VOL. 17, NO. 2 – 2020

GEOExPro

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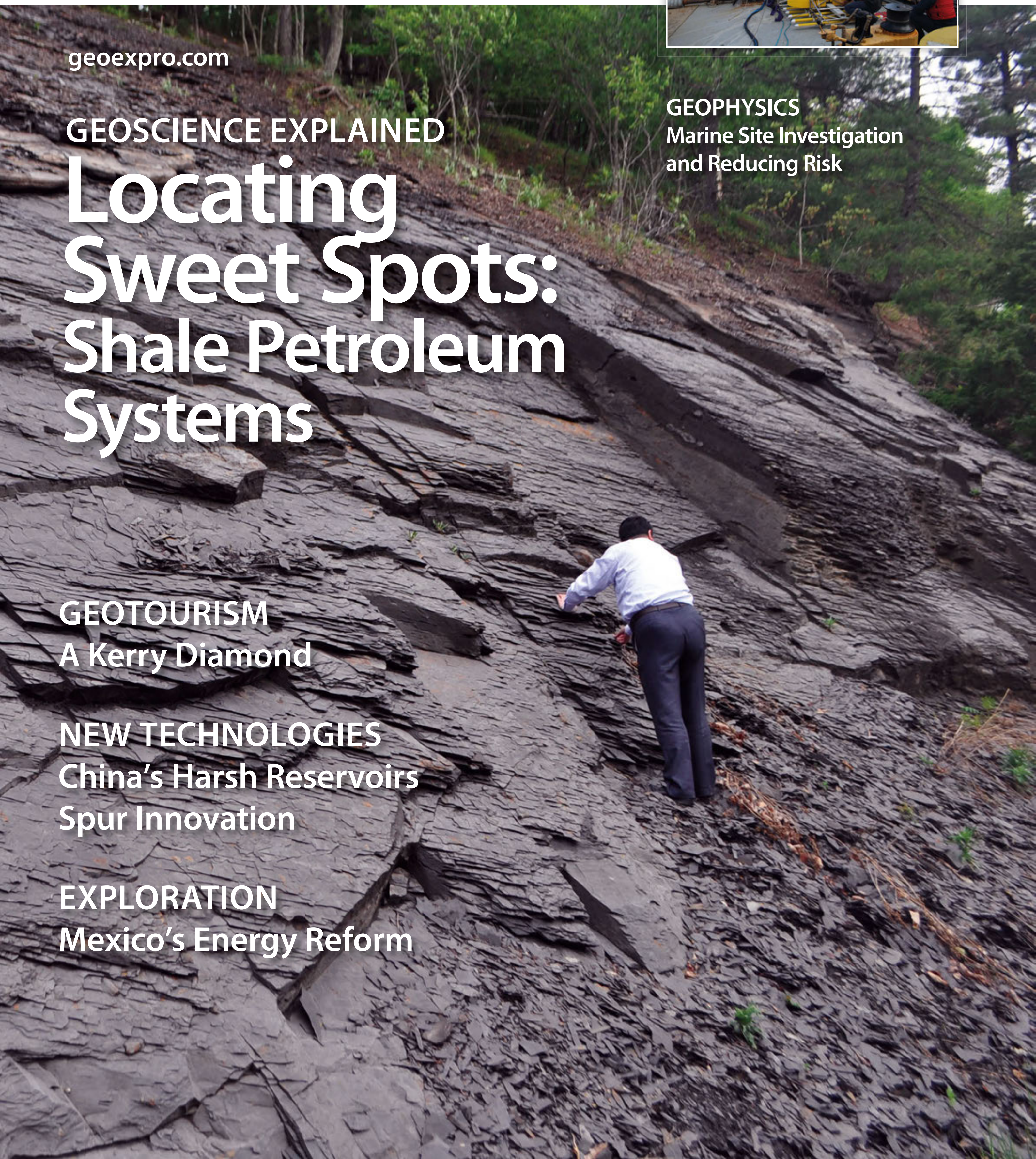

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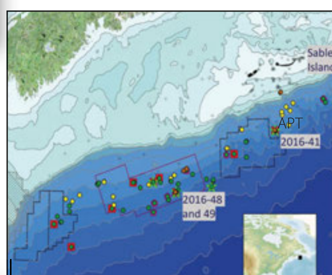

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Thomas Chidsey is a senior scientist at the Utah Geological Survey and likes nothing better than telling people about the geology of his adopted state.

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This edition of *GEO ExPro* focuses on North America and the Gulf of Mexico; New Technologies; Near Surface Geophysics; and Changing Public Perceptions.

The World in Freefall

Gerd Altmann/ Pixabay

All over the world, there is only one topic of conversation: Covid-19. The pandemic has resulted in some welcome shows of solidarity, as countries help each other out with medical assistance, urgent supplies and, importantly, research into vaccines and cures. It will undoubtedly have some positive long-term effects on the environment, as people appreciate the clear skies, low pollution and sounds of birdsong resulting from fewer planes and cars. Working from home and video-conferencing may well become the norm.

Like many industries, however, oil and gas has been severely hit by the fallout from the pandemic, with both demand and the price of oil slumping at a time of already worldwide surplus, exacerbated by additional pumping by Saudi Arabia and Russia as they follow their own competitive agendas. A number of E&P companies are reported to be cutting their CAPEX budgets for 2020 by around 20%, which will see many planned exploration projects, particularly in capital intensive areas like deepwater, mothballed for the foreseeable future. As a debt-heavy industry, the security for which is usually oil and gas reserves – now worth a lot less than they were just a few months ago – we can expect to see bankruptcies, in the service sector as well as E&P companies of all sizes. These will result in further job losses, in an industry that was only just beginning to climb out of the last slump. It is a miserable scenario.

Oil will recover, but it will take time. Because of the glut in supply, an increase in demand will not immediately result in rising prices – although the cheaper energy resulting from this lag in oil price increase could help world economies recover faster once the virus restrictions are lifted.

You will be pleased to hear that *GEO ExPro* will continue to publish both online and in hard copy, bringing you the information on exploration and technology in the upstream geosciences you need in order to be ready to bounce back when the crisis is over. The print magazine will be distributed to companies and subscribers worldwide as usual; many conferences and meetings have been postponed until later in the year, so we will also reserve copies of each edition to be distributed at those, whenever they may be held.

I would like to take this opportunity to send best wishes from the whole *GEO ExPro* team to anyone affected by the virus, either in health or in business, and look I forward with you to better times ahead.

Jane Whaley
Editor in Chief

LOCATING SWEET SPOTS: SHALE PETROLEUM SYSTEMS

Our cover shows long-term *GEO ExPro* contributor Rasoul Sorkhabi inspecting the Marcellus Shale. For decades, shales were only viewed as sources or seals, never studied for their reservoir properties. Can conventional petroleum systems methodology help unlock the secrets of these enigmatic rocks?

Inset: Using a 3D Chirp sub-bottom profiler during a marine site investigation survey off western Canada.

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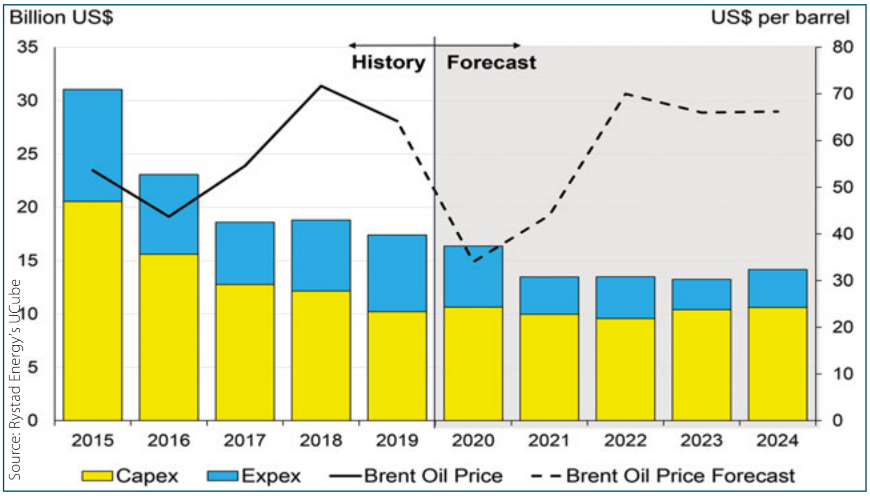
A Dreary Investment Outlook?

Gulf of Mexico final investment decisions are likely to be put on hold.

Exploration and production companies in the Gulf of Mexico have now joined the budget-cutting parade, slashing capex in order to stay afloat in this new oil market reality. Players such as Talos Energy, Murphy and Kosmos have put new sanctioning on pause, with the exception of approved projects, and additional cuts are being evaluated. Indeed, signs have already emerged indicating that the dual supply and demand shock will have a deeper impact on E&P sanctioning in the region than seen during the previous oil price crash in 2016. Reduced exploration activity and postponed new development sanctioning will be key to improving the current cash flow situation.

Investments furthest removed from revenue generation will be the first to go as part of E&P cost-cutting efforts. In that sense, exploration activity will take a hit in 2020 as operators postpone the spud timing of exploration wells in order to push exploration expenditure further into the future. Over the last five-year period, infrastructure lead exploration (ILX) has been a favored exploration strategy in the Gulf of Mexico due to higher success rates, lower required development investment and quicker payback time. However, the current situation is of such magnitude that we believe even ILX will take a hit.



Capital and exploration expenditures in the US Gulf of Mexico.

Looking Ahead

In the mid-term, cost-cutting measures will affect the development side of the investment cycle as well. The rapid oil price decline has left investment decisions more or less on hold. E&P companies are closely monitoring the situation, awaiting greater clarity in the oil price outlook before committing cash to currently unsanctioned projects. One example of this is the North Platte development, where platform construction bids have been put on hold by Total. However, as time marches onwards and E&Ps become accustomed to a lower oil price outlook, we expect some sanctioning will occur in the latter part of 2020; subsea tieback developments can have breakeven prices that offer positive net present value in a $30 oil price environment.

Capital and exploration expenditures will get a trim, but we see that the efforts will be made on discretional expenditures, which can be deferred. Sanctioned projects are expected to proceed, although some delays might occur in order to temporarily reduce expenditures. Current investments directed at the Gulf of Mexico are primarily related to existing projects under execution, and we see that the ongoing lack of investment decisions – in addition to a lower oil price outlook – could cause a dreary investment outlook in the coming years. ■

Joachim Milling Gregersen, Rystad Energy

ABBREVIATIONS

Numbers
(US and scientific community)

M: thousand = 1 x 10^3
MM: million = 1 x 10^6
B: billion = 1 x 10^9
T: trillion = 1 x 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

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

Covid-19 Hits Licensing Rounds

As Covid-19 spreads its infectious tentacles ever further and tighter around the globe, it is no surprise to see the knock-on effect of the pandemic on licensing round plans throughout the world. Here is a brief summary of some announcements to date.

Bangladesh: The Ministry of Power, Energy and Mineral Resources had planned to announce in March that the launch of Bangladesh's next offshore licensing round – the first for eight years – would open on 15 September 2020, with a deadline for bid submissions on 10 March 2021 and the award of production sharing contracts by 26 May 2021. This has now been postponed indefinitely. The round would have concentrated on deepwater blocks thought to be prospective for gas, close to the maritime border with Myanmar. After the last offshore round, several blocks were awarded, but no wells have yet been drilled.

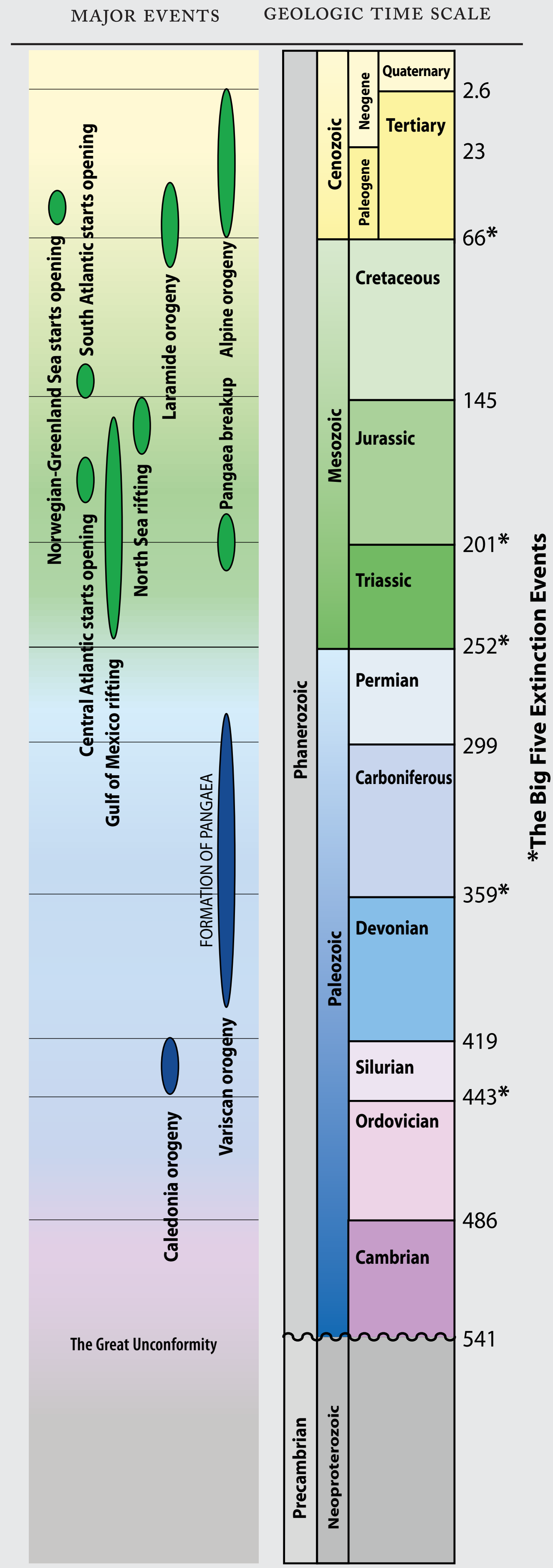
Lebanon: As reported in *GEO ExPro* Vol. 16, No. 1 (2019), the deadline for submission of applications for the 2nd Lebanese Offshore Licensing Round was initially set for 31 January 2020. In January this deadline was postponed to 30 April 2020, and it has now been pushed that back to 1 June 2020. Award decisions are expected to be made about September 2020. The round encompasses Blocks 1 and 2 in the northern part of the Lebanese offshore, and Blocks 5, 8 and 10 in the south, close to the Israeli border.

Liberia: The Liberia Petroleum Regulatory Authority opened its 2020 round qualifications on 15 April 2020 as planned, but to prevent the spread of Covid-19 the launch event was conducted via a webinar, attended only by Liberian delegates. The round covers nine blocks in the Harper Basin, one of the last unexplored and undrilled regions offshore West Africa.

India: India's Directorate General of Hydrocarbons has announced that, in view of the lockdown due to the Covid-19 pandemic, the last date for bid submissions in the Open Acreage Licensing Policy Bid Round V will be extended, although no revised date has yet been notified. This round covers 11 blocks, eight of which are onshore and three offshore. In addition, the 'Expression of Interest' (EOI) cycles for Round VI, due to have ended March 31 and Round VII, scheduled to end July 31, 2020, will be merged, with bidding based on EOIs received by the end of July.

South Sudan: The world's youngest country had planned to launch its first license round in Q1 2020, with 14 blocks in the north of the country on offer. However, with uncertainty around the state of the industry post coronavirus, the launch has been deferred indefinitely. South Sudan produces 178,000 bpd but hopes to reach 250,000 bpd soon.

United Kingdom: The UK's Oil and Gas Authority has confirmed there will be no new offshore licensing round in 2020. It hopes that this will allow more relinquishments to take place so more areas will be available when a round is announced at an as yet unplanned date. ■



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URTeC 2020: Now More Than Ever

Get the training your team needs to maximize efficiency and profitability. Business and social connectivity is particularly important during challenging times. That's why the **Unconventional Resources Technology Conference (URTeC), July 20–22** in **Austin, Texas**, remains critical to you, your colleagues and your business.

URTeC will deliver value by leveraging expertise from all technical backgrounds – geochemistry, rock mechanics, seismic technology, horizontal drilling, completion methods, cost control, and project management – and by examining what is working within the current business environment. It is the best opportunity you will have to exchange information, formulate strategic ideas and solve problems to manage and optimize your unconventional resource plays.

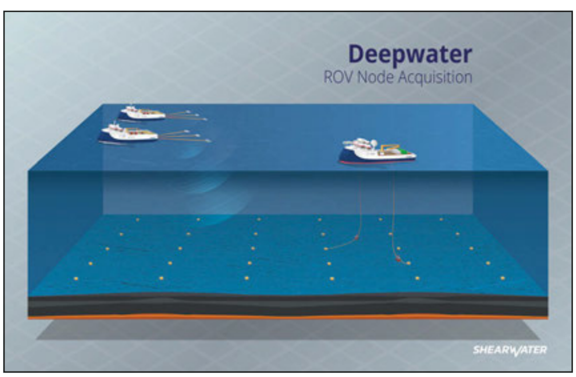
The objectives of the conference are to provide a high quality and peer reviewed science and technology experience; to create a premier forum for technical exchange between vendors and users; to identify and solve E&P problems; and to raise the competency of all petroleum professionals.

In good and in difficult times, bringing together professionals from across disciplines is the best way to find solutions. Plan now to attend URTeC to connect with everyone and everything unconventional. ■

Shearwater Enters Deepwater OBS Market

Provider of marine geophysical services **Shearwater GeoServices** has been awarded a major **ocean bottom seismic (OBS) deepwater remotely operated survey (ROV)** project by TGS and partner in the **US Gulf of Mexico.**

The company already has an extensive track record of innovation and commercial success in OBS, but this is the company's first OBS ROV survey, making Shearwater the only company offering a complete portfolio covering towed streamer and OBS marine acquisition, along with associated processing services. The addition of deepwater OBS ROV operations to its ocean bottom node capabilities will leverage the company's strengths in source capabilities, operational scale and flexibility and marks its presence in all sectors of the OBS market, in both acquisition and processing.



The survey will start in Q2 2020 and is expected to take about four months. It will use the SW Diamond and SW Emerald, which are equipped with three high-capacity sources each composed of three sub-arrays, allowing the data to be acquired using two source vessels instead of three for the survey, with a consequent increase in efficiency and reduction in operational greenhouse gas emissions. ■

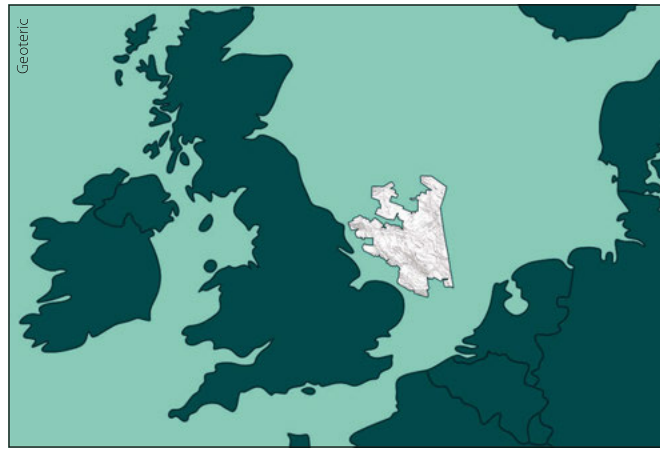
Waste to Tackle Waste

Researchers at **Flinders University** in Australia have come up with a novel way to **clean up oil spills**, using **waste cooking oil** from fast food outlets and **sulfur**, a by-product of the petroleum industry. The resulting product (right) is a hydrophobic polymer – meaning that it separates from water and binds well to oil, which it absorbs much like a sponge, forming a gel that can be scooped out of the water. It is capable of absorbing 2–3 times its mass in oil or diesel and is reusable, as recovered oil can be squeezed from the polymer like water from a sponge; the oil can also be reused.

Flinders University have now entered into a deal with **Clean Earth Technologies**, a company that specializes in developing cleaner approaches and outcomes for tapping the earth's richness, in order to commercialize the absorbent polysulfide, which can also be used as a clean-up solution to other environmental problems like mercury pollution and fertilizer runoff.

Using waste to tackle waste; a truly 'green' solution. ■

Structural Reconnaissance with Artificial Intelligence


Geoteric

Artificial Intelligence (AI) algorithms can significantly speed up the interpretation of large datasets. **Fault delineation** is one of those areas where AI can deliver an independent, unbiased input for the structural interpreters. A basin scale structural reconnaissance provides an efficient overview of the main structural elements and trends, while a regional resolution structural framework assists in understanding the development of a trap. A more detailed analysis can focus on the reservoir to understand its compartmentalization. And finally, at well resolution the AI algorithms can highlight fault-related risks and offer valuable insight for the post-drill well performance analysis.

In the example on the right, the **Southern North Sea Megasurvey,** provided by the UK Oil and Gas Authority, was analyzed with the **Foundation Network** developed by **Geoteric** (see *GEO ExPro*, Vol. 16, No. 2, 2019). Although there are blank zones in the dataset, the actual seismic data covers around 24,000 km^2, offering an unparalleled insight into the complex tectonics of the North Sea. The high quality results offer an excellent starting point for further, more focused studies, revealing intricate details of a complicated tectonic history. ■

AAPG Annual Conference Update

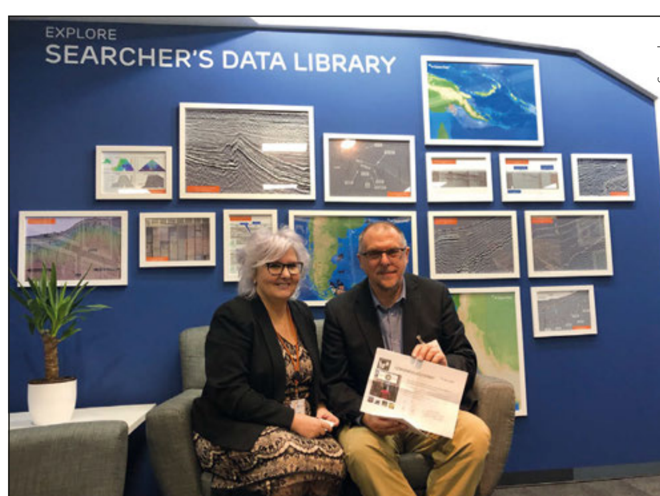
Geoscientists and industry professional alike have asked about the current status of the **American Association of Petroleum Geologists (AAPG) Annual Convention and Exhibition (ACE), June 7–10, 2020**. Based on ongoing evaluations, close coordination with the City of **Houston**, and our understanding of current advisories, the event is still scheduled as planned, but we are carefully monitoring the situation.

As the global community confronts these challenging times, the health and safety of our members, customers and employees remains our primary concern. With many of the current declarations and advisories in effect through April, we will provide additional updates on May 1 or sooner as warranted.

The program features more than 1,000 diverse and informative technical talks and posters spanning 15 concurrent sessions. Newly integrated presentation formats, topics and content will provide a more engaging and dynamic geoscience exchange. The event will also include 15 forums and special sessions, 11 short courses, eight field trips, nine networking events, four luncheons, U-Pitch presentations, student and young professional activities, and more.

Attend with complete confidence as our registration cancelation policies have been updated. Cancelations will now be accepted with a full refund if received before May 1, 2020 and any cancelations received between May 1–31 will be assessed a $75 processing fee and the balance will be refunded. Unless ACE is postponed or canceled, refunds will not be processed after May 31, 2020. Due to instructor and direct expense obligations, the refund deadline for Short Courses and Field Trips will continue to be April 23. No refunds for field trips and/or short courses can be made after this date. ■

Searcher Opens UK Office

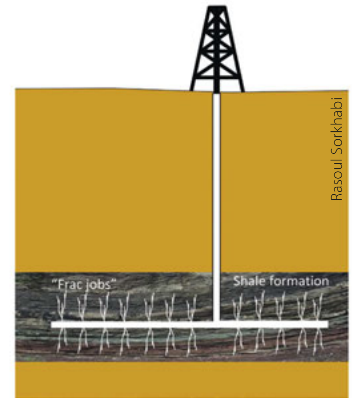


Searcher

Ground-breaking privately owned seismic company **Searcher** has opened a **UK office** in Woking, near London, as a platform to manage its future global new business activities. This is a perfect location to manage the creation of new seismic datasets in Latin America, Africa, Europe, Middle East and the Far East, building on the extensive multi-client datasets Searcher already holds. "We are so thrilled to be launching this new platform into a market excited for **innovative 3D and 2D seismic datasets**," said Debbie Sewell, Searcher's new VP Global Business Development. "With our sister companies 'Finder' and 'Discover', this will help us to bring additional value and business solutions."

One of Debbie's first tasks for Searcher was at the 2020 APPEX event in early March, where she awarded Kevin Dale, Geoscience Advisor at Sasol, with the booth draw prize; 40 trees planted for carbon offsetting. She explained that carbon offsetting is a major part of the Searcher creativity message and that she believes that attention to detail is what makes the company special. ■

Locating Sweet Spots: Shale Petroleum Systems



Petroleum system analysis has been a major tool in petroleum geoscience and exploration – but can it help locate shale 'sweet spots' and thus increase production, reduce risk and minimize the environmental footprint?

RASOUL SORKHABI, Ph.D.

In the last decade US oil production increased by 60%, to over 13.4 MMbopd by early 2020. This increased production, which has been partly responsible for depressing oil prices, has been made possible essentially because of the shale revolution, since US conventional crude production has been in decline for decades.

The shale revolution in the US is currently limited to a few basins and formations: the Permian, Barnett and Eagle Ford in Texas, the Bakken in North Dakota, and the Marcellus in the Appalachian east. However, there are numerous other shale plays in North America and elsewhere in the world, and many other countries regard their shale resources producible if economic and technological conditions became optimal. Meanwhile, there are some fundamental questions about shale science that we do not understand. Given that shale formations are self-sourced and self-sealed reservoirs, how can we apply petroleum system analysis, a methodology developed for conventional reservoirs and prospects, to these formations? Can petroleum system analysis reduce risk and increase productivity of shale petroleum? This article aims to address these questions.

Petroleum System Analysis

When the oil industry began in the 1860s, all oilmen wanted to find were seeps and anticlines to drill. In the 1920s, they began to develop concepts and technologies to quantitatively study reservoir rocks. For the next 50 years, subsurface mapping and characterization of reservoirs and traps by geological and geophysical methods was the focus in exploration. It was not until the 1970s that source rock studies drew serious attention from the industry and geochemists developed techniques to identify kerogen types and estimate thermal maturity of source rocks, based mainly on vitrinite reflectance microscopy. As computational and digitization techniques were developed in the 1980s, it became possible to perform basin-scale modeling of oil generation, migration, and accumulation, as geochemists developed ideas and methods to characterize petroleum source rocks.

A petroleum system consists of physical elements and associated processes and here we briefly describe them for shale formations.

A view of fractured Marcellus Shale of Devonian age in West Virginia (the author is in the picture for scale).

Element		Process	Characteristics of Shale Systems
Source Rock		Generation	High TOC, Hydrogen Thermal maturity Thickness
Migration Pathways		Migration	Expulsion into overlying sediments Intra-formational migration In-situ retention (no migration)
Reservoir	Accumulation	Storage & Yield	Porosities: Matrix, Kerogen, Fracture Permeability: Open natural fractures and hydraulic fracturing (stimulation)
Seal	Accumulation	Sealing	Self-sealed tight rock Low porosity, low permeability
Trap	Accumulation	Entrapment 3D closure	Self-trapped: Tilted or flat geometry Facies changes laterally and vertically
Overburden		Preservation	Basin deep shale

Rasoul Sorkhabi

Petroleum system analysis in shale formations.

