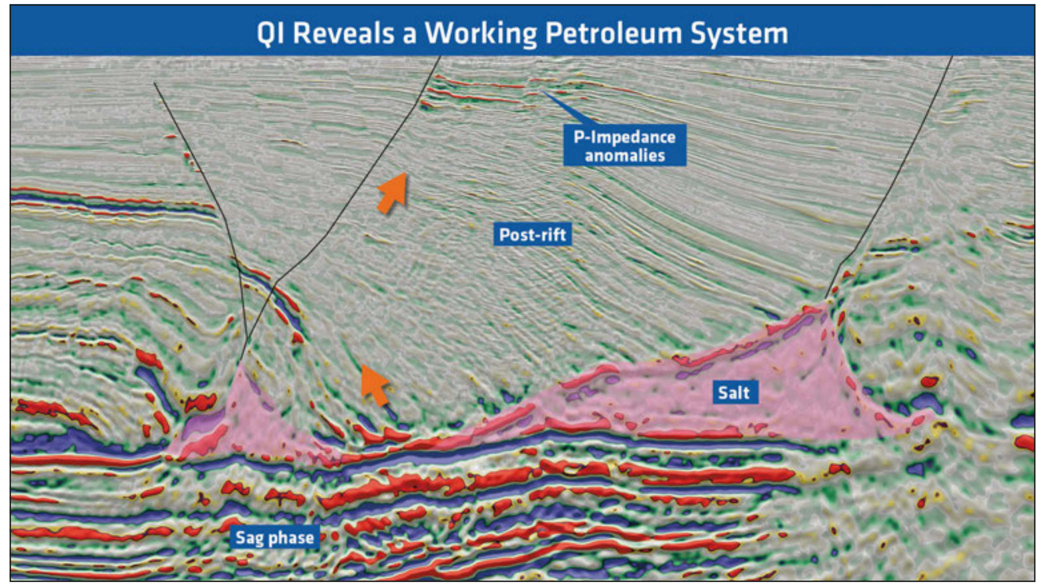


Figure 3: Overlay of full-stack amplitude and relative acoustic impedance derived from 3D Kirchhoff Pre-Stack Depth Migrated (KPSDM) data, highlighting a possible migration route for hydrocarbons from a syn-rift source rock to stacked turbidites in the post-rift section.

Enhanced 3D Broadband Imaging to Reveal Potential

Improved imaging of the Aptian Loeme Formation salt is vital in unlocking the future prospectivity of the underexplored Kwanza Shelf area, and a detailed velocity model is key to revealing the intricate geometries associated with the salt. For this, tomography (reflection and refraction) and Full Waveform Inversion (FWI) have been used to unveil the complex structure associated with halokinesis while addressing the challenges in the imaging at the pre-salt interval. Figure 1 (foldout image) shows the significant imaging gains and the impact on seismic inversion products. The pre-salt is better imaged compared with vintage 2D time data and the sharpening of pre-salt fault planes allows a more accurate interpretation of the basin controlling syn-rift tectonics.

Improved 3D Broadband Quantitative Interpretation to Highlight Prospective Areas

Quantitative Interpretation analysis has been performed over the entire section (post-salt and pre-salt) using conditioned partial angle stacks. For the seismic conditioning, a Reservoir Oriented Processing (ResOP) workflow was performed using four angle stacks. The processing sequence included de-noise, spectral harmonisation, and time misalignment correction. Thereafter, intercept and gradient attributes were estimated and integrated through the Prospect Scanner workflow to derive elastic attributes such as relative Acoustic Impedance and relative Vp/Vs. Attributes were calibrated to available well data ensuring a consistency between well and seismic data. Seismic responses that could not be associated to in-situ well response, were further analysed using the available interactive rock physics atlas (PGS rockAVO), via perturbation in real time of porosity, fluid and saturation over each reservoir interval.

The post-salt Albian play, proven in the Cegonha and Mubafo fields, highlights a working petroleum system with reservoirs in post-rift fluvio-deltaic sandstones and shallow marine carbonates. The Albian Tuenza and Catumbela Formations show excellent reservoir potential with porosities ranging from 20 to 25% within the shelfal area, as evidenced by wells drilled in the vicinity. A total porosity seismic volume calibrated to well data has been used to confidently map high-porosity carbonates over the Kwanza Shelf (Figure 2).

Multiple direct hydrocarbon indicators (DHIs) can be identified within channelised stacked sandstone deposits in the post-rift section. Tertiary turbidite facies on the Kwanza Shelf are analogous to the prolific gas and oil-bearing turbidites found to the north in the Lower Congo Basin. Porosity in these sandstone deposits is estimated to be in the range of 26–30%, with permeabilities above 400 mD. Two main structural configurations can provide a pathway for hydrocarbons generated from syn-rift source rocks to migrate into these younger deposits. The first occurs in areas where complete salt withdrawal results in mini-basin salt welds. The second is found in areas where faults caused by halokinesis extend through the post-rift section and terminate at the top of the syn-rift (Figure 3).

Opportunities Revealed by GeoStreamer Dataset for Offshore Angola 2021 Licence Round

The new GeoStreamer seismic dataset over the shallow-water Kwanza Shelf provides exceptional 3D imaging of both pre- and post-salt sequences in the area. The new seismic data, in conjunction with an interactive rock physics atlas, allows for a fully integrated quantitative seismic data interpretation workflow which reveals opportunities across the underexplored Kwanza Shelf area. The insights gained from this study demonstrate how important new data is for unlocking the prospectivity of the area for the upcoming Angolan 2021 licence round. ■

North Sea Core: An Undervalued Asset

How unwanted core is finding a second life and renewed purpose within the Geoscience Community through the North Sea Core Initiative.

K.A. WRIGHT and H. KOMBRINK, North Sea Core CIC

As oil and gas fields across the UK Continental Shelf are increasingly being abandoned, the geological samples obtained to help understand the subsurface are no longer required and are often of little economic value for operators. This has led to an increase in the disposal of core material and was the catalyst behind the creation of North Sea Core. At the time of this article's publication, we will have been operating for four years, having gradually evolved from a purely voluntary and unofficial initiative to becoming a Community Interest Company (CIC) in 2020. To date, we have received donations of core from 12 different operators and have rescued over 20,898 ft (6,370 m) from 104 wells.

Our CIC is founded on the idea that core provides such an important resource for understanding the subsurface, and geology in general, that it is too valuable a material to be disposed of once it has served its purpose within the oil and gas sphere. Therefore, our aim is to collect and distribute core to the wider geological community, making it accessible to everyone from amateurs to academics, and those in between. This is achieved through supply of a range of raw and upcycled material for educating the next generation of geoscientists, supporting existing to emerging energy research and facilitating science communication with non-scientists.

Collaboration is the Key

We are acutely aware that core is a finite resource. Where possible, we work in conjunction with the Oil and Gas Authority (OGA) and the various oil and gas companies to encourage donation rather than disposal. All the core we receive has been cleared for donation under the Petroleum Operations Notice (PON) 9 guidance set out by the OGA. We also collaborate with the British Geological Survey (BGS) to facilitate identification of key sections for the BGS Core Store and National Archive, with this taking priority over the selection of material for redistribution through North Sea Core.

Encouragement for the work we at North Sea Core undertake has also been strong from the wider geoscience community, ranging from significant social media engagement to support from businesses within the energy sector. This includes DownUnder Geoscience (DUG), who helped facilitate access to their DUG Insight software and Aeon Geoscience, who included us in their Public Data Repository. We have also had several of our upcycled core products financially supported by geological organisations such as the OGA, the Petroleum Exploration Society of Great Britain (PESGB) and the Energy Group of the Geological Society.

Academic Outreach

Our ability to act as both store and supplier places us in a unique position. It has proved of particular interest to universities, for whom we create a wide and varied range of teaching sets, making the most of our access to material from almost every key geological period and a wide range of North Sea depositional environments. Our teaching sets have so far been shipped to universities and research centres across the UK, Italy, France, Germany, the Netherlands, Norway, South Korea and South Australia, as well as many others. To accompany the physical material, we collate a range of data including published literature, high resolution core scans from the BGS and subsurface digital data from the

Kirstie Wright and Henk Kombrink in the North Sea Core CIC core store

K.A. Wright and H. Kombrink

Map of global distribution of core material by North Sea Core CIC.

OGA National Data Repository (NDR). This allows us to be a conduit to provide knowledge of, and access to, a variety of open access data that many people – especially abroad – are not necessarily aware of.

For those engaged in research, both academic and commercial, access to samples previously unavailable due to either confidentiality or field activity, means potential new breakthroughs. This is important as the same geology, subsurface skills and hydrocarbon fields can be of use in the journey to Net Zero. As an example, we provided core to the German Research Institute GEOMAR for CO_2 injection tests and sent a selection of core to the Carbon Capture and Storage Association for use as a demonstration set. Similarly, companies operating in the geothermal sector have contacted us to acquire core to demonstrate how geothermal energy is being derived from the same reservoirs as those used for hydrocarbon extraction.

Open Access

We continue to make our own data open access and available to download from our website, with the aim of supporting the geoscience community to further support research and education. This includes data created internally, such as presentations, core photos and drone footage, and produced externally through several active collaborations with small, independent companies, who specialise in core scanning, geochemical analysis, detailed photography and computerised tomography (CT) scans. In exchange for the provision of material, we gain access to the results and are in the process of assembling datasets that are representative of the North Sea geology using the latest technology and greatest breadth of core material.

In addition to supplying material to an ever-growing network of people and projects, we are also working to put the core into a wider geological context and to help preserve the offshore geoheritage of the North Sea and surrounding continental shelf. We offer core viewings, workshops and webinars based on our expertise and access to materials, including our own curated teaching set containing key reservoir sections and evidence of geological events within the North Sea Basins. The availability of physical samples combined with a storytelling approach to present the geological and depositional history of the wider North Sea area has proven a powerful tool in showcasing the vast amount of research undertaken over the decades and has helped introduce new people to the area.

Core material has also proven popular with the very industry it is sourced from. This has ranged from the creation of office displays documenting the geological history of the North Sea to providing mementos of an individual's time working on a single field or well. Our core has been presented as prizes and speaker gifts at several conferences, including the PESGB evening lecture series, PETEX and DEVEX and others.

In summary, the variety and scale of the requests we receive indicates a need and appetite for accessible, well-documented geological samples across all geoscience disciplines. At its inception, it was difficult to envisage the scale of demand and if there would be a future for North Sea Core. In reality, we have experienced a steady influx of requests, with over 600 unique enquiries to date. At the time of writing, core for personal use and collections (46%) dominates, but material for education and research (27% and 7% respectively) has been steadily increasing, occupying most of our time and representing the largest physical volume of core we curate and send. We still see a healthy interest from commercial and professional organisations, with a growing number of requests from those involved in outreach, such as Science, Technology, Engineering and Mathematics (STEM) Ambassadors and science communicators.

A North Sea Core teaching set in action at the Université Grenoble Alpes.

How Can our Industry Help?

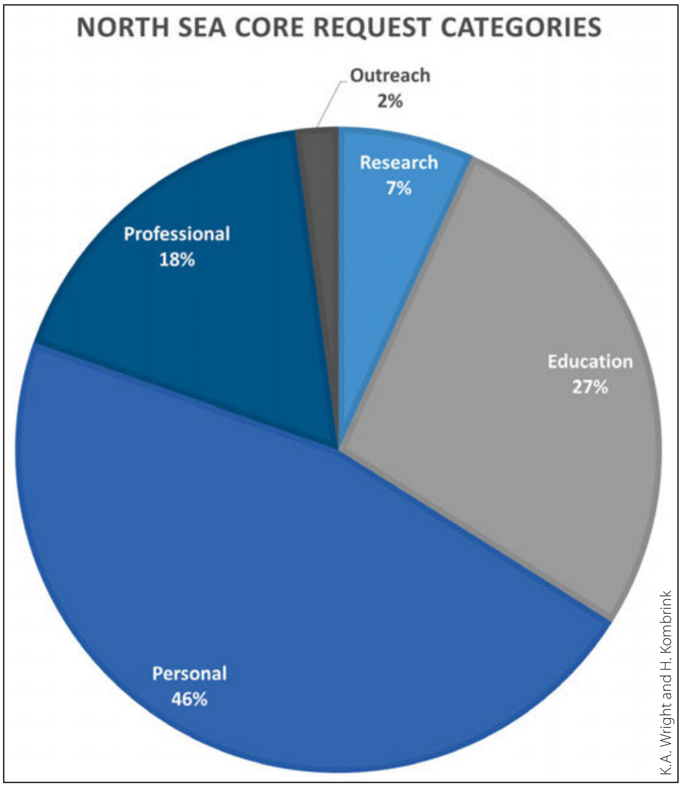
We believe that North Sea Core CIC has proven the importance of collecting, transforming and redistributing core material. We also hope that by 'exporting' the geology of the North Sea to universities and research institutes across the UK and globally, we demonstrate that there is still incredible value in the basin and the scientific knowledge acquired around it. We are extremely grateful to those who have supported us so far in achieving our goals, especially as North Sea Core CIC is not a large organisation. It is run 50/50 by two directors who provide their time outside of their full-time employment, with a team of volunteers and a Geological Assistant on a zero-hours contract.

All core handling, logistics, communications, and marketing are undertaken by our tiny team, mostly in our spare time. Our effort to save and make use of core material that would otherwise be destined for disposal in landfill is time consuming, hard work and so far, has been without stable funding. To help facilitate our work, in 2020 we were fortunate to welcome the privately owned Dutch exploration and production company ONE-Dyas as the first operator to sponsor us for the duration of two years. This provided us with much-needed security, but we have now grown to the point where to be able to continue to undertake outreach and provide core material to schools and universities across the world, we are seeking further financial support.

To safeguard all funding we receive now and, in the future, as part of being a Community Interest Company, we have in place a legal provision called an 'asset lock'. This is designed to ensure that all profits generated through our activities are reinvested and used for the benefit of the geoscience community, rather than used as dividend payments. This provision also means that in the event of North Sea Core CIC ceasing to operate, any outstanding balance will be transferred to an equivalent organisation or charity.

We would like to see North Sea Core continue to provide educational material for the next generation of geoscientists and make subsurface material accessible for research into the energy transition. However, we cannot do it without greater financial support from the industry, as demand for our services, and opportunities to be involved in outreach continue to grow. If you are interested in sponsoring the work we do, please get in touch via our website or via social media. ■

North Sea Core requests by category.



A Straightforward Workflow for Monitoring CO_2 Storage

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MARC-ANTOINE DUPONT, SVEN PHILIT and FABIEN CUBIZOLLE, Eliis

In the context of climate change and the search for atmospheric CO_2 reduction, CO_2 sequestration has been underway for a couple of decades and a few carbon capture storage projects have been implemented and monitored.

An abundance of data and a good understanding of the Sleipner CO_2 storage project offers the opportunity to test workflows aimed at quickly accessing the CO_2 volumes injected into the reservoir. Two comparative methods for estimating and understanding the distribution of injected CO_2 are proposed. The first method is a semi-automatic approach where geobodies are delineated from an attribute threshold value identified as highlighting the CO_2 accumulation anomaly, as mapped on a series of geologically consistent surfaces. The second method takes advantage of the AVO tool newly implemented in PaleoScan™ to generate geobodies derived from an Intercept vs Gradient correlation and the identification of gas anomaly classes. The two methods are finally compared in the light of the available literature.

Sleipner

The Sleipner field is located in the North Sea, about 250 km offshore Stavanger, Norway and was initially developed in 1974 as a gas field, with production from Palaeocene and Jurassic sandstone formations. The younger Utsira Formation, intersected by the Sleipner Block, was later envisioned as a storage reservoir and 12.1 Mt of CO_2 was injected between 1996 and 2010. The injected gas is monitored using 4D seismic (Figure 1).

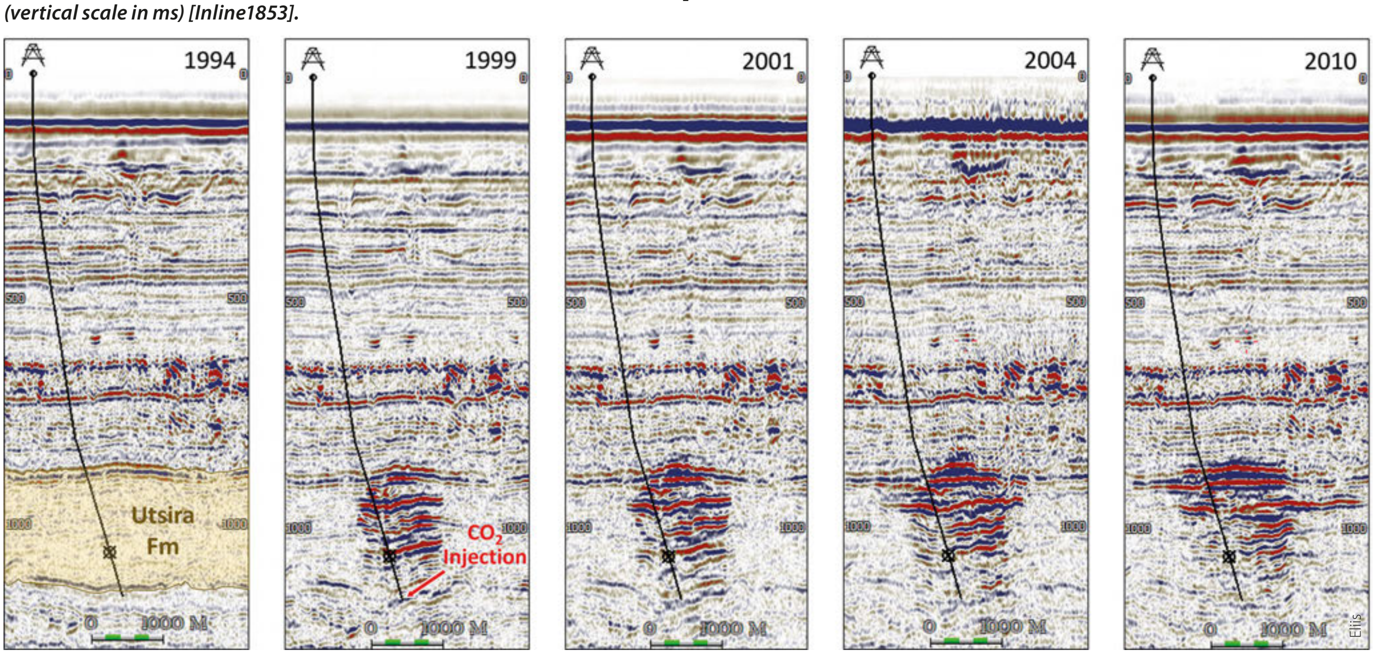
The Miocene Utsira Formation consists of a regional sand aquifer capped by a thick, sealing shale formation (Figure 1a). The gas accumulation is distributed into several sand units which are separated by thin clay/mudstone layers of limited extent that vertically compartmentalise the reservoir. The injection well has been drilled to reach the base of the Utsira sand formation at about 1,100m below sea level.

The Geobody Extraction Workflows

Method 1: The Horizon Stack delineation

The first method relies on the traditional workflow for geobody extraction in PaleoScan™. This workflow

Figure 1: Seismic section near the injection point where the impact of the CO_2 accumulation is observed in the Utsira Formation from 1994 to 2010 (vertical scale in ms) [Inline1853].



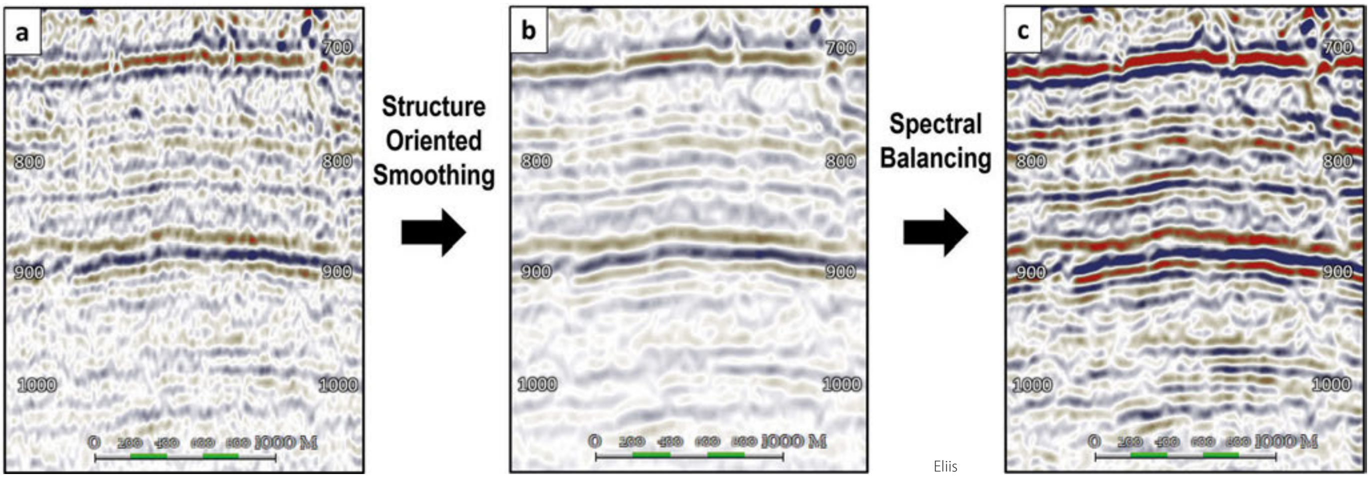


Figure 2: Vintage seismic from 1994 with different conditionings. a) Original seismic. b) Structure oriented smoothed. c) Structure oriented and smoothed, then spectral balanced. Same colour bar and colour setting for a), b) and c). PaleoScan™.

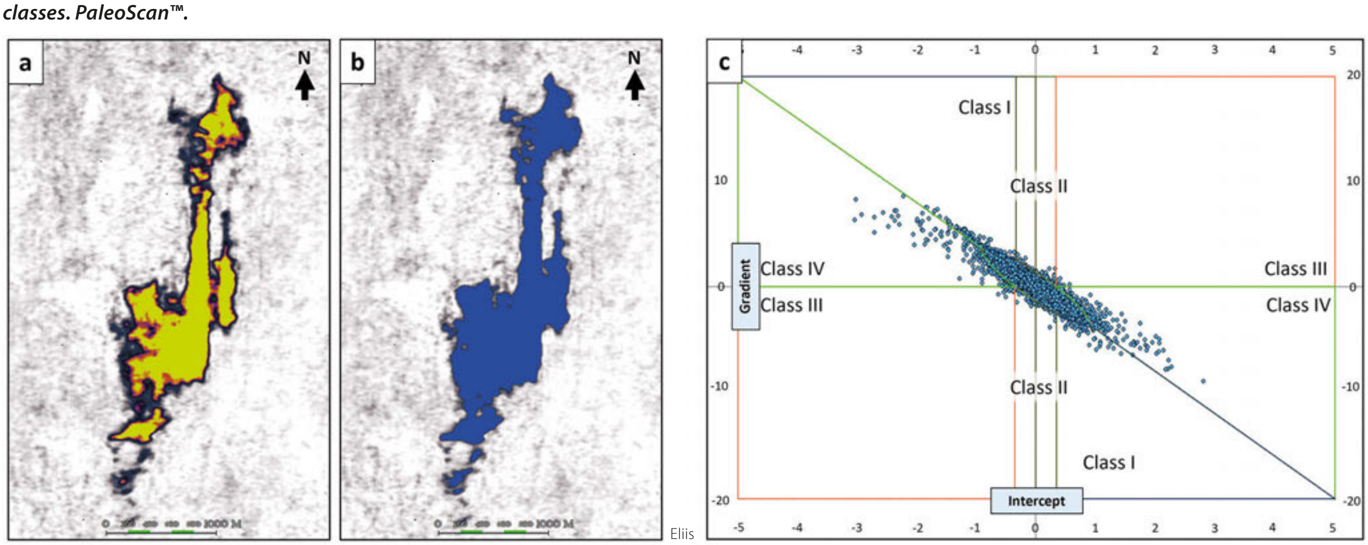
involves a semi-automated seismic interpretation to constrain the creation of a Relative Geological Time model. This model is then used to generate a dense series of surfaces or "horizon stack" on which attributes are mapped to highlight anomalies and allow the geobody extraction.

Because the efficiency of the automated seismic interpretation depends on the quality of the seismic data, two conditioning processes are subsequently applied to the seismic data before interpretation commences (Figure 2). First, a structure-oriented smoothing is applied to reduce the noise effect (Figure 2b). The structure-oriented smoothing relies on a Gaussian smoothing technique based on the dip variation of reflectors to enhance the reflector continuity. Secondly, as reflectors in some stratigraphic intervals of low-impedance contrast (e.g., carbonates, shales) are characterised by low amplitudes, a spectral balancing is applied to the signal to boost the reflectors of lower amplitudes (Figure 2c). These coupled conditioning steps offer an optimised seismic interpretation.

The seismic interpretation is then performed via a semi-automated method: the horizons are auto-tracked across the entire seismic volume, chrono-stratigraphically sorted, and then used as geometrical constraints to generate a geological time model. The geoscientist can manually refine the interpretation of every horizon and iteratively increase the accuracy of the model. Thanks to the previous conditioning, the auto-tracked horizons are now more continuous (auto tracking enhancement of approximately 20% in the Utsira reservoir) and of better quality, thus shortening the manual interpretation time. The models are generated from the interpretation of the 1994 vintage seismic (prior to gas injection) and 2010 vintage (after 12.1 Mt of CO_2 had been injected).

From the model, a stack of a hundred horizons is extracted from both vintages of the seismic. The average energy attribute, chosen because this efficiently highlights the amplitude anomaly induced by gas accumulations, is computed from the original seismic vintages and then mapped on each horizon of the stack. The gas accumulation signal is extracted semi-automatically based on the mapping: a range of average energy amplitudes is used to delineate patches on every horizon intersecting the anomaly (Figure 3a&b). This

Figure 3: Horizon stack with average energy mapping highlighting the gas accumulation: a) gas accumulation evidenced high amplitudes and b) thresholded high amplitude range (blue) used for the anomaly delineation and geobody extraction. c) Intercept vs gradient cross plot with the different classes. PaleoScan™.



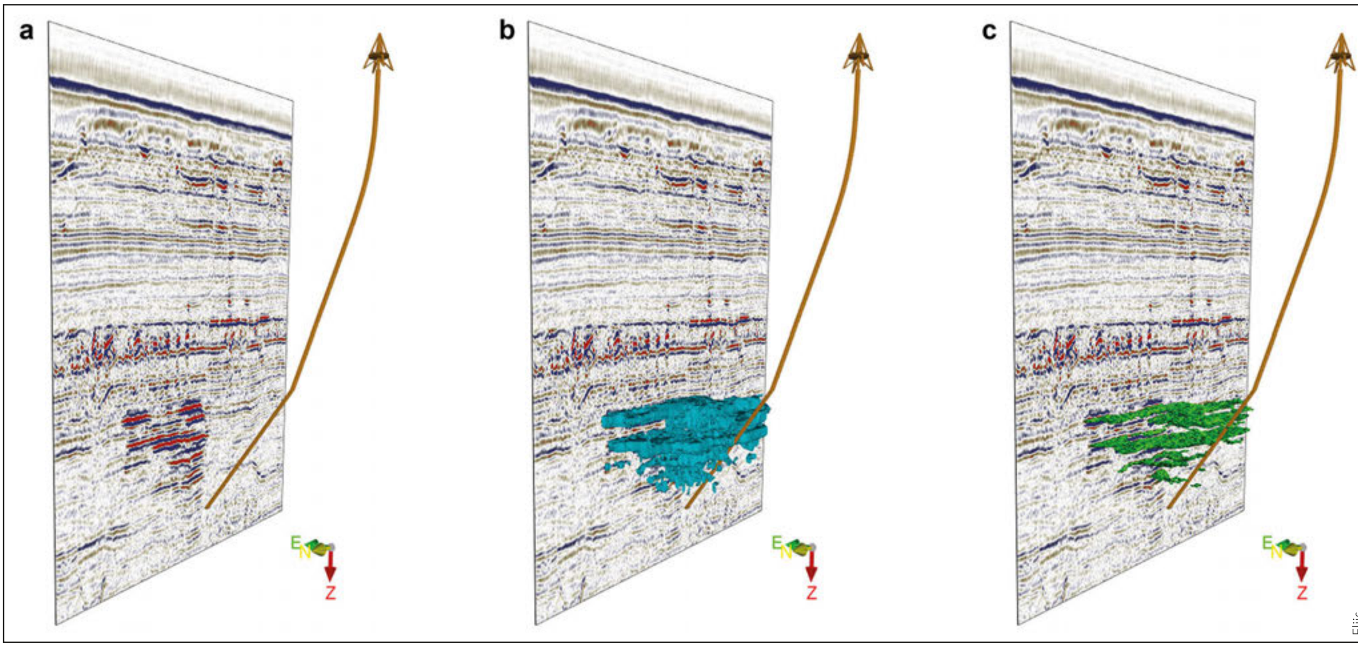


Figure 4: a) Injected well and seismic inline 1843, with b) the geobody obtained via Horizon Stack delineation, and c) the geobody obtained via AVO post-stack analysis. PaleoScan™.

series of delineations defines a volume ultimately extracted as a geobody (Figure 4b). The volumetrics of this geobody is converted in the vertical depth domain using a conversion factor of 1.8m per ms for an output of ca. 0.467 km^3. To permit a coherent comparison with the observations reported by the literature, we account for an average reservoir porosity of 36%, an average water/CO_2 saturation of 0.8, an average CO_2 density of 675 kg/m^3 and a dissolved fraction of 0.1, in accordance with the values commonly reported. With these considerations, we estimate a CO_2 accumulation of 82 Mt of injected CO_2 in 2010 vs 12.1 Mt in reality. This large overestimation is underlined by the bulky shape of the geobody, where the several gas layers are not clearly differentiated.

Method 2: The AVO post-stack analysis

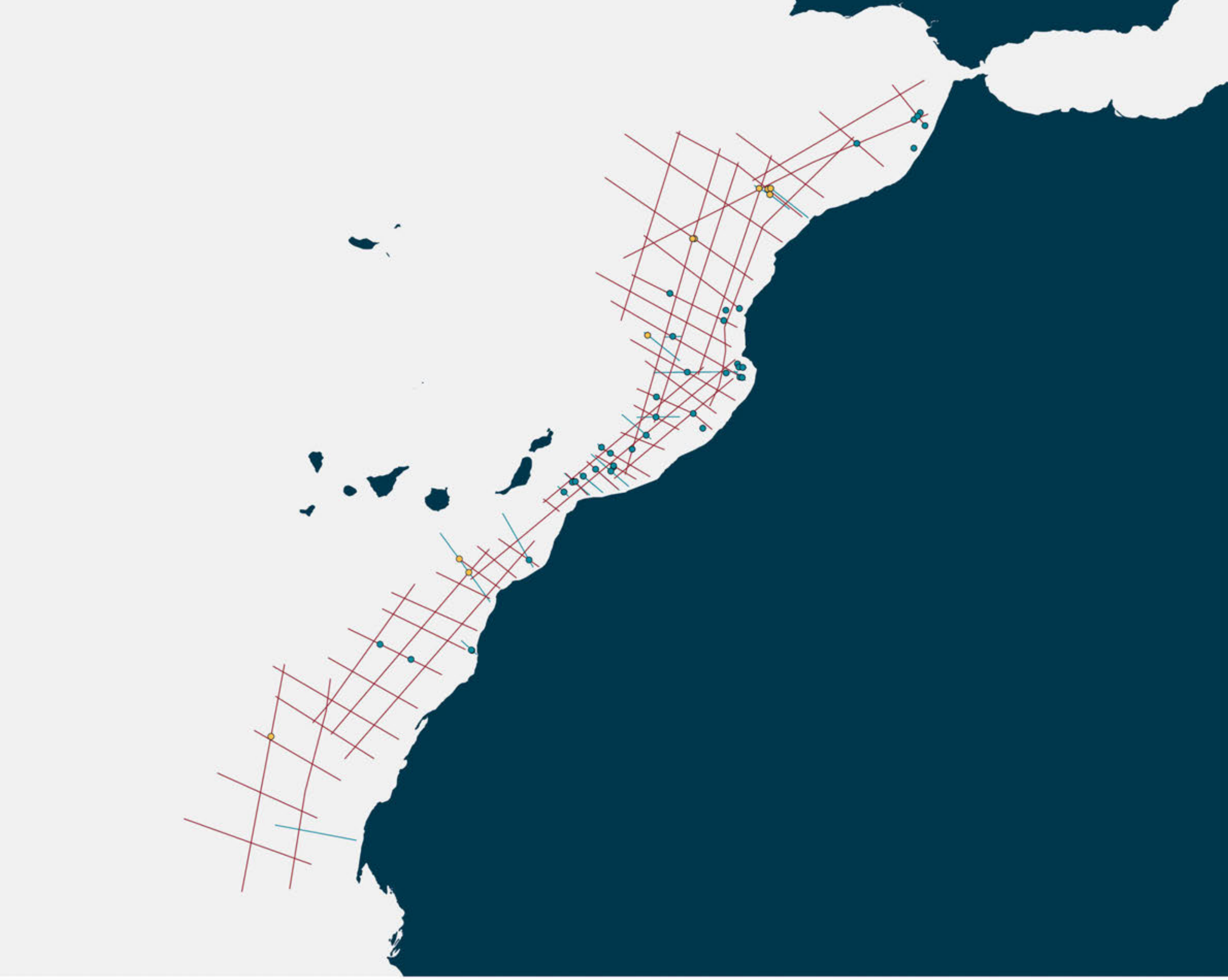
With Amplitude Variation with Offset (AVO) post-stack volumes with near, mid, and far angles approaching or lower than 30 degrees, the intercept and gradient volumes derived from the Shuey two-term approximation can be correlated to perform an AVO analysis and obtain the CO_2 anomaly geobodies. These attributes, highlighting fluids or petrophysics properties, are cross plotted to perform an AVO reservoir classification (Figure 3c). By delineating the background trend and identifying the AVO anomalies in the cross plot, one can interpret that this corresponds mainly to a class IV anomaly. This class is supposed to represent the main gas-bearing reservoirs (different sand layers bearing the CO_2). The corresponding extracted geobody contains nine distinct layers as suggested in the literature (Figure 4c). Following the same assumptions as the previous method, the volumetrics of these layers is of ca. 0.095 km^3, estimated to a CO_2 accumulation of 20 Mt. This value is quite close to the measured one (12.1 Mt). The compartmentalisation of the gas accumulation is properly captured by the structure of the geobody.

Take-Home Method

Despite the use of volumetric approximations for simplification (e.g., time/depth conversion factor, porosity, CO_2 density), we see in the context of gas monitoring, that one method yields more precise output than the other. The traditional Horizon Stack delineation method could be attractive because it allows visualising of the anomaly mapped on geological consistent surfaces. However, in addition to involving a longer workflow, the choice of the mapped attribute and the selection of the anomaly amplitude range, significantly impacts the volumetrics of the extracted geobody, in this case leading to a CO_2 accumulation overestimation of more than 600%. On the other hand, while the AVO post-stack analysis is independent from conditioning, seismic interpretation and Horizon Stack creation from a model, it also yields a volume estimation of injected CO_2 close to that depicted in the literature. In this work, the overestimation of 165% is most likely induced by imprecisions in the Intercept vs Gradient cross-plot class delineation and an inaccurate time/depth conversion factor. Besides the more accurate volumetrics, the vertical CO_2 compartmentalisation reported by the literature is neatly reproduced through this workflow. On balance, the Horizon Stack delineation method may be appropriate for the identification of more subtle features belonging to a given geological surface such as channels. It seems that the AVO analysis remains an efficient tool for quick gas accumulation assessment and particularly for future CO_2 gas storage monitoring.

Acknowledgements

The workflow presented was obtained using PaleoScan™, software developed by Eliis. The authors would like to thank the Sleipner Group for their permission to use and publish the Sleipner dataset. ■



Productive Petroleum Basins of Morocco

STUART HARKER

Do the low volumes suggest these basins are simply underexplored or is it underperformance?

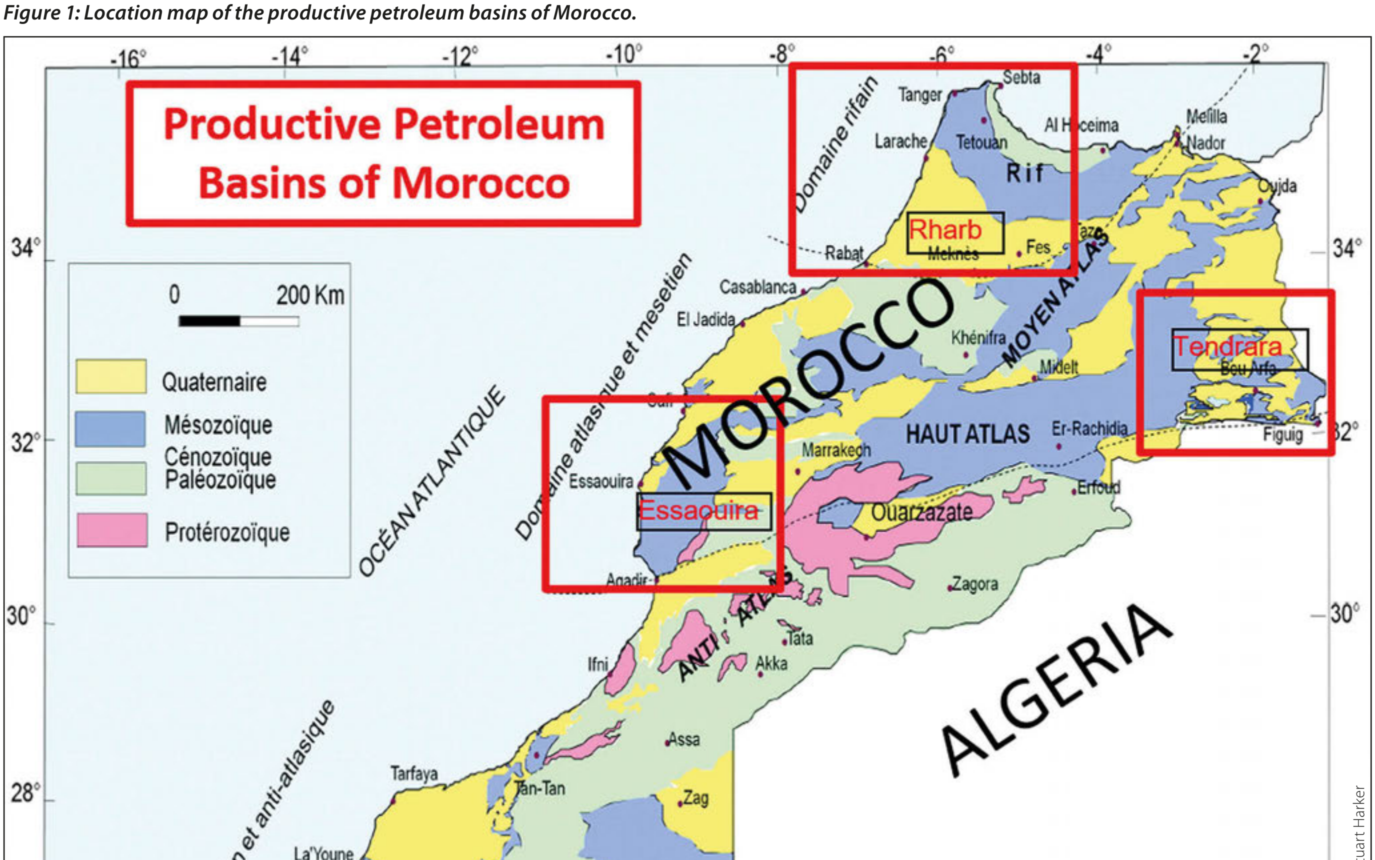
There are three productive basins in Morocco: Essaouira, Tendrara and Rharb, with the majority of fields lying onshore (Figure 1). The hydrocarbon volumes found and produced in these basins are very low in comparison to their aerial extents. This is possibly the result of underexplored stratigraphy and trap types and/or possibly due to underperformance of the petroleum systems themselves. The principal petroleum systems of the three basins are detailed and illustrated below.