Source Rock and Generation

Petroleum source rock contains kerogen – highly complex organic compounds that thermally crack to hydrocarbon molecules as the rock is progressively buried and heated by overlying sediments. The source rock is the petroleum basin's 'kitchen.' Black claystone (mudstone, shale and marl) is the best source rock because it retains plenty of kerogen within its pore space. Limestone can also be a good source rock. Coal essentially generates natural gas, although deltaic coal formations can produce some oil.

Not all clay-rich rocks generate hydrocarbons; it depends on the amount of organic carbon in the rock, which is measured as percentage of total organic carbon (TOC). Less than 0.5% suggests poor source rock, while TOC of 2–4% indicates very good source rocks. Aside from high TOC, the source rock should also possess organic hydrogen (measured as Hydrogen Index or S2/TOC from pyrolysis); otherwise, pure organic carbon would produce graphite.

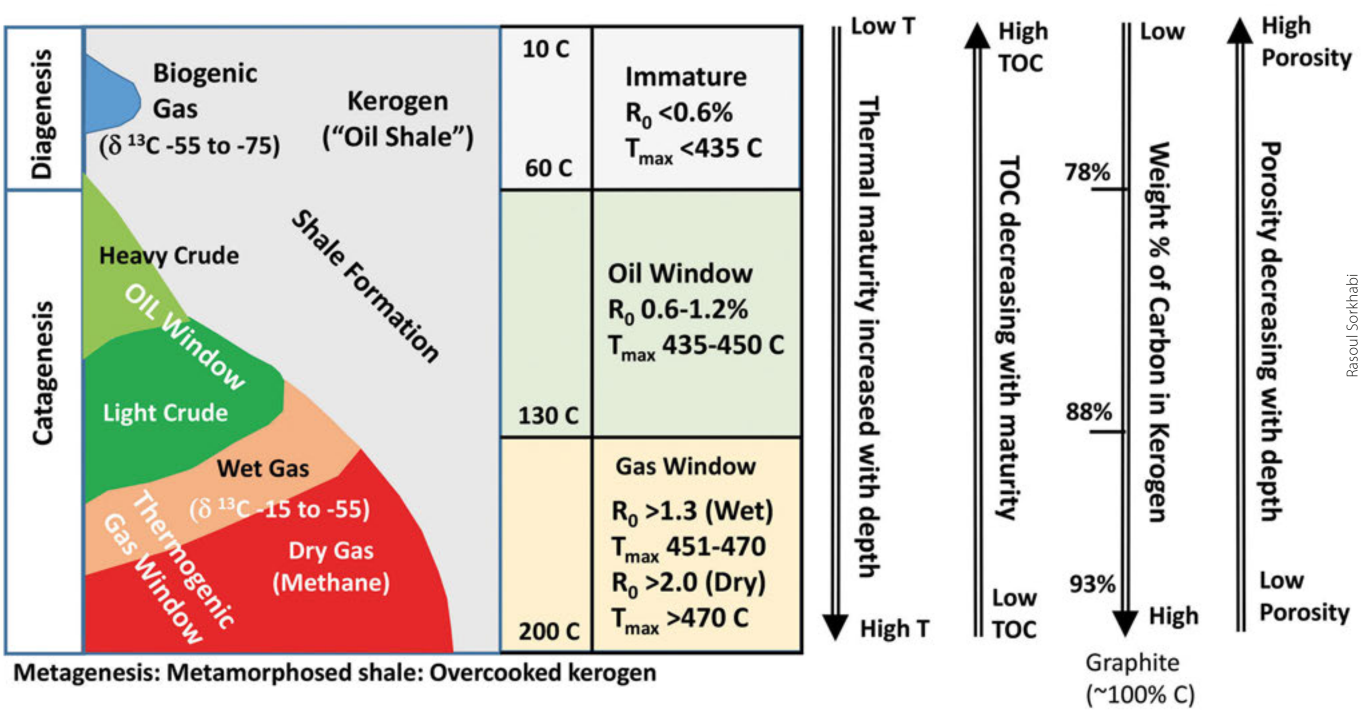
Moreover, the rock should be sufficiently buried and heated to generate hydrocarbons. There are several methods to estimate the paleo-temperatures of source rocks, including burial history diagrams, T_{max} readings from S2 peak in pyrolysis experiments, and vitrinite reflectance (R_0) measurements. Hydrocarbons are generated in a temperature-dependent, step-wise sequence of kerogen (insoluble in ordinary organic solvents) to bitumen (soluble in organic solvents) to heavy crude, light crude, wet gas, and dry gas. In this fractionation, hydrocarbons become simpler and lighter molecules.

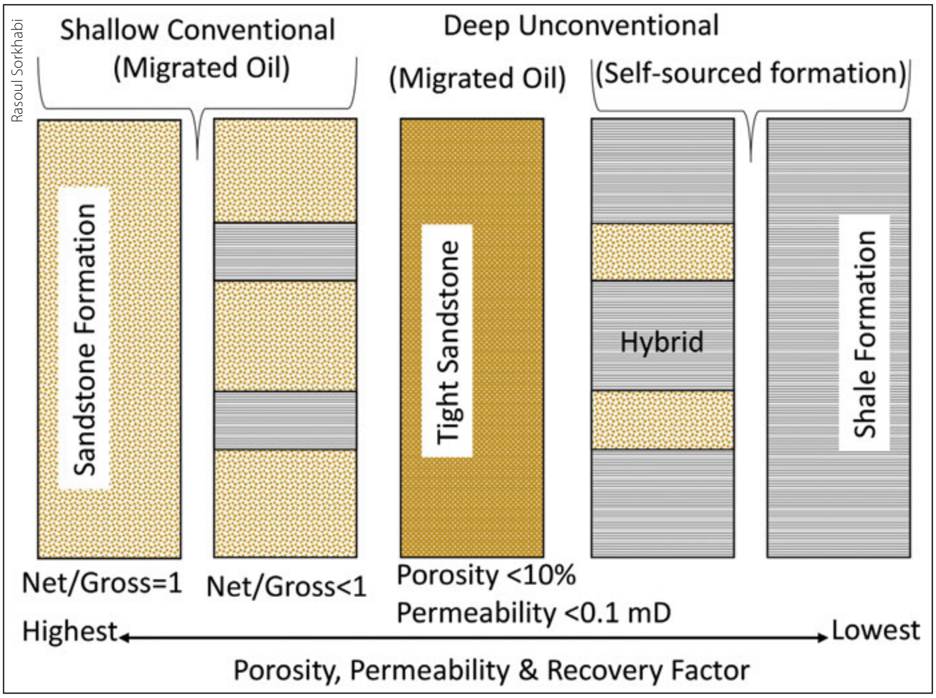
Many Faces of Migration

Once oil and gas have been generated in the source rock, some will be expelled and will enter the basin, but some will remain within the formation. Hydrocarbon expulsion from the source rock is called primary migration. The expelled oil and gas, being buoyant, will then flow (secondary migration) through porous carrier beds or open fractures and will eventually accumulate in enclosed reservoirs (pools). Most of the expelled hydrocarbons, however, diffuse in the basin.

The ratio of how much oil or gas is expelled from the source rock and how much is retained in the rock formation differs for various source rocks depending on their conditions. Studies of Barnett Shale, for instance, suggest that 60% of generated oil was expelled and 40% was retained in the shale. However, some researchers do not consider expulsion mechanisms to be very effective, and believe that perhaps as much as 80% of hydrocarbons are retained in the source rock, possibly because oil saturation in shale plays has been found to be over 75% of the rock's porosity. How much hydrocarbon is generated in shale and how much is expelled or retained

Hydrocarbon generation in shale. Note that aside from temperature, kerogen type also plays a role in the amount of oil or gas generation.





Lithological spectrum from sandstone to shale reservoirs and their petrophysical comparisons.

remain interesting questions to be investigated using various cases and simulations.

The retained oil in shale can both stay in place and migrate within the formation. Intra-formational migration seems to be counter-intuitive because shale as a source rock is a very tight (low permeability) oil-wet rock. But two important mechanisms can migrate oil or gas within the shale formation. First, shale formations are not homogenous; they contain relatively high-permeability layers (sand, silt or limestone) and fractures which can facilitate oil and gas migrating updip the formation. Second, during the compositional fractionation of hydrocarbons (from heavy oil to dry gas), the buoyancy of lighter hydrocarbons (with high APIs, high solution gas-to-oil ratios and lower viscosity) will provide a migratory force. Compositional fractionation of hydrocarbons also happens during production when the produced hydrocarbons have different gas-to-oil ratios than their initial values in the rock.

Intra-formational migration observed in the US Barnett, Niobrara and Bakken Formations indicates that polar hydrocarbon compounds (resins and asphaltenes) remain in situ because of their high sorption (adsorption and absorption) in kerogen porosity, while saturates and aromatics move into organic-lean porous intervals.

Reservoir Storage and Production

A petroleum reservoir has two functions: firstly, it stores oil or gas; and secondly, it acts as a conduit to yield oil or gas into production wells. The storage capacity is measured by porosity (the percentage of pore space in a volume of rock); the yield capacity is measured by permeability (milliDarcy for conventional reservoirs).

Shale formations are tight rocks with clay-sized grains less than 4 µm diameter and small pore throats 0.1–0.005 µm. Shale formations have porosities less than 10% and rock permeabilities in nanoDarcies. Because of these tight properties, shale targets are stimulated by hydraulic fracturing to produce oil or gas.

Porosity structure in a shale is divided into matrix (inorganic) porosity, kerogen (organic) porosity, and natural fracture porosity. Free (mobile) oil resides in the matrix and facture pores; adsorbed and absorbed oil is in kerogen (organic) porosity. Organic matter has 44 times more adsorptive power than quartz; therefore, kerogen porosity is important, although the quality and producibility of sorbed oil in shale should also be considered. Fracture porosity has not been observed to be a major storage feature. Shale porosity can be calculated on samples in a laboratory or from wireline log measurements such as bulk density, neutron porosity, and sonic logs, although these have traditionally been developed and calibrated for sandstone and carbonate reservoirs, so well log petrophysics for shale requires more work.

Fractures provide the main permeability in shale formations. Natural fractures in shale may be divided into four categories: *bedding-parallel fractures* (if mudstone has been deeply buried to develop fissile platy structures, so typical of shale); *bedding-vertical joints* with spacing related to the layer thickness: fracture spacing increases with thicker beds; *tectonic fractures* associated with

Kerogen types in shale and their pyrolysis characteristics. Hydrogen Index and S2/S3 are derived from pyrolysis of shale samples. S1 is the amount of free hydrocarbon in the sample; S2 is the amount of kerogen (in mg HC/g); S3 is the amount of carbon dioxide. The unit for all these three peaks is mg HC/g. Hydrogen Index is S2/TOC (Peters and Cassa, 1994, AAPG Memoir 60).

Kerogen Type	Maceral Component	Hydrogen Index	S2/S3	Hydrocarbon product
I	Alginite	>600	>15	Oil
II	Liptinite	300-600	10-15	Oil
II/III	Desmocollinite	200-300	5-10	Oil & Gas
III	Humic/Vitrinite	50-200	1-5	Gas
IV	Inertinite (Inert C)	<50	<1	None

folding and faulting; and *micro-fractures* arising from hydrocarbon generation in the rock (conversion of kerogen to hydrocarbon involves volume increase and fluid overpressure in the rock). Natural fractures in the rock may be open or closed (healed by mineral veins or compressional stress) but only open fractures will be conductive.

Hydrocarbon	API gravity	Gas-to-Oil Ratio (scf/stb)	Methane (mole %)	Color
Heavy Oil	5-20	0-200	<15	Black
Black Oil	20-40	200-1000	<50	Brown to Dark Green
Volatile Oil	40-50	1000-3500	50-70	Greenish to Orange
Gas Condensate	50-55	3500-50,000	70-85	Light Amber to Water-white
Wet Gas	55-60	10,000-100,000	75-90	Clear Water-white
Dry Gas	>60	>100,000	>90	Colorless

Hydrocarbon fluid types in reservoirs. API values are for stock-tank-oil gravity at surface conditions. The gas-to-oil ratio is in standard cubic feet per stock-tank oil barrel at standard conditions of 60°F and 14.7 psi.

Sealing and Entrapment

In conventional (migrated hydrocarbon) reservoirs, cap (seal) rock is necessary to prevent the upward migration of oil or gas. The cap rock, usually mudrock or salt, is a fine-grained, water-wet, low porosity and low permeability formation. By contrast, except for the expulsion or tectonic fracturing processes, shale formations are self-sealed reservoirs.

Traps are geometrical configurations that provide a closure for the accumulated oil or gas in the reservoir. Traps in conventional prospects are divided into structural, stratigraphic, hydrodynamic and combination types. This classification is not directly applicable to shales; however, lithological variations (both lateral and vertical) related to depositional processes play an important role in the framework of shale formations.

Classification of Shale Reservoirs

Compared to sandstone and carbonate reservoirs, our knowledge of shale as a petroleum reservoir remains poor. In recent years, some researchers have classified shale reservoirs in North America into three categories: *tight shale*, in which source and reservoir localities are the same; *hybrid shale*, where shale is interbedded with more porous but organic-lean siliceous or calcareous layers; and *fractured shale*, often rich in heavy oil or dry gas, where natural fractures provide considerable permeability and porosity. Of course, these are end-member categories. It is inconceivable to have a shale formation which does not exhibit lithological heterogeneity or has remained unfractured.

Some researchers divide shale reservoirs into argillaceous, calcareous and siliceous, based on the relative abundance of clay, carbonate, and silica minerals in the rock. Ternary diagrams using these mineralogical data indicate if the shale is more brittle (high silica) or not. These are informative exercises to understand the response of the shale formation to hydraulic fracturing.

A third classification is to divide shale plays into ‘active’ (still in the oil or gas window) or ‘inactive’ (overcooked or uplifted) systems. It is important to know if a shale formation has producible oil or not before drilling. Daniel Jarvie has suggested that if S1/TOC ratio is greater than one (i.e. >100 mg oil/g TOC), the shale has producible oil, although he also notes that measurements of S1 peak (free hydrocarbon in pyrolysis) and TOC need to be reasonably accurate for this exercise.

Back to the Future

Shale gas production dates back to the 19th century and hydraulic fracturing began in the 1940s. Nevertheless, at the turn of this century, no one would have predicted the coming shale revolution. Shales were only viewed as sources or seals; they were not cored, logged or studied for their reservoir properties. Shale petroleum system analysis is, therefore, in its infancy. Nevertheless, several important points require attention.

Firstly, total petroleum systems include both migrated and self-sourced reservoirs; this is a major addition to the global hydrocarbon budget. Secondly, like conventional ones, petroleum systems in shale are dynamic, in which all the elements and processes need to be evaluated and integrated to locate sweet spots for drilling and production. Given the heterogeneities and complexities of shale formations, it is necessary to conduct petroleum system analyses in numerous locations of the same shale play. Thirdly, the shale revolution has motivated us to investigate significant uncertainties in our measurements of TOC, pyrolysis (for example, correcting for evaporative loss of hydrocarbons in S1 peak), porosity, permeability, and so forth. Shale production requires higher resolution geoscience.

Finally, production from shale formations are drastically different from conventional reservoirs. Recovery in shale is less than 10% for oil and about 15–20% for gas, compared to about 50% oil recovery and up to 80% gas recovery in conventional reservoirs. Shale wells have sharp decline rates and last only a couple of years, compared to decades-long conventional wells. Moreover, shale production consumes a lot of water for fracking and is associated with induced seismicity, fugitive methane and other environmental issues. All this calls for better science and technology. ■

Mexico's Energy Reform

Five years on, what has Mexico's energy reform delivered for the country's exploration and production ambitions?

ARUNA MANNIE, Premier Oil

The Mexican Constitutional Energy Reform took place in 2014 in response to decreasing production, low oil prices, increasing foreign debt and competition from neighboring countries. It was the first time since 1938 that the country had opened its doors to foreign energy investment.

Over 100 Licenses Assigned

Though it got off to a disappointing start with only two out of the fourteen blocks successfully awarded in the first round, it wasn't long before the license round bidding became competitive. Since then more than US$1.6 billion has been paid in signature bonuses. The consistency, transparency and persistence of the Mexican regulatory bodies over the past five years saw 111 licenses assigned and at least US$35 billion of investment from more than 76 companies (Figure 1), with commitments to drill a total of 413 wells for hydrocarbon exploration and extraction by 2023.

However, with the change in governmental regime in the latter part of 2018, the incoming administration has halted subsequent licensing rounds until the energy reform delivers on its committed work programs and production starts. This hiatus has advantages, in that it allows the service and support industries to prepare for the rapid growth and expansion of activities that is expected to occur in the next few years. More importantly, it will allow time for exploration wells to be drilled and evaluated to de-risk plays in the basin and allow companies and the government to sensibly allocate capital spending and drill fewer dry holes.

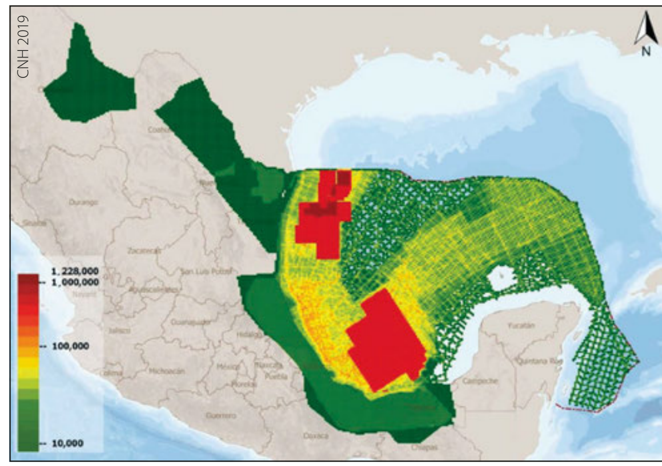
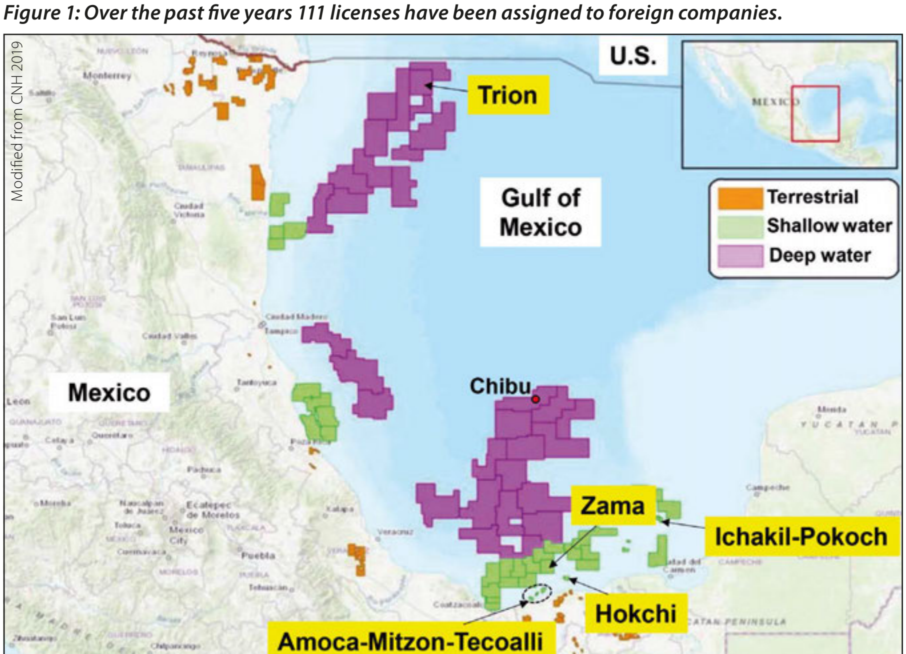


Figure 2: Investment in seismic acquisition and reprocessing activities (US$).

The country has benefitted from a requirement for companies to commit to a minimum percentage of capital investment on national content and various technology transfer initiatives, ranging from collaboration on projects with universities to the introduction of software and technology. The rapid pace of the license rounds saw more than US$3 billion invested in 2D and 3D seismic evaluations (Figure 2) and the energy reforms have already delivered considerable success with the billion-barrel Zama discovery, as well as the Cholula and Saasken discoveries (Figure 3). Within just three years the Amoca-Mitzon-Tecoalli, Hokchi, Ichakil-Pokoch and Trion discoveries have been appraised by foreign oil companies, adding more than two billion barrels of 2P reserves (Figure 1). Mitzon first oil was in July 2019, producing 8,000 bopd, with Amoca and Tecoalli expected to come onstream in early 2021, producing a combined total of 100,000 bopd. Hokchi and Ichakil are projected to produce first oil by 2020. With PEMEX existing contracts, planned field developments and the extraction contracts assigned in the energy reform, peak production in 2021 is expected to be around 1.8 MMbopd, up from the current 1.6 MMbopd, although less than the 600,000 bopd expected by the government by 2025. Further increases will be dependent on

Figure 1: Over the past five years 111 licenses have been assigned to foreign companies.



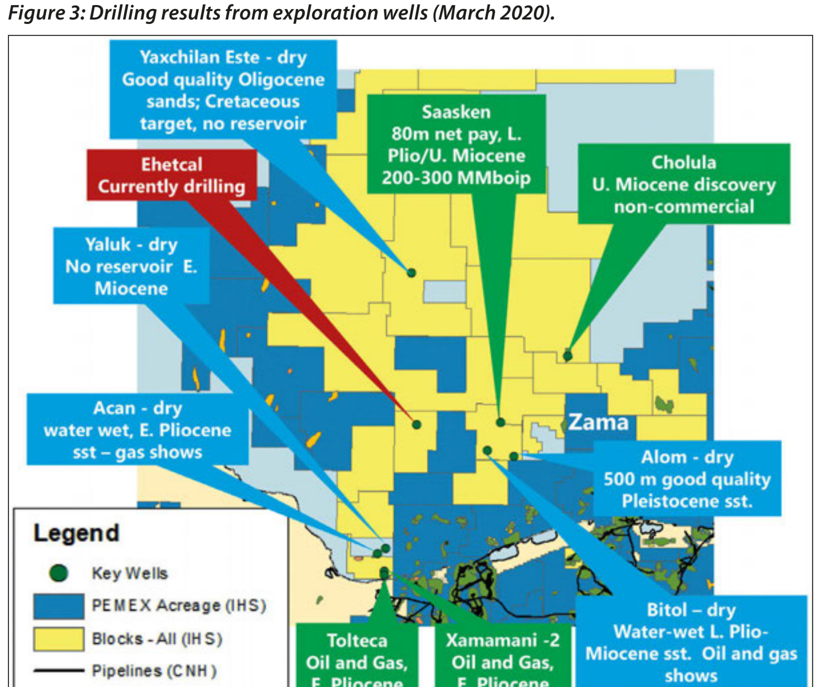
exploration success from wells bid in license rounds following the energy reform.

What Were the Challenges?

There were definitely advantages for Premier Oil in being a first mover in terms of international companies, but entering any new international basin poses its own technical and operational challenges and the Sureste Basin was no different. There were a number of geological and geophysical questions, many common to entering any underexplored basin, especially in a country which is opening its doors to foreign energy investment for the first time in 76 years. Stringent regulatory compliance such as financial corporate guarantees and justification of technical capabilities as an operator were some of the barriers faced within a time-constrained environment of the license round. This was to ensure companies had the financial and technical capabilities to invest what they promised to deliver without having to be rescued by farm-outs or ending up with licenses sitting idle for years.

Sparse well data availability and inconsistencies in generic well data resulted in the need for significant investment of time spent on conditioning wireline logs and QC of reports. In many cases the seismic imaging was moderate quality at best, which challenged the imaging and mapping of salt-related traps. In the next few years, as discoveries are made and the race to first oil continues, there will be challenges in supply chain management and the construction of infrastructure whilst maintaining the national content requirement.

Figure 3: Drilling results from exploration wells (March 2020).



Exploration Risks Identified

With nine main geological basins in Mexico, covering a diverse set of sedimentological and tectonic settings, comprising clastics, carbonates, extension, compression, strike-slip, salt diapirism, shale diapirism and even a meteorite impact there is nothing more a geologist could ask for! With natural oil seeps oozing at the seabed, one can easily be captivated by the untapped potential within this oil-mature province.

Mexico shares its early geological history with the US Gulf of Mexico. Rifting initiated in the Middle Jurassic, providing the accommodation for deposition of the laterally extensive Louann and Campeche salt deposits and subsequent deposition of the world class Type II marine carbonate Tithonian source rock. The Chicxulub meteorite impact at the end of the Cretaceous is responsible for the carbonate fields to the east of Mexico. The Paleogene Laramide and Neogene Middle Miocene Chiapaneco compressional events resulted in rapid clastic deposition which influences the present day structural styles, such as salt-withdrawal mini-basins, salt diapirs and associated structures, compressional folds and listric faults.

In the early days of exploration, the focus was primarily on the Sureste Basin, also known as the Salina de Istmo, a proven prolific hydrocarbon province. It has produced in excess of 18 Bboe to date, mainly from Cretaceous carbonate reservoirs, and is known for the supergiant multi-billion barrel Cantarell oilfield, one of the largest anywhere in the world. Prospective resources are in the order of 13 Bbo and 6.5 Tcfg (CNH 2018). With current production focused mainly on the carbonates, the majority of the established clastic players entering the basin were drawn to the seismic 'bright-spots' in the supra-salt and salt flank plays with the poorly imaged sub-salt traps as a potential upside. Post-drill analysis of wells in the Miocene and Pliocene plays in the Sureste Basin revealed reservoir presence and seal as the main risks with a smaller percentage due to migration.

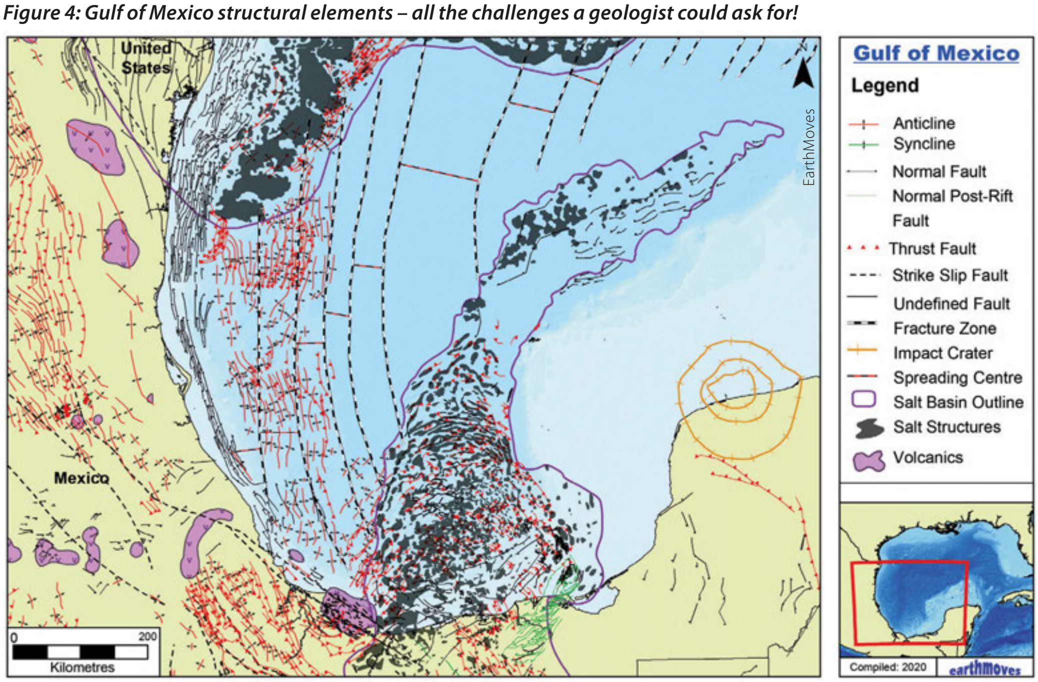
With wells few and far between and limited access to seismic angle stacks it was difficult to properly understand the amplitude responses especially in light of the fact that there are structural traps at similar depths and age without AVO responses. Having an understanding of the regional geology, including features such as tectonic history, petroleum systems expulsion and timing and gross depositional environment were important for prospect risking. To date, with ten other exploration wells drilled in the Sureste, we know that seismic 'bright-spots' are not always a reliable indicator of hydrocarbons, and wells which lack an AVO response were dry. The deepwater Sureste Basin (also known as the Campeche Basin), is a frontier experience testing unchartered territory, with the Norphlet and Wilcox plays (successful in the US Gulf of Mexico) targeted by wells in 2020, including Chibu-1, which is currently drilling (Figure 1). As further exploration wells are drilled in the basin, many of which target the clastic plays, the amplitude story will be unraveled and result in better drilling decisions.