Essaouira Basin

Lying on the Atlantic coast, this basin has a similar Pre-Tertiary geological history to the Scotian Shelf on the conjugate margin of Canada (Figure 2a). The stratigraphy of the Essaouira Basin can be divided up into the pre-rift Palaeozoic section culminating in the Hercynian compressive events, a syn-rift Triassic to mid-Jurassic section deposited during the Proto-Atlantic opening, and the post-rift Late Jurassic to Late Tertiary section culminating in the Atlassic compressive events. Potential source rocks are located in the Siluro-Devonian and Lower Oxfordian shales; however, the true distribution of the source rocks remains uncertain. The principal reservoir rocks are found in fractured Argovian (Middle Oxfordian) carbonates and thinly bedded Upper Triassic fluvial sandstones. Potential reservoirs are found in fractured Devonian carbonates, Ordovician sandstones and Liassic carbonates. Seals are present throughout the succession, but of note above the main reservoirs are the Late Jurassic evaporite/carbonate section, the Upper Triassic Evaporite, basal Triassic shales and Siluro-Devonian shales.

There has been a resurgence of activity in the offshore area over the past decade where sizeable structures have been drilled. However, the onshore petroleum systems, with Jurassic source rocks and carbonate reservoirs and Cretaceous carbonates and clastics, has remained enigmatic and to date, no commercial successes have been recorded. Onshore, the working Jurassic–Cretaceous petroleum system is illustrated by the small Jurassic Sidi Rhalem

Figure 1: Location map of the productive petroleum basins of Morocco.



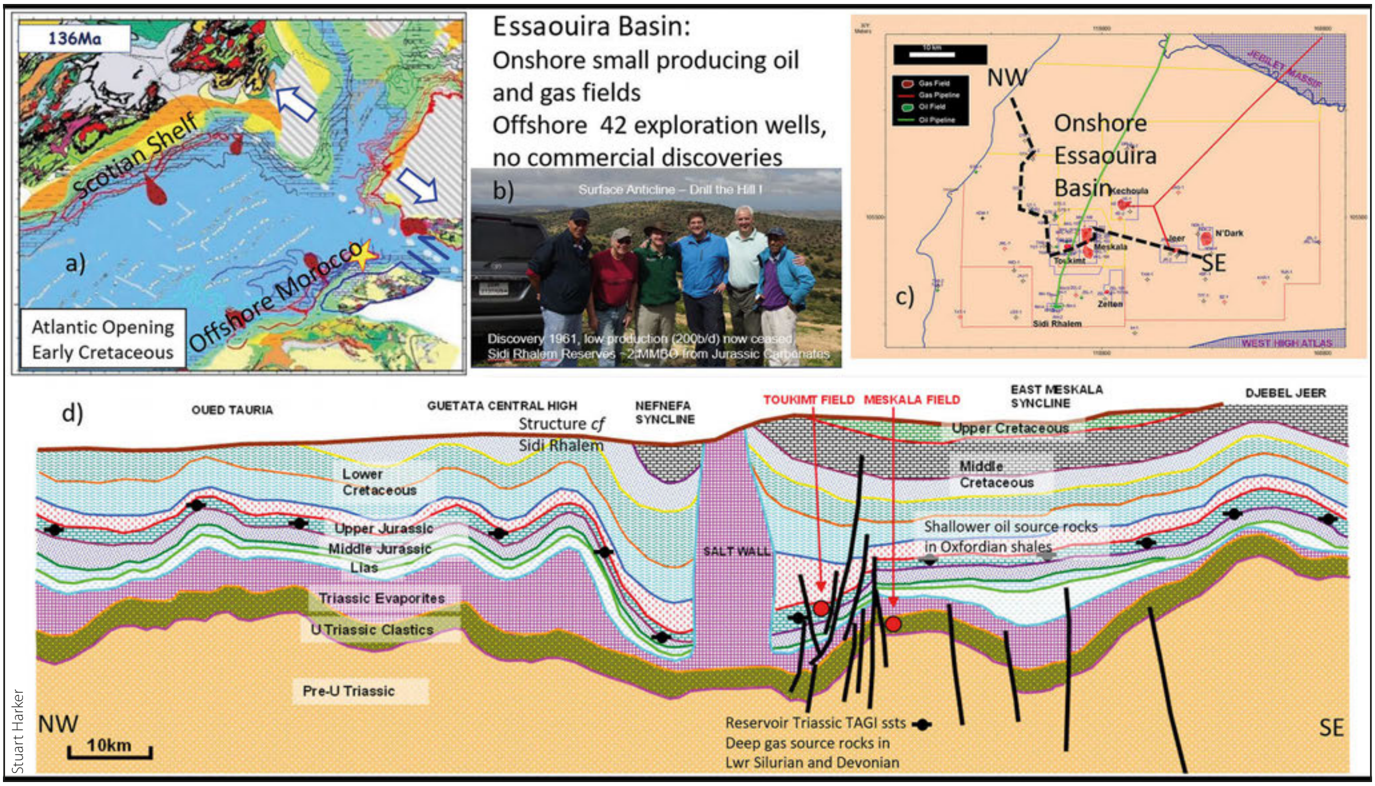
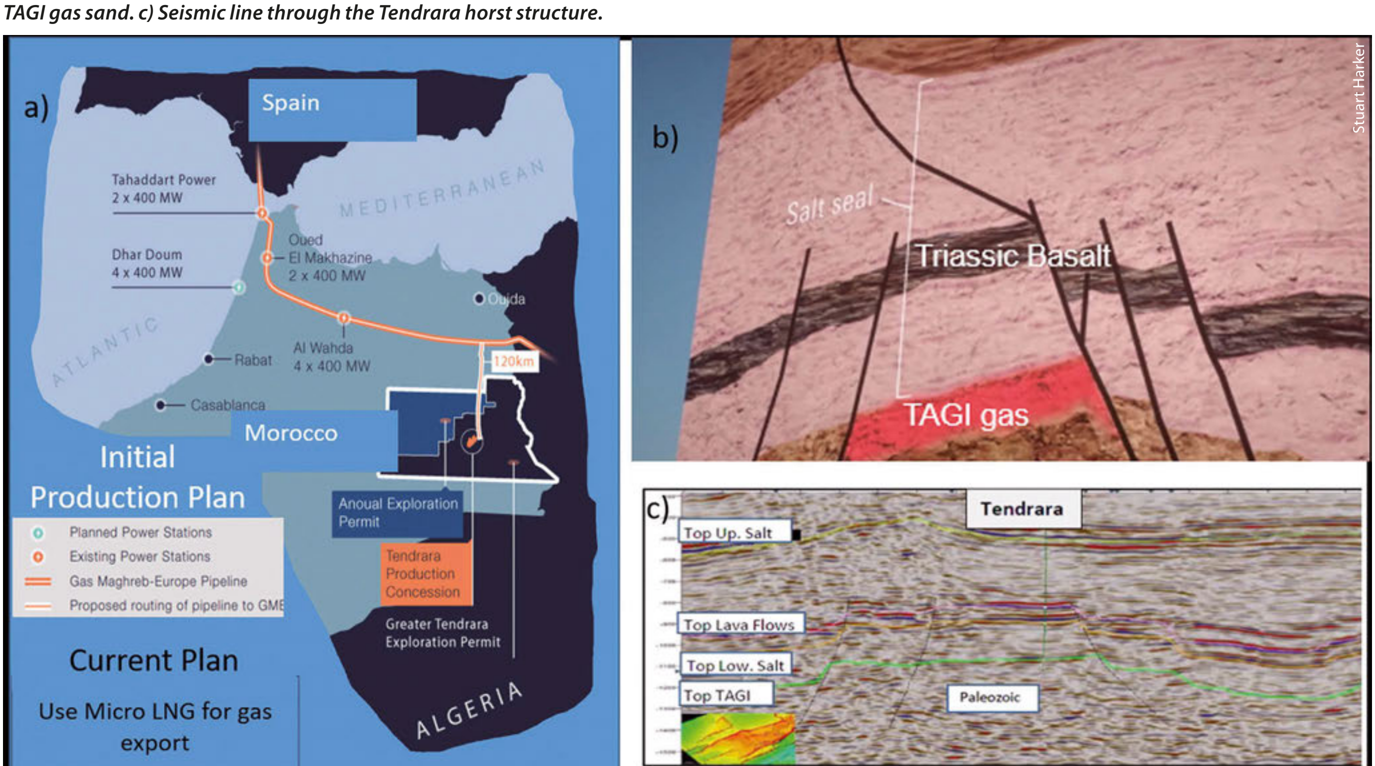


Figure 2: Essaouira Basin onshore and offshore: a) Offshore Morocco Early Cretaceous opening of the Atlantic Ocean. b) Sidi Rhalem onshore field surface anticline – field trip photo. c) Onshore Essaouira fields and pipelines. d) NW–SE geoseismic cross-section.

field (discovered in 1961, Figures 2b–d). The distribution of mature Oxfordian source rocks is limited (as is the prospectivity of shallow targets) by the generally shallow depth of burial. However, there is a more deeply buried Palaeozoic–Triassic system and Triassic fluvial sands of the TAGI that are productive in the Meskala gas field, discovered in 1977 and operated by the Moroccan National Company, ONHYM. A key element of the Essaouira Basin fields is the Triassic salt providing a seal for Meskala and structural deformation of the overlying strata by halokinesis. However,

Figure 3: Tendrara Basin: a) Location map with proposed production plan and pipelines summary. b) Schematic structural section showing the Triassic TAGI gas sand. c) Seismic line through the Tendrara horst structure.



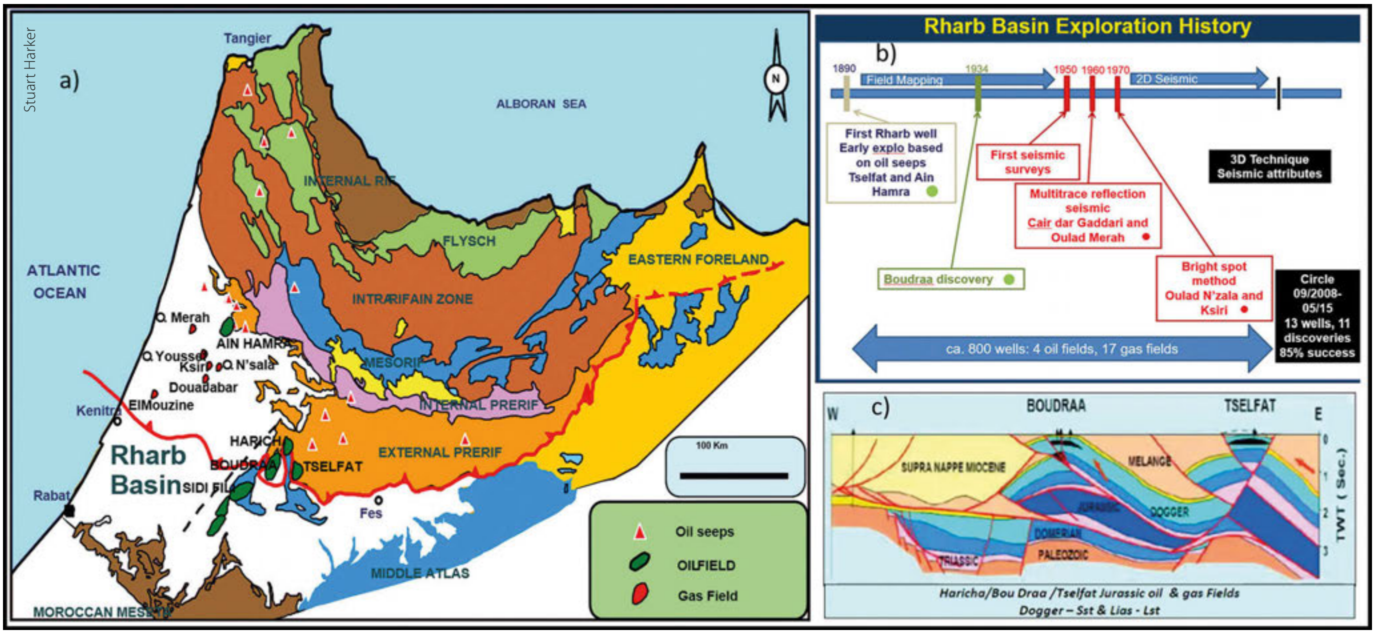


Figure 4: Rharb Basin: a) Location map showing some early discovered oi and gas fields. b) Schematic of the exploration history of the Rharb Basin. c) Schematic structural section through the Bou Draa and Tselfat oil fields.

Jurassic–Cretaceous traps appear to be small to moderate in size and improved seismic coverage is needed to better define drilling targets. The deeper Palaeozoic has yet to become a more popular target for exploration.

Tendrara Basin

Situated in eastern Morocco near the Algerian border and sharing similar geology, this basin has the potential to provide substantial gas reserves (Figure 3a). However, the location is fairly remote and the area is some 120 km south of the Maghreb–Europe gas pipeline. The main gas-bearing horst structure was discovered by Maghreb Petroleum in 2006. Recent drilling by Sound Energy (current operator) has had mixed results primarily because it is difficult to predict reservoir quality within the the TAGI sands, leading to a change of development to using micro-LNG plants for gas export from the current Tendrara discovery, rather than building a connecting pipeline to the north. The source rocks are the deeply buried Lower Silurian shales and like Meskala the caprock is provided by the overlying Triassic salt (Figures 3b–c). There is upside potential in the Palaeozoic, similar to that of the Essaouira Basin with reservoirs in both the Devonian and Ordovician. The rift-generated horst block trapping style is present over a wide area and further drilling is needed to delineate the ultimate extent of the Tendrara plays.

Rharb Basin

Located to north of the Moroccan capital of Rabat and south of Tangier and the Rif Mountains, the Rharb Basin contains a thick succession of Late Tertiary sediments. Exploration based on field geology and on the presence of surface oil seeps started in 1890 (Figure 4a–b). The Ain Hamra field was discovered in 1923. Field mapping of surface structures and later magneto-telluric surveys continued through to the 1950s with the discovery of some small shallow oil fields (Tselfat, Haricha and Bou Draa) and a series of small gas fields on the Sidi Fili trend associated with thrust folds in the Rif Mountain front (Figure 4c). The Mesozoic rocks involved in this thrusting as the African plate collided with Europe in the mid-Tertiary, are collectively known as the 'Nappe'. The later Miocene to recent sediments of the foreland basin are locally termed the 'Supra-Nappe'.

Petrofina started using multi-trace seismic in the 1960s leading to several small gas discoveries. In the 1970s with the advent of 'bright spot' technology, additional gas discoveries were made, though several dry holes were also drilled. 2D seismic was the 'norm' in the Rharb until the winter of 2007–2008, when Circle Oil acquired a 3D seismic survey over the Sebou concession, which had been granted in 2006. The initial drilling programme commenced in September 2008 following interpretation of the 3D seismic and the first well was successfully tested as a gas discovery which was tied back into the existing small capacity pipeline to the local industry in the coastal town of Kenitra. First gas was produced in November 2008 and during the author's time at Circle Oil, further drilling campaigns achieved an 85% success ratio to mid-2015. The succeeding operator has been Sea Dragon Energy who have continued with the play concept and have had further success.

A sequence stratigraphic subdivision of the mudrock-dominated Mio-Pliocene 'Productive Series' was used by Circle Oil to distinguish and map eight units for the central part of the Rharb Basin (Figure 4a–c). The gas-bearing sands are of good reservoir quality, but usually thinly bedded (1–15m). The sands appear to have been sourced from erosion of the uplifted Rif Mountains and transported into the

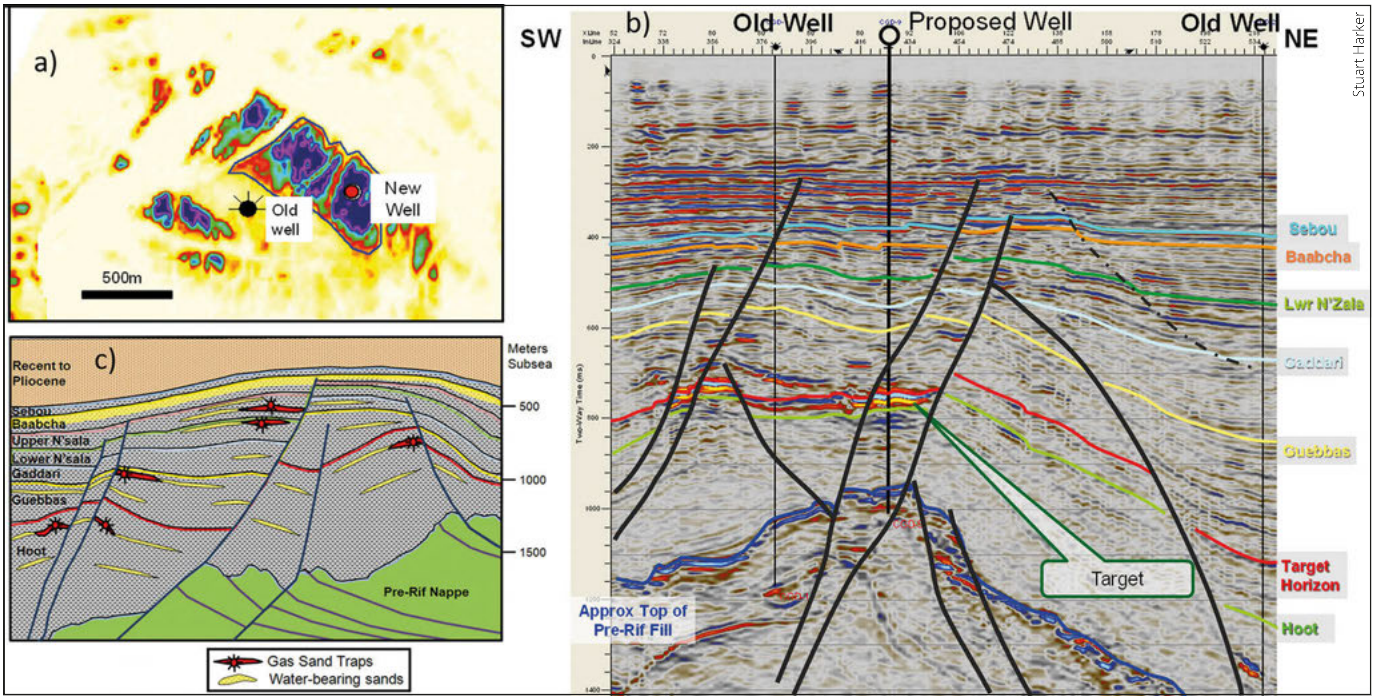


Figure 5: Rharb Basin: a) Seismic amplitude extraction map of +/- 40ms around top of bright amplitude anomaly. b) Seismic line through the bright amplitude anomaly. b) Schematic of Rharb productive series stratigraphy and gas trapping styles.

Miocene foreland basin to the southwest into the opening eastern margins of the Atlantic Ocean. There are no Late Miocene evaporites in the Rharb Basin, as the Rif Mountains formed a barrier to marine incursions from the Mediterranean to the north. A recent exploration venture on the eastern margin of Morocco's Mediterranean coast in the Guercif Basin is underway by Predator Oil and Gas holdings. The block lies 180 km north of the Triassic Tendrara discovery, but there is a different objective. Predator are targeting the same Miocene sands interval as the Rharb gas fields for shallow gas.

Modern 3D Seismic Application

Where gas bearing, the seismic response of the sands shows up as bright negative amplitudes, due to the lower density and slower seismic velocity compared to the water-bearing sands and the encasing mudrocks (Figure 5). Modern 3D seismic makes the location and geometry of these anomalies stand out as clear drillable targets. The gas is contained in combination structural-stratigraphic pinchout traps, with top, bottom and lateral seals provided by coeval marls and shales. The reserves of the small onshore gas fields discovered to date, range from 1 to 20 Bcf. Circle Oil built a new gas pipeline to Kenitra on the coast for export and sale to local industries in 2011. Much larger structures are present in the offshore extension of the Rharb Basin, where ENI discovered the Anchois gas field in 2009. At that time the discovery was considered too small for development; however, Chariot Transitional Energy have taken over the blocks including Anchois, and the company has reprocessed and interpreted the 3D seismic and is now proceeding with development plans.

The example shown in Figure 5a–b illustrates the accurate placement of a gas discovery only 800m away from an abandoned well, based on amplitude extraction and geological understanding of the trapping mechanism. The faulting as shown is currently normal over the crest of a thrust anticline in the Nappe. The effective keystone stretching of the overlying younger rocks has created the structural trap and provided a migration pathway for hydrocarbons generated from the Jurassic/Cretaceous source rocks. Sourcing from the coeval, organically lean Miocene mudrocks is unlikely to provide local biogenic gas and the more likely source is considered to be the biogenic degradation by bacteria of an original thermogenic liquid phase hydrocarbon. This has been also reported by Sea Dragon Energy for their recent discovery in the Lalla Mimouna Block located just to the north of the previously successful Sebou Block in the Rharb Basin. The apparent lack of reservoir quality rocks in the few wells drilled to date into the 'Nappe' succession may locally downgrade the prospectivity of those strata.

Unfulfilled Potential

Morocco's productive petroleum basins appear to suffer from a mixture of underexploration and underperformance. This may be due to the failure of early wells and then poor follow-through exploration ideas. Deeper drilling and alternative target horizons and traps have often led to success in other petroleum basins such as the Alberta Basin in Western Canada, as well as the North Sea. New exploration concepts and technology improvements are essential to the rejuvenation and success of exploration ventures. Just as in some of my old school end-of-year reports, perhaps explorers in Morocco – 'could try harder and do better'. ■

Africa at the Crossroads

JANE WHALEY

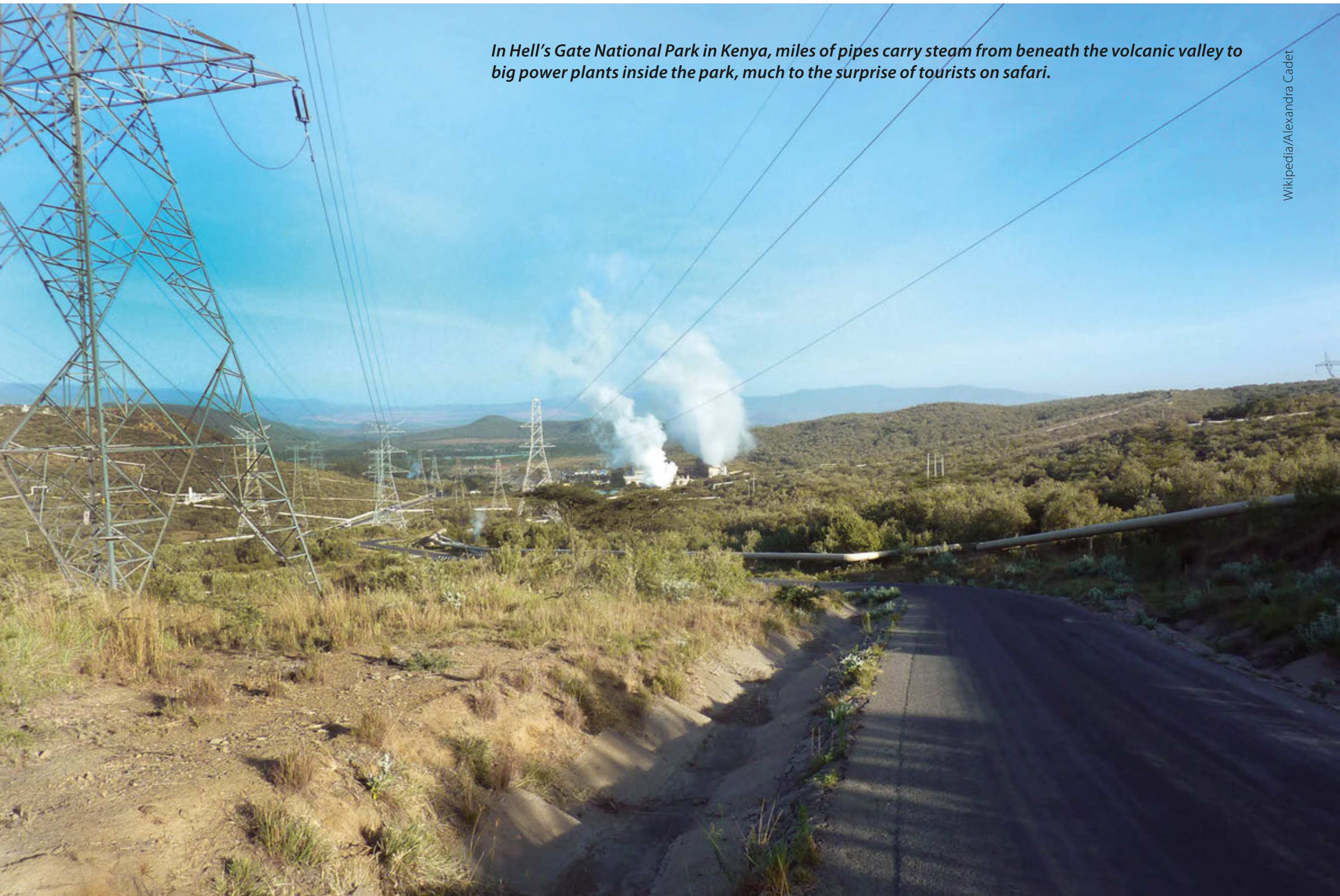
Energy transition in Africa: can the continent leapfrog the fossil fuel era?

About 43% of the African population have no access to electricity, and a staggering 80% rely on traditional biomass, mainly wood and charcoal, for cooking. Car ownership is low, at about 45 vehicles for every thousand inhabitants in Africa; the global average is 203. With population growth, increasing urbanisation and rising living standards, demand for both energy and transportation is set to grow dramatically, but can this be done without further investment in fossil fuels, as proposed by the International Energy Agency? Or are the nations of Africa, which together emitted 2% of the total global man-made CO_2 emissions in 2019, being asked to pay for a problem which is not of their making and which is disproportionately affecting them?

Plentiful Potential

Africa possesses fantastic renewable resource potential, probably the best of any continent. Solar potential is almost limitless, with 80% of African land receiving more than 2 MWh/year/m^2, while there are substantial opportunities for harnessing wind power, particularly in the coastal areas of northern, western and southern Africa. There are abundant hydro-power possibilities in central Africa, with the total theoretical potential of the continent standing at 1,500 TWh/y, about 90% of which is currently unexploited – although ongoing climate change poses a threat to that. Commercial biomass also has potential in central Africa, while geothermal energy is available in the Rift Valley corridor of east Africa, stretching from Mozambique to Djibouti. These renewable resources also offer opportunities for the development of green hydrogen, with applications in both the transport and industrial sectors, as well as for energy storage.

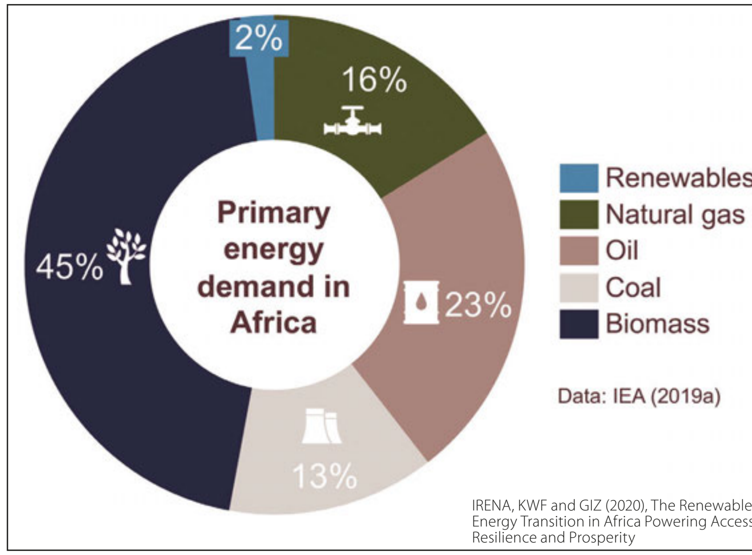
In 2018, about 20% of electricity generated in Africa was from renewable sources, up from just 5% in 2013. Solar energy, in particular, has shown encouraging growth in recent years, especially in Egypt, South Africa, Kenya, Namibia and Ghana, driven by dramatic reductions in cost, underpinned by technological innovations. The International Renewable Energy Agency (IRENA) claims that the costs for electricity from utility-scale solar photovoltaics fell 82% between 2010 and 2019, making it cheaper than the fossil fuel alternatives across Africa, so long as the right regulatory and policy frameworks are in place: an important caveat.



In Hell's Gate National Park in Kenya, miles of pipes carry steam from beneath the volcanic valley to big power plants inside the park, much to the surprise of tourists on safari.

Wikipedia/Alexandra Cadet

And, of course, Africa has considerable oil and gas resources, much of which has yet to be exploited. The big question is whether countries which have yet to produce petroleum, which for the most part are the poorer, less developed nations, could leapfrog that stage directly to generate their much-needed electricity through renewables, or whether fossil fuels will provide a quicker and more economic route to alleviating energy poverty while providing a bridge to a cleaner future?



Primary energy demand in Africa. Based on data from the IEA, 2019.

Planning for a Greener Future

According to IRENA, many African countries have begun to develop policies that direct them towards a greener future. All 15 nations in West Africa, for example, have developed National Renewable Energy Action Plans, while some of the larger states, including Egypt, Ethiopia, Kenya, Morocco and South Africa, are accelerating their use of modern renewable energy.

Of course, Africa is large as well as geographically and socio-economically diverse and there are huge differences across it. While average per capita emissions throughout the continent are low, in 2017 just six countries – South Africa, Egypt, Algeria, Morocco, Libya and Nigeria – accounted for around 84% of Africa's total CO_2 emissions from electricity generation. Therefore, pathways to energy transition will show regional differences, with southern Africa, for example, needing to concentrate on reducing its heavy reliance on coal. Central Africa, where less than 5% of the population have access to electricity, and West Africa, where electricity demand is forecasted to grow by more than 250% by 2030, ways of increasing access through mini-grid or off-grid systems will be paramount. East Africa has good hydro and geothermal power potential, but will those be able to fulfil demand that is also expected to grow 250% by 2030. In contrast, countries in northern Africa, which already have near-universal access, are actively concentrating their efforts on transitioning power generation from oil to gas and renewables.

Ailing Infrastructure

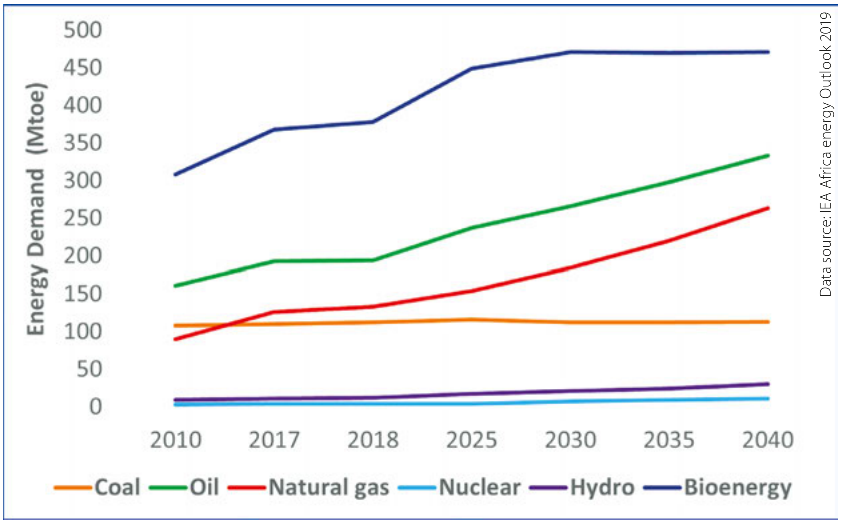
One of the biggest impediments preventing increased access to electricity across Africa, both for domestic and industrial purposes, is an ailing and chronically underfunded infrastructure. According to the World Bank, utilities in only two nations in sub-Saharan Africa – Uganda and the Seychelles – were able to fully recover their operational and capital costs through customer payments in 2016. Improving infrastructure is hindered because most counties do not have access to the necessary capital, and also because they lose much potential revenue through theft, estimated bills and non-payments. In addition, the majority of the infrastructure was built decades ago and was never designed to transmit the demand now needed, let alone cope with two-way flows required to move power from sources such as solar rooftops back across the grid. These poor quality systems mean that access to energy is not the only problem – a reliable supply is just as much of an issue in many places, plus the age of the infrastructure in many countries means it is vulnerable to IT security breaches. It can therefore be seen that a huge investment in the power system is required throughout the continent before reliable energy access for all can happen.

Where will this investment come from? Many countries in Africa are heavily dependent on the revenues from the export of their oil and gas, but large investment banks and international funds are reducing the funds available for oil and gas projects, unless they are attached to net zero emissions targets. A number of large western oil companies are also divesting themselves of assets or reducing their commitments. China, however, is actively investing in both oil and gas and renewables projects, as well as in infrastructure, giving a disturbing amount of power to a single country; one that is not as committed as many others to mitigating climate change and is responsible for nearly 30% of global greenhouse gas emissions. A number of African countries have already had to hand over important assets to China when they found themselves unable to keep up with loan payments.

Could Gas Reduce Risk?

For Africa to abruptly transition out of fossil fuels is feasible, according to IRENA, although it admits it will be hugely expensive and require major investment in new technologies, including new off-grid renewable energy systems to allow affordable access. It will also require innovative financing methods such as local currency lending and results-based financing schemes, as well as new business models and, very importantly, improved regulatory frameworks which will need to be regional as well as national. Political will and regional cooperation are paramount.

There is risk in this approach, as failure to invest in all aspects of a renewable energy system, including infrastructure, while simultaneously stopping exploitation of fossil fuels could see many parts of Africa slide further into energy poverty; and energy insecurity leads to economic insecurity and geopolitical instability.



Total primary energy demand (actual and predicted) using International Energy Agency Stated Policy scenario shows continued use of both oil and basic biomass until at least 2040.

The alternative option is to continue investing in fossil fuels to enable countries that are not yet producers to build a new income stream as they develop their renewable energy sources, whilst allowing those that are already producers to use oil and gas revenues to fund a move into cleaner energy. Sonangol, the Angolan NOC, for example, has recently announced a restructuring that includes investing in new oil and gas projects, extracted with the least possible emissions, while also increasing investments in solar energy and the production of green hydrogen. Any further developments in fossil fuels would need to ensure that emissions from production are kept as low as possible, including a major reduction in flaring.

Gas is key in this scenario; the reserves potential in Africa (2019) was estimated to be as much as 558 Tcf. Even IRENA agrees that natural gas can play a role in supporting the expansion of variable intermittent renewable energy generation as a medium-term bridge technology, a point ignored by many of the organisations pushing for complete divestment from fossil fuels. The African Energy Council (AEC) strongly believes that such divestment is not practical; as its Chair, NJ Ayuk, points out: "Ending investment is not a transition." Instead, it believes that African nations should take a slower path, using their fossil fuels to create jobs, economic diversification and develop and update their power distribution systems.

The AEC also believes that, rather than withdrawing from fossil fuel projects, western institutions should be helping African nations to create a local energy transition towards net zero using gas, while also investing in the technological developments needed to make the renewable sector work economically on a continent-wide scale. With the withdrawal of western investment in fossil fuels, African countries like Mozambique, Tanzania and Senegal, which have plentiful identified gas reserves waiting to be produced, will either become further dependent on China or left relying on foreign aid, which is not a sustainable or satisfactory option for anyone.