What Does the Future Hold for Mexico?

With more than 77 committed exploration wells to be drilled in the next five years there will definitely be no slowing down of activity in Mexico. There is also the added advantage of being protected by the Production Sharing Contracts in a lower oil price environment. Plays will be de-risked and our understanding of the petroleum systems of the Mexican sector of the Gulf of Mexico will evolve rapidly. Billion-barrel fields will be few and far between due to confined trapping geometries, and it is thought that many discoveries are likely to contain recoverable reserves in the 50–250 MMboe range, requiring cluster developments. This could potentially lead to another wave of divestments and acquisitions in the next 3–5 years.

The energy reform can help reverse Mexico's declining production and contribute toward the government achieving its goal of increasing production by 600,000 bopd by 2025. However, this will require greater collaboration between the international oil companies and the Mexican regulatory bodies in order to reduce the timeline from discovery to first oil without compromising technical and HSES standards. Clarity from the Mexican government on the future for foreign investment in the country's energy sector will be advantageous. The future could be a period in Mexico's history of increasing production and development of the Mexican economy as a whole, placing its people and the country on a global stage with other producing countries worldwide. ■

Figure 4: Gulf of Mexico structural elements – all the challenges a geologist could ask for!

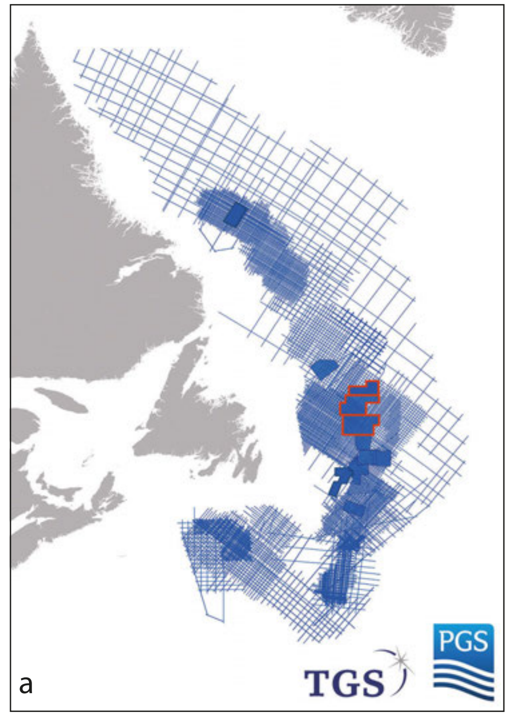


Orphan Basin, Canada:

From Regional Prospect Screening to Reliable Reservoir Attributes Estimation

A new, high quality regional dataset covering 22,469 km^2 is enabling the identification of important petroleum system elements in the underexplored Orphan Basin, offshore eastern Canada. Block evaluations for the upcoming license rounds can be performed with confidence with this multi-sensor broadband seismic data and its reliable pre-stack attributes. The most recently acquired part of this regional dataset is the North Tablelands survey, acquired in 2019 as an extension of the Tablelands and Long Range surveys, which were shot in 2017–2018 by PGS and TGS.

Fast-track data was delivered just five weeks after the last shot of the North Tablelands survey. A full integrity volume is available now and provides a single, continuous high-resolution seismic dataset available for licensing early next year, encompassing the Long Range, Tablelands and North Tablelands surveys.



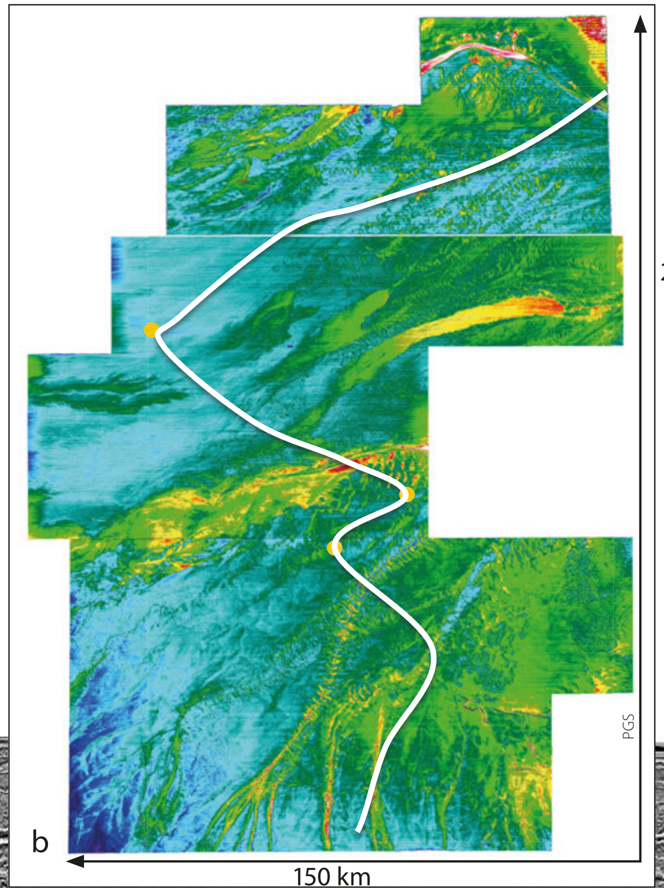
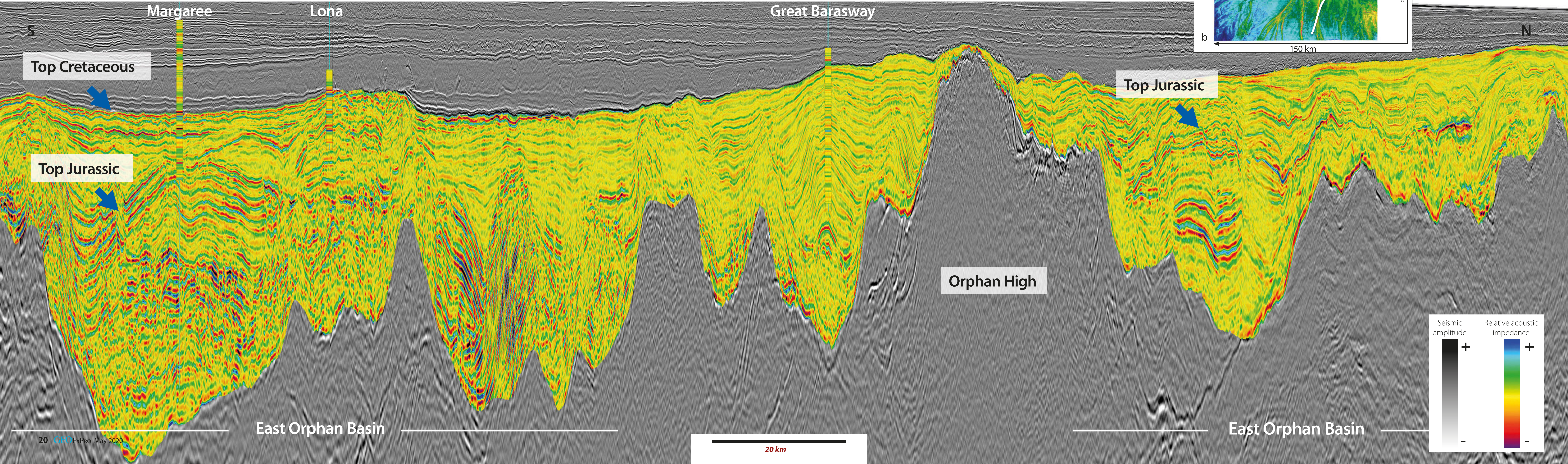


Figure 2: (a) Location of the Long Range, Tablelands and North Tablelands 3D surveys; (b) Locator map looking north across the surveys. The amplitude extraction on the seafloor demonstrates the modern day depositional directions. The white line shows the track of the 2D seismic section below.

Figure 1: Regional line through the Long Range, Tablelands and North Tablelands surveys and key exploration wells showing the horst and graben structure of the Orphan Basin. Relative acoustic impedance is overlaid on the Top Cretaceous to Base Jurassic interval into the grabens resolving detailed structures and revealing additional opportunities characterized by low relative acoustic impedance (dark red).



Exploring the Highly Prospective Orphan Basin

Eastern Canada is one of the most promising deepwater exploration areas in the world, where the implementation of state-of-the-art imaging technology is critical to develop a more detailed local subsurface understanding.

SCOTT OPDYKE, CYRILLE REISER, TIAGO ALCANTARA and ELENA POLYAEVA; PGS

First oil in the Jeanne d'Arc Basin was produced in 1997 from the Hibernia Field and since then the world-class oil-producing fields Terra Nova, White Rose and North Amethyst have come onstream, while oil production from the Hebron Field started in 2017. The Mesozoic basins of Grand Banks alone are estimated to hold recoverable reserves of 4.6 Bbo and 18.8 Tcf of natural gas. The 2009 Mizzen oil discovery in the Flemish Pass Basin, estimated at 200 MMbo recoverable reserves, proved the extension of a working petroleum system, sourced by the prolific late Jurassic source rock, into an area where it was previously untested. This was followed in 2013 by Harpoon and Bay du Nord fields. The Bay de Verde appraisal of Bay du Nord was successful in 2015 as was the Baccalieu discovery in the same area in 2016.

PGS, in partnership with TGS, have been acquiring 2D and 3D GeoStreamer MultiClient data in Newfoundland and Labrador since 2011. The extensive library offshore eastern Canada and the seismic-based geological products for Newfoundland and Labrador are comprehensive. Now this library also includes the contiguous Long Range, Tablelands and North Tablelands surveys in the Orphan Basin (Figure 2). The seismic data shown in the foldout (Figure 1) from Long Range in the south to North Tablelands in the north demonstrates the numerous horsts and grabens present in this part of the Orphan Basin. The existing fields and discoveries are often drilled into rotated fault blocks in the older section and are adjacent to tilted half grabens and this line indicates multiple opportunities for prospective traps for the industry to test. The 3D data delineates play fairways from the Orphan Basin in the north to the Jeanne d'Arc Basin in the south while the 2D data is available for regional interpretation and basin analysis.

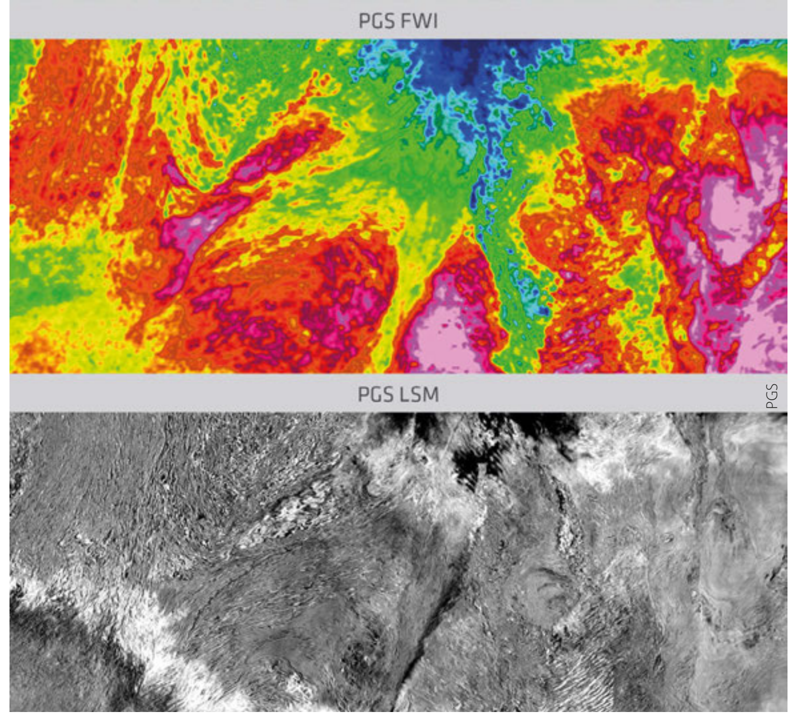
Open Acreage in Prospective Basins

Eastern Canada is one of the most promising deepwater exploration areas in the world. In addition to the producing basins of East Canada, there are also some highly prospective underexplored basins such as the Orphan Basin with potential for exciting new discoveries and world-class oil production. Access to new acreage, transparent fiscal terms and a predictable land-sale policy make East Canada an attractive region for oil and gas exploration.

Exploration targets include Late Jurassic to Early Cretaceous fluvial to shallow marine sandstone reservoirs sourced by prolific oil-prone Late Jurassic marine shales. A mainly extensional margin provides large structural traps and thick regional seals. Potential reservoirs from Lower Cretaceous to Lower Tertiary are stratigraphically positioned above the Kimmeridgian source rock super highway.

GeoStreamer broadband data reveals a well-defined rift section and high fidelity pre-stack seismic attributes in the Tertiary section make identifying stratigraphy and possible fluid effects easy. Work over the three datasets using pre-stack relative inversion has demonstrated fan geometries in the younger section of the Orphan basin and the northern portion of the Flemish Pass basin.

Figure 3: FWI velocity model and LSM depth slice showing the structural conformability of the estimated high-resolution seismic velocity field.



Advanced Tools Image Complex Geology

In addition to the regional imaging effort over this very large dataset, the implementation of state-of-the-art imaging technology is critical to develop a more detailed local subsurface understanding. Full waveform inversion (FWI) and least-squares migration (LSM) use the extra-broad frequency range recorded in the GeoStreamer data to better estimate a detailed velocity field and produce a robust image of the subsurface. In combination, they can minimize drilling risks and aid reservoir understanding (Figure 3).

Depth migration techniques have been widely used in areas with strong lateral velocity variation. Though very robust, traditional depth imaging methods suffer from acquisition and propagation effects that limit resolution and impact the amplitudes in the resulting seismic images. LSM is an emerging new imaging technique that compensates for acquisition limitations and variable illumination, and provides more reliable amplitude information in particular in areas of high structural complexity. In Tablelands, a data-domain LSM approach was selected to improve the vertical seismic image resolution and enhance the fault definition especially in the syn-rift section (Figure 4).

Rapid Prospectivity Screening

To facilitate a more rapid assessment of subsurface prospectivity potential, a fast-track image was delivered for North Tablelands together with QI products for interpretation and integration with pre-stack broadband attributes. Turnaround time was significantly reduced by integrating the imaging and QI work efforts. Pre-stack AVO QC was performed during the processing to ensure that the final pre-stack data was fit for purpose and AVO/AVA compliant for further QI analysis.

A final QI analysis including lithology and fluid prediction through a three-term AVO inversion was performed on the full integrity data from the Tablelands survey using all the available information including well log data. Three wells are present in the region of Long Range, Tablelands and North Tablelands: the Great Barasway F-66 well (drilled in 2006), Lona O-55 (drilled in 2010) and the Margaree A-49 well (drilled in 2013). These three wells drilled the main reservoir and source rock in the area. The Tithonian to Kimmeridgian interval was used to build a regional rock physics model. The Great Barasway well was modeled and has a good tie to the source rock and high quality siliciclastic reservoirs.

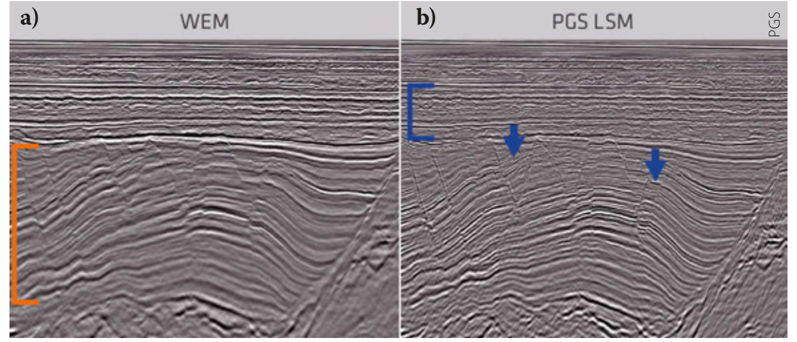


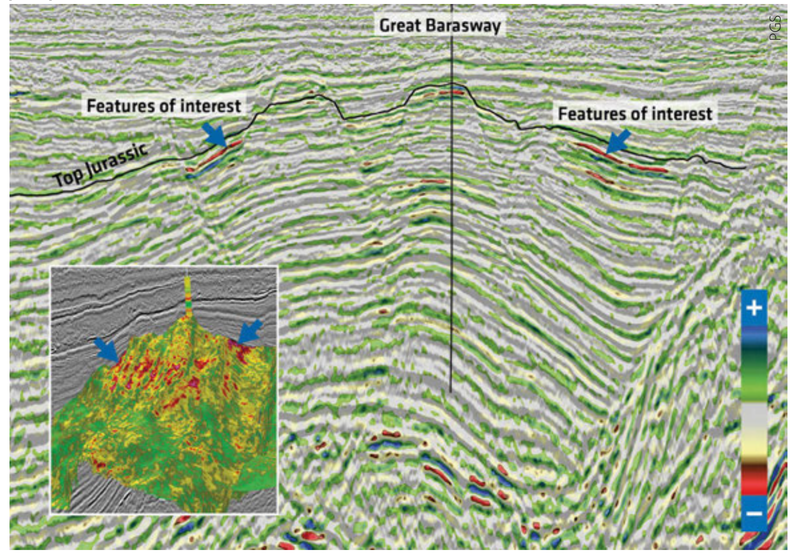
Figure 4: (a) 60 Hz one-way wave equation migration. (b) LSM delivers a higher resolution image with significantly improved fault definition. Blue and orange markers indicate improvements in the Tertiary and Jurassic respectively. Blue arrows indicate improvements in the Cretaceous and Jurassic.

Relative Vp/Vs overlaid on the pre-stack seismic (Figure 5) around the Great Barasway well reveals some interesting AVO anomalies characterized by very low relative Vp/Vs values on the flank of the main structure. Based on the rock physics work, low relative Vp/Vs could indicate the presence of hydrocarbons. These anomalies are of reasonable size, and can be spatially tracked on the 3D inset in Figure 5 bounded by some well-imaged faults.

Rapid Prospectivity Evaluation

3D GeoStreamer broadband seismic data acquired in the last three years by PGS and TGS in the Orphan Basin demonstrates how regional prospectivity scanning can be combined with a detailed local appraisal of hydrocarbon potential using the high quality pre-stack data and rock physics analysis. The use of state-of-the-art depth imaging technologies leads to better subsurface images and improved reservoir understanding. For the most recent North Tablelands survey high quality fast-track QI products were produced to aid more rapid prospectivity evaluation for ongoing and upcoming license rounds. ■

Figure 5: Relative Vp/Vs extraction along a random line going through the Great Barasway F-66 well. Note the features of interest off-structure that could be prospective both on the line of section above and the 3D visualization in the inset.



Marine Site Investigation and Reducing Risk

The evolving role of seismic reflection data within offshore site investigation.

MARK E. VARDY, SAND Geophysics

Marine site investigation is, at heart, about reducing risk. Sometimes it involves minimizing the risk to operations posed by UneXploded Ordnance (UXO), shallow gas, and/or unexpected ground conditions. Other times, it mitigates the design risk for subsequent infrastructure, such as wind farm monopiles, by providing enough relevant information about the nature of the subsurface to ensure the design is appropriate for the entire installation lifecycle. Alternatively, it can simply involve reducing financial risk, such as ensuring the aggregates being targeted for extraction are a profitable resource.

At the core of these investigations sits seismic reflection data, a key methodology that is utilized across all manner of site investigation projects worldwide. Relatively cheap and fast to acquire when compared to intrusive sampling techniques, seismic reflection surveying offers the ability to image the seafloor and subsurface structure continuously in 2D or 3D over large areas and at a high fidelity. By combining multiple different seismic methods, it is possible to blend data with different resolutions and penetrations, providing both sub-meter-resolution imaging of the shallow subsurface and lower-resolution penetration of the full top-hole section, as required.

Are We Maximizing Data Potential?

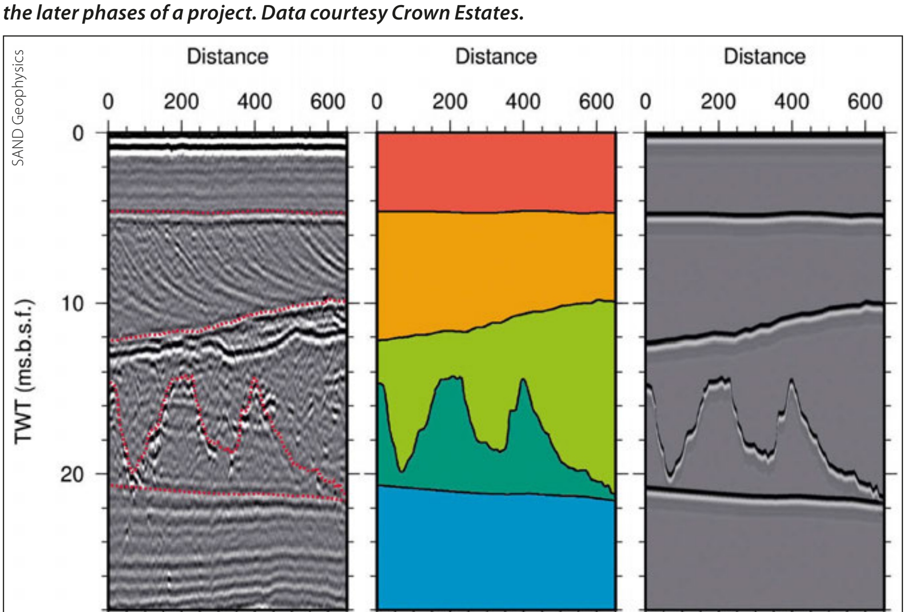
As is the case within all industries, however, one must always be asking the question: are we getting maximum value from the techniques being employed?

This question has been posed many times in recent decades with regard to the seismic reflection data acquired as part of site investigations, primarily because the output from the geophysical part of a site investigation that feeds into subsequent design and/or risk mitigation phases is somewhat limited. For hazards, such as UXO or shallow gas, this often takes the form of a presence/absence map, with limited information regarding the dimensions of the potential UXO or the gas saturation within a possible gas front. When predicting ground conditions, the output from the seismic reflection interpretation commonly takes the form of a simplified ground model, mapping the depths of key interfaces, facies thickness variations and key structural features such as faults.

In reality, the seismic reflection data contains much more detailed information about the nature of the subsurface. Variability in the amplitude, phase, and architecture of the reflections provide extremely useful first-order information on the nature of the sediments comprising the subsurface, under what conditions they were deposited, and how they may have been deformed post-deposition. Changes in bedding and post-depositional deformation are captured both across major facies boundaries as well as the, potentially more subtle, internal patterns within each facies.

The latter information can be particularly pertinent as it provides a direct indication as to how the properties of a particular facies might vary across a site. Within the aggregates and offshore mining industries, such information can be critical in assessing the financial viability of a deposit, characterizing it as a 3D (or pseudo-3D) rock volume. For offshore construction projects, the variability of ground conditions within each facies is important for both health and safety decision-making, such as understanding the differential loading profile between jack-up rig locations, as well as the engineering design. For cable and pipeline installation projects, understanding spatial variability in

A boomer seismic reflection section from a wind farm site survey. The seismic profile is overlain with an example interpretation of major facies boundaries, along with a ground model constructed using these. To illustrate how little of the complex, subtle detail on the original seismic reflection profile is communicated in this ground model, a synthetic seismic section generated using only the major facies boundaries is also shown (right). It is clear that, unless engineers and project managers look at the seismic data, a huge amount of potentially useful information may not be communicated into the later phases of a project. Data courtesy Crown Estates.



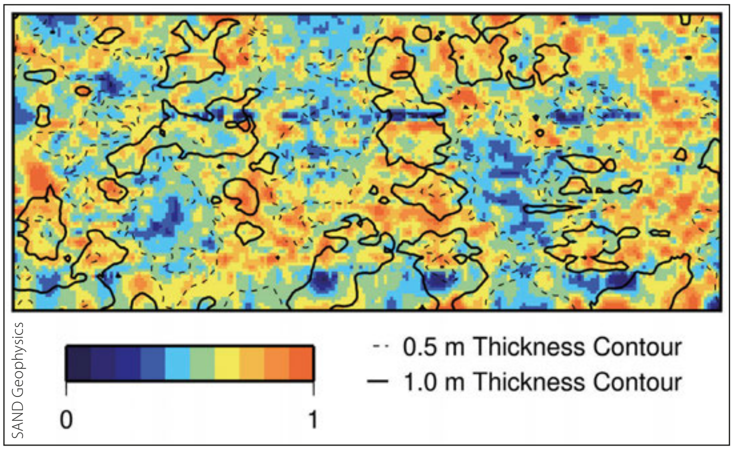


Chart of rock quality metric for a marine aggregates area, estimated using seismic attributes (warmer colors indicate greater resource potential). The rock quality data is overlain by deposit thickness contours, illustrating the complex relationship between thickness and quality of the deposit; thicker deposits do not necessarily make the best extraction targets. The combination of these data permit project managers to efficiently make well-informed, high-level decisions about the resource potential within a prospect area and whether it is financially viable.

the shallow geology is critical in route planning to maximize cable performance and identify the correct trenching tool(s) for installation.

Can We Communicate Better?