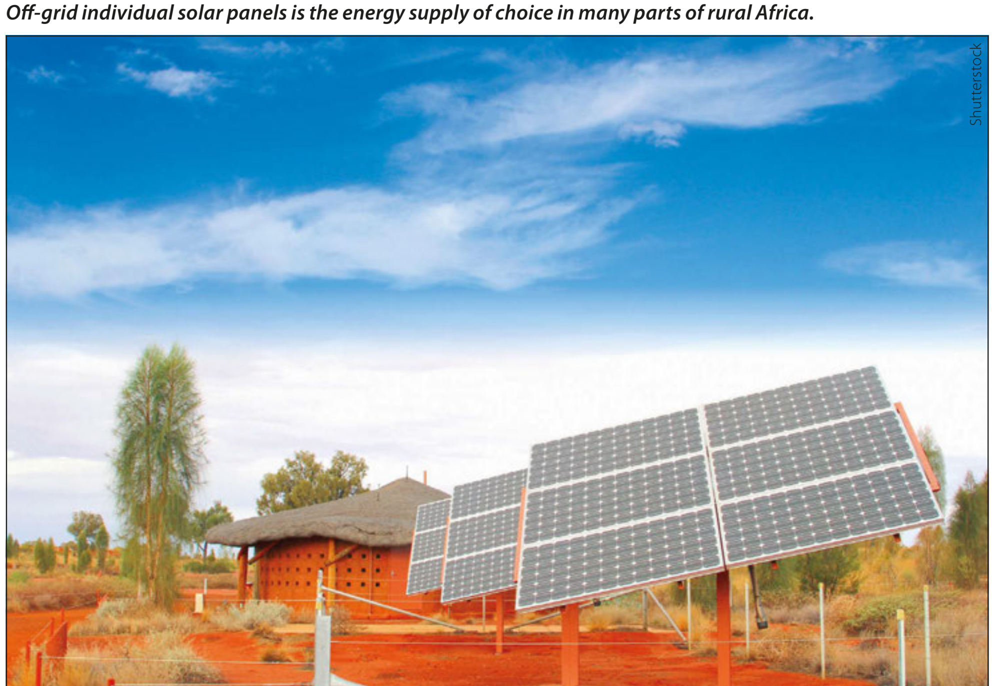
Africa's Dilemma

Africa is at a crossroads. Will the continent ditch fossil fuels completely and become the frontrunner in the global clean energy transition, developing new technologies and different ways for its people to access electricity using its plentiful renewable resources in a new, emissions-free environment? Or will African countries continue to extract their equally plentiful fossil fuels and pay primary attention to developing their own economies before transitioning to renewable energy sources?

The answer is probably a mixture of the two, as what works for one country will not work for another. Gas, at least, will remain in the mix for a number of years. However, it is important that Africans themselves make these decisions, supported by the rest of the world, and that they are not forced into a corner by directives from countries that have already enjoyed the benefits derived from exploiting fossil fuels – and which have thus caused the climate changes which are being felt disproportionately across Africa.

References available online. ■

Off-grid individual solar panels is the energy supply of choice in many parts of rural Africa.



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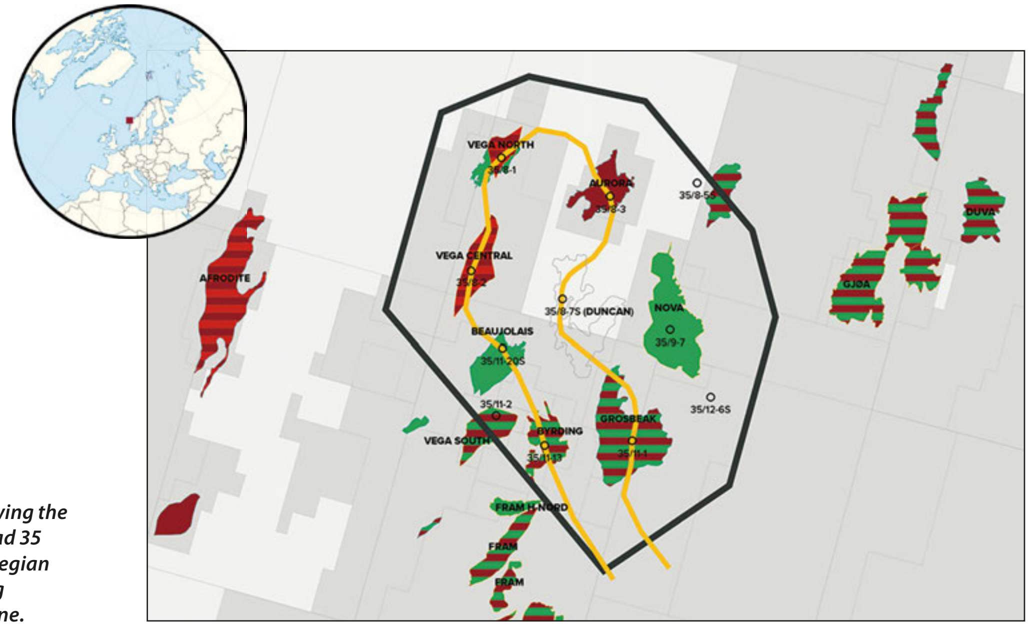
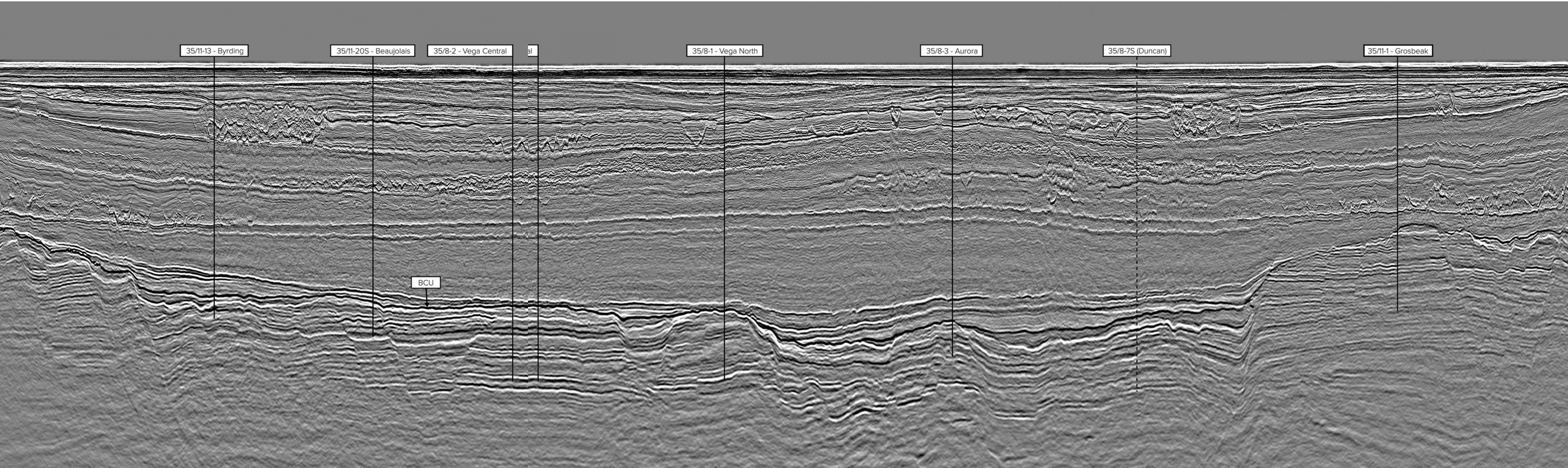


Figure 2: Map showing the location of the Quad 35 survey in the Norwegian North Sea and long arbitrary seismic line.

Figure 1: Long arbitrary line through the main discoveries inside the Quad 35 survey area.



The World's First Combined, Simultaneously Acquired Ultra-High Density Streamer and Node MC3D Survey

Geoex MCG and Seismic Partner initiated the Quad 35 project in the winter and spring of 2020 and formed partnerships with several service providers to both financially and operationally realize the project. The UHD streamer acquisition was performed by BGP, ocean bottom nodes were delivered by Magseis Fairfield and deployed and recovered with ROV by Reach Subsea, and the data processing was done by Downunder GeoSolutions (DUG). The Quad 35 MC3D Hybrid survey was acquired between August and October 2020 with the final processed data being ready in July 2021.

JEROEN HOOGEVEEN, Geoex MCG; KRISTEN BERLI, Seismic Partner; LARS IVAR LEIVESTAD, Geoex MCG and TOR ÅKERMOEN, Geoex MCG

The new Quad 35 MC3D survey data has significantly improved the imaging of the Upper Jurassic sands and the complex faults for which this area is known. The data is ideal for the oil companies that are developing existing discoveries and for companies that are looking for additional resources close to existing infrastructure.

Why Quadrant 35?

Quadrant 35 is located immediately downdip of, and in the migration pathway of, the world class Troll accumulation, believed to have reserves in the order of 1,766 Mbbls Sm^3 oil equivalent. This is by far the biggest accumulation on the Norwegian Continental Shelf (NCS). This suggests that the area has access to enormous amounts of migrating hydrocarbons. Almost every valid fill and spill trap on the migration fairway from the basins to the Troll field has been found to be hydrocarbon bearing.

The area covered by the Quad 35 survey is therefore known to be hydrocarbon rich and contains several discoveries (Nova, Vega, Aurora, Grosbeak, Byrding, Beaujolais, Orion). Figure 1 on the adjoining seismic panel shows a long arbitrary line going through many of the discoveries. Several of these are in the process of being developed. In addition, the increased focus on near-field exploration has made this area very attractive for new and improved seismic acquisition and imaging technology.

Prior interpretations of existing data covering this area has proven to be challenging, because of imaging difficulties due to complex overburden and faulting.

Exploration Targets and Challenges

The main exploration target in the Quad 35 area is Jurassic and as in the Troll field, Upper Jurassic sandstones play a major role, mainly due to their large quantities and role in the migration fairway. In addition, the Middle Jurassic is trapping significant hydrocarbon accumulations. Although Lower Cretaceous sandstones are proven as a trap to the north-east of the survey area, it remains to be proven within the acquired data. This new data paves the way for a fresh and closer look for accumulations in the Lower Cretaceous.

The main challenges historically in the Quad 35 area have been to understand the Upper Jurassic sand distribution, erosion and sealing faults, and the imaging due to a complex overburden with associated velocity anomalies. All those issues have been addressed and significantly improved through the hybrid LumiSeis™ solution used to acquire this project.

The Solution – Hybrid Streamer and Node Acquisition – LumiSeis™

Historically, the seismic node and streamer industry have been working on separate fronts to improve their solutions, while competing for the same markets. The LumiSeis™ hybrid concept from Seismic Partner has been developed on the basis that none of these technologies are ideal on their own. The hybrid concept aims to combine and jointly harness the potential of these two proven methodologies.

Geophysical modelling of the Quad 35 area was performed to find out how to solve the imaging challenges. The conclusion was that very high-density data with many near offsets, to improve the signal-to-noise ratio, and the best possible velocity model by use of Full Waveform Inversion (FWI), were needed. Geoex MCG and Seismic Partner therefore decided to use the LumiSeis™ acquisition technology to improve the imaging. LumiSeis™ is an optimised combination of streamers and seabed nodes. This unique approach has allowed all the data in this hybrid project to be acquired

simultaneously and with the same source, resulting in an efficient acquisition, both operationally and cost-wise, ensuring high quality data with a competitive price.

The node data was used to define an improved velocity field through FWI. This velocity field was then used to improve the migration of the ultra-high density (UHD) streamer data. The hybrid method also allows summation of the UHD streamer data with the node data. This in turn will provide better imaging of the subsurface, unlocking new opportunities in exploration and production.

In addition to the hybrid acquisition technology, the survey was also acquired in an optimal strike direction to the main faults.

Hybrid LumiSeis™ Acquisition – The Geophysical Reasoning

The geophysical reasoning for acquiring ultra-high density streamer data together with node data is simple and sound: the high-resolution data from the dense streamer dataset is focused and placed correctly in depth by the better velocities derived from the OBN dataset. The acquisition set-up gives ultra-high fold data, which boosts the signal-to-noise ratio and thus higher frequencies are recovered at depth as compared to existing high-end surveys. It also offers smaller grid bin size which leads to increased lateral resolution. The velocity model benefits from the high-fold and good near-offset coverage from the streamer data in the shallow, and the longer offset data from nodes in the middle to deep parts of the section. The FWI velocity model updates using both streamer and OBN datasets to give a very detailed velocity model. Conventional velocity models derived from reflection data are good at flattening events but lack detail and accuracy. Offsets up to 15 km from the node data were used to drive the deeper velocity model updates using FWI. The net result is a detailed velocity model that puts data in the right place after imaging. Figure 3a and Figure 3b shows how the detailed FWI velocity model improves the imaging below the complex overburden. The final velocity model includes anisotropy and produces an excellent correlation with the wells in the area.

The streamer survey was designed to produce a well-sampled source grid, exposing the nodes to data from all azimuths and offsets. Simultaneous acquisition of streamer data and node data meant that no extra source effort was needed. With this benefit, the timeframe and level of underwater sound emission was limited. This contrasts with current methods for acquiring node data, where duplication of source effort is the norm.

The hybrid acquisition can yield several datasets which each have their merit:

- A stand-alone high resolution streamer dataset, with similar quality to site surveys in the shallow
- A stand-alone OBN dataset, using for example mirror migration and RTM
- A detailed FWI velocity field from both streamer and node data
- A correctly imaged ultra-high density streamer dataset using the FWI velocities
- A blended streamer/OBN product
- A shear wave product

This means there is still more potential in the acquired data by also utilising the OBN data for imaging.

Results and Future Plans

The final Quad 35 data shows superior imaging compared to other data covering the Quad 35 area. The dataset will play an instrumental role in positioning development wells as well as assisting producing assets in identifying near-field exploration targets. The hybrid acquisition method has shown to be extremely effective in imaging the Quad 35 geology, while also proving to be applicable in other geological settings.

With the successful completion of the Quad 35 survey, Geoex MCG and Seismic Partner are already planning more hybrid acquisition projects in the years to come. In conclusion, this method produced the next level of imagery that the exploration industry has been asking for. ■

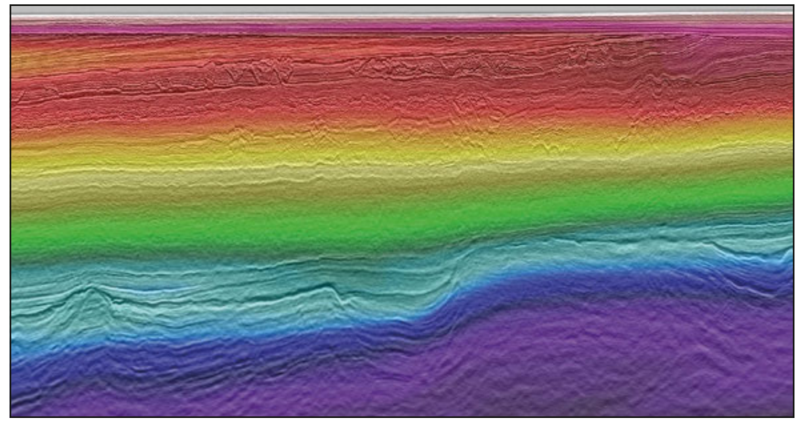


Figure 3a: Quad 35 PreSTM Fast Track stack in TWT and the Fast Track migration velocity model.

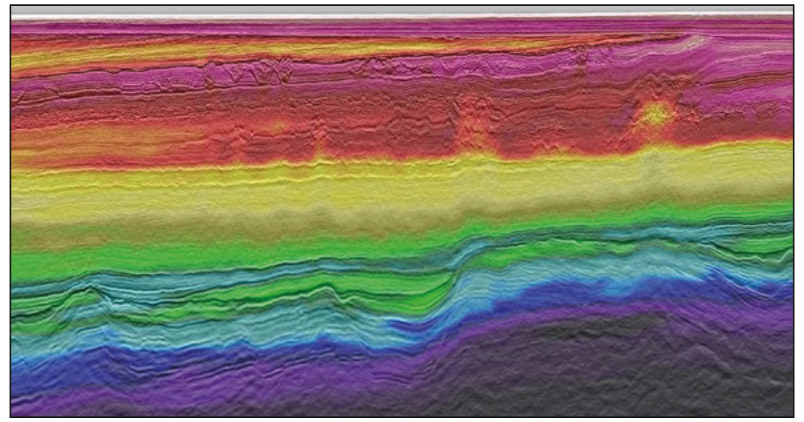


Figure 3b: Quad 35 Final PreSDM post processed stack in TWT and the final FWI velocity model.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The Complexities of Secure Energy Supply

Internationally renowned energy expert and public speaker, Dr Scott Tinker, in conversation with Iain Brown about the future of energy in a transitioning world.

Negative public opinion and the accelerating climate emergency create significant challenges for the oil and gas industry. Do you see an effective way to communicate to the public how fossil fuels are part of the transition to cleaner energy?

You use some interesting words like climate emergency, cleaner energy and energy transition. Words matter a lot and we must define them. Clean is a fascinating word. I think if we were to ask a global sample of people, we would get a lot of different definitions. In Western Europe and the US, many take it to mean, almost exclusively, CO_2 and methane emissions. But around the world, people in emerging and developing economies understand that the land, air and water are also vital to a clean environment, human health, and of course the health of all species on Earth. So clean is not just greenhouse gases. It's the four pillars of atmosphere, land, air and water.

When people in Western Europe and the US think about clean energy they think solar, wind and electric vehicles. Governments are mandating and massively subsidising these now. So to approach people indoctrinated in this type of clean energy thinking, I try to broaden the conversation and ask if they think that mining is clean? That usually provokes the response, "Well, no, of course not, mining isn't clean, it's a dirty process." So, I ask if dumping chemicals, batteries, and other materials into landfills is clean? Or large-scale chemical manufacturing or metals production? "No, that's not clean."

Then I ask if electric vehicles are clean? The usual response is, "Of course, they're zero emission!" So I ask what the fuel that runs electric vehicles is? A battery, which was mined, manufactured and eventually (despite some limited recycling) dumped back in the earth. Suddenly, we're having a different conversation about the land and the water and the atmosphere. And the definition of clean.

I think it's important, because they know I'm concerned about climate. Just not exclusively. So, as we think about a clean energy transition, we need to think about all four pillars of the environment. It's a very important critical thinking, communication challenge. I speak to young people all over the world, including recently to a private girls' school in London.

Scott meeting Masai children in Ethiopia.

Harry Lynch

They are smart, and curious. I push them to think critically, beyond 'clean and dirty, good and bad'. Beyond a binary conversation. Communication starts this way, a few minds at a time. And broadens through their social networks.

I think people are interested in science, so it's incumbent upon us to talk in schools, to civic gatherings, scout troops and church groups and begin to expand the education. Most of the people I encounter are ready to learn. Some don't like everything I tell them, but they say, "Well, you're showing all this data, and you have references for everything, so I'm going to look that up." That's what science is about. Questioning. Hypothesising. Experimenting. Testing. Never settled. Always more to learn.

Much of the world has been brought out of general extreme poverty, because of the availability of cheap energy. If we suddenly decide that we should not use hydrocarbons anymore, that's a decision that can be made, but there are consequences to go with it. That is something that many young people, who are very concerned about climate change, don't seem to fully grasp.

Let's not challenge that directly, but suggest instead that if we eliminate hydrocarbons we're likely to harm the world's environment. And they're going to think, "What? What are you smoking?" And then you explain that the data show that the cleanest air in the world is in the most economically rich countries. Same for the cleanest water, which you can drink from the tap, and the cleanest soils. I don't drink water from the tap in most of the 60 countries I've been fortunate to visit, for good reason. And the soils are often polluted and the air is bad. Poor countries simply cannot afford to invest in the environment. They have other more pressing challenges. Developed, healthy economies invest in the environment and have the regulatory systems to enforce clean-up.

Energy sources, particularly fossil fuels, have negative impacts on the environment, to be sure. But in a larger sense they have made for a cleaner environment by creating wealth. We don't get rid of hydrocarbons *per se*, we clean them up. This is a message they're likely not going to have heard. But then we can look at the data again. At maps of clean air, clean water and clean soils.

In terms of climate and emissions, which countries are going to capture their emissions? Rich ones, not emerging and developing ones. Why? Because rich ones can afford to. So, there's an important directional link between energy, the economy and the environment.

As geoscientists we love ternary, or triangle, diagrams. Let's take the points on the triangle to be clean environment, cheap energy, and a reliable economy, which must add up to 100%. If I want 100% clean, I get 0% reliable and cheap. The world won't do that. If I want 100% cheap, I damage the environment. If I want 100% reliable, it won't be cheap! We must come to the middle and find the balance. I call this the 'radical middle' where big challenges are addressed.

So, the conversation isn't trying to explain to the public how good their lives are thanks to energy. Even if true, they feel guilty about that. When they realise how many people still subsist in economic poverty globally, they will agree that it makes sense to lift the emerging and developing economies up with energy. And the unexpected benefit is that then those economies can become part of the global 'clean-up'. Energy is not just a poverty conversation; it's also an environmental conversation.

You mentioned earlier the transition; again, people would define what that means differently, and in my mind, a successful transition is from poverty to prosperity. And that's enabled by energy. If you were to get rid of oil, gas, coal and nuclear from the energy mix today, you would end up with maybe 10 to 12% of the world's present energy, half of which is hydro. First, the world is not going to do that. More importantly, they shouldn't.

The big oil companies are trying to become integrated energy companies but, in the meantime, their underlying businesses are all driven by oil and gas production. They have to appeal to not only the public but their shareholders and stakeholders. Do you feel these two challenges are somewhat mutually exclusive?

I don't think they're mutually exclusive. Shareholders, at the end of the day, expect to make money, and being profitable is a good thing. Profit provides taxes and other capital to clean up the environment. And the public wants to see energy companies move towards 'clean' energy. But as discussed previously, the public, and politicians that represent them, can be a bit myopic in terms of the definition of clean.

We can look at other industries not under the public microscope yet, like the tech sector, auto industry, or battery and solar panel manufacturers. Think about the massive chemical manufacturing plants for polysilicon, batteries, and the like. And when panels, turbines and batteries wear out, as we discussed earlier, we dump them in landfills. As these 'clean' energies scale up, it's going to be really impactful on the environment and not in a positive way.

So, I don't think the challenges of profit and environmental stewardship are mutually exclusive, but instead must become mutually *inclusive*. Companies, governments, and educators need to do a much better job of understanding and explaining these relationships.

I've talked about the four pillars of the environment and lifting people out of poverty. These fall under the broad theme of Environmental, Social, and Governance (ESG). Companies are getting measured on ESG performance, yet there is not consensus on the metrics. How do we measure ESG rigorously? Same challenge for Carbon Capture Utilisation and Storage (CCUS). Who's going to verify how much CO_2 is captured and remains safely in place? And then there are carbon offsets. It's a bit like the Wild West: people are buying and selling offsets that have little if anything underpinning them.

In summary, I think energy companies will evolve to become integrated energy companies, but oil and gas will, and should, remain an important part of the mix.

There is a challenge in replacing fossil fuels as a high-density energy source. The UK is a good example: we have massive wind farms off the coast, and they're fantastic

when the wind blows, and we're a particularly windy country, but there are still periods when there's no wind and then we have had to fire up a coal power station to meet demand. So, my question is really about other potentially renewable sources of energy, for example, geothermal, tidal, and I suppose in a different category, nuclear. What are your thoughts on the future potential of expanding these sources, and I wondered if you had any views on geothermal, because that tends to be very localised now, but perhaps there are ways of broadening this energy source?

Before we get to geothermal, it is important to set the stage with an understanding of energy density: how much energy is available in a square metre of land. That's called surface power density. Or we could look at energy density by volume or weight. It turns out, biofuels are the least dense of all, requiring tremendous land areas to grow plant material, and a large amount of energy to convert a carbohydrate (plant) to a hydrocarbon. These processes of growing, harvesting, transporting, converting, transporting again and burning have major environmental impacts.

Then come batteries, solar and wind, which are very low density, and so you need a lot of stuff – panels and turbines – to collect and store the sun and wind. And all that stuff is mined. This density framework helps us understand that although the sun and the wind are renewable, everything to collect and store the sun and the wind comes from the earth and goes back into the earth when it wears out, and must be made again. Unfortunately, this is not renewable.

Nepalese family living in energy poverty

Oil, methane, hydrogen, uranium and thorium are hundreds of times denser than the sun and the wind. The bang for the buck is much better. Explaining this requires a bit of a conversation. It's not a snappy one-liner like 'clean and sustainable', or the binary portrait of energy as 'good–bad, clean–dirty, believer–denier'. But unfortunately, these simplified discussions present choices that don't actually exist, and the sooner we get people to begin to think critically, the better.

As an example, we can look at the Big Chill that happened in February in Texas. Texas is a very windy state, like the UK. We are approaching 40 gigawatts of installed wind now, and it keeps growing. Wind is also intermittent, so you need a lot of backup available when the wind is not blowing. And that idle backup is expensive. It adds significant costs to the consumer.

Timing really matters when reviewing the history of the Big Chill. First the solar panels got covered in snow, and then wind power diminished greatly. From 7 to 14 February coal and nuclear held steady and natural gas grew tremendously from its typical winter levels to meet growing demand. Then on 15 February, with continued freeze, a few coal piles froze and coal plants went down, one nuclear reactor cooling pump froze and a reactor went down, and natural gas began to decline, because electricity wasn't being prioritised to the gas pipelines and plants to keep them from freezing. Blackouts began, and it took another week of mostly gas, coal and nuclear until the 22nd when everything got back to a 'normal winter'.

You could see that play out in real time and understand the impact of intermittent solar and wind, and what happens when you can't access dispatchable coal, nuclear and gas. Plenty of finger pointing is still going on, arguing around the data. The point is, each type of energy has pros and cons. A careful cost–benefit analysis is needed to determine what makes sense in terms of structuring for the future.

As another example, just this week President Biden announced an effort to go to 45% solar for electricity generation in the United States by 2050, which is only 29 years. 45% solar! We have about 3% now. Like everything, solar is a resource and we develop the best regions first. Continued solar development will be in less favourable areas, and therefore less efficient. And of course, there is night, when something else is needed to back up the sun. And that something – natural gas, coal or batteries – adds significant cost to the consumer. Physics and economics need to work hand-in-hand with passion and politics.

Which brings us to geothermal. There's high-heat gradient geothermal to make electricity. In Iceland and other places with active plate boundaries that heat is near the surface. Sounds great, but most places aren't like that, so you need deep wells to bring up hot fluids and convert that to electricity. They are more expensive because you need more infrastructure.

Then there's low-heat geothermal, like a heat pump. Cool fluids flow through your home in the summer, and help supplement the heat in the winter. There's a lot of good potential for that kind of geothermal. But like all primary sources of energy, geothermal is a resource, and it's going to take subsurface understanding to develop efficiently and economically, because it's not everywhere. Even in a high-heat source scenario, such as Iceland, as you produce the heat you've got to manage the geothermal reservoir as you deplete it. It requires subsurface knowledge and understanding.

Hydrogen represents another opportunity for subsurface scientists, and it comes from splitting the methane molecule (blue hydrogen) or the water molecule (green hydrogen). Steam reforming of methane is cheaper today than hydrolysis. Hydrogen is an energy carrier. It can be burned to make heat and electricity. It can also be used in fuel cells for transportation, with no emissions out of the tailpipe. So that helps with transportation emissions challenges.

Hydrogen is also interesting as a storage strategy to back up intermittent energy. A fuel cell has a lot denser energy than a battery in terms of energy per unit weight. To use hydrogen at scale will require it to be stored in large volumes. Hydrogen has seasonal storage capability by utilising salt domes, geologic formations or engineered containers so you can get it when you need it, and also large discharge capacity.

So, to summarise, opportunities for the oil and gas industry include such things as producing hydrogen, methane, and geothermal heat, and storing hydrogen and CO_2 (CCUS). These are all areas that reduce emissions and offer opportunities for people that understand the subsurface.

Loss of personnel and key geoscience skills from the industry in North America and Europe is an important issue. Particularly in Europe, encouraging young people to want to engage in this field of study is a major challenge because they perceive it as being a dirty science.

It's difficult in the US because the voices that paint the story are very powerful, well-funded, and use clever terms like clean and dirty. Therefore, kids and adults think oil and gas are dirty. I work hard to explain that if you're passionate about the sun, the wind and batteries, go into geology because that's where you can have an impact on developing and cleaning up the mining, manufacturing and the landfill disposal required for solar, wind and batteries. All the solar panels, wind turbines and batteries are mined from the earth, and there are jobs there. The earth is where rare earth elements and metals and chemicals come from, and where they get disposed later. We need geoscientists for these efforts.

I sometimes think the only way that we can address the challenges that we face as a species right now are just to use significantly less of the planet's resources. I don't know if science and technology are going to develop fast enough to get us out of this hole. Therefore, it comes down to using less resources and ultimately it is probably a population issue. We need fewer people on the planet. Do you agree with any of this, or have a particular view on it?

I often wrap up my talks up with thoughts about population, healthcare, immigration, rights of women, environmental investment, and the like. In terms of fewer people, fertility rates are directly tied to education. The more highly educated a population is, the lower the fertility rate. The US would have a declining population right now if it weren't for people immigrating. The same is true for most of Western Europe. So how do you broaden education globally? Well, it takes energy to light the homes and schools, and provide technology and access. Education is something we should all be passionate about. It helps address so many important issues.

But I have a slightly different take on the issues of declining resources. The world has actually run out of very few things so far. When supply of a commodity is stressed, price increases and technology advances help to produce more, such as oil and natural gas from shale, or technology creates a better replacement, like the car for the horse, or kerosene for whale oil. Or the smart phone! When I was young, I was in a closet on a landline connected by a long wire, trying to talk without everybody hearing. The cell phone, this little technological marvel in my hand, is better technology. It's so much more than a phone. By contrast, is an electric car really better than a combustion engine? More efficient motor, but much less efficient fuel, called a battery. Trade-offs.

These are some of the open and civil conversations we need to be having, and I appreciate meeting with you today. ■

New Life for Legacy Well Cuttings

National Cuttings Digitalisation

JACK CAWTHORNE, MIKE SNAPE, DOUGLAS LANGTON and PETER WELLSBURY, Rockwash Geodata; ANDREW BARNWELL, Barnwell Parker Geoscience

Around the world, there are millions of drill cuttings samples from thousands of oil and gas wells lying dormant in warehouses and core repositories. These samples often remain unwashed and inconvenient to access. However, growing recognition of the untapped value of these samples is changing the attitude towards cuttings and there is now real momentum behind the concept of digitalising entire national archives.

Unwashed cuttings samples are generally placed in bags and boxes at the rig site and, in many cases, never see the light of day again. Washed and dried sets are sometimes available, but volumes can be depleted in key stratigraphic intervals, which need to be replenished through the washing of remaining unwashed material. Innovative technology is now being employed to digitalise samples from legacy wells at scale and, in doing so, make cuttings data more accessible to geoscientists at remote workstations. Before digital data can be generated, each sample must be logged and cleaned effectively (Figure 1a and b). Only once drilling fluids and contaminants have been removed can the sample be subject to further analytical techniques.

Unlike other subsurface rock samples, cuttings are almost always available in vast quantities and provide information about the majority of the stratigraphic section. These qualities mean that digitalised cuttings data are well-suited for training machine learning models with potential for use in both supervised and unsupervised models. In the supervised scenario, a properly labelled database can be coupled with image segmentation and careful integration of elemental X-Ray Fluorescence Spectroscopy (XRF) data to provide lithological predictions and interpretations for thousands of samples at a time. However, the results of any computer-driven analyses are only as good as the input data and therefore consistency in sample preparation and analytical procedures is paramount.

From Old Wells to National Archives

A breakthrough in sample preparation emerged in 2010 when a methodology and apparatus for the automated washing and drying of cuttings samples was developed by Rockwash Geodata. Initially, the demand for cuttings to be washed at scale was to feed further analytical techniques such as Fluid Inclusion Stratigraphy, but it soon became clear that, as thousands of samples were being processed systematically, there was a golden opportunity to generate layers of additional data.

After several years of refining the procedure, the standardised digitalisation workflow today includes sub-sampling and logging, automated sample washing and drying, high-resolution cuttings photography and the analysis of a sample's constituent chemical elements using XRF. Consideration is given to maintaining an entirely non-destructive process, maximising the volume of cleaned rock material that is then re-bagged, ready for further analysis, while the digital data is stored in a database. All raw data is subject to a rigorous quality control process to ensure total consistency, making it possible to compare from well-to-well and vintage-to-vintage. This includes a careful colour calibration process to facilitate an easier distinction between different lithologies.

In many cases, geoscientists are burdened with enormous datasets that undoubtedly hold value, but without the correct tools are difficult to exploit. Once an entire well of cuttings samples is digitalised, the user must be able to digest it using visualisation software. Depending on the specific technical objective, the user must be able to interrogate grain-scale features within individual samples,

Figure 1a and b: Bagged unwashed samples are first logged and then a subset is potted and labelled ready for processing.

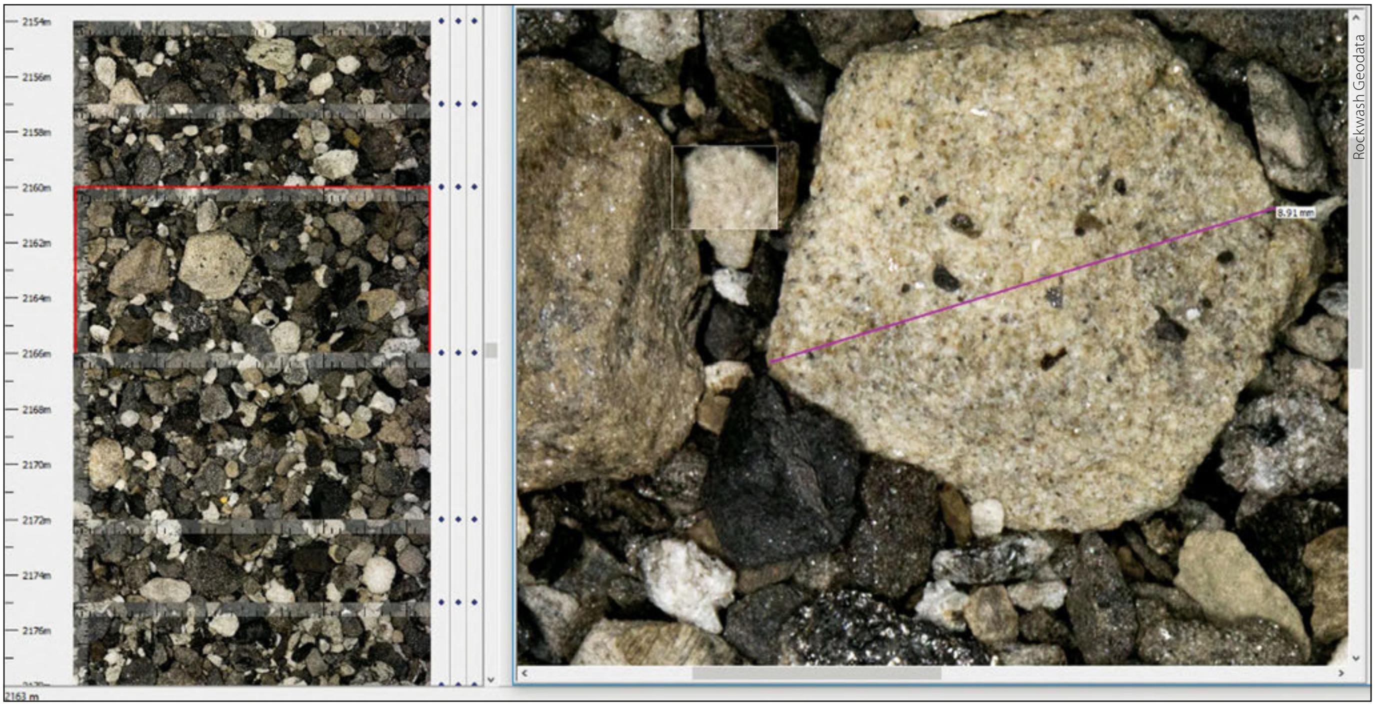
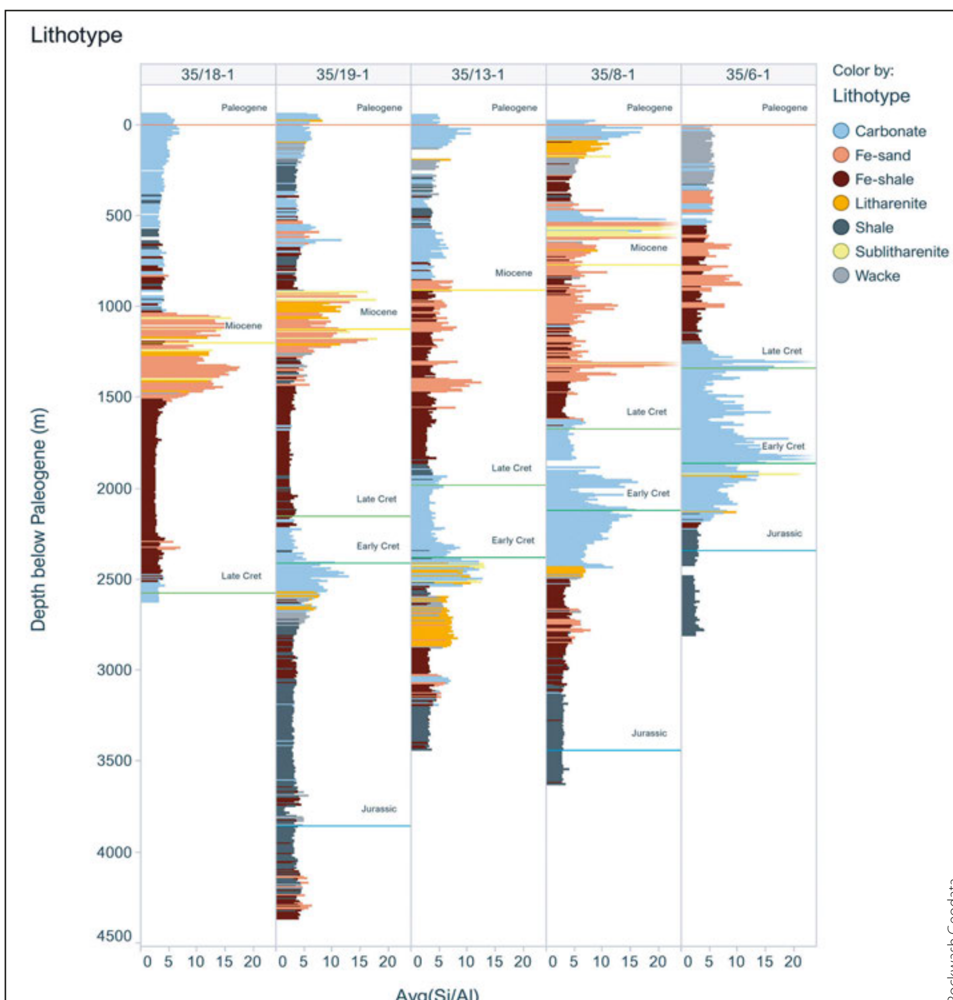


Figure 2: Examples of high-resolution cuttings images displayed within visualisation software that facilitates detailed lithological investigations from remote locations.

whilst also having the option to compare basin-scale variability (Figures 2 and 3).