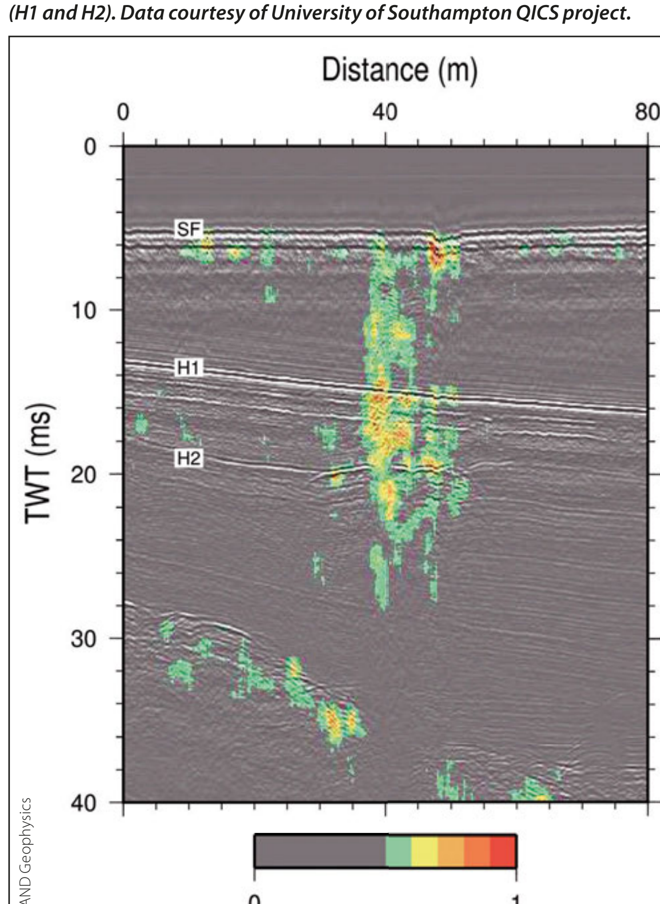
These features of seismic reflection data are a key piece of information used by the seismic interpreter when building a seismostratigraphic model, aiding the interpreter in deciding where the major facies boundaries are located and how those facies relate to each other (e.g. is the boundary conformable or unconformable?). While an experienced interpreter will combine all this information into their decision-making process, it commonly does not move beyond that interpreter's desk. Observations and example images of this complex seismostratigraphic architecture are often included in the seismic interpretation and geological ground model reports, but not in a manner that effectively consolidates all the information available into an easily communicable form that can be digested by project managers and engineers working on subsequent project phases.

As such, there are obvious and significant benefits to the wider project if this more subtle and complex information can be better communicated, ideally at a higher level.

One potential solution is to use seismic attributes that can enhance specific variations in seismic architecture, providing a clearer distinction between seismostratigraphic facies with contrasting characters (likely, therefore, to have different material properties) as well as capturing the more subtle spatial changes within facies with similar characters. A wide range of seismic attributes can be derived from both 2D and 3D seismic data, some of which are based upon the physics of the seismic wavefield (e.g. instantaneous frequency, average energy), while others are derived from image analysis techniques (e.g. edge detection, seismic texture). The correct attribute(s) to use will vary between projects, depending on the nature of the geology being imaged and the features to be highlighted.

These methods are widely used in the hydrocarbon sector to help identify and characterize potential features of interest, like gas channels, salt or fault structures, but have yet to see widespread use within the site survey sector. However, the potential is significant, particularly for the effective communication of geological complexity into the later project phases. Not only do such attributes more effectively highlight key features of interest on seismic sections, which often appear confusing to non-specialists, but many also readily lend themselves to being efficiently summarized. For example, using a combination of attributes that highlight the chaotic and high amplitude reflections from a heterogeneous, aggregate-rich substrate can be used to both better constrain the thickness of such deposits (often hard to interpret on seismic reflection sections) as well as the variability of the heterogeneity, which indicates resource potential. Both these features can be easily summarized as charts, providing a high-level communication of relatively subtle detail within the geophysical dataset that would otherwise not have been used.

A Chirp sub-bottom profiler section across a controlled carbon dioxide injection site. Seismic amplitudes are overlain with a free gas potential metric derived using seismic attributes. Warmer colors indicate a higher potential for free gas being present in the shallow subsurface, which highlights not only stratigraphic levels where free gas may have accumulated (e.g. horizon H2), but also, potentially more importantly, vertical gas migration pathways, which here can be seen to extend right to the seafloor (SF), crossing the two main subsurface stratigraphic horizons (H1 and H2). Data courtesy of University of Southampton QICS project.



Be More Quantitative?

One significant limitation of such properties, however, is that they are not truly quantitative. In the aggregate example described, it is assumed that more heterogeneous facies have a better resource potential, but the actual resource potential in terms of grain size distribution and volume fraction of viable aggregates is not derived. Such questions regarding deriving more quantitative information from site investigation geophysical data have been posed for many years, in particular related to deriving geotechnical properties that are useful for infrastructure design and installation.

Generally, extracting quantitative information regarding the nature of the subsurface from seismic reflection data is classified under the umbrella term 'seismic inversion', which contains a smorgasbord of different techniques/methods to derive estimates of the subsurface properties from the recorded seismic data. While the inversion of exploration-scale data for reservoir characterization has been relatively common for decades, the inversion of site survey data has been slow to catch on. In part this is because site survey geophysical data does not lend itself readily to inversion, often suffering from noise contamination (due to smaller source sizes and shallow tow depths) and recording a more limited representation of the seismic wavefield because of the smaller offset ranges and lack of low frequency content. In addition, the properties that are of most interest to site investigation applications, like grain size, gas saturation and relative density, are related to the recorded seismic reflection data in a very complex, non-linear manner that is, in the case of the more advanced geotechnical properties, site specific.

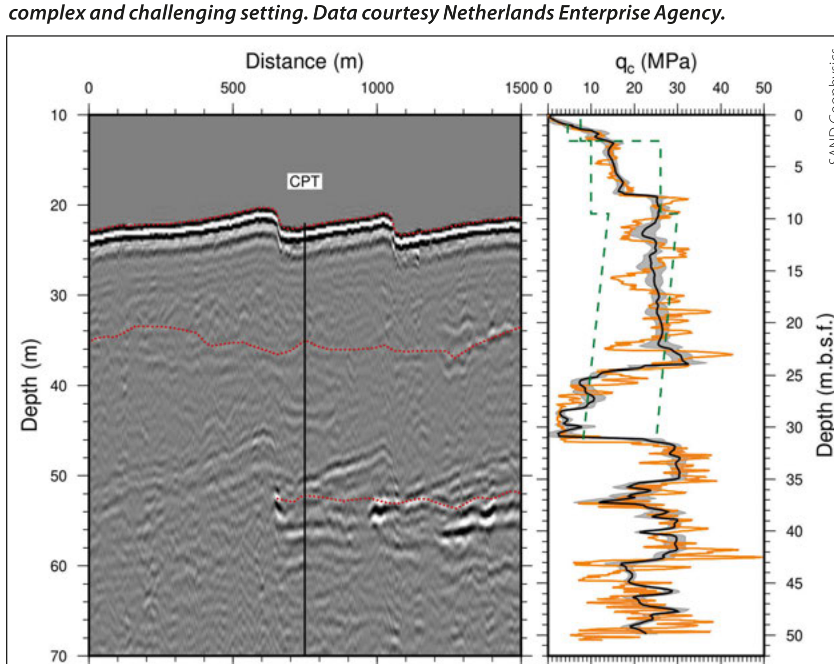
Together, these make the problem computationally challenging, but recent advances in computing power and algorithms mean they are not insurmountable. Casting the inversion within a stochastic framework, which searches a broader range of potential solutions, provides a more robust solution that has been reliably applied to all manner of site investigation data, from single-channel sub-bottom profiler to 3D ultra-high-resolution multi-channel seismic volumes. While it is still not possible to cast these inversions as a one-stage prediction of geotechnical properties, optimization algorithms that mimic natural processes, such as Genetic Algorithms or Simulated Annealing, allow bulk physical properties (e.g. acoustic impedance, bulk density, porosity, Poisson's ratio) to be derived with confidence. Combining these results with modern machine learning (ML) techniques capable of solving highly complex, non-linear problems, it is possible to make predictions of the geotechnical properties from these bulk properties. Particular success has been had when using these methods to generate synthetic CPT profiles at specific sites of interest, allowing the core geotechnical parameters (undrained shear strength and relative density) to be generated using a standard engineering workflow where they are most needed.

An immensely useful additional feature of casting the quantitative process within such a stochastic/ML framework is the ability to estimate confidence intervals. As the initial conditions of these algorithms are random (or at least pseudo-random), multiple independent runs with the same input data will provide subtly different predictions. Therefore, combining the results from multiple runs provides the interpreter with a useful tool to understand whether the inversion is stable as well as capture an estimate of the uncertainty in the final prediction. For infrastructure design and installation applications, the potential of such information cannot be understated.

The Way Forward

This article has looked at some of the ways in which the use of seismic reflection data for site investigation applications is evolving. Its role is changing from being a simple facies boundary interpretation tool, into something that effectively contributes across all phases of a project cycle, capturing and communicating information on the variability of the ground conditions, both qualitatively and quantitatively. The potential of these and similar techniques has garnered significant interest across all sectors of the offshore site investigation industry, making it an exciting time for marine near-surface geophysics. ■

A sparker ultra-high resolution profile from an offshore wind site investigation at a geologically complex location that has suffered multiple periods of glacial loading/reworking, along with the measured and blind predicted CPT tip resistance curves. Shaded gray region is the confidence range of the blind prediction, black line is the 'best' blind prediction, and orange line is the independently measured values. The dashed green lines show the tip resistance envelope predicted using a traditional geostatistical approach. The ML prediction effectively captures all the large-scale structure along with some of the higher fidelity layering, significantly outperforming the geostatistical results in such a geologically complex and challenging setting. Data courtesy Netherlands Enterprise Agency.

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Central Utah Thrust Belt: A Lost Cause?

THOMAS SMITH

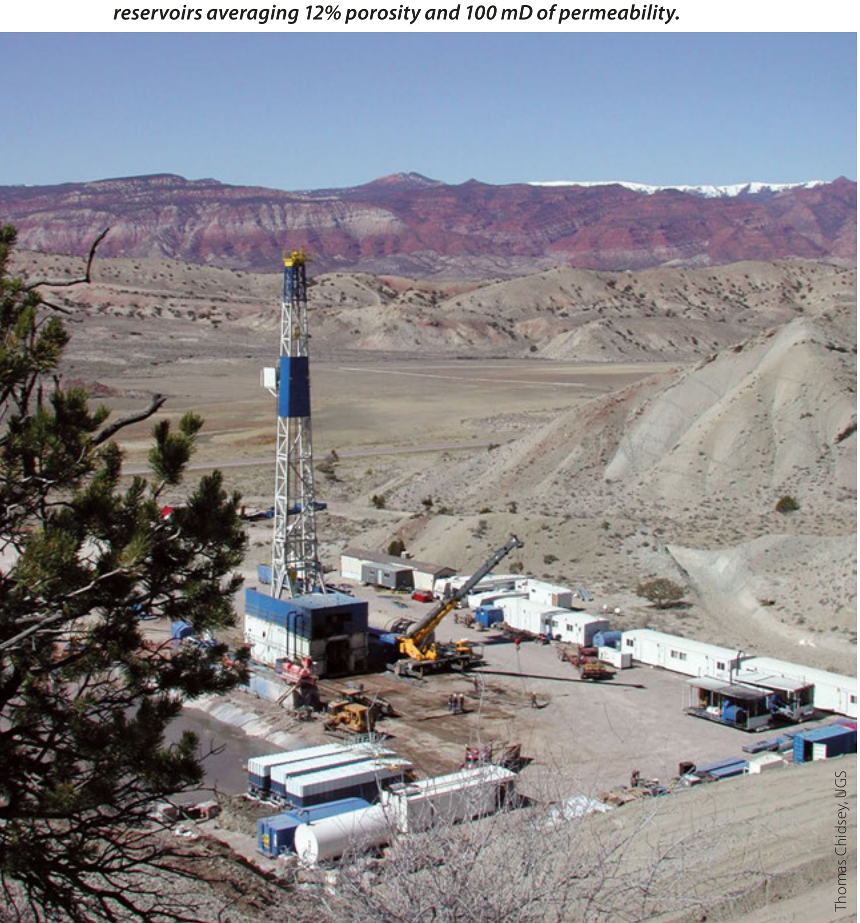
The 2004 Covenant oil field discovery promised to open up a very favorable, large onshore oil province. Thirty additional wells have been drilled in the play since, but only one found producible oil. What happened?

Editor's note: New Life for Overthrust Belt, in GEO ExPro, Vol. 3, No. 6, 2006, was Tom's first article for the magazine. This update covers some of the lessons learned since that discovery.

After the Covenant discovery, the April 2005 *AAPG Explorer* reported in an article entitled *Utah Play Makes Lots of Headlines* that "the Covenant field discovery in central Utah opens up one of the most promising onshore plays in the United States in recent memory." Doug Strickland, exploration manager for Michigan-based Wolverine Gas and Oil Corporation at the time, had spent over 25 years studying the central Utah thrust belt (also referred to as Utah's 'Hingeline') and was instrumental in obtaining their acreage position. After the discovery, he is optimistically quoted in the same *Explorer* article, "I honestly expect this to be a billion-barrel province – I expect we'll find another 10 fields out there."

Before the Kings Meadow Ranches No. 17-1 well flowed over 700 Bbopd, the central Utah thrust belt had tested the patience of explorationists for over 50 years. Their efforts had resulted in 58 consecutive dry holes for the area, so this discovery set off a great deal of speculation in the play. Landowners received large cash offers in order to lease subsurface rights; seismic crews descended on central Utah to obtain better subsurface mapping; and geologists studied new and old data to locate additional traps to be drilled. While the discovery and the new field have performed well, producing over 27 MMbo from 34 wells for Wolverine, the play continues to disappoint, plaguing explorationists with dry holes. Thirty exploratory wells have been drilled since, finding only the small, one-well Providence field located 20 km north-east of Covenant. With each well drilled, the story is still unfolding in this complex play.

Drilling operations at the newly discovered Covenant field, March 2005. Wolverine's Kings Meadow Ranches No. 17-1 encountered 150m of Temple Cap Formation and Navajo Sandstone pay to end more than 50 years of disappointing results in the central Utah thrust belt. The well flowed 40° gravity oil from excellent reservoirs averaging 12% porosity and 100 mD of permeability.


Thomas Chidsey, UGS

The Reservoir

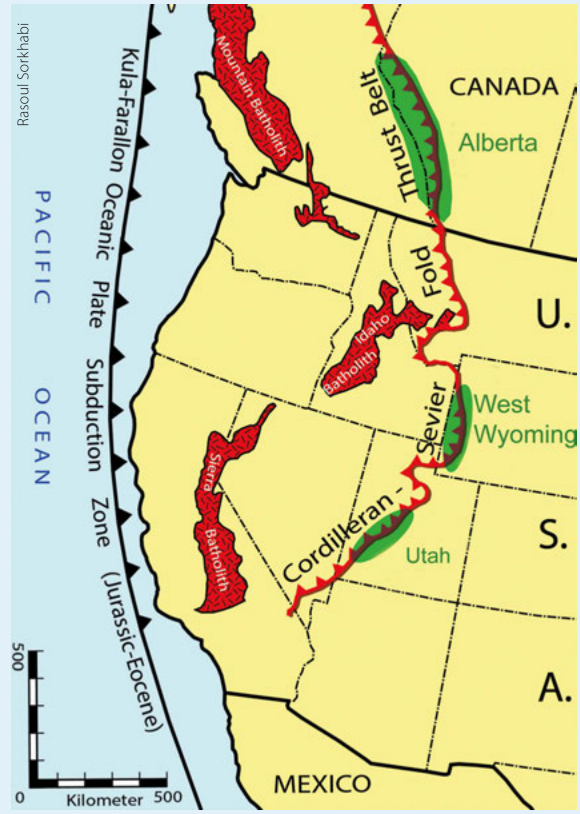
In 1999, Wolverine obtained data and an acreage position in the area from which Chevron pulled out after drilling just one well back in 1981. This well provided some key dip meter data and, combined with 2D seismic data, helped identify a prospect that was considerably updip from the well. Wolverine used some of the latest drilling methods and mud systems to get through the Jurassic Arapien Formation, which consists of highly contorted mudstones and evaporites that make both drilling and seismic mapping of structural traps difficult. The company tagged their reservoir objective, the Early Jurassic Navajo Sandstone, 425m higher than anticipated (more on this later). The well was completed and later flowed 40° API gravity oil from the 360m-thick sandstone, with the top 150m oil-saturated.

The Navajo Sandstone is probably best known for the massive exposures (670m thick) in Zion National Park (see *Navajo Sandstone – A Scenic Reservoir; GEO ExPro* Vol. 4, No. 1). The eolian-derived deposits that later formed the Navajo and equivalents cover parts of five western states. Back in the Jurassic, you would have encountered a great sea of sand, (often referred to as an erg, from the Arabic 'arq' meaning dune field), similar to today's Sahara Desert in Northern Africa or the Alashan area of the Gobi in northern China.

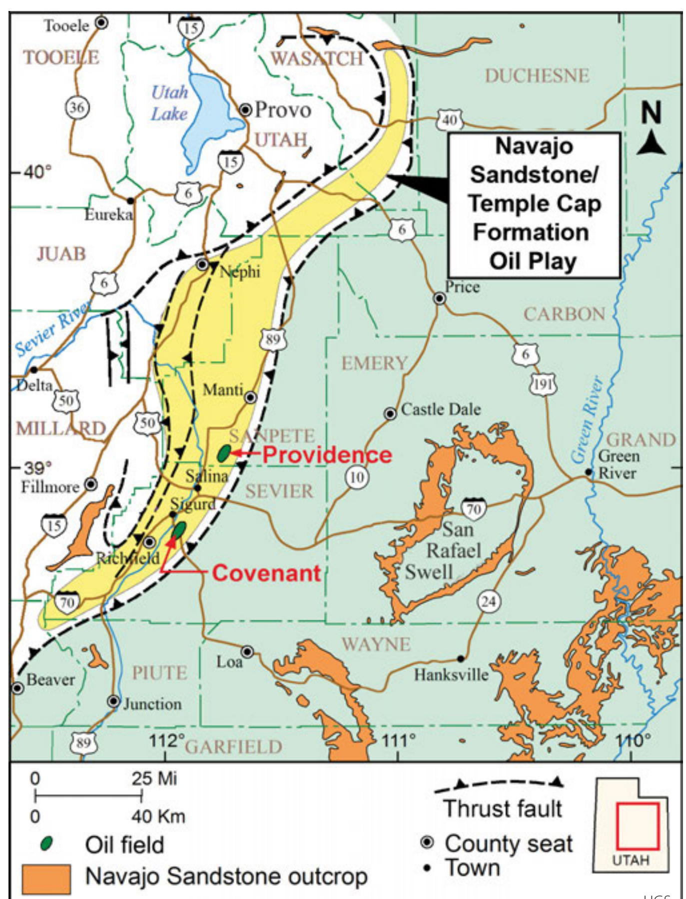
Structural Setting of the Sevier Belt

The central Utah thrust belt is a segment of the much larger Cordilleran orogenic belt that stretches several thousand kilometers from Alaska to Central America. The Middle Jurassic to early Tertiary Cordilleran orogenic belt formed during subduction of the Farallon Plate beneath North America, with associated intrusion magma cooling slowly to form large granitic plutons like the Idaho and Sierra Nevada Batholiths. Deformation along the Cretaceous Sevier orogenic belt extends from south-west Montana, across eastern Idaho and western Wyoming, through Utah and into southern Nevada. Folding and thrust faulting occurred in this area during the Cretaceous to Paleocene Sevier Orogeny (130–60 Ma). The Sevier Orogeny was a time of active compression in response to the Farallon Plate subduction beneath the North American Plate.

Along this orogenic belt, sedimentary rock has been deformed by horizontal compression effectively shortening the rocks. Reservoir rocks can be faulted and stacked on top of each other or tightly folded to form hydrocarbon traps. This region hosts numerous fields, mostly gas, in the Canadian salient in western Alberta. The 1914 Turner Valley light oil discovery was this area's first (see *GEO ExPro* Vol. 5, No. 6). In 1975, the Pineview discovery in northern Utah set off exploration in the Utah-Wyoming salient that led to the discovery of 11 additional fields including two giants (Anschutz Ranch East and Whitney Canyon-Carter Creek). The central Utah segment is located approximately 300 km south-west of the Utah-Wyoming segment where the Covenant field lies. ■



Location of the Covenant and Providence fields in central Utah. Provo is the nearest large city and Utah's capital, Salt Lake City, lies just off the map 70 km north of Provo.



"Since the Covenant discovery, new outcrop work, regional well correlations and age-dating has refined our understanding of the reservoirs," says Thomas Chidsey, senior scientist at the Utah Geological Survey (UGS). "Building on the initial age-dating work by Chris Tolland with Oolithica Geoscience Ltd., UK, it was determined that the upper section of the reservoir is the Middle Jurassic Temple Cap Formation, which unconformably overlies the Navajo. The reservoir consists of coastal dunes (White Throne Member) associated with tidal flat deposits (Sinawava Member). Today's analogs for these deposits are found along the Namibia coast of south-western Africa."

Covenant is currently the only field in Utah that produces from the Temple Cap Formation. The White Throne Member, much like the Navajo, has excellent porosity and permeability and the field produces about equally from both reservoirs.

The Structure

"Before drilling the discovery and subsequent wells, Wolverine geoscientists had mapped an anticline that had formed on an east-directed thrust off a larger, underlying thrust fault," says Chidsey. "Yet, when an injection well was drilled west of the field into the Navajo Sandstone where they expected to encounter the Navajo twice based on their mapping, it was only hit once."

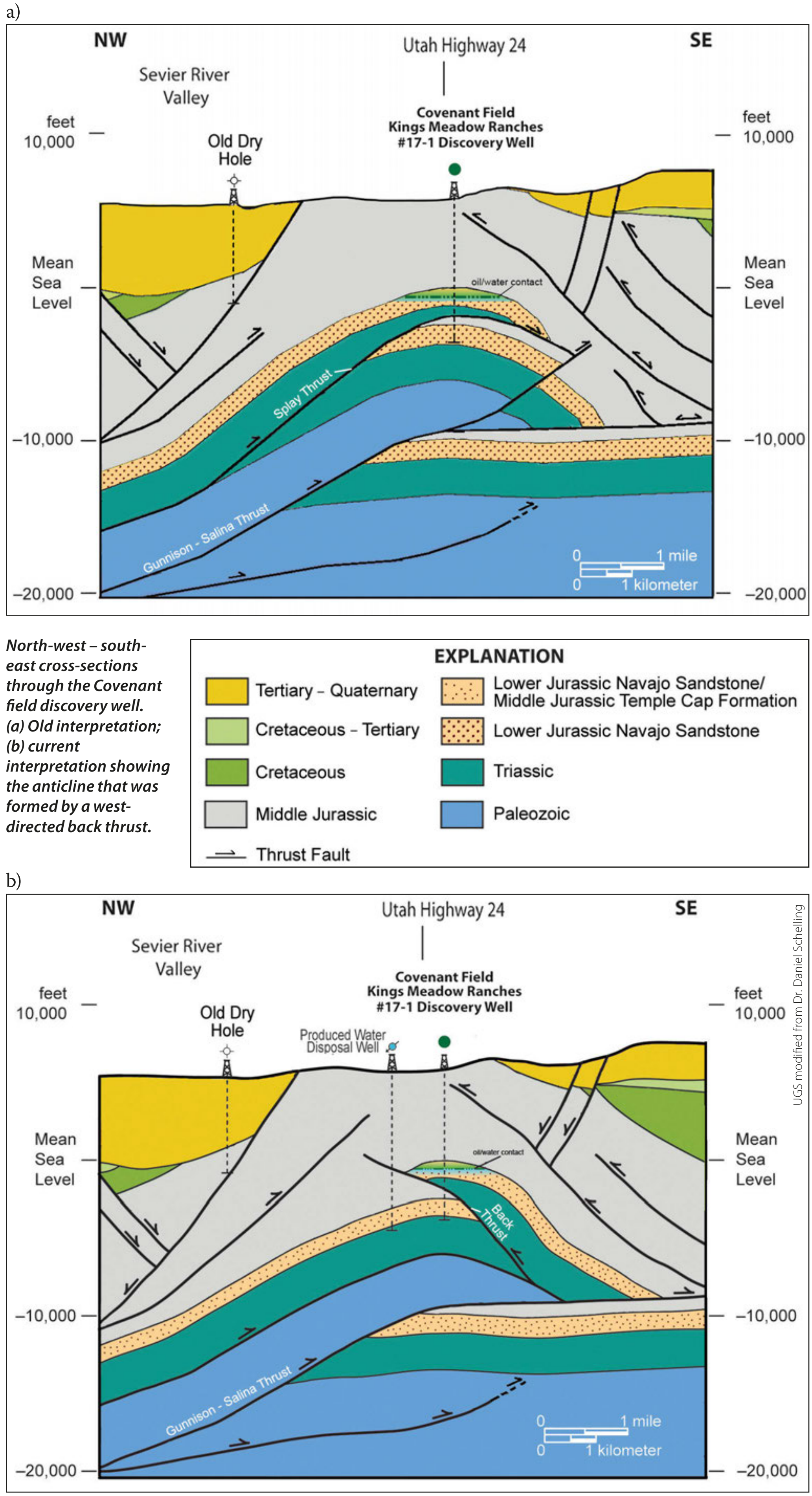
Chidsey explains, "Their new interpretation fits more closely with the type of structural features found along the regional-scale Sanpete-Sevier valley anticline that has been extensively mapped by Utah Geological Survey geologists and others. Now, we were looking at the producing anticline being formed by west-directed back thrust rather than the east-directed thrust splay fault. The now-mapped back thrust likely developed after the anticline had formed. This thrust reconfigured the 'paleotrap' proven by Dr. David Wavrek, president of Petroleum Systems International, Inc., and others in the 2010 paper, *Central Utah Thrust Belt Discoveries – A Tale of Two Hydrocarbon Charges*. The lack of significant associated gas at the Covenant field is due to water washing during the remigration event."

Complicating Factors

Finding the Covenant and Providence fields took a great deal of hard work by the geoscientists and possibly a little luck. These two finds, and a lot of dry holes, lend more complexity to the play than had been anticipated by geoscientists at the time of the Covenant discovery. Unraveling the petroleum system and accurately mapping structure are two of the complexities facing explorationists in this play.

Petroleum systems models take in all the elements that are necessary for hydrocarbons to accumulate and be preserved. In most mature producing basins, the geologic elements (source rock, migration, reservoir, trap and seal) and the timing relationships are relatively well understood.

"We are just starting to demonstrate the complexity of the petroleum system in the central Utah thrust belt," says Dr. Wavrek.



North-west – south-east cross-sections through the Covenant field discovery well. (a) Old interpretation; (b) current interpretation showing the anticline that was formed by a west-directed back thrust.

"The two discoveries give us a clue as to this complexity. The Covenant and Providence hydrocarbon charge was generated from Mississippian source rocks but at very different times. The Covenant hydrocarbons were generated early on at 90–100 Ma when the current field configuration was not established. A paleo-trap was necessary for the accumulation to form. Subsequent structural deformation that formed the current trap (70–80 Ma) resulted in hydrocarbon remigration with concurrent oil–water interaction stripping volatiles from the liquid phase. The hydrocarbon charge for the Providence field was later than the Covenant field (70–80 Ma) and was coincident with the structural development of the field. This field also contains the original gas-saturated liquid hydrocarbons that the Covenant field lacks."

This is not the only complexity in the petroleum system that Dr. Wavrek would like to bring out. "The Arapien Formation poses two additional complicating factors in finding producible hydrocarbons," he explains. "First, this complex and deformed mixture of clastic components, salts, and carbonates does not always provide the perfect seal. While the Arapien Formation is considered a regional seal, there are situations where it does leak that lead to dry holes. Satellite imaging shows the effects of micro-seepage through this shale by altering mineral signatures at the surface (*GEO ExPro* Vol. 3, No. 6). The complex mixture of greatly variable rock types pose the second complexity by distorting the time to depth conversion on seismic; hitting the reservoir much higher than predicted at the Covenant field was a clear example of this phenomenon. Since velocities through most salts are much faster than through carbonate and clastics, a salt pod (known to exist in the Arapien Formation) would be underlain by a seismic pull-up and a false anticline could be mapped."