Since this workflow was established, Rockwash has endeavoured to employ these methods on a national scale, having generated large, digitalised cuttings databases in countries and regions such as Ireland, Atlantic Canada and North Slope Alaska. Globally, the governmental organisations who take responsibility for national rock archives work tirelessly to both preserve and add incremental value to the samples in their custody. Historically, a lot of resources have been allocated to the digitalisation of core and thin sections, successfully connecting geoscientists to this vital information regardless of their proximity to the rock itself. That leaves cuttings as the last frontier of subsurface rock digitalisation. With renewed interest in their suitability for exciting new machine learning methodologies and a greater focus on bringing all data types into a seamless digital environment, it is expected that more large-scale cuttings digitalisation projects will commence worldwide.

Figure 3: Well correlation panel displaying five full wellbores from offshore Ireland allowing basin-scale stratigraphic assessments to be carried out. Each sample is given an XRF-derived chemical lithotype, aiding the interpretation process.



Every Sample, Every Well: The NOROG Released Wells Initiative, Norway

Understanding this concept fully, Norwegian industry body Norsk Olje & Gass (NOROG) decided in 2019 to commit to digitalising their full national cuttings archive in a landmark project, commonly referred to as the 'Released Wells Initiative', that represents the first of its scope and scale being carried out worldwide.

Having delivered many similar projects of a lesser scale at both the Norwegian Petroleum Directorate (NPD) and with individual Norwegian companies, Rockwash was awarded the contract to generate this database alongside Joint Venture partners, Stratum Reservoir.

Still ongoing, the project's objective is to wash and digitalise each cuttings sample from every exploration and appraisal well drilled on the Norwegian Continental Shelf, ultimately providing a vast repository of cuttings-derived data that will be available for public access.

The scope of work currently consists of more than 700,000 samples from approximately 1,900 wells. Every sample is subject to the aforementioned standardised digitalisation workflow, with selected additional analytical techniques being performed on 5% of the samples. The additional techniques include Infra-Red Spectrometry (performed by Spectra-Map), X-ray Diffraction (XRD), Total Organic Carbon (TOC) and quantitative electron microscopy (QEMSCAM) (performed by Rocktype). With an eye on developing a database free of any geological bias, the decision was taken to perform these additional analyses only on every sample from the most recently drilled 75 wells, rather than maintaining sole focus on the traditional reservoirs or key intervals.

The project is scheduled for completion in the spring of 2022. To date (August 2021), more than 500,000 samples from Norway have been processed and over 2 million files have been uploaded to the Norwegian national data depository, the DISKOS database (Figure 4).

The pro-active approach that NOROG has taken with this project won it the Exploration Innovation Prize at the NCS Exploration Conference, 2021. Now with a critical mass of data, there is a strong appetite within the Norwegian geoscience community to continue carrying out these digitalisation techniques as a standard on future exploration and appraisal wells to keep supplementing and improving the national database.

A Database for The Energy Transition

In addition to the suitability of digital cuttings data for computer-driven models, there are of course applications in a more traditional geological evaluation. Combining the ability to remotely visualise all the rock in a well with detailed downhole chemical profiles offers insights into a range of subsurface problems including sediment provenance, the preservation of organic matter and reservoir heterogeneity, to name but a few (Figure 5). When available on a regional scale, E&P companies are obvious beneficiaries, but these datasets are also beginning to garner interest in other growing subsurface industries including the CO_2 and H_2 storage sectors.

Not only do decades of hydrocarbon exploration offer great resources and expertise to those tackling this challenge, there is also a wealth of available samples and data from legacy oil and gas wells that can be used to leverage the risk of any given storage project. With various candidate storage sites being touted in saline aquifers and reservoirs that would traditionally be considered the 'overburden', many of these geological intervals have not been cored or comprehensively studied.

Moreover, with a key geological risk factor being the leakage of injected CO_2 into overlying groundwaters and beyond, it is imperative to understand the quality and integrity of the seal, as well as the chemical interactions that will take place at the reservoir-seal interface once exposed to CO_2 and more acidic CO_2-rich pore fluids. It will also be crucial to understand the parent mineralogy of the storage reservoir to be able to assess its viability for effective sequestration of CO_2 in precipitating carbonate minerals such as dawsonite and ankerite.

As the need to reduce greenhouse gas emissions becomes more urgent, there is an obligation to strain every technological sinew to meet the challenge. In the context of the energy transition, cuttings from historical oil and

Figure 4: Rockwash machines carrying out automated washing and drying of cuttings samples for the NOROG Released Wells Initiative in Stratum Reservoir's Sandnes facility.

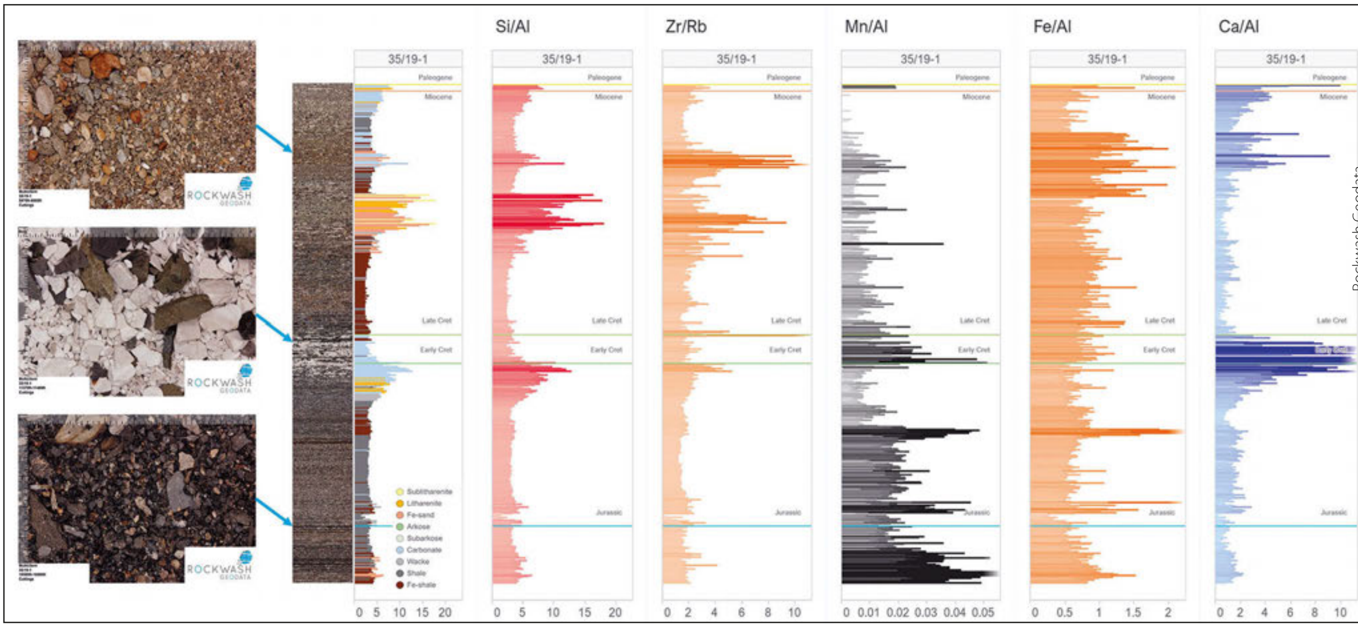
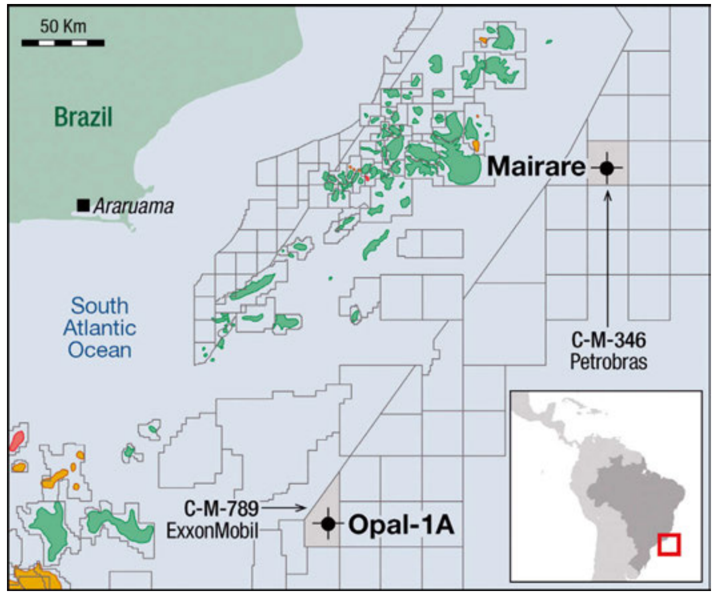


Figure 5: An integrated data display of well 35/19-1 from offshore Ireland illustrating individual cuttings images of varying lithologies, a stack of all of the available images from the well and a selection of elemental ratios for every sample allowing the user to understand the detailed visual rock properties and chemical stratigraphy.

gas wells are residual resources that can and should be exploited to propel advances in new industries, wherever possible. Geoscientists working on CO_2 storage projects in Norway are being encouraged to use data generated by the NOROG Released Wells Initiative, which is the correct and pragmatic thing to do.

The example being set by the Norwegian geoscience community offers a platform on which other ambitious national cuttings digitalisation projects can be imagined. Greater efforts to do so will ultimately preserve finite and important geological resources, allowing us to address the geological challenges of present and future generations. ■

ExxonMobil Kick-Off Major Pre-salt Wildcat Campaign in Campos-Santos



ExxonMobil lead the way in the latest push for pre-salt exploration offshore Brazil on the boundary of the **Campos** and **Santos Basins** with hydrocarbons encountered at **Opal-1A** (as reported to the National Agency for Petroleum, Natural Gas and Biofuels (ANP)).

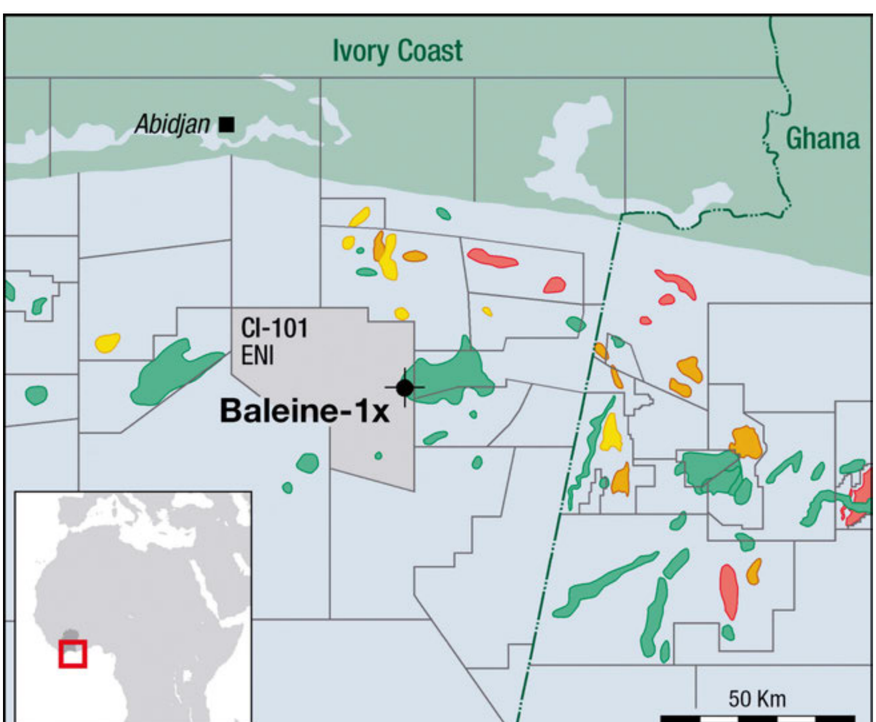
ExxonMobil spudded the **Opal-1** well (1-EMEB-1A-RJS) in the Campos Basin **Block C-M-789** in January 2021 using the West Saturn drillship. The well, in **2,681m** water depth, targeted the **Opal prospect**, a pre-salt Aptian clastic system with an estimated TD at around **6,000m**. After drilling problems in the first quarter of 2021, Opal-1A was re-spud. Latest reports suggest an oil discovery for the supermajor and their partner **Qatar Petroleum**.

C-M-789 was awarded as part of the **15th PSC Bid Round** in 2018, for a record signature bonus of US$848 million. ExxonMobil has received authorisation to drill up to five more wells.

Following work on Opal, the West Saturn has spud **Titan-1**, in the adjacent **Tita Block**, with follow-up prospects **Espinela** and **Ametrina**. The Opal drilling programme will be regarded as a good start to the 15th Round drilling campaign, with **Shell, BP, Equinor, Repsol**, **Wintershall** and **Chevron** all having well commitments in adjacent blocks, along with **Petrobras**. Petrobras and ExxonMobil have since spudded the **Mairare well** to the north of Opal in **C-M-346 Block** with the West Tellus rig. ■

Eni Hit the Sweet Spot Offshore Ivory Coast with Baleine-1X

The **Baleine-1X** well was drilled by **Eni**, their first wildcat in **Ivory Coast**, as part of a global multi-year drilling campaign with the Saipem 10000. Baleine-1X was drilled in **1,200m** water to a TD of **3445m** on 1 September 2021. The well targeted Cretaceous sands in the Transform Margin basin: probably a fan complex coming off the Baleine High and draped over the main pre-rift structure there. **Vanco** held the acreage in 2007 and just fell short of drilling this major prospect, supported by amplitude and a large 'gas cloud'. In **2013** and **2014**, **Lukoil** drilled the **Capitaine East**, **Independence** and **Orca fields** nearby, finding sub-commercial volumes of oil in **Upper Cretaceous** sands.



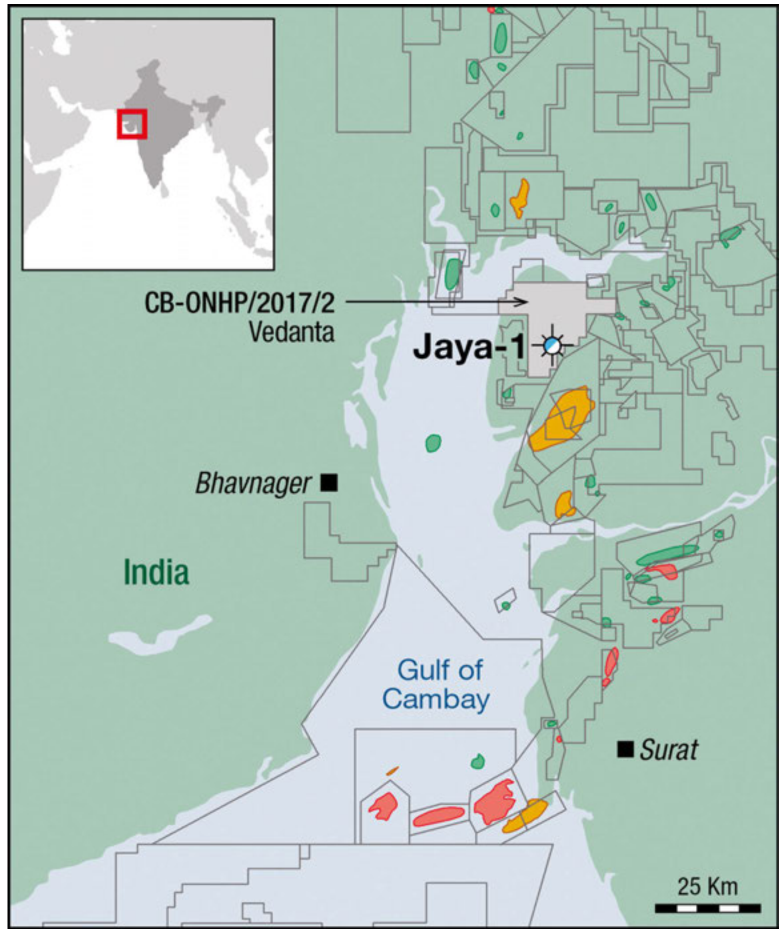
Eni have reported **40°API oil** pay in the **Santonian** and the **Cenomanian/Albian**, with volumes in place of between **1.5** to **2 Bbo** and between **1.8** and **2.4 Tcf** associated gas, a major boost to the upstream sector for Ivory Coast.

Eni were awarded **Blocks 205** and **101** in **2017** by direct negotiation. **Vitol** were reported to have farmed-in to Block 101 in September 2020; however, this did not appear to receive formal approval. ■

Vedanta Step-Out to Success in the Cambay Basin with Jaya

Vedanta (aka **Cairn Oil & Gas**), the largest independent oil and gas company in India, contributing 24% of the country's domestic oil production in 2020, has reported a gas and condensate discovery at **Jaya-1**. The well (previously **Jambusar-Updip-1**) finished drilling on 23 August 2021 onshore **Block CB-ONHP/2017/2** in Bharuch District of Gujarat in north-west India.

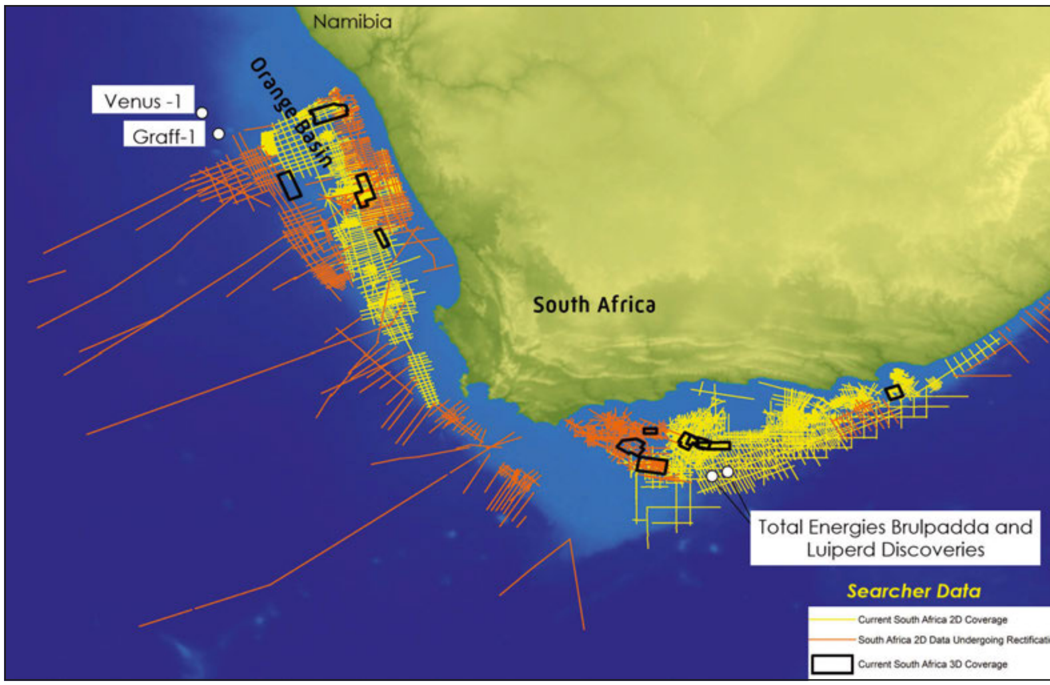
This gas condensate discovery is located at the southern end of the **Cambay Basin**, a narrow elongated rifted graben with a **Paleogene** sag basin, situated between the Saurashtra craton on the west and Aravalli on the north-east and Deccan craton to the south-east. Gas and condensate are currently produced from the nearby **Gandhar field** to the south, from deltaic sands of the **Hazad Formation** of **Mid-Eocene** age. ■



South Africa Poised for Exploration Greatness

Orange Basin wells are set to ignite an exploration boom.