"Finding good reservoir rocks could also be another complicating factor," Chidsey points out. "Outside the excellent reservoirs in the Navajo and Temple Cap sandstones, other formations in the region often have low porosity and permeability and are unable to store or produce oil."

Primary reservoirs for the Covenant field: the White Throne Member of the Temple Cap Formation is pictured along the skyline, underlain by the Navajo Sandstone. These two formations are separated by the J-1 Unconformity located at the tree line just above the Navajo Sandstone. The early Jurassic Kayenta Formation is in the foreground.

The Next Steps

While geoscientists have learned a great deal about the central Utah thrust belt, successful results have been very hard to come by, in part, from the true complexity of this play. This play may never see the results seen in the thrust belt salients that lie to the north. The Covenant may just remain the 'lucky one' until some geoscientist finds yet another prospect that a company is willing to risk big on. "There is much still to understand in central Utah," says Chidsey. ■

A hallmark of the Navajo Sandstone is the distinctive cross bedding, as exposed along the scenic drives through Zion National Park.

From Arrhenius to CO_2 Storage

Part VII: Arrhenius' Greenhouse Rule for CO_2

LASSE AMUNDSEN and MARTIN LANDRØ, NTNU/Bivrost Geo

"Is the mean temperature of the ground in any way influenced by the presence of heat-absorbing gases in the atmosphere?"
Svante Arrhenius, 1896

In Part II of this series (*GEO ExPro* Vol. 16, No. 3, 2019) we referred to Arrhenius' relationship between radiative forcing (heat warming) of CO_2 and its concentration in the atmosphere, and glibly informed you that the effect is logarithmic. However, there is no simple proof as to why this is the case. In this article we investigate this, as it sheds light on understanding climate feedback and sensitivity. We go on to show how the surface temperature changes with variation in CO_2 concentration. Our simplifications should only be regarded as the first steps toward getting a feeling of the greenhouse effect.

Radiative Forcing

The greenhouse effect is caused by the absorption of longwave, infrared radiation from the Earth by greenhouse gases in the atmosphere. Changes in the concentration of these gases lead to a change in the radiative energy absorbed, and thus a change in the temperature of the atmosphere, leading to a change in its radiation back to Earth. The difference in radiation received by the Earth between two defined conditions is called radiative forcing (Myhre et al., 2013).

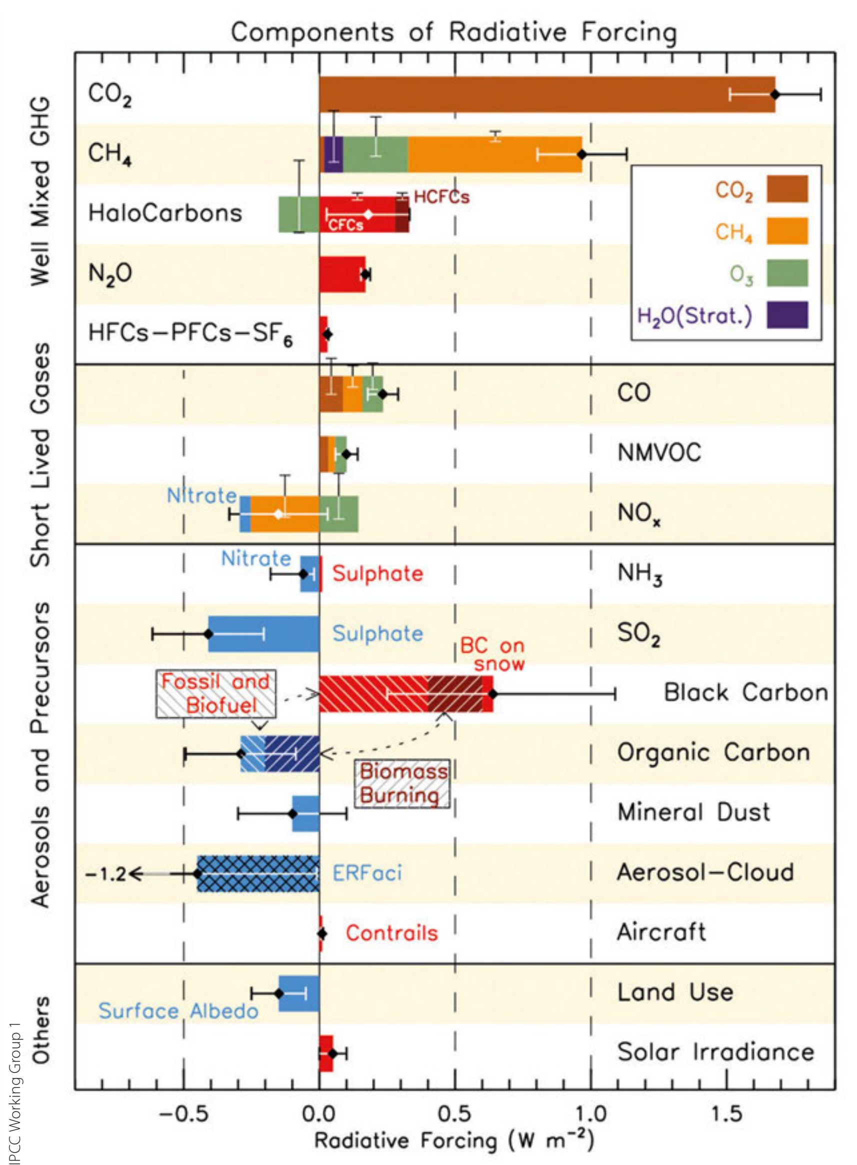
There are two common examples given in the literature. The first is the forcing believed to be caused by an increase in atmospheric CO_2 concentration since pre-industrial times. The second one, obtained from computer climate models, is the forcing produced as a result of doubling the concentration of atmospheric CO_2. The forcing can be converted to a mean global surface temperature change by multiplying it by a climate sensitivity parameter which varies between the different models. Radiative forcing is considered a direct measure of the amount by which the Earth's energy budget is out of balance.

In 2014, NASA launched the satellite OCO-2 (Orbiting Carbon Observatory-2) to monitor CO_2 in the Earth's atmosphere.

On Arrhenius' Greenhouse Rule for CO_2

The history of CO_2 and climate usually starts with Arrhenius' 1896 paper arguing that increased levels of CO_2 could raise global temperatures. Other scientists rejected this assertion, based on their belief that CO_2 did not absorb any radiation wavelength that was not also absorbed by water vapor: the atmospheric CO_2 level is so small compared to the level of water vapor that its effect would be insignificant. Therefore, for nearly 50 years the scientific consensus stated that CO_2 could not affect Earth's temperature.

However, Arrhenius believed that atmospheric CO_2 (and other gases) had an effect on surface temperatures; and he formulated a greenhouse rule for CO_2 by stating: "If the quantity of carbonic acid increased in geometric progression, the augmentation of the temperature will increase nearly in arithmetic progression." The augmentation of the temperature is the change in the rate of heating Earth's surface (i.e., radiative forcing).



IPCC Working Group 1

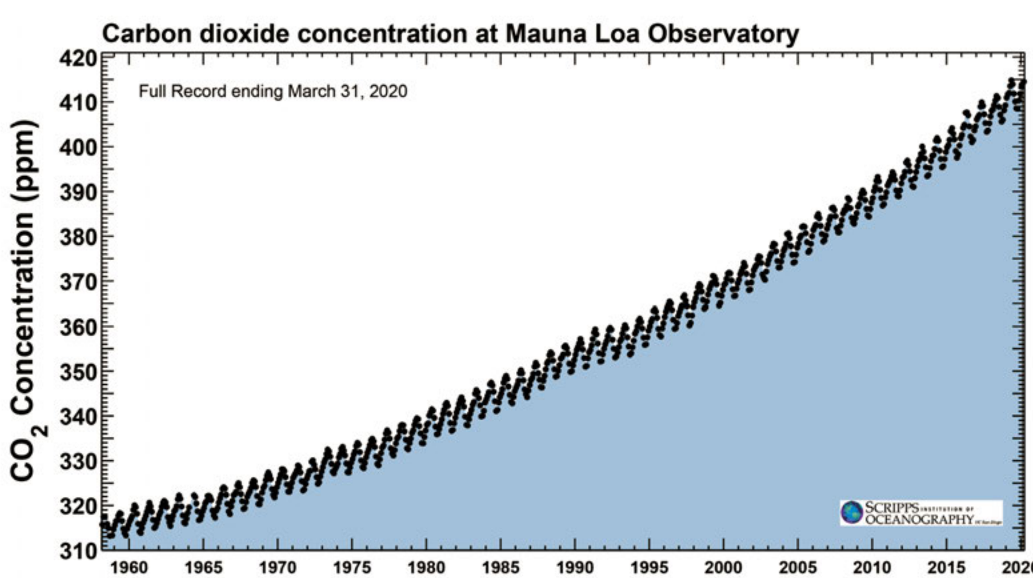
Radiative forcing since 1750.

To interpret Arrhenius' statement, we need to recall some basic math. Progressions (also called sequences and series) are numbers arranged such that they form a predictable order; i.e. that given some numbers, we can find the next numbers in the series. A sequence of numbers is an arithmetic progression if the difference between any two consecutive terms is always the same. When the initial term of an arithmetic progression is a_1 and the common difference of successive members is d, then the n'th term of the sequence is given by $a_n = a_1 + (n-1)d$. A sequence of numbers is called a geometric progression if the ratio of any two consecutive terms is always the same. The general form of a geometric sequence is $a, ar, ar^2, ar^3, \ldots$ where r is the common ratio, and a is a constant. What is of interest to us now is that geometric sequences show exponential growth (or decay), as opposed to the linear growth (or decline) of an arithmetic progression.

Now, according to Arrhenius' calculations, when CO_2 increases in geometric progression – say, from 1 to 2 to $2^2 = 4$ to $2^3 = 8$ … i.e. has exponential growth – the radiative forcing increases (nearly) in arithmetic progression – i.e. shows linear growth. Since logarithmic and exponential functions are inverse functions, equation (1) below suggests itself. In particular, when $C/C_0 = (1,2,4,8\ldots)$ then $\Delta F = (0,1,2,3,\ldots)\alpha\ln(2)$.

In Table VII of his paper (see Part II), Arrhenius lists calculations of variation of radiative forcing caused by a given variation of CO_2. At latitude 0, CO_2 ratios of 1, 1.5, 2.0, 2.5, 3.0 yield temperature increases of 0, 3.1, 4.9, 6.3, 7.2, respectively. We can

The Keeling Curve is a graph of the changes in atmospheric CO_2 concentrations since 1958 taken at the Mauna Loa Observatory, 3,300m above ground level in Hawaii, by the Scripps Institution of Oceanography. The measurements show a steady rise from about 316 ppm in 1959 to 414 ppm in March 2020. The annual fluctuation in CO_2 is caused by seasonal variations in CO_2 uptake by land plants. Since CO_2 is a greenhouse gas, the curve has been interpreted by many climate scientists as a warning signal for global warming. The effect of the outbreak of the coronavirus pandemic declared by the World Health Organization (WHO) on 11 March 2020 is expected to show up in this curve after some time.



easily check the validity of Arrhenius' observation by calculating the constant α for each of his calculations, which we find to be in the range 6.6–7.7 and thus in agreement with the quote we have taken from Arrhenius' paper. The relationship between concentration and radiative forcing is nearly logarithmic.

Why Logarithmic?

Logarithmic equations for calculating the radiative forcing of CO_2 are common. The functional form:

$$\Delta F = \alpha \ln(C/C_0) \text{ [W/m}^2\text{]} \qquad (1)$$

was published by Wigley (1987) using the model of Kiehl and Dickinson (1987). Here, C is the CO_2 concentration and C_0 is the reference concentration at the beginning of the period being studied. The form in equation (1) was used by IPCC 1990 with coefficient α derived from Hansen et al. (1988). The best estimate based on radiative transfer calculations with 3D climatological meteorological input data (Myhre et al., 1998) is $\alpha = 5.35$. Even though there is no theoretical basis for formula (1), it has been accepted by the scientific community as a reasonable approximation for the range from 275 ppm to 378 ppm of CO_2, the levels from the beginning of the Industrial Revolution to 2005. The logarithmic relationship implies that radiative forcing will rise by roughly the same amount for each doubling of CO_2 concentration. Thus, increased concentrations have a progressively smaller warming effect.

Let's calculate the radiative forcing from the beginning of the Industrial Revolution, $C_0 = 275$ ppm, to October 2019 when $C = 408.55$ ppm. Equation (1) gives the warming effect $\Delta F = 2.06$ W/m². That may not sound like much until you multiply by Earth's total area, which gives a total warming effect of about 1,050 TW – more than 58 times the world's average rate of energy consumption, which is currently about 18 TW.

The logarithmic dependency is intriguing. Clues of its usefulness are given also in textbooks, usually pointing to the spectroscopic features

Do Goats Combat Climate Change?

U make me goat crazy.

All animals emit methane, which can be converted into CO_2 equivalents; goats in Norway emit approximately 24 kilotons per year. Since the goat and sheep population is decreasing, the area of cultivated land is also decreasing, to be replaced by bushes and trees. This causes a reduction of approximately 6% in the albedo effect (the difference between cultivated agriculture landscape and the same landscape covered by bushes and trees). So, there are obviously two counteracting effects: the decrease in global temperature caused by increased albedo if, say, five goats keep 1,000m² clean, compared to the increase in temperature caused by the emissions from the same goats. For simplicity we assume that the goats are only fed by the grass and vegetation they eat. We use the equations derived in this article to obtain a ballpark estimate and compare the two effects.

The change in temperature due to change in albedo is $\Delta T_{albedo} = T\Delta\alpha/(4(1-\alpha))$. The change in albedo for the 1,000m² has to be scaled by the earth's surface. In addition, we have to correct for the fact that approximately 70% of the incoming solar radiation is reflected by clouds and does not hit the earth's surface. Then $\Delta\alpha = 0.06 \cdot (1 - 0.7) \cdot 1{,}000/(5.1 \cdot 10^{14}) = 3.53 \cdot 10^{-14}$, leading to a temperature change of $\Delta T_{albedo} = 3.65 \cdot 10^{-12}$K which of course would have a negligible effect on climate.

The five goats emit approximately 1.86 tons of CO_2 per year; this represents $1.86/(35 \cdot 10^9) = 5.31 \cdot 10^{-11}$ of the total global yearly emissions. The yearly increase in atmospheric CO_2 is (see the Keeling curve) approximately 1.82 ppm/year. From equation (6) we find that the change in temperature is $\Delta T_{co2} = 3.71 \cdot 10^{-13}$K. We observe that the albedo effect is approximately ten times the CO_2 emissions from the five goats. It is of course a very simplified example, where several of the numbers used are not perfect, but we can actually state: goats do combat climate change. ■

of the absorption lines. The interested reader may consult Goody and Yung (1989) or Pierrehumbert (2010). More recently, Huang and Shahabadi (2014) have proposed a simpler argument for why we would expect logarithmic dependence for monochromatic radiance, i.e. at a single wavelength.

Temperature Increase

A figure in Part VI (*GEO ExPro* Vol. 17, No. 1) depicts radiative equilibrium for the Earth system with a single-layered atmosphere. At the surface the downward radiation flux emitted by the atmosphere is $F = (\beta/2)\sigma T^4$, where we have substituted the atmospheric temperature with the surface temperature according to equation (2) in Part VI. Increasing, say, CO_2 concentration by a given amount corresponds to an increase $\Delta\beta$ of the absorption efficiency. The radiative forcing is the radiative response to the forcing agent, taking place quickly without change in temperature; then the energy imbalance imposed on the climate system is:

$$\Delta F = \Delta\beta\sigma T^4(\beta)/2 \qquad (2)$$

Now, since more energy is radiating down on Earth than is radiating back out to space, the planet gets upset; its response is to heat up. Eventually, after decades, a new equilibrium state is reached where the surface temperature has increased by ΔT. Equation (1) in Part VI defines the new temperature as $T(\beta + \Delta\beta)$. For a sufficiently small perturbation, a Taylor series expansion of $T(\beta + \Delta\beta)$ yields:

$$\Delta T = T(\beta + \Delta\beta) - T(\beta) = \frac{T(\beta)\Delta\beta}{8(1-\beta/2)} \qquad (3)$$

By use of equations (1, Part VI) and (2) above we can eliminate $\Delta\beta$ in equation (3) and obtain the linear relation:

$$\Delta T = \lambda\Delta F \qquad (4)$$

where λ is the climate sensitivity factor:

$$\lambda = T(\beta)/(S(1-a)) \qquad (5)$$

We proceed with a cavalier disregard for the observed limitations of the one-layer educational atmospheric model and insert Arrhenius' rule (1) into equation (4), thereby suggesting that:

$$\Delta T = \gamma \ln(C/C_0)\ [\mathrm{K}]\ ;\ \gamma = \lambda\alpha \qquad (6)$$

The Earth is generally regarded as having warmed about 1°C since the beginning of the Industrial Revolution, around 1750, when the global average amount of CO_2 was 275 ppm. We can use that temperature T = 15°C (288.15K) as a baseline for estimating the effect of CO_2 doubling.

First, calculate from equation (5) the climate sensitivity factor λ = 0.302 km^2 W^{-1}. Secondly, calculate $\gamma = \lambda\alpha$ = 1.61 and insert into equation (6) to find the temperature increase ΔT = 1.61 ln(2) K = 1.12°K. Thus, the simple greenhouse model predicts a global warming of around 1.12°C for a doubling of CO_2. This value is too low compared to more advanced models, which allow for positive feedback, notably from the increased water vapor due to increased temperature. A simple remedy for including this feedback process is to posit an additional increase of $\Delta\beta$ to approximate the effect of the increase in water vapor that would be associated with an increase in temperature.

Allowing $\Delta\beta$ to double, the model then predicts $\Delta T \approx$ 2.24°C for a doubling of CO_2, roughly consistent with the IPCC understanding that climate sensitivity is somewhere between 1.5–4.5°C of warming for a doubling of pre-industrial CO_2 levels.

We await the IPCC's new assessment of global warming, due in 2021. New computer models predict a warming surge, where equilibrium sensitivity looks to be 5°C. However, in assessing how fast climate may change, the next IPCC report is expected to look to other evidence as well, in particular how ancient climates and observations of recent climate change constrain sensitivity. ■

China's Deep, Hot, Harsh Reservoirs Spur Innovation

The experiences, lessons learned and best practices of Chinese geoscientists working in difficult reservoirs can be of benefit to others.

SUSAN SMITH NASH Ph.D., AAPG

In the quest to produce hydrocarbons from China's famously deep, harsh and hot reservoirs, Chinese companies, together with research efforts involving key state laboratories and universities, have developed innovative new techniques and technologies, many of which have direct applicability to other basins and reservoirs in the world.

The following examples are just a few of those which were implemented in 2019 and early 2020. The first ones involve research performed at the Chengdu University of Technology, while the final example is the result of findings by Sinopec's research facilities and operations. The full studies are forthcoming in issues of Sinopec's Petroleum Drilling Techniques, with abstracts to be available through AAPG's Search and Discovery website.

Chengdu University of Technology is one of four AAPG-China Research Centers, which were formed to provide a means for scientific exchanges and conferences between geoscientists. These research centers are located at China University of Petroleum-Beijing, Chengdu University of Technology, China University of Petroleum East (Qingdao), and Northeast Petroleum University.

Drilling and Completion for Ultra-Harsh Conditions

Moving outside the lab and looking at drilling and completion operations in the complex environment of the southern Sichuan Basin, engineers and geologists have worked together to develop innovative X-Ray Fluorescence and logging-while-drilling techniques in order to successfully geo-steer wells and to avoid moving out of the target zone. The new tool was successfully applied in 18 wells in the Weirong Gas Field operated by Sinopec.

Slim Liner Cementing Technology

China's ultra-deep wells, such as those in the Shunbei Block, present serious challenges when it comes to cementing, particularly in the case of a narrow annulus. Some of those challenges include high bottom hole temperature and pressure, weak cement sheaths, high displacement pressure in the downhole pump, and the development of a high-pressure brine layer. To solve the problem, a team at Sinopec developed a new slim liner cementing technology that involved enhanced rheology design and a gas-kill valve that avoided the problems of channeling.

EOR Technologies in China's Continental Oilfields

The low price of oil and gas does not have the same impact on Chinese oil and gas exploration and production that it might for other countries, primarily due to the fact that the petroleum is destined for domestic consumption, and forms a part of the country's 5-year and 10-year plans. There is particular emphasis in EOR (enhanced oil recovery) in China's mature fields because of the existence of excellent infrastructure, such as pipelines, gas conditioning, as well as proximity to markets. As a result, there have been two major thrusts in Sinopec's research. The first was to develop CO_2 injection whenever possible, using carbon captured in coal-fired plants, in order to store it and then inject it into the old fields. Secondly, there has been an emphasis on reducing noise, eliminating methane emissions and on conserving water, particularly in the fields that are technically in urban areas. One promising technique is to use dual parallel simultaneous injection and production, or SIP.

Chengdu University of Technology in Sichuan province.

SIP in the Daqing Oilfield

The technique of dual parallel simultaneous injection and production uses a downhole oil–water separation device, which allows the separated water to be injected back into the formation, while the oil with a now much reduced water content is lifted to the surface. In essence, what this gives us is simultaneous injection and production. Used in the Daqing Oilfield operated by PetroChina, initial results included an impressive reduction of water cut from 98% to 77%. Research work is continuing on this technique, with further improvements in sensors and analytics being noted, resulting in improved efficiency and better prediction of equipment failure.

New Technologies for Prospectivity Determination

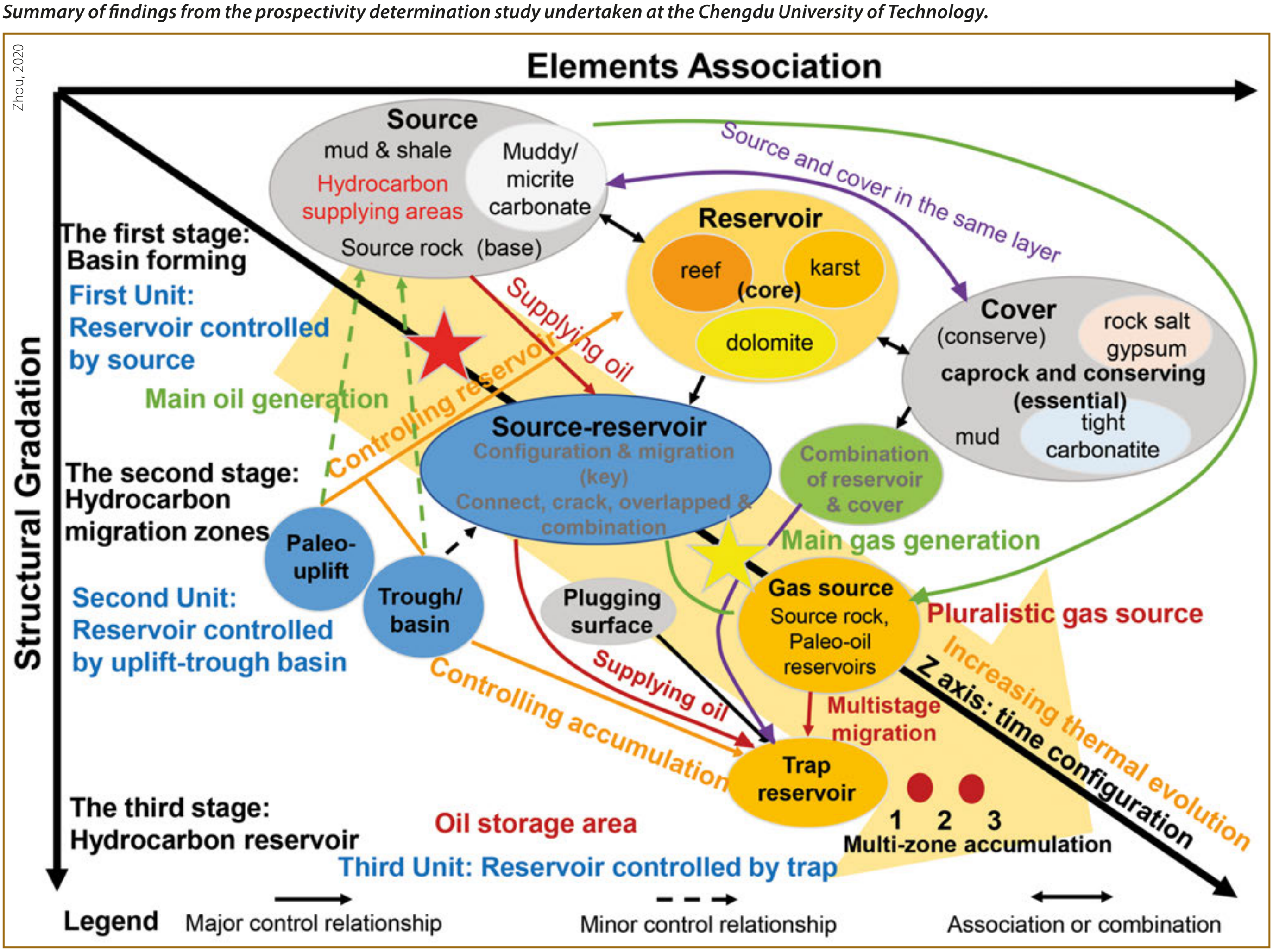
The exploration process starts by determining the prospectivity of the reservoirs. To that end, new approaches to basin modeling are built by bringing together in-depth geochemical and pore characterization studies. For example, at the Chengdu University of Technology, researchers such as Professor Wen Zhou, Dean of the School of Energy Resources, study the prolific but extremely challenging Sichuan Basin, which contains several petroleum systems, and possesses challenges like carbonate reservoirs, tight gas sand, volcanic reservoirs, shale oil and shale gas, coalbed methane and oil sand. One effective method for determining the age of petroleum generation and then identifying faulting, fracturing, and migration pathways has been to use advanced geochemistry, including isotope fingerprinting, to clarify the dates of five major tectonic movements, before then tracing the 12 separate unconformities.

Because the 13 separate oil and gas reservoirs in the Sichuan Basin primarily produce gas, with the exception of the Jurassic Ziliujing Formation, which also contains oil, the study of gas adsorption along with the reservoir's geomechanical profile has allowed teams of geologists, geophysicists and engineers to develop 4D models that display how stresses and strains change over time, and the impact of this on the maturation of kerogen, and thus identify the regions of preferential enrichment. In conducting this simulation, it is possible to start building a model that includes recommendations for the location of the laterals. Findings were summarized in the diagram below.

Many Successful Innovations

The technologies described in this brief article represent only a few of the innovations designed to successfully tackle the challenging reservoirs in China. While the conditions in most of the world's reservoirs are not so daunting, the lessons learned can be applied in many places, with better initial success, lower costs and longer-lived production. ■

Summary of findings from the prospectivity determination study undertaken at the Chengdu University of Technology.



Buscador:

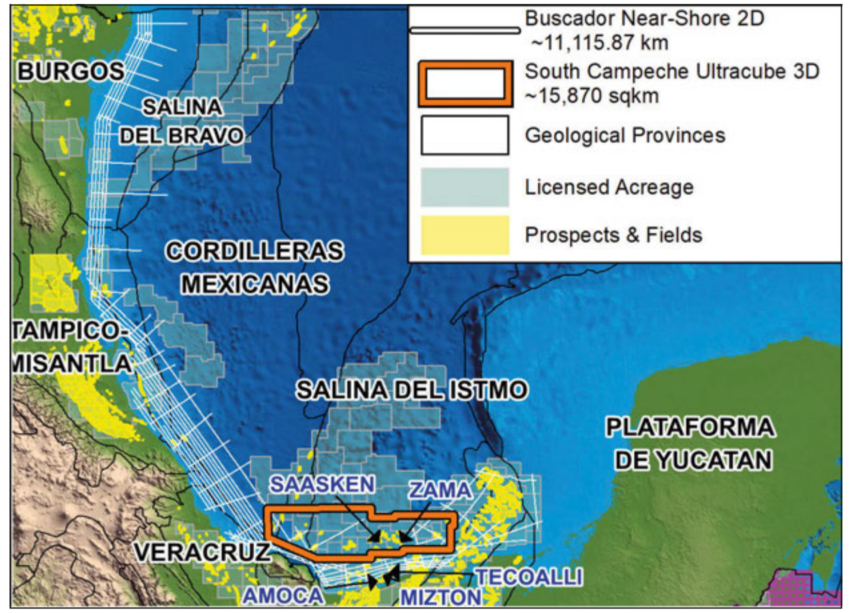
The 'Searcher-Engine for Oil' in Mexico's Hottest Hotspot

In 2016, in the white heat of Mexico's newly opened offshore exploration scene, Searcher overcame the operational challenges of acquiring data in water depths between 20 and 2,000m, to produce the amazing quality Buscador 2D survey. The much-improved images obtained in the shallow water compared to legacy data allow the identification of many new plays and prospects.

In addition, in what has proved to be an even more prolific area over the last two years, the survey ties ENI's Mizton and Tecoalli Fields, successfully showing the same stacked amplitude anomalies that ENI recently revealed as the key to success in their reprocessed 3D dataset.

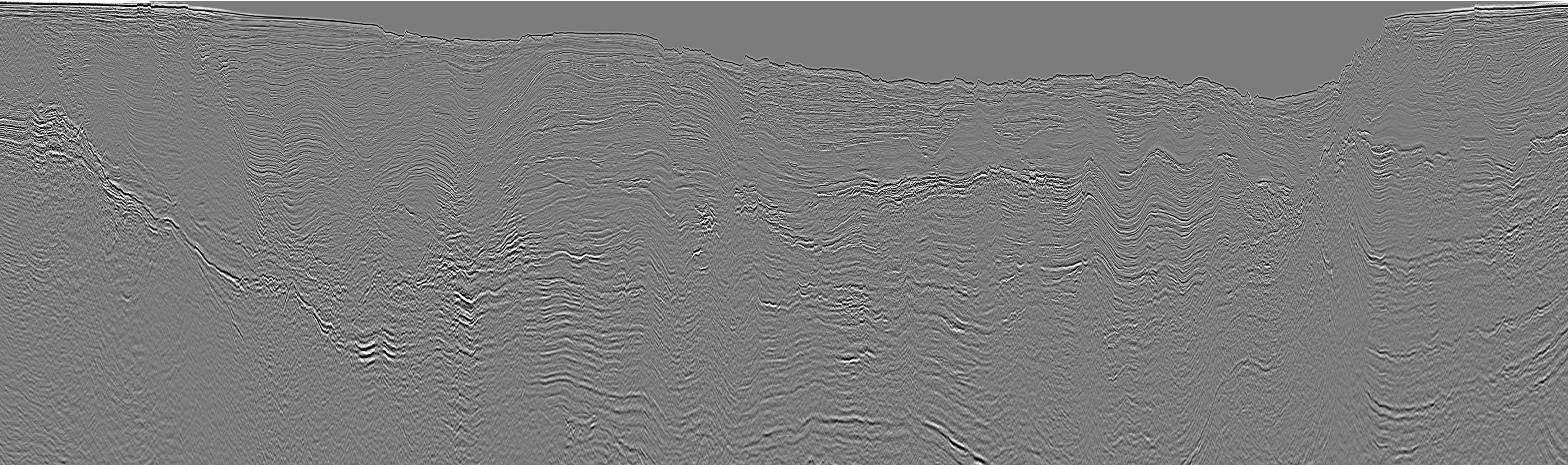
The foldout line below demonstrates the quality of the seismic, where it is possible to see amplitude supported structures; amplitude anomalies in potential stratigraphic traps in turbidite channels associated with mixed turbidite contourite systems; and good shallow and deep water reflectivity enabling regional source rock mapping for thermal maturity and migration pathway modeling.

Searcher



Location of Searcher's seismic datasets offshore Mexico with geological basins outlined and the location of major recent Talos and ENI discoveries.

Buscador 345-km-long 2D strike line in TWT, demonstrating the many features visible in this high quality dataset.



Offshore Mexico: Extraordinary Play Systems Identified

Improvements in seismic processing are revealing huge potential in the southern Gulf of Mexico.

KARYNA RODRIGUEZ and NEIL HODGSON, Geoscience Team; Searcher

The Mexican part of the Gulf of Mexico (GOM) is a proven world class hydrocarbon province. With a staggering 56 Bboe cumulative production and proven 1P, 2P and 3P reserves of around 80 Bboe, it is estimated to still hold prospective conventional resources of around 52 BBboe (www.pemex.com). The Sureste (Salina del Istmo/Cinturon Plegado Catemaco) Basin is the most explored, with 61 Bboe recoverable from 480 discoveries, including the super-giant Cantarell Field – one of the largest hydrocarbon accumulations in the world.

These impressive oil resources were mostly charged from the world class Tithonian source rock (average 5% TOC, HI of 600 and 120m thickness). A unique sequence of tectonic events combined with a fortunate stratigraphic evolution has resulted in multiple stacked play systems in both deeper, older carbonate systems and shallower, younger clastic deposits. Despite this significant potential, since 2007 production has been declining from the mature fields and new fields have been slow to come on stream.

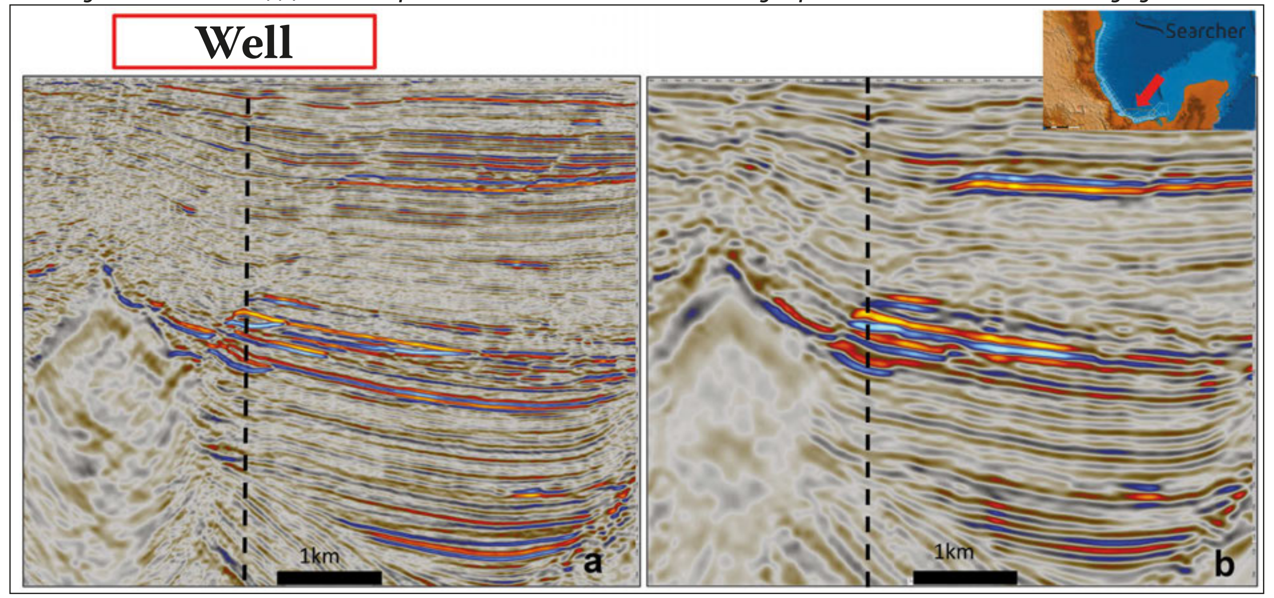
To revitalize the economy and exploration for oil and gas, in 2013 Mexico introduced new reforms, inviting participation from international exploration players and generating a lot of interest in the country, resulting in several major seismic acquisition campaigns to support the very successful series of license rounds held between 2014–2018. In 2017 this new initiative began to bear fruit with the Zama discovery, operated by Talos Energy. This is a great example of utilizing modern, high fidelity seismic processing to realize the potential of the extremely prolific Sureste Basin.

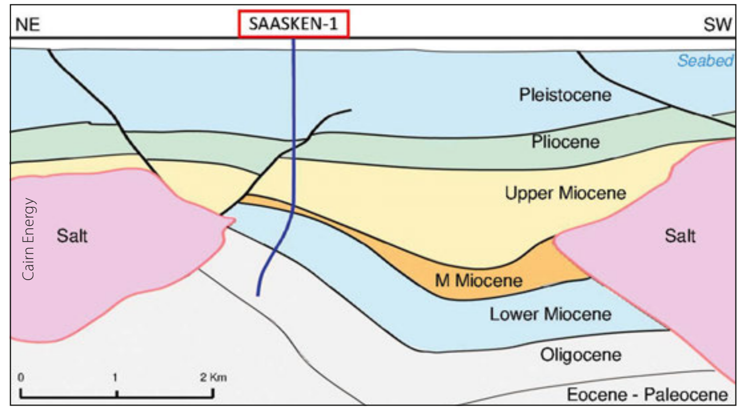
Advances in Seismic Processing Key

In our industry, the area that has shown most advancement over the last ten years is seismic processing. New algorithms, better processes and undreamed-of computing power enable even legacy data to be reprocessed and reveal previously unimageable treasures. Another example from the Sureste Basin, but in shallower water depths nearshore, is the ENI reprocessed legacy seismic data over the Amoca, Mizton and Tecoalli discoveries, which has revealed multiple stacked amplitude anomalies. When tested in an appraisal campaign, this more than doubled the original reserve estimates to 2.1 Bboe. This complex of fields, which had only been awarded in September 2015, was brought onstream as quickly as July 2019.

To the north-west of the Sureste Basin, the much less explored Cordilleras Mexicanas, Tampico Misantla and Burgos offshore basins lie in an arc stretching all along the east coast of Mexico. In 2016, whilst overcoming the extreme operational challenges of acquiring data in water depths between 20 and 2,000m, Searcher recorded a nearshore regional grid of modern 2D seismic across all these basins (see map previous page). These new data were acquired with longer streamers, allowing more precision in the use of far-offsets to find hydrocarbons directly – something still difficult to do with legacy reprocessing. With excellent imaging across all the western part of the Mexican GOM, the survey design provides modern, high quality imaging of the most prospective nearshore areas sweeping around the coast, as well as tying key wells, main discoveries and 22 previously mapped prospects and leads. Aided by Searcher's Seisintel, which captures 2D and 3D seismic activity, streaming survey navigation directly from vessels to a desktop in real-time, a special feature of this program was to make sure the grid tied lines from the other surveys which were being acquired at the same time.

Searcher's 2017 reprocessed Ultracube South Campeche 3D with the well projected on Kirchoff and RTM versions: (a) South Campeche 3D Kirchoff – note high vertical resolution; (b) South Campeche 3D RTM iterative salt model building sequence. Note excellent salt flank imaging.





Sketch section through the Saasken well (preliminary results).

To complement this dataset, a deeper water 3D cube was reprocessed in the same year, covering the South Campeche Basin where the Zama Talos and more recently, in February 2020, the Saasken ENI discoveries were made.

Regional Basin Analysis

The acquisition and reprocessing of the aforementioned datasets was supported by a regional basin analysis study carried out by Searcher with the participation of geoscientists who had previously worked in Finder, a company with extensive experience in the area, who see clear evidence to support the 'in situ plate tectonic model' (Keith James, 2009) for the Caribbean. The in situ model was modified in this study (Jablonski and Larsen, AAPG DataPages 2017) and its influence extended to the GOM, providing a simpler explanation for some of the observations made in the region, such as an increase in Upper Wilcox Formation sand deposition attributed to the onset of the Cayman Trough spreading ridge and associated compression onshore Mexico and eastern US Cordilleras. It also provides an explanation for the much wider distribution of the thick Jurassic and Cretaceous sequences particularly in Jamaica, where little sedimentation is expected according to the Pacific model, as well as insights into the Pacific plate history and its interaction with North America, suggesting that subduction only affects the western portion of the continent, with the thrusts observed in the eastern lowland of Mexico being the result of the Caribbean plate expansion. It also proposes a trigger for Miocene gravity slides as the Cayman Trough spreading accelerates, continuing to create compressional tension onshore Mexico as well as a trigger mechanism for halokinesis and some important insights into hydrocarbon migration and timing.

The objective of the new acquisition and reprocessing campaign was to provide a cost-effective dataset to allow oil companies to focus their exploration budgets on key prospective areas. Additionally, the accompanying basin analysis report developed by Searcher identified 24 distinct play levels across 15 geologically separate regions, with play intervals from Jurassic through to Pleistocene. The area around the coast in general is highly prospective with more outboard potential plays including basin floor fans and gravity driven structures in the south of the Gulf. Early access to the geological framework in the basin analysis report was conflated with Seisintel information to identify existing seismic data gaps on the margin. This in turn informed the optimization of the 2D survey (Buscador Near-Shore) and the specification of the 3D surveys that needed reprocessing (South Campeche Ultracube).

In each basin, extraordinary play systems are developed, such as fractured carbonate, salt evacuation basins, Early Tertiary turbidites, Late Tertiary subsalt, Late Tertiary supra-salt mini basins and Pliocene drape, each tapping into the proven hydrocarbon source, and mostly revealing good Direct Hydrocarbon Indications (DHIs) on both Searcher's 2D and 3D seismic datasets. Offshore Mexico, in the area covered by Searcher's seismic datasets, there remain significant unexplored clastic prolific play fairways with abundant undrilled amplitudes, salt-related traps, carbonate potential where the fracture network was not fully understood, and fractures not intersected. Drilled plays are likely to have missed pay potential, and there are valid structures with drilling issues classified that were as dry and a Jurassic secondary play which remains mainly untested.

High Quality Regional Datasets

Whilst it had been assumed that Mexico's declining production had resulted from a of lack of funding for exploration, in fact a subtler problem has been revealed. The issue was not a lack of key investment in drilling wells but instead a lack of investment in the underlying seismic data. Globally, seismic acquisition – and more so, seismic processing – has been advancing at a prodigious rate over the last 10–15 years.

Now, explorers offshore Mexico can take advantage for the first time of this superior imaging in the nearshore, manifestly demonstrated in the Buscador 2D data. New DHIs are imaged, new prospects mapped and the potential of new plays can be hunted down and evaluated. The handicapping of the past has handed explorers today a huge advantage with the chance to use high quality regional datasets to focus on finding the giant fields of the future. The Zama and Saasken discoveries, as well as the ENI development success story, just mark the beginning of this journey, started by improvements in seismic processing, and still to be traveled by an industry that will be focused more than ever now on oil in shallow water giant potential plays. ■

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Big Data and Post-Graduate Training

The future for subsurface analysis and graduate training: a call to universities to respond and adapt to industry needs.

Dr. MIKE BOWMAN, Honorary Professor, University of Manchester

Today's upstream oil and gas subsurface geoscience and engineering technical communities are facing a new world as Artificial Intelligence (AI), data analytics and big data become an increasingly core part of the subsurface workflow. Not since the late 1980s have such challenges presented themselves to upstream oil and gas. Successful companies will be those that are flexible and adapt to the changes, which will also have a knock-on effect on universities that have developed petroleum-related geoscience and subsurface engineering graduate and research programs. The challenges are exacerbated by the impact of the climate emergency, with some institutions shifting consciously away from carbon-related investment and research. Many larger company strategies are also moving away from coal and oil to cleaner gas and renewable fuels with no damaging emissions. All of this is being accompanied by reduced exploration investment and increasing focus on improving recovery efficiency in existing fields, providing a further dimension to the challenge.

A Dramatic Challenge

The last 30 years has seen a growth and proliferation of petroleum-focused subsurface master's training programs. These developed in response to increased demand and a conscious shift of companies to needing broader-based generalists with master's level education. In parallel with this the number of sponsored applied Ph.D. studentships, which had flourished during the 1980s, dropped significantly. At the same time demand for specialist subsurface geological and engineering skills flattened out and, in some areas (e.g. biostratigraphy), began to decline. These changes fundamentally shifted the focus and balance of applied subsurface post-graduate education at many universities and institutions.

Today we are facing what promises to be an equally dramatic challenge that is likely to have far-reaching effects on those universities that do not respond and adapt to industry needs. AI and data analytics are leading to profound changes to the nature and scale of the technical subsurface workforce in many operating and service oil and gas companies and

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as a result, on future employment demand. The growth in automation underpinned by data analytics and AI is already reducing demand for graduate level entries in many of the medium to large-size companies that have traditionally been the source of much employment in the recent past. The data analytics revolution is leading to a change in working practices with less need for dedicated asset teams constantly upgrading and rebuilding subsurface models and descriptions throughout the life of a field. The future looks very different, with much smaller asset teams and more automated workflows and model upgrades, where interventions and new work will be driven by deviations outside an uncertainty range defined by an asset's data-driven models and descriptions. Larger companies will likely evolve to have small subsurface asset teams supported by larger centralized groups comprising experts, specialists and broadly experienced practitioners, organized to react to any alarms or deviations from a model-based subsurface description and reservoir performance prediction. This organizational model will likely be replicated by the major service providers, supporting smaller operating companies.

Rapidly Changing Demand

All of the above is leading to a profound change in the graduate education supply model. The numbers registered on master's programs will probably continue to decline or at best level out for those well-recognized and established programs. Some programs may disappear completely if they cannot evolve and adapt to changing needs. Commensurately there will likely be increased demand for Ph.D. level recruitment in the areas of subsurface description and reservoir performance prediction. Models like the UK's CDT (Centre for Doctoral Training) might evolve to produce more business-oriented and commercially-savvy students complementing their research expertise. In the immediate future, key skills gaps will be in subjects such as geomechanics and reservoir scale structural geology, as well as digital petrophysics, rock description and modeling.

Successful universities will evolve their programs and offers to address the rapidly changing demand. A wider range of subsurface energy industry systems will become part of the mix and drive demand, including topics such as geothermal, carbon capture, ultilization and storage and radioactive waste disposal. Many of the skills needs in these non-petroleum areas are generic, being related to subsurface description and modeling. Partnerships and collaborations between universities and industry similar to the CDT model offer a possible route to sustained success.

Collaboration Needed

It is really important that higher education institutions adapt and evolve to these changing demands or many programs will disappear and the pipeline of appropriately skilled graduates will not meet the demand from a broader subsurface energy systems agenda. The next five years promise to be a fascinating time as these changes begin to take effect.

Collaboration and partnerships are not an easy working model for what are often naturally competitive and reluctant-to-change higher education establishments and those more conservative oil and gas companies, but some universities are already beginning to adapt and evolve, and many larger companies are recognizing the changing organizational models and their impact. ■

A Kerry Diamond

The locals call them 'Kerry Diamonds'; beautifully clear, euhedral quartz crystals found on the Dingle Peninsula in south-west Ireland – but the real gem is the Peninsula itself!

Prof. BRIAN WILLIAMS

The Dingle Peninsula, the most northerly of the major peninsulas of south-west Ireland, is an area of outstanding natural beauty. About 50 km long and 25 km wide, it is dominated by a mountainous spine stretching from the Slieve Mish Mountains near Tralee in the east, through the dramatic Brandon Mountain Range in central Dingle and onwards to Mt. Eagle and the Blasket Islands in the south-west. The stunning mountains reach to 950m, terminating at sea cliffs interspersed by beautiful sandy bays; scenery beloved by film producers, from *Ryan's Daughter* to *Star Wars*!

The unique landscapes of the Peninsula are generated by the very wide diversity of preserved rock sequences, mainly sedimentary and volcanic, together with large-scale tectonic features that have evolved through 485 million years (Ma) of Earth history.

Three Major Deformation Periods

The Peninsula preserves a unique succession of Ordovician to Carboniferous rocks (485 to 330 Ma in age), dominated by a thick, continental red-bed Devonian sequence which comprises the most complete Old Red Sandstone magnafacies in Ireland. Together with the underlying shallow marine and volcanic Silurian sequence, this Mid-Paleozoic suite accounts for over 5.8 km of the Peninsula's rock assemblage.

The Dingle Peninsula is situated to the south of the Iapetus Suture zone (the Early Caledonian plate boundary). It is bounded by two long-lived, east-north-east trending lineaments, the North Kerry Lineament (NKL) and the Dingle Bay Lineament (DBL) that provided the foundation for both its tectonic and sedimentary evolution.

The Paleozoic rocks of the Peninsula have been profoundly affected by three major periods of deformation related to plate tectonics over a 185 Ma period: the Early Caledonian (around 470 Ma); the Late Caledonian [Acadian] (around 400 Ma); and the Variscan Orogeny (318–297 Ma). These deformational episodes generated folding on various scales and thus repetition of rock sequences is present throughout the Peninsula. Five major fold structures dominate the area (Figure 2) and five large faults have played an important role in controlling basin initiation, subsidence and sediment infill. The Fohernamanagh Fault (FF) in particular is possibly of great significance in that it has been interpreted as a 'terrane boundary', bringing together two quite different Lower Devonian basin fills of contrasting sediment provenance and climatic overprint (Figure 3).

Into the West: The Dunquin Group

To achieve an overview of the Mid-Paleozoic geology of the Dingle Peninsula, head to the village of Dunquin at the western extremity of the mainland. Two excellent roadside viewpoints en-route on the flank of Mt. Eagle allow one to take in the breathtaking views of the Blasket Islands (Figure 4). Then on to Clogher Head, where the view to the north embraces the reference section of the marine Silurian Dunquin Group, and the high cliffs of the Sybil Head area where red-bed outcrops of the proposed accreted terrane, the Smerwick Group, can be seen on the skyline (Figure 1).

Figure 1: View north from Clogher Head of the low cliffs of the Silurian Dunquin Group and high cliffs of the Devonian Smerwick Group. Inset: A 'Kerry Diamond' (courtesy Monika Razkova, Rocky Road Minerals).

Brian Williams

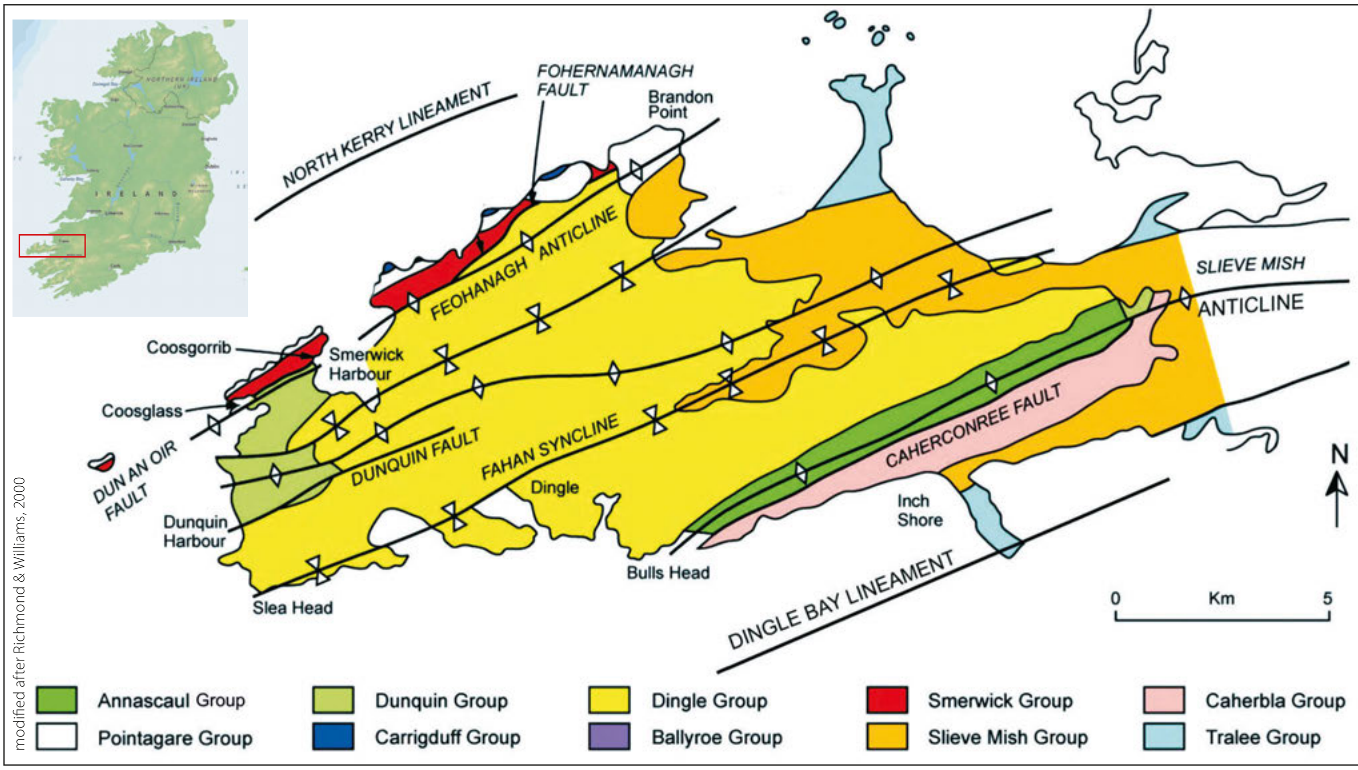


Figure 2: Simplified geological map of the Dingle Peninsula.

The 1,500m-thick Silurian succession in the Dunquin Inlier comprises fossiliferous shallow marine sediments interspersed with volcanic and volcaniclastic horizons. Low in the succession, upward-coarsening parasequences with shelfal siltstones, storm-induced sandy bedforms and interbedded volcanic ash horizons indicate rapid sea level fluctuations controlled by volcano-tectonic events. These give way to major volcanic intervals of andesitic/dacitic lavas and pyroclastic fall and flow deposits, magnificently seen in the immediate vicinity of Clogher Head. The geochemical signature of these volcanics indicate occurrence at a destructive plate margin: a rare example of Wenlock volcanism south of the Iapetus Suture. The post-subduction thermal subsidence, following the acme of volcanic activity in the Late Silurian, saw a return to shallow marine storm-dominated sedimentation.

The conformable transition from the shallow marine Silurian to the continental, red-bed facies of the Devonian is only seen on the Blasket island of Inishnabro; everywhere else in the Peninsula this contact is unconformable or faulted, missing the youngest Silurian stages of the Dunquin Group (Figure 5).

Backbone of the Peninsula

The Devonian Dingle Group dominates the geology and landscapes of the Peninsula. The Dingle Basin developed as a sinistral pull-apart continental

Figure 3: Geological cross-section of the Dingle Peninsula.