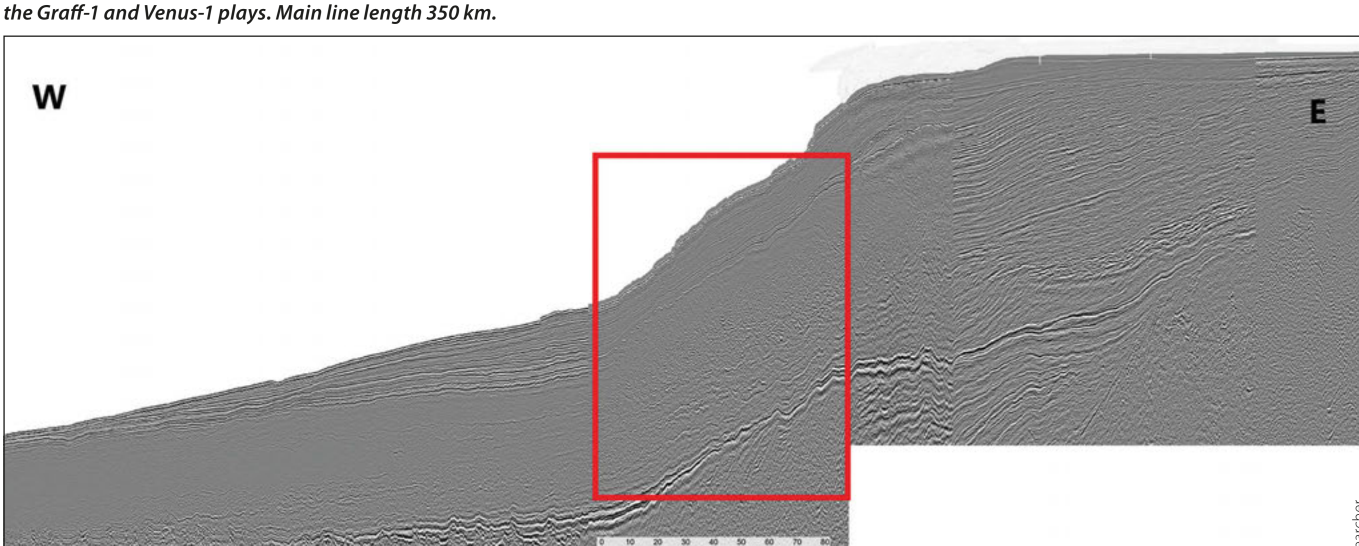
NEIL HODGSON, KARYNA RODRIGUEZ, Searcher Seismic; and JULIA DAVIES, Discover Geoscience



South Africa has already astonished the world with its recent discovery of large volumes of gas condensate in its southern Outeniqua Basin. Now, the Orange Basin is poised to erupt as the world's next exploration hotspot with the drilling of two new paradigm-changing deepwater plays. These two wells are being drilled late in 2021 in Namibia by the border with South Africa. If either is successful, the on-trend extension of these plays will decisively confirm southern Africa's rightful place in the spotlight of the exploration community.

The Graff-1 and Venus-1 wells, located on adjacent acreage, will be operated by Shell and TotalEnergies respectively and represent a culmination of exploration efforts that were sparked into life by the results of three deepwater wells drilled in Namibia by HRT in 2013. Each of these wells encountered thick, mature Aptian source rocks, and in one case recovered light oil to surface, proving the northern extension of this source rock system which had previously been encountered in the southern margins of the Orange Basin by DSDP well 361. The HRT wells (Wingat-1, Murombe-1, and Moosehead-1) have gone down in exploration folklore for their bravery in

Figure 1: West–East TWT dip line through the Orange River Basin close to the border with Namibia. Inset shows the toe thrusts of the 'megaslide' above the Graff-1 and Venus-1 plays. Main line length 350 km.



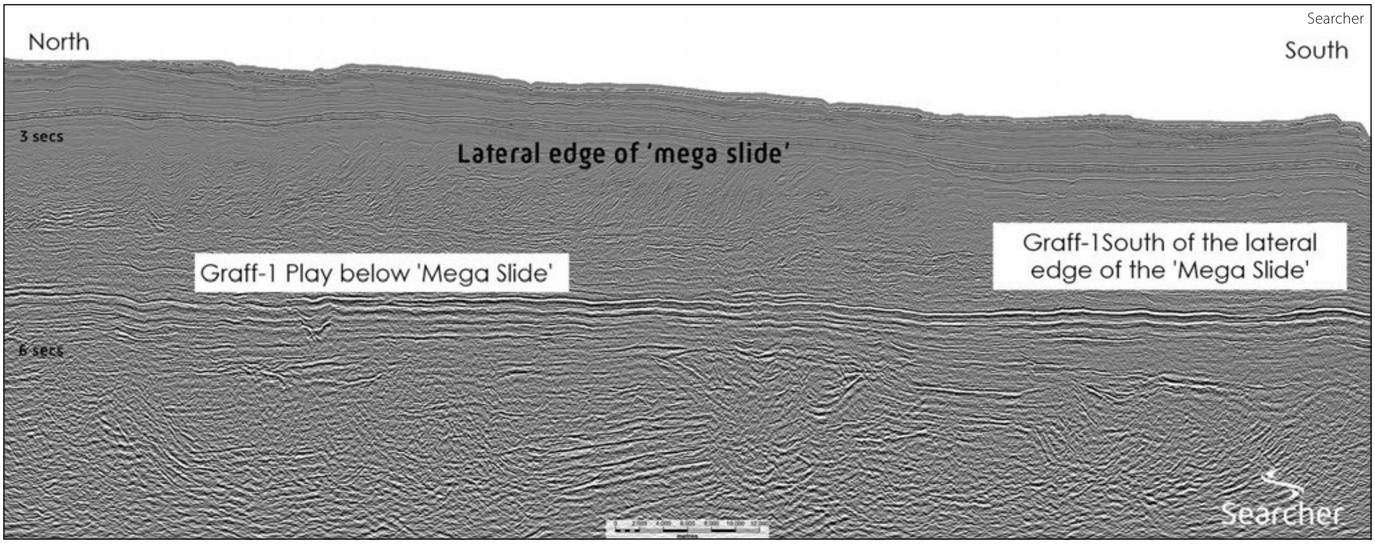


Figure 2: North–South strike line through the Orange River Basin from the border with Namibia. The extension of the Graff-1 play is visible below the 'megaslide' and extending far beyond to the south.

proving the existence of the important 'source rock' piece of the exploration jigsaw. Whilst this is one part of the hydrocarbon system that is associated with the earliest moments of the opening of the Atlantic – next the reservoir and trap need to be proven as well. The legacy of the HRT wells was that the industry saw that with a thicker overburden than that encountered at the DSDP 361 location, this source will be an effective generator of oil, ushering in a race to find the final pieces in this puzzle: the wells where all the hard-won elements of the hydrocarbon system come together.

Source Rocks Provide the Key

The Aptian source rock can be mapped on a regional grid of modern 2D seismic data that extends from the Luderitz Basin of Namibia to the Orange Basin's southern margin in South Africa. Like many 'magma rich' passive margins, the crustal architecture of this margin changes as you move offshore. This transformation is from a rifted crust which becomes more and more dominated by volcanic lava flows which were erupted as the Atlantic opened and formed an outer, high feature before turning into true oceanic crust (Figures 1 and 2). The Aptian source deposited on either side of this high has a characteristic seismic response – a soft top associated with a decrease in acoustic impedance and a hard base with a low frequency character, associated with a Type-IV AVO anomaly (Eastwell et al., 2018; Davidson et al., 2018). With confidence in the source rock much higher, each of the imminent wells, Graff and Venus, will target different reservoir/trap pairs, to clarify what play combination is effective on this margin. Graff-1 will target a Late Aptian/Albian sandy slope hybrid turbidite contourite channel system and Venus-1 will target slightly older sands, in an Aptian base of slope/fan setting. Both targets appear to have an element of stratigraphic trapping.

Graff-1 lies within the slope setting, down-dip of a stratigraphic trap. The trap is formed where sands are not deposited (a bypass zone) or subsequently eroded creating a break in the migration route for oil as it tries to escape out of the basin. When the oil cannot bridge this break or gap, it is left effectively stuck down-dip and trapped in the prospect. Figures 1 and 3 show a West–East seismic dip-line from the South African Orange Basin close to the Namibian border, with analogue positions of the Graff-1 and Venus-1 plays indicated. Figure 3 shows a strike line running from the Namibian border over the extension to the Graff play in South Africa. These also show the extraordinary Orange Basin 'megaslide' that sits right above the slope play. The dip line is familiar (for example De Vera et al., 2010) but the strike line shows the lateral toe thrusts of this gravity collapse feature. This megaslide has long captivated geoscientists as it demonstrates the extreme instability of this margin in the Latest Cretaceous. Actually, all through the Late Cretaceous this margin became even more unstable, evidenced by basinal mass transport systems, as the continent of Africa slid across a complex net of upper mantle convection cells (Hodgson and Rodriguez 2017; 2018). The megaslide, formed by a gentle slow collapse of the shelf, is ironically an indication that the instability was drawing to a close.

Slope bypass as a trapping mechanism is very hard to nail down on seismic – as a thief zone would be at a sub-seismic scale, yet a characteristic of the seismic response from the Graff sands indicates the presence of oil or gas, so hopes are running high. A similar style of slope channels with encouraging seismic responses has led to the multiple and repeated success seen offshore Guyana and Suriname. Just a few years ago, that play was considered uncertain with unproven source and trapping style. With the right regional bypass system – extraordinary repeatability will follow a 'play-making' well.

Venus-1 also requires an up-dip stratigraphic trap – yet this prospect is even more ground-breaking as it targets sands deposited on the basin floor out beyond the volcanic 'outer high'. The industry has wanted to explore the basin floor fan plays of the Atlantic for many years; for it is on the basin floor that

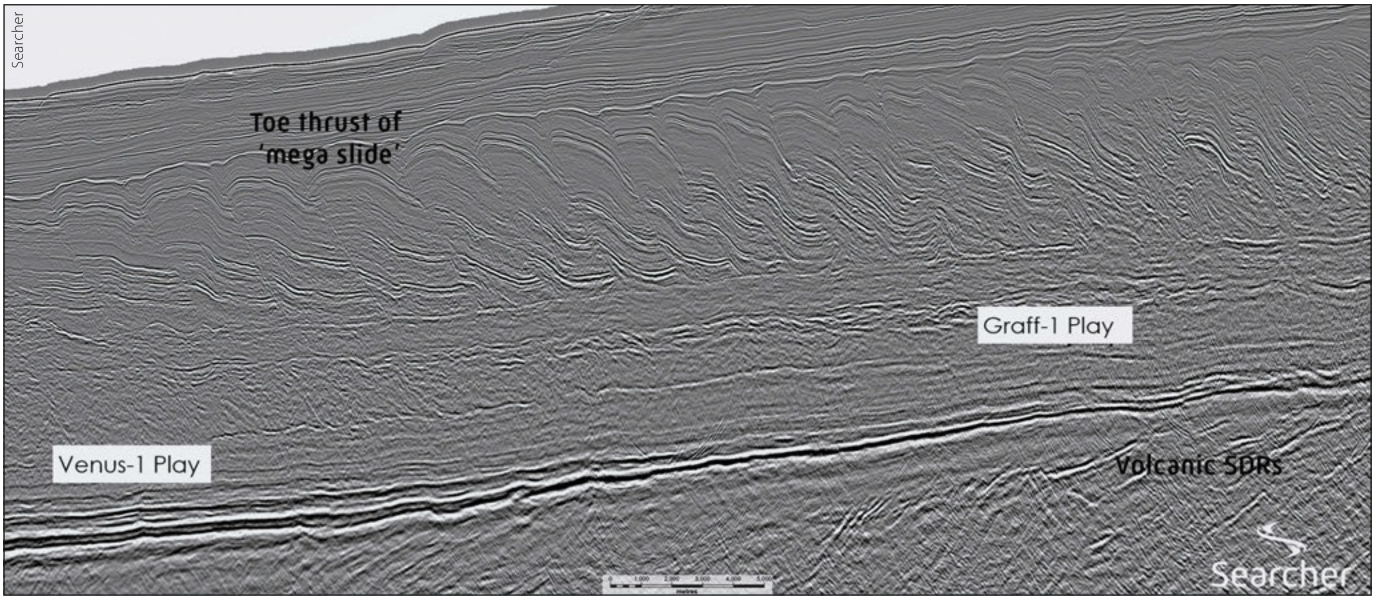


Figure 3: North–South strike line through the Orange River Basin from the border with Namibia. The extension of the Graff-1 play is visible below the 'megaslide' and extending far beyond to the south.

the traps become truly big, and Venus is no exception, yet only recently has technology allowed deepwater drilling to target this setting. The upward convecting parts of the net of mantle cells that caused the shelf instability at the end of the Cretaceous is also responsible for lifting basin floor fans sitting on Oceanic Crust into drillable water depths. Recently, huge discoveries in similar settings in Senegal and Mauritania have been in uplifted basin floor fans of this type. The Venus prospect too, has an encouraging seismic character that indicates hydrocarbons at the prospect crest, whilst this character switches off at the spill point; a very significant observation that provides a lot of confidence that this well will be successful. Success here will invigorate 'Atlantic opening plays' on both margins – from Sergipe to Pelotas in the west and Cameroon to Cape Town.

Drilling Success Will Flow South

Whilst these two wells will be drilled in Namibian waters, should either of the plays be successful, the acreage to the south in South Africa will become white hot with interest. The play is predicated on the Aptian source rock extending to the south and sand equivalents of either the Graff or Venus plays are also evident on the available 2D regional grids.

To facilitate the investigation of the distribution of plays and traps in South Africa's Orange Basin, Searcher has built a subscription-accessed cloud-based review and delivery system in South Africa of >100,000 line km of legacy 2D data (examples in Figures 1 and 2). This dataset is adequate for preliminary exploration analysis – basin modelling, isopach and play fairway building, but Searcher want to help refine this analysis more and so are currently reprocessing a selection of these legacy lines. These data are focused on generating a dataset that will allow extrapolation of the Graff and Venus plays, into South Africa. Searcher will also add to these data in the next seismic acquisition season, by collecting over 20,000 km of new long streamer, deghosted 2D data. This will allow the results from drilling in Namibia to be fully integrated into the geological understanding of the southern Orange Basin.

With each well drilled in the deepwater of Namibia and South Africa we have moved closer to removing the uncertainties that surround the exploration jigsaw puzzle. After the HRT wells we could see for the first time the picture on the 'exploration puzzle box' and with these next two wells we will see which reservoir/trap pair will fit with the source rock (or perhaps both will!). Following the example of the Liza discovery in Guyana it is clear that deepwater discoveries are best monetised quickly, so it is expected that success will ignite a surge of activity over the next five years with a string of follow-on exploration interest, to indeed rival the activity that Guyana and Suriname have experienced in the last five years. Good geoscience and 'brave wells' have led the way to the start of this race; now it is time to settle into the blocks, get under starter's orders – and we're off!

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Scotland's Energy Mix

Take the Nigg Ferry in Scotland across to Cromarty and there is plenty of evidence of an industry in transition. As the ferry dips and rolls between Cromarty and Moray Firth, two giant platforms look down from their parking places. On the move though is a wind turbine service vessel, heading out of the port of Invergordon en route for the Moray East wind farm. Oil and gas still dominates in these parts, but offshore wind is the coming energy source.

Small wonder then that oil and gas majors figure strongly among the 74 bids received for licences to develop a series of large floating wind farms off the coast of north-east Scotland. There are 15 seabed locations up for grabs and while wind power this far north in the UK is still a drop in the ocean, estimates suggest that this new generation of facilities could provide power for a quarter of the UK domestic market – or to put it more regionally, every home in Scotland.

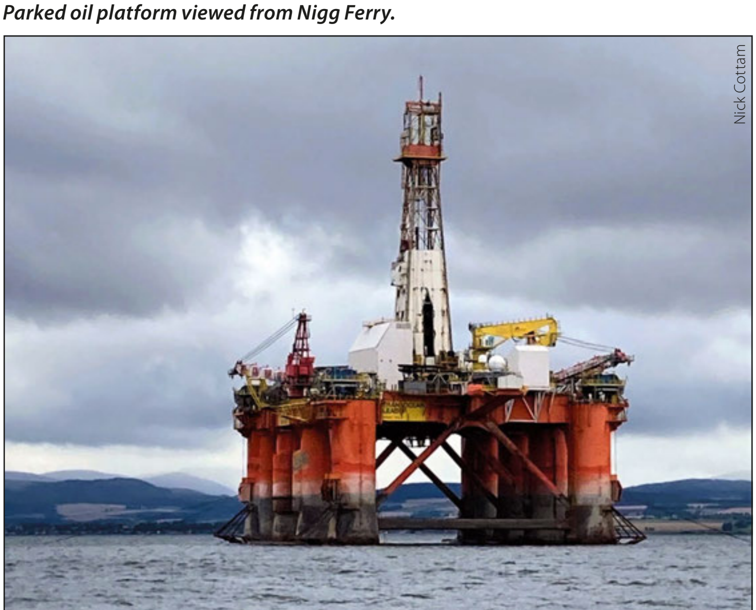
Among those bidding in a leasing round, which could net the Scottish government up to £860 million, are Shell which has teamed up with Scottish Power, Eni, Total, Equinor and BP. The Italian supermajor Eni, for example, expects to deliver 60 GW of installed renewables capacity by 2050 and has hived off renewables into an 'Energy Evolution' business which it notes will produce a growing share of the company's revenues. This is transition in practice for all the majors who eye up gas prospects before oil and see renewables as the medium and long-term route to transformation.

In the meantime – and alongside the ambition of Cromarty Firth as a future hub for offshore wind facilities – there is a continuing need for those fossil fuel revenues – in the short to medium term at least. While demand for oil has fallen off lately because of a rise of Covid cases in Asia, there are now signs of an uplift as infection rates abate, notes the International Energy Agency in its most recent monthly oil market report. While average demand fell to just under 91 million barrels a day last year, it is expected to increase by 5.2 million barrels this year and rise to just under 100 million barrels a day in 2022, back almost to pre-pandemic levels.

The upshot for Cromarty and Moray and deepwater ports around the world, is a highly competitive mixed bag of energy transition. Those Nigg-sighted platforms may not be parked for too much longer. ■

Nick Cottam

Parked oil platform viewed from Nigg Ferry.



Conversion Factors

Crude oil
1 m³ = 6.29 barrels
1 barrel = 0.159 m³
1 tonne = 7.49 barrels

Natural gas
1 m³ = 35.3 ft³
1 ft³ = 0.028 m³

Energy
1000 m³ gas = 1 m³ o.e.
1 tonne NGL = 1.9 m³ o.e.

Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

Supergiant field
Recoverable reserves > 5 billion barrels (800 million Sm³) of oil equivalents

Giant field
Recoverable reserves > 500 million barrels (80 million Sm³) of oil equivalents

Major field
Recoverable reserves > 100 million barrels (16 million Sm³) of oil equivalents

Historic oil price