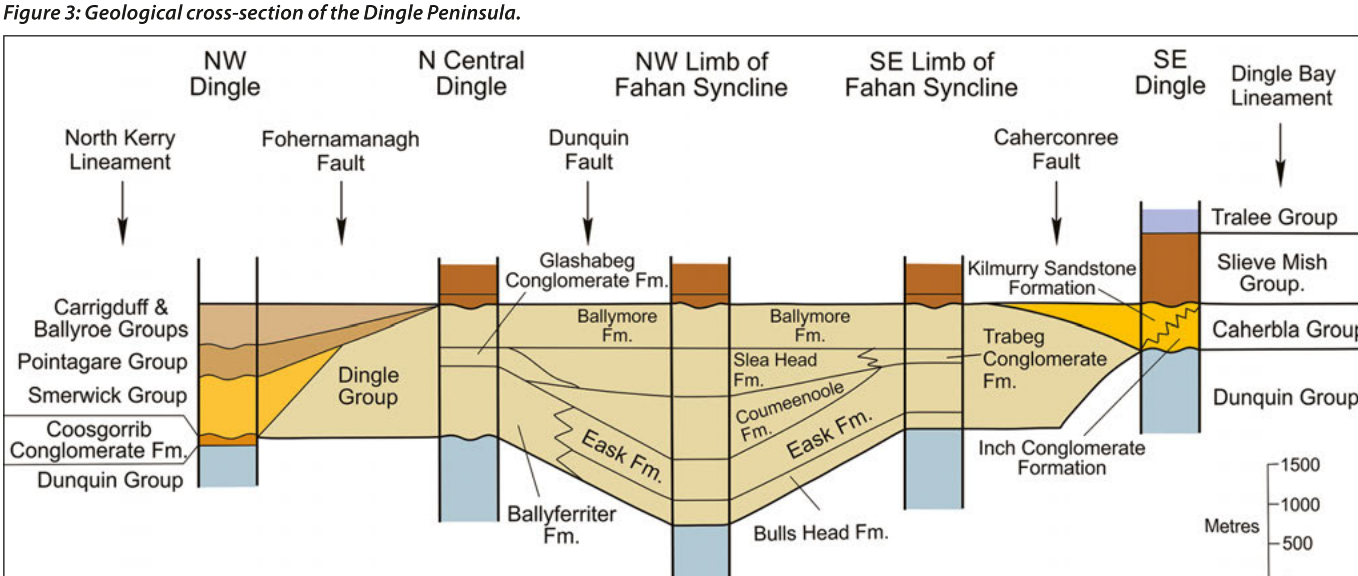


Figure 4: The Blasket Islands from Mt. Eagle. Comprising Dingle Group rocks, these abandoned islands are known for their Irish literary significance as well as their geology!

basin bounded by the NKL and DBL, and subsidence centered along the Dunquin Fault accommodated the accumulation of 4.3 km of sediment.

Dingle Group sediments are exposed extensively around the south and south-west coasts, forming the backbone of the mountains in central and western Dingle. They are red/purple in color due to oxidation of the iron-rich sediments that accumulated under semi-arid climatic conditions. The rocks are almost exclusively fluvial or lacustrine in origin, so are largely devoid of body fossils but locally preserve trace fossils. Microflora help to constrain the age of the Group as Lower Devonian, 415 to 407 Ma.

The Siluro-Devonian boundary probably occurs within the initial red-bed deposit of the Dingle Group, the lacustrine Bulls Head Formation, which is beautifully seen on Great Blasket Island and at Dunquin harbor. It was deposited in a shallow ephemeral lake mapped over 500 km^2, but contemporaneous subsidence facilitated a preserved 220m thickness. Wind-wave ripples and mud cracks abound in this heterolithic fine-grained facies. The lake was rapidly infilled from the south, forming the Eask Formation, an 800m-thick, low slope fan apron, the result of a series of superimposed sheet flood events with a lateral input into the Dingle Basin.

In middle Lower Devonian times a dramatic change in the fluvial input into the basin occurred, as ephemeral conditions gave way to perennial river deposits, this time along a major axial pathway. This was probably due to a combination of climatic and tectonic events. The result was the fluvial input of sand and gravel from a catchment area to the west-south-west, with sediment dispersal toward the east-north-east. This is the Coumeenoule – Slea Head River facies and represents a low sinuosity fluvial system comparable to the Brahmaputra River of today, with a drainage area possibly in excess of 10,000 km^2. Rapid subsidence along the line of the Dunquin Fault accommodated the 1.25 km of preserved sediments in these formations.

Tectonic activity in the hinterland intensified with time, evidenced by the upward-coarsening nature of the system. At the same time the NKL, FF and DBL were all active, undergoing sinistral, strike-slip movement and generating gravel-rich alluvial fans with lateral input into the Slea Head River (Figure 6) from the north (Glashabeg Conglomerate Formation) and south (Trabeg Conglomerate Formation).

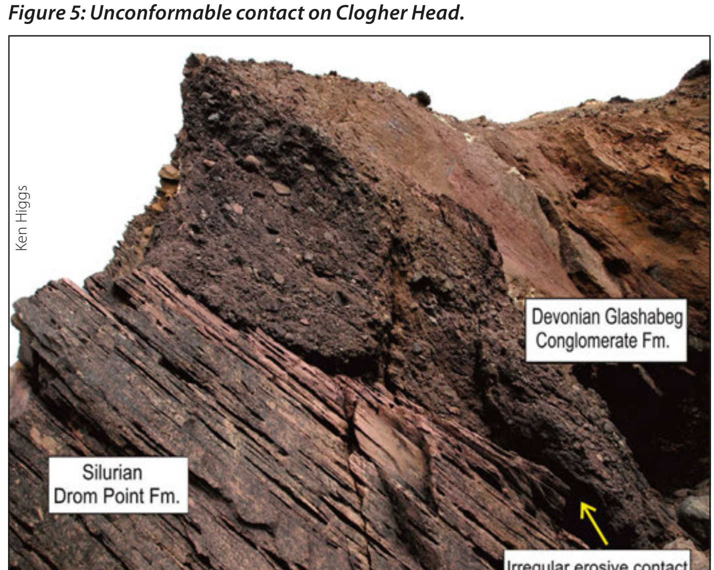
In early Emsian times the fan systems shut down and the axial river system became sand dominated. All this occurred prior to the onset of the Lower Devonian Acadian Orogenic event.

Into the Desert

The Smerwick Group rocks – up to 1 km thick – in the north-west Dingle domain (Figure 2) were deposited in an isolated, hydrologically-closed basin, under an arid climatic regime; the basin sequence contains arguably the oldest aeolian deposits in the British and Irish Isles. The Group's outcrop is constrained between the NKL and the FF. They are comparable in age with the Lower Devonian Dingle Group to the south of the FF. Some authors interpret the Smerwick Group as an allochthonous terrane tectonically emplaced from the north-east by sinistral strike-slip movement along the FF. The Smerwick and Dingle Groups were both uplifted and deformed by the Acadian Orogeny; thus the Middle Devonian sequence in the Dingle Peninsula rests with marked unconformity on the Lower Devonian (and older) rocks of the Peninsula.

The Acadian orogenic event was followed by a period of crustal extension, so Middle Devonian sediments of the Dingle Peninsula were deposited under a very different tectonic regime to the Lower Devonian. The Middle Devonian comprises the coeval Caherbla/Pointagare Groups which crop out extensively in the south-east and north-east of the Peninsula. The extensional Caherbla Basin developed across the entire Peninsula as a hot, arid intra-continental rift

Figure 5: Unconformable contact on Clogher Head.



bounded to the south by the DBL reactivated as a normal fault down-throwing to the north.

The 1,000m-thick Caherbla Group comprises a massive aeolian complex where the wind-generated phenomena include both dune- and draa-scale bedforms into which coarse-grained breccio-conglomerate alluvial fans flowed. The hot, arid Caherbla landscape supported a thriving arthropod community, evidenced by the abundant trackways and burrows in this mixed aeolian/ fluvial depositional system.

In the Dingle Peninsula compression from the Late Carboniferous Variscan Orogeny (~300 Ma) resulted in very large (km-scale) open upright folds, which trend north-east to south-west in the west and east-west in the Peninsula's eastern sector as evidenced by the Slieve Mish Anticline (Figure 2). The orogeny also tightened some of the earlier Caledonian and Acadian folds and reactivated older major faults.

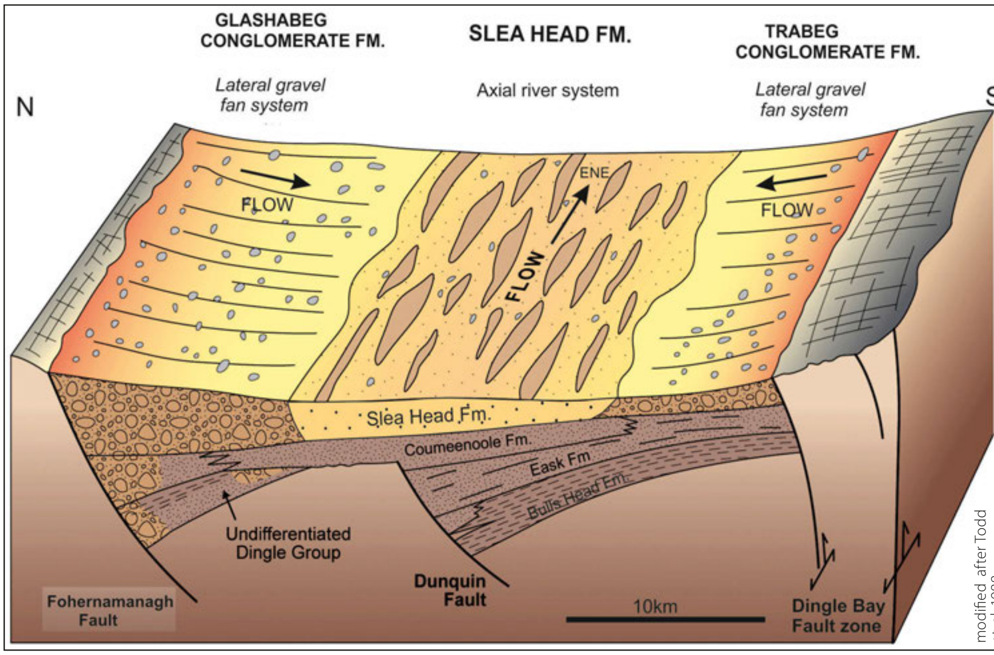


Figure 6: Depositional model, Upper Dingle Group – the axial Slea Head River and the lateral alluvial fan systems.

The Late Devonian, mainly the Slieve Mish Group, largely fluvial sandstones and conglomerates, and the overlying shallow marine shelfal limestones of the Lower Carboniferous Tralee Group dominate the Upper Paleozoic sequences in the Dingle Peninsula. These are best seen at outcrop toward the eastern end of the Peninsula near Tralee, flanking the Slieve Mish Anticline, which plunges toward the east and closes near the town of Tralee, with the declining topography of the Slieve Mish mountains beautifully reflecting this closure.

Final Modification of Dingle's Landscapes

The Irish landscape was molded into its present shape during the Quaternary ice age in Ireland (2.85 Ma–11.7 Ka). There were several glacial events and interglacial episodes, and it is the products of the younger Munsterian and Midlandian glaciations that are best preserved in the Peninsula.

The glaciated valleys of Derrymore Glen and Annascaul well-illustrate the glacial modification of the landscapes in the eastern area. More dramatically, the higher mountain ranges of central and western Dingle display magnificent erosive landforms, particularly in the Mt. Eagle area, Brandon Ranges (Figure 7) and the Owenmore Valley. U-shaped valleys; misfit streams; hanging valleys – often with striated margins; glacial lakes in corries such as at Lough Doon, or drowned corrie amphitheaters like Sauce Creek all attest to the power of glacigenic processes in shaping landscapes.

Thus, the final touches were produced to the topography of the beautiful Dingle Peninsula for us to enjoy today – a 'Kerry Diamond' indeed!

Brian Williams is Emeritus Professor of Geology, University of Aberdeen and Adjunct Professor in Geosciences, University College Dublin.

A longer version of this article and the references are available online.

Acknowledgments

Much of the illustrative material used in this article is derived from Higgs, K. and Williams, B., 2018, *The Geology of the Dingle Peninsula: a Field Guide*, Geological Survey of Ireland, Guide Series. I thank Professor Ken Higgs (University College Cork) for his excellent field photography GSI (Dublin) for permission to reproduce the figures. Many of the maps and models are from the Ph.D. Geology research in Dingle over a 20-year period by my splendid students – Drs. Doug Boyd; Simon Todd; Rod Sloan; Lorna Richmond and Lance Morrissey, from both Bristol and Aberdeen Universities. ■

Figure 7: Glaciated landforms viewed from the vicinity of Mt. Brandon.

Pannonian Basin: Repeated and Repeatable Success

JON FORD, NVentures

The last three years' technical success rate in the eastern European Pannonian Basin ranges between 83 and 94%, while the commercial success rate is at least 50% and will probably approach the technical success rate.

Reported flow rates are in the range 1.4–17.2 MMcfgpd; typical individual pool size is modest at 20 Bcf, but wells target stacked reservoirs, so success, once established, is repeatable. Reservoir depths average 2,200m and drilling costs are low. Existing gas infrastructure and manageable permitting and legislative environments lead to quick-connect commercialization. Work program commitments are moderate.

Key to this success is a simple application of modern techniques, in particular 3D seismic hunting for DHI's, across a multiplicity of reservoir targets in a structured basin where the risk on hydrocarbon source and migration is low. In 2006 the US Geological Survey estimated a mean Yet-To-Find of 1.1 Bboe for the basin, with an upside of 2.2 Bboe.

Why then is the Pannonian Basin not a key destination for more players?

Play Elements

The primary petroleum system can be seen as a classic back arc: the broad Pannonian Basin is the post-rift result of a series of discrete back arc Middle Miocene syn-rift basins developing on the north-easterly directed Alpine thrust belt. The pre-rift contains a secondary petroleum system.

Syn-rift sequences occur in restricted basins containing source rock candidates mature for oil at depths as little as 2,000m due to the high heat flows from the thinned rifted crust, with maximum depths of burial into the wet gas window. A biogenic gas source is recognized in the post-rift Pliocene.

Carbonate and marine to fluvial sandstone reservoirs occur in both the syn- and post-rift. At least 18 different reservoirs are recognized in Hungary in the Badenian, Sarmatian and Pannonian stages (Middle Miocene to Pliocene). For example, the Algyo field in Hungary has produced >600 MMboe from 34 separate reservoirs, with average pay thickness of 9m per sand reservoir, porosities of 17–25% and permeabilities up to 0.5D. The combined stratigraphic and structural trap extends over 80 km^2. Deep tight and shale gas concepts are being tested.

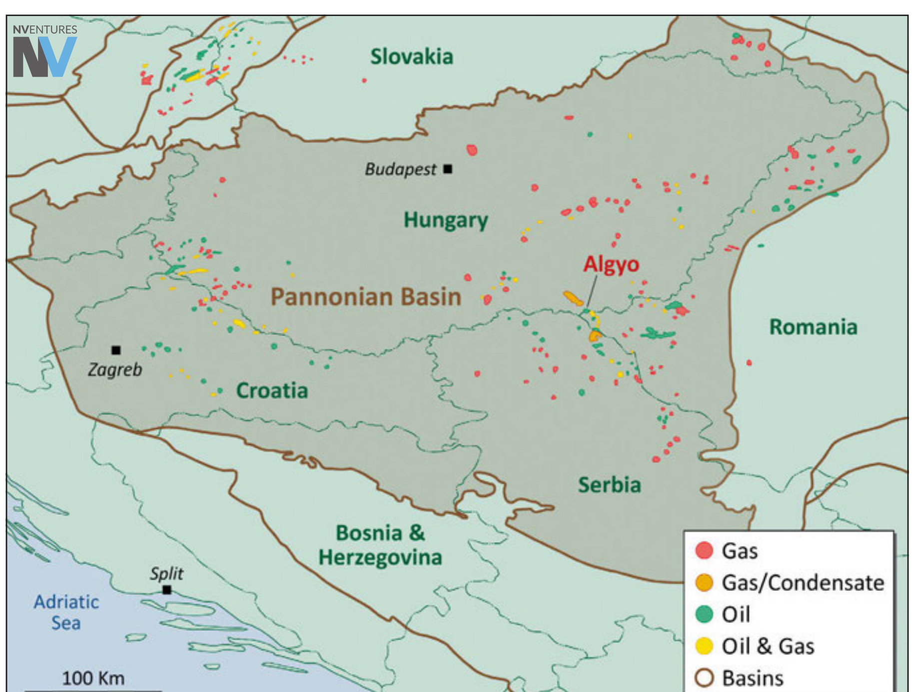
Multiple structural trapping mechanisms result from rifting geometries and from post-rift alteration through inversion and strike-slip faulting. Stratigraphic traps result from continental, fluvio-deltaic and marine sandstone depositional geometries shed off footwall highs.

Surface Issues: Licenses, Players and Politics

The Pannonian Basin stretches over Bosnia, Croatia, Slovenia, Austria, Hungary, Slovakia, Ukraine, Romania and Serbia. This multitude of jurisdictions may be perceived as a barrier for new entrants; however, most countries are either members of the EU or follow EU guidelines and overall there is contract integrity. Formal license rounds are a regularity, with Bosnia and Herzegovina and Romania announcing offerings in the Pannonian Basin in 2020, following Croatia's success in 2019. Seismic and drilling permitting is thoroughly regulated: straightforward access demonstrates an 'open for business' atmosphere compared to Western Europe.

In addition to former state players such as MOL, INA, NAFTA and NIS, just four oil companies have operated exploration wells in the Pannonian Basin in the last three years: ADX, Aspect, Serinus and Vermilion, all of whom have had success, mostly finding gas. Vermilion have built a portfolio across Croatia – where they are the dominant acreage holder – Hungary and Slovakia, based on the recognition of underinvestment in the Pannonian Basin and the opportunity to apply modern technology at low cost. Vermilion have had five successes from six wells in 2019 and plan five wells in 2020.

Additional strategy is the redevelopment and extension of existing discoveries via 3D seismic and modern drilling and completion techniques. ■



Geochemistry and Microbiology in Seep Prospecting

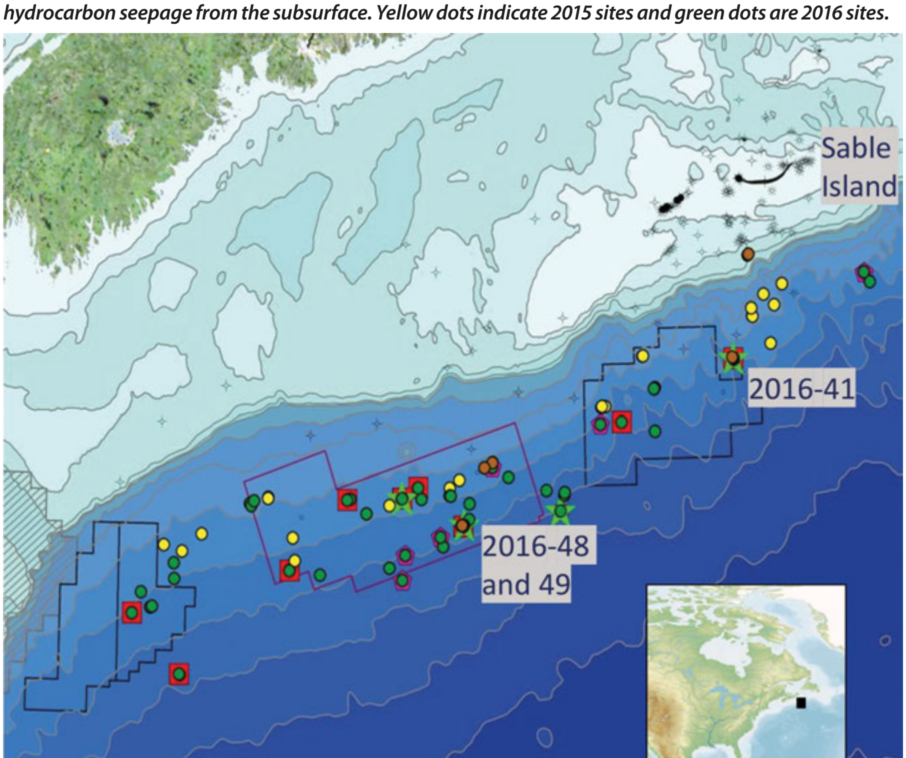
Studies offshore Nova Scotia have shown that combining geochemistry and microbial genomics can effectively de-risk offshore deepwater oil and gas exploration.

MARTIN FOWLER, APT Canada and CASEY HUBERT, Geognomics Inc. and University of Calgary

Hydrocarbon seep detection is often the first step in indicating possible prospectivity in frontier offshore basins. Hydrocarbon seeps can be detected indirectly by satellite imagery and, if available, by seismic evidence. Since these are indirect methods, they are usually followed up with surface core sampling with geochemical analysis to provide stronger evidence of actual occurrence. Geochemical data can be then used to differentiate between biogenic and thermogenic hydrocarbons. In practice, detecting subsurface petroleum seepage from analysis of cores is difficult. This is because the geochemical expression of the seepage area is very limited, and the geochemical character of a shallow sediment core sample is a usually a mixture of different inputs, including migrated hydrocarbons and recent and ancient organic matter deposited with the sediments.

Microbiological approaches have been used to complement geochemical data in detecting petroleum seepage for de-risking exploration (e.g. Hubert and Judd, 2010). One method is to examine sediments for bacteria that actively metabolize hydrocarbons in the seabed. This is most often done using traditional growth-based screening and more recently, as in the study described here, using genomic tools like PCR assays to target functional genes, such as methane- and alkane-monooxygenases for aerobic or anaerobic hydrocarbon degrading microbial populations. The advent of these genomics tools is critical since growth-based screens are typically failing to capture a large majority (i.e. >99%) of the microbial diversity in natural samples (Amann et al., 1995); by sequencing DNA directly this 'uncultured' majority is included in the analytical signal. Here we describe how combining geochemical and microbiological data is increasing confidence that there are hydrocarbons migrating to the surface, close to deepwater prospects offshore Nova Scotia.

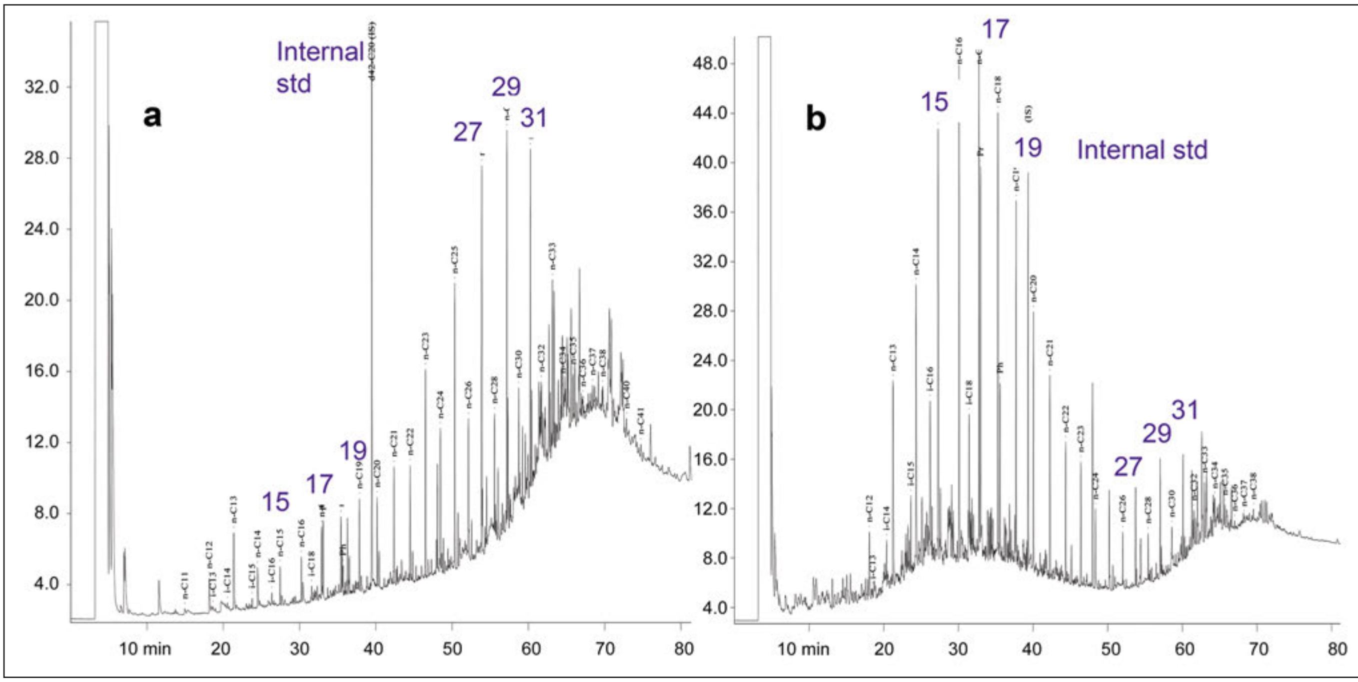
Map of offshore Nova Scotia. Highlighted locations are site 2016-41, which shows the presence of thermogenic gas hydrate and strong indications of petrogenic liquid hydrocarbons, and sites 2016-48 and 49 (very close to each other), which show the presence of biogenic gas hydrates. The sites by a star are additional 2016 sites where there is support from both geochemical and microbiological data for hydrocarbon seepage from the subsurface. Yellow dots indicate 2015 sites and green dots are 2016 sites.



Offshore Nova Scotia

The shallow water Scotian Shelf (<200m water depth) is relatively well explored, with 25 discoveries and production until recently from the Sable Island area. In contrast, the deepwater Scotian Slope, which extends from the shelf break at 200m to almost 4,000m water depth, is poorly explored. Just 13 locations have been drilled over an area of 80,000 km^2, with only four of these in more than 2,000m water depth. There have been only minor discoveries or shows in shallower wells reported to date. Although drilling has not been very successful, oil and gas seeps have been reported using indirect methods. However, there has been no definitive proof to link these seep reports to the presence of working petroleum systems on the Scotian Slope.

The principal objective of offshore piston-coring expeditions has been to identify evidence for an oil-prone source rock on the Scotian Slope from geochemical analyses of sediment samples in close proximity to surface expression of petroleum seepage. Prospective sites were evaluated on



Extractable Organic Matter Gas Chromatograms (EOM-GCs) of samples from: (a) site 2016-1, which shows no evidence for the presence of petrogenic hydrocarbons and is dominated by C_{23}–C_{33} odd numbered n-alkanes derived from recent higher land plant material; and (b) site 2016-41, which shows strong evidence of petrogenic hydrocarbons seeping to the surface, indicated here by the higher abundance of C_{15}–C_{20} n-alkanes relative to those derived from recent organic matter. The C_{15}–C_{19} and C_{27}–C_{31} odd numbered n-alkane peaks are labeled.

the basis of available seismic reflection data, interpretations of sea-surface hydrocarbon slick occurrences imaged in satellite data, and near real-time assessment of seabed and water column anomalies using multibeam echo sounder and high resolution seismic reflection systems. It should be noted that even when the sampling vessel is on location, hitting a target feature with a piston core is very difficult, with the majority of cores not managing to sample the seabed close to the target. Piston coring in 2,500–3,000m water depth can vary as much as 500m laterally from the target as a consequence of the wireline deviating 5° from vertical, which is not uncommon when working on the open ocean. This is critical, as Adams and Dahdah (2011) noted that sediment cores collected 15 to 25m (49–92 ft) away from a real target might not show a thermogenic geochemical signature in the resulting sediment core.

Three expeditions took place between 2015 and 2018. In 2015 and 2016, a total of 70 piston cores were taken from different locations (Campbell and MacDonald, 2016, Campbell, 2019). In 2018 an autonomous underwater vehicle revisited interesting sites, where additional gravity coring was performed (Campbell and Normandeau, 2019).

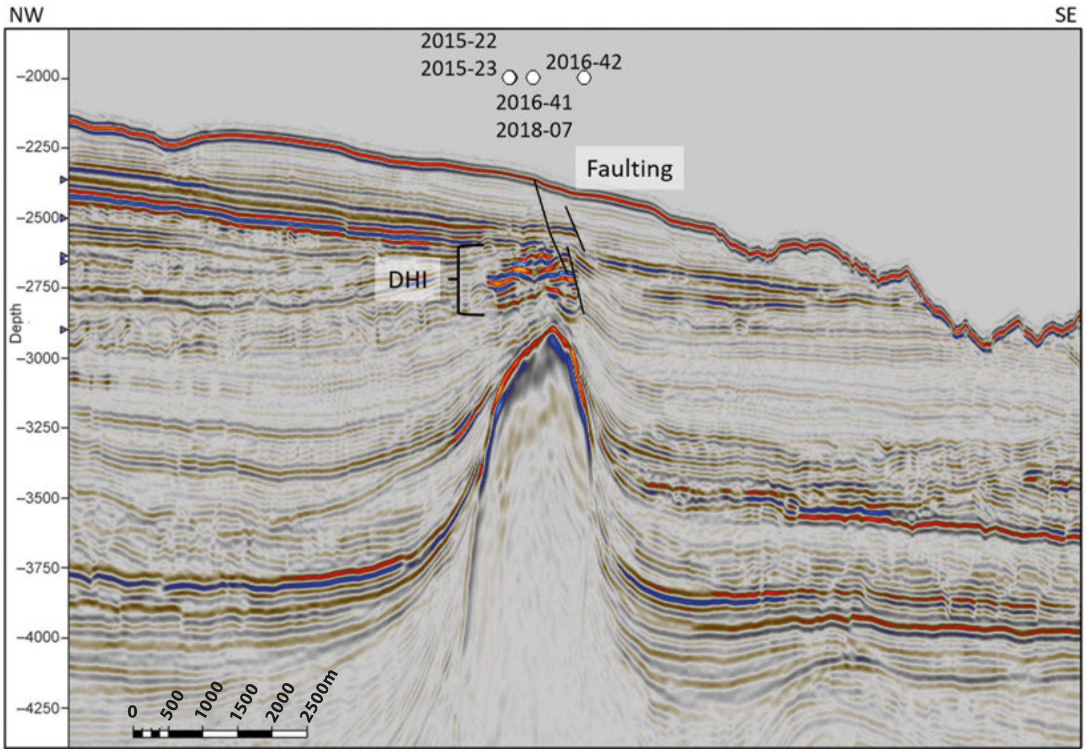
Data Obtained from Cores

Recovered cores were variable in depth and up to 10m long. They were immediately sampled near the base for headspace gas analysis and multiple additional depths were sampled from each core for geochemical and microbiological analysis. Geochemical analyses were performed by Applied Petroleum Technology (APT) and microbiological assays were performed by the Geomicrobiology Group in the Department of Biological Sciences at the University of Calgary. Gas samples were analyzed for composition and isotopes. Sediment samples were evaluated for their Total Organic Carbon (TOC) content, extracted and the total extract (EOM) analyzed by gas chromatography (GC). A subset of extracts was selected for more detailed gas chromatography-mass spectrometry analysis based on the appearance of their EOM-GCs. Geochemistry methods and data can be found in Fowler and Webb (2015, 2017, 2018). Bacterial community composition was determined on triplicate sediment samples throughout the entire depth of the cores through 16S rRNA gene amplicon sequencing using the method of Dong et al. (2017).

During the 2016 expedition, gas hydrates were encountered for the first time on the Scotian Slope, at three separate sites (Campbell, 2019). At sites 48 and 49 the methane in the hydrate had a mostly biogenic origin, whereas the gas composition and isotopes at site 41 indicated a thermogenic oil-associated gas, based both on its composition (i.e. its wetness) and isotopes (e.g. δ^{13}methane values between −42.2 and −49.0‰). Sediment samples from site 41 have EOM-GCs that show high amounts of lighter hydrocarbons over the nC_{15}–nC_{20} alkane range (see figure above), including an unresolved complex mixture (UCM). Shallower samples show a larger UCM with n-alkanes in lower abundance relative to isoprenoids such as pristane and phytane, suggesting biodegradation is occurring in the shallow seabed. Samples from site 41 also show a higher relative abundance of thermally mature biomarkers compared to biologically inherited isomers which dominate most other samples, and also a higher concentration of diamondoids.

Site 41 appears to provide the best evidence to date for a mature oil-prone source rock on the deepwater Scotian Slope. This site was revisited in 2018, resulting in gravity core samples that confirmed this location is where petroleum seepage reaches the surface.

A seismic cross-line through the Tangier 3D Survey in the proximity of site 2016-41. It shows a salt diapir with a bright spot amplitude anomaly above it, indicating the possibility of reservoired hydrocarbons. Faults to surface are also present, representing potential for hydrocarbons to seep to the surface. This probably explains why petroleum seepage was detected in cores from sites 2016-41 and 2018-7, as they were taken in the closest proximity to the fault expression at surface. Other cores taken in 2015 and 2016, further from the surface expression of faulting, did not detect petroleum seepage.



Subsequent analysis of recently available 3D seismic data (BP's Tangier 3D), indicates that sites 2016-41 and 2018-7 were collected above a buried salt diapir with overlying seismic amplitude anomalies and crestal faults that likely act as conduits for migrating fluid, as shown on the seismic section above.

Geochemical indications of thermogenic gas and/or sediments with possible petrogenic hydrocarbons were observed at a number of other sites but, unlike at site 41, the data is ambiguous enough that varying degrees of uncertainty remain. To address this, geochemical results were compared with microbiological data. DNA sequencing of bacteria and archaea revealed that sites which showed geochemical anomalies for the presence of hydrocarbons had conspicuous microbial community profiles, with anomalies in certain groups of uncultured bacteria. The lack of cultured representatives for these bacteria means that they are poorly understood, since the only information about them comes from DNA sequencing and not culture-based physiology experiments. Therefore, the metabolic explanations for observed patterns are not straightforward, despite the striking distribution patterns in the seabed.

The microbial groups detected in the hydrocarbon-positive sediment samples are commonly observed in deeper sediments and were ubiquitous in the deeper (>1m) layers of the cores in this study. Depth profiles associated with a handful of microbial sub-species (i.e. differentiated by their gene relatedness) revealed patterns that are consistent with geochemical anomalies for hydrocarbons, suggesting that these bacteria (and their associated genomic marker sequences) can serve as biomarkers. As such, microbiology is offering an additional line of evidence in petroleum seep prospecting on the Scotian Slope. Studies in deepwater prospects in the Gulf of Mexico have shown similar patterns for closely related microorganisms (Hubert et al., 2018). Sites 48 and 49, where biogenic gas hydrates were encountered, show similar anomalies but with slight modifications, indicating that some bacteria do not distinguish between thermogenic and biogenic methane whereas others might, hinting at the possibility for bioassays that can identify migrated thermogenic hydrocarbons.

Increasing Certainty

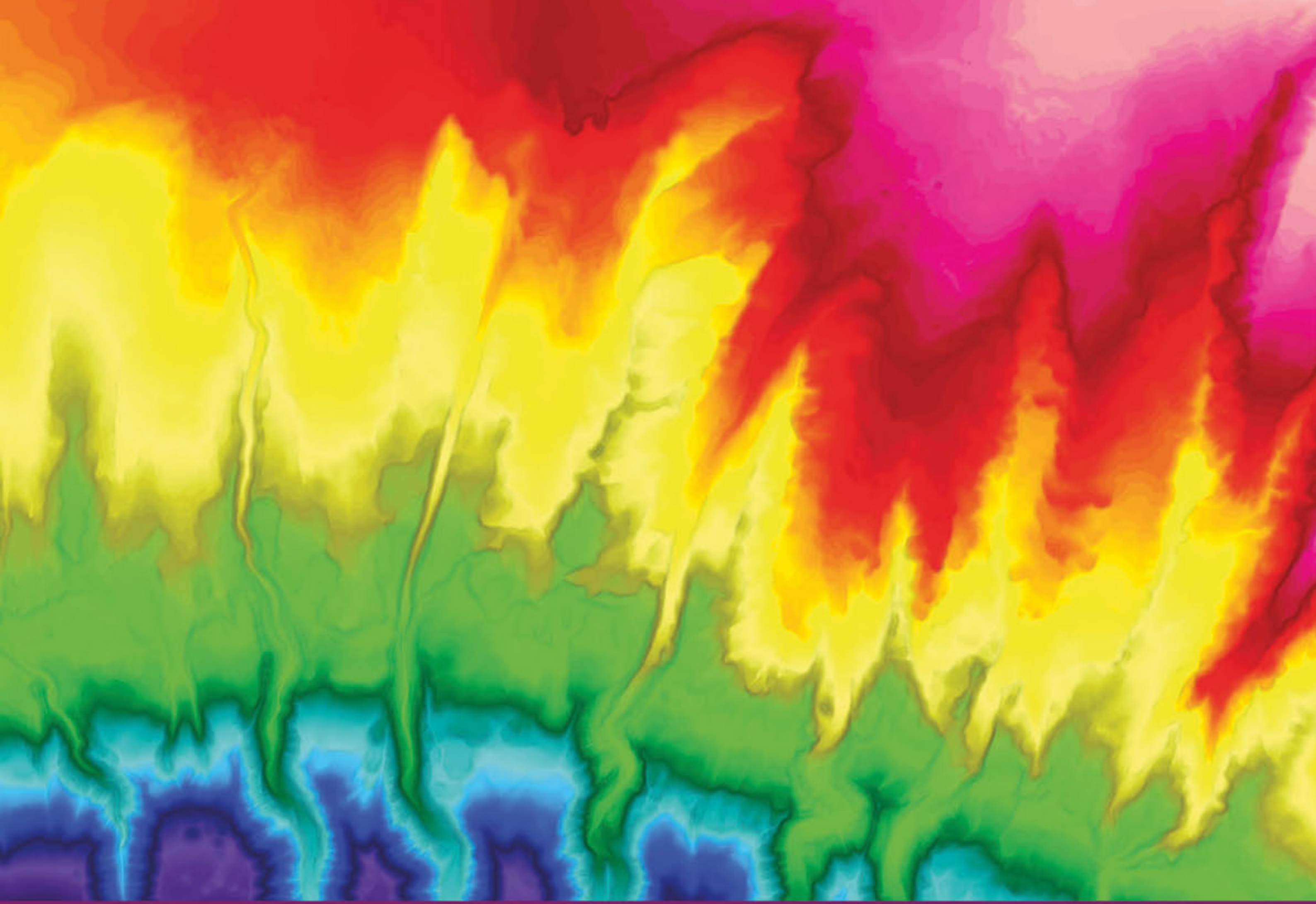
Sites with strong geochemical evidence for the presence of hydrocarbon seepage were mostly those with positive microbiological indications. Using data from two completely different techniques, we are confident that there is subsurface petroleum seepage close to four coring sites in the deepwater offshore Nova Scotia. These interpretations are supported by pore water sulphate concentrations that drop off rapidly with depth in these sediments, suggesting anaerobic hydrocarbon-degrading populations are active at these sites.

From a petroleum systems perspective, our seep data supports the presence of one or more mature source rocks on the Scotian Slope, with at least one capable of generating a black oil in the vicinity of site 41.

References Available Online

Acknowledgments

The authors acknowledge funding for this project from Nova Scotia Department of Energy and Mines (NSDoEM), Offshore Energy Research Association, Genome Canada and the cooperation, support and guidance of the Geological Survey of Canada. Natasha Morrison (NSDoEM) provided helpful comments and the seismic figure above and Carmen Li (Geogenomics Inc and University of Calgary) provided data. ■



Going the Extra Mile

Thomas Chidsey quietly goes about his work at the Utah Geological Survey, rarely making any headlines or seeking notoriety, yet this dedicated and humble geoscientist carries out those 'extras' that clearly set him apart from his peers.

THOMAS SMITH

After working with Thomas Chidsey and using his knowledge of a variety of geologic subjects, I realized that he is a special, one-of-a-kind person. Yet, when co-worker Michael Vanden Berg, Energy and Minerals Program Manager at the Utah Geological Survey (UGS), related the following anecdote to me, I knew I had to find out more about Tom and tell his story.

"I met up with Tom Chidsey in London at the 'Microbial Carbonates in Space and Time' symposium that was held in June, 2013 at The Geological Society," Michael explained. "We were there to deliver two posters, one on the Great Salt Lake and one the Green River Formation covering microbial carbonates. Chidsey brought an entire suitcase full of cores to display as well as little slabs of microbialites and 75 bags of oolitic sand from the Great Salt Lake to hand out at the conference. From Utah and through the London tube to Piccadilly Circus, Tom lugged this heavy suitcase to the conference. I have to say it was a smashing success; everyone loved the little giveaways and viewing the core."

This is just one example of what a dedicated geoscientist and educator Thomas Chidsey really is; a person who always goes above and beyond, which lifts him into a rarified space well above the crowd.

Early Adventures

Growing up in the Wilmington, Delaware and Washington, D.C. metropolitan areas, Tom was a western movie fan and always dreamed of heading west. Being a member of the Church of Jesus Christ of Latter-day Saints, he could not help notice that Church-owned Brigham Young University (BYU) could achieve one of those dreams. Located in Provo, Utah, along the beautiful Wasatch Mountain Range just south of Salt Lake City, Tom ventured west to get his education.

"I had no idea of what I was going to major in when I started school," says Tom. "A sophomore in my dorm

Tom Chidsey at 'The Wedge' overlook in the San Rafael Swell of east-central Utah.

Michael Chidsey, Sqwak Productions Inc.

recommended I take a non-science geology course called 'Life of the Past'. This course was to fulfill a general physical science requirement for my first semester just because 'it was easy'. Just after two months into the course, my search for a major had ended, changing my life forever."

"After taking this introductory geology course," says Tom, "I went to the office of the lecturer, Dr. Morris Petersen, who also happened to be the Chairman of the Geology Department and told him I wanted to major in Geology. To my surprise he replied, 'we would love to have you major in geology!' Dr. Ken Hamblin introduced me to the geology of the Grand Canyon and Dr. Lehi Hintze eventually became my thesis advisor. Most of my professors are gone now but all had a great influence on me and my career." Tom remains very connected to BYU, collaborating with professors on projects and teaching core workshops to their students.

After graduating with a Masters in geology, Tom joined Exxon in 1977 to work in south Texas out of Kingsville. "Exxon had a very active production office there and hired a lot of geoscientists fresh out of school," says Tom. "There was a wonderful camaraderie among us, with the older geologists teaching us about logs, finding prospects, and sitting wells. I was able to see most of my prospects drilled in the area before an opportunity to work back in Utah beckoned."

Rick Fritz, the current American Association of Petroleum Geologists (AAPG) president-elect, was one of those young hired hands that arrived in Kingsville just a month before Tom. "This was an exciting time for all of us young geologists," remembers Rick. "We were all assigned to an engineer and told to keep the drill bit turning. Busy was an understatement. We all had to generate prospects as Exxon had a large gas contract to fill. I remember Tom as a bright pioneer and very driven, developing a lot of prospects and getting them drilled. We were a close group and when I left Kingsville, I created the 'Weevil' award, as that is what we called ourselves, made out of an old, very ugly bowling trophy of mine. It was 'awarded' to new hires as they left the area for other offices, and guess what … I got it back when I became director at AAPG. It is a history of those of us that had worked the area; Tom's was the first of 20 names on the award. Anyway, we are still all great friends and ski together every spring break."

Tom left Texas to work on the hot Utah thrust belt play along with the Uinta Basin, Utah and the Green River Basin of south-western Wyoming. The geologic knowledge of the region he gained while at BYU was a valuable asset during his nine-year career with Celsius/Wexpro (now Dominion Energy). Tom also became active in the Utah Geological Association (UGA). "During this time, I led field trips, published some papers and gave presentations of the geology of Utah, all of which I found enjoyable and appealing," says Tom. "This experience would eventually help me land my job at Utah Geological Survey."

The Dream Job

Tom started working at UGS in 1989. "It was my dream job come true," he says. "I've had the freedom to work an incredible variety of projects all across the State and beyond. Three geologic provinces come together in Utah and rocks of just about every age and depositional environment can be found here along with some very interesting modern analogs of these same rocks. All of this is less than a day's drive away."

While taking full advantage of the freedom provided by his new job and the geology that surrounds their offices in Salt Lake City, he certainly hit the ground running. Tom has numerous publications on Utah petroleum geology, carbon dioxide resources and sequestration, oil and gas outcrop analogs, microbial carbonates, the general geology of Utah's many parks, and is even a co-author of papers on Mars rover protocols using Utah sites. He has been the editor/co-editor of nine UGA, AAPG and UGS field guidebooks and bulletins.

Studying the microbial carbonates in the Great Salt Lake, Utah; Tom and co-authors were able to shed light on the formation of these microbial mounds that are similar to important reservoir targets offshore Brazil and in other petroleum basins around the world.


Michael Vanden Berg, UGS

Some of his work and publications explain oil and gas activity in Utah to its citizens and he has devoted considerable time and energy in educating the public about geology and petroleum resources. His enthusiasm for geology can be contagious. “I have been told that when I talk to people about Utah’s geology, my face lights up,” he says. “Everyone has a natural curiosity about how our world formed and I am happy to try my best to explain some of the things I have studied and know. I am always surprised that few people realize that Utah has significant petroleum resources. It is fun to fill them in and give them what I call ‘Petroleum Geology 101’. I try to be humble and less technical in explaining the technology that helps meet our energy needs to a public that may truly lack a full understanding.”

Retracing Major Powell’s 1869 travels, Tom and his elder son, Michael, enjoy rafting the Colorado River and admiring the amazing geology exposed in its cutting of the Grand Canyon.

Past and Future

Tom recently published one of his ‘outside’ interests, a story entitled *Major John Wesley Powell’s 1869 Journey Down the Green and Colorado Rivers of Utah*. He has retraced the trip and his attention was often “arrested by some new wonder” Powell had marveled at during his journey. “I first saw the Grand Canyon while on a four-day field trip taught by the late, great Ken Hamblin,” says Tom. “With this great introduction to geology, I have often felt a debt of gratitude for the incredible contributions and ideas past geologists have given all of us in this field. They are an inspiration to me personally.”

Tom with his wife of 44 years, Mary, at Hutton’s unconformity, Siccar Point, Scotland.

In addition to retracing Powell’s journey, Tom’s interest in geology and history has taken him to all 50 states and 17 countries, seeking out new places and geosites. He has stood in Charles Darwin’s study and scrambled down the craggy cliffs to James Hutton’s famous unconformity at Siccar Point in Scotland. To him, “seeing such revered sites in the history of geologic study is the BEST.”

His interest in history runs deep and very personal. “Great grandfather Chidsey fought for the Pennsylvania Volunteers in the Civil War and my grandfather in World War I,” says Tom. “I have visited all the battlefield sites where they fought and plan to write about their experiences for the family after I retire.”

When not being a geologist, Tom’s life, along with that of his wife Mary, centers around their two sons, a daughter and nine grandchildren. Active in his church and community, Tom would like to be remembered “as one who loved geology, particularly Utah, and wanted to share this with others through publications, field trips and presentations.”

“Timing is everything in life and it has worked out very well for me. My professors, colleagues, friends and family, and the support of UGS, UGA and AAPG in what I have worked on have given me the wonderful career I have had.” ■

Morocco:

Lixus Offshore: How new data analysis techniques are transforming a basin

Since early 2019, Chariot Oil & Gas has performed an extensive interpretation program on over 1,700 km^2 of legacy PSTM 3D seismic data, shot over the Lixus Offshore license area in 2006 and 2010. Figure 1 highlights the Mio-Pliocene siliciclastic succession, which reaches over 5 km thickness in the central area. Sediment loading of thick high net-gross reservoir systems drives syn-depositional salt and mud tectonism, controlling sediment accommodation space and developing trapping geometries for the on-block hydrocarbon accumulations and exploration prospects, including the 2009 Anchois thermogenic gas discovery.

Advancements in data analysis and imaging techniques throughout the past decade have provided insights into reservoir distribution and enabled the discrimination of gas-filled sands. Approximately 1 Tcf of remaining recoverable gas is estimated to be held in the Anchois discovery and surrounding analogous satellite prospects, with on-block resources increasing to over 2 Tcf when incorporating other Miocene targets identified to date.

As Moroccan energy demand is forecast to double between 2015 and 2030 and the country remains reliant on imported fossil fuels for 96% of its energy, understanding how to maximize value from previously overlooked indigenous exploration plays becomes increasingly important. The potential contribution of gas from the Lixus Offshore block would allow Morocco to significantly reduce its reliance on imported fuel, ushering in a new era of increased self-sufficiency and reduced environmental impact from power generation.

Figure 2: Merged Miocene top reservoir seismic amplitude map.

Figure 3: Location map of the Lixus license in the offshore Rharb Basin (3D seismic extent in blue).

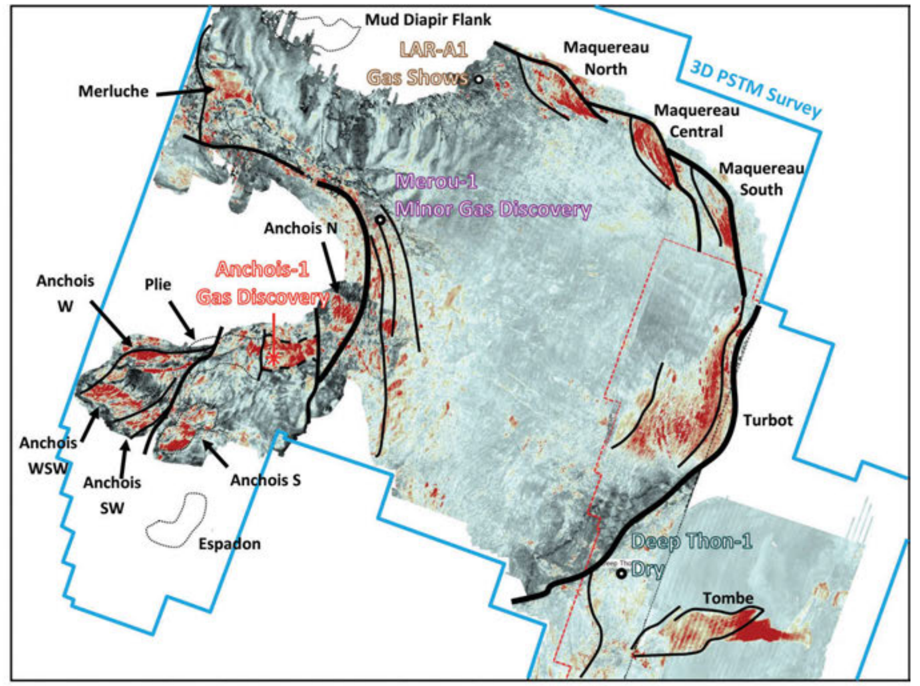
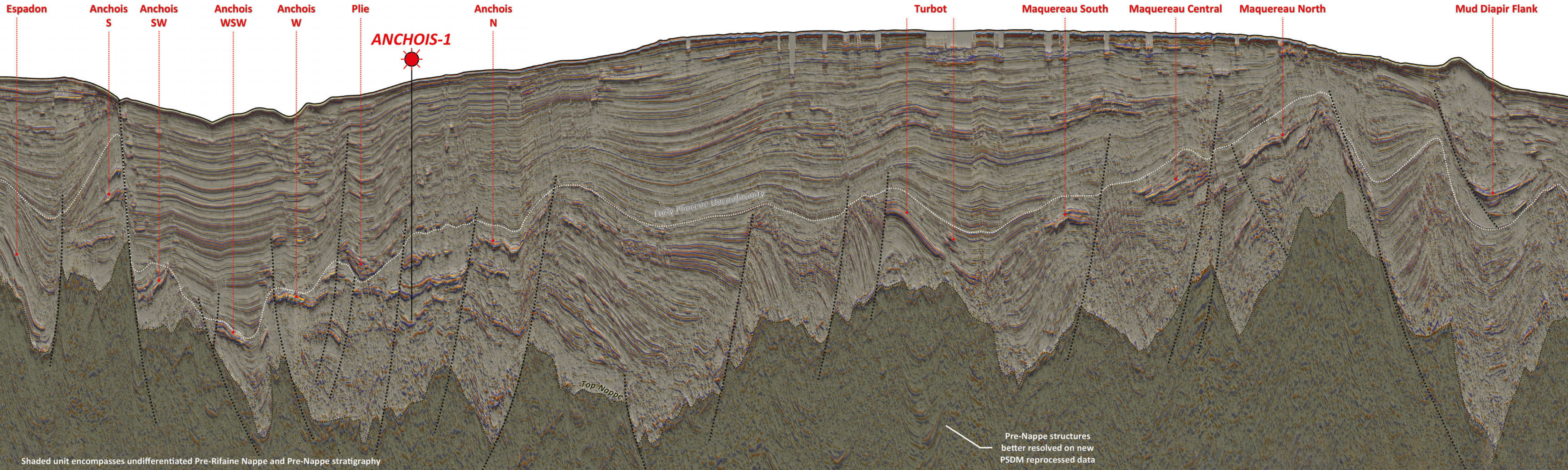


Figure 1: Regional [PSTM] arbitrary seismic line across the Lixus license (display is full stack amplitude co-blended with seismic relief attribute).



Resolving Neogene Clastic Fairways

Using modern analysis techniques to understand the true potential of reservoir systems in a diverse basin.

MELISSA CHIN and DUNCAN WALLACE; CHARIOT OIL & GAS

The Lixus Offshore block is located within the Rharb Basin on the north-west Moroccan Atlantic shelf (Figure 3). The Rharb Basin represents the westernmost foredeep of the African Rif Belt, part of the greater Betic-Rif-Tell range, which spans the Mediterranean margins of North Africa and southern Iberia. The focus of recent exploration throughout the Rharb Basin has predominantly been the post-nappe Neogene basins, so called as they are set atop a thick, argillaceous, olistostrome known as the Pre-Rifaine Nappe.

The significant Upper Miocene–Pliocene post-nappe section is dominated by deep marine sediments, composed of hemipelagic mudstones punctuated by massive deposits of sand-rich turbidite flows. The sands are represented on seismic data (Figure 1) by high amplitude, high relief, laterally coherent reflectors; a stark contrast to the underlying Pre-Rifaine Nappe, which is imaged as a chaotic, slow velocity, amorphous unit.

A characteristic feature of the post-nappe section is the division into a complex network of 'mini-basins'. These are created by the mobilization of underlying Triassic salt and olistostrome muds, which is driven by rapid sediment loading of Upper Miocene–Pliocene units. Soft sediment withdrawal takes place below areas of greater overburden, causing the redistribution of salt and mud into tall sediment walls and diapirs. This process also led to the development of significant basin-edge listric and normal fault systems, providing major structuration throughout the post-nappe section.

In 2009, the Anchois-1 exploration well penetrated three stacked high quality reservoir sand intervals. The two upper sands were gas bearing, both with 50m gas columns; the third sand at the base of the well was water-wet. This well was key in calibrating the seismic response of gas-filled reservoirs and in demonstrating that thermogenic gas is able to migrate through the Nappe from deeply buried, gas-mature source rocks.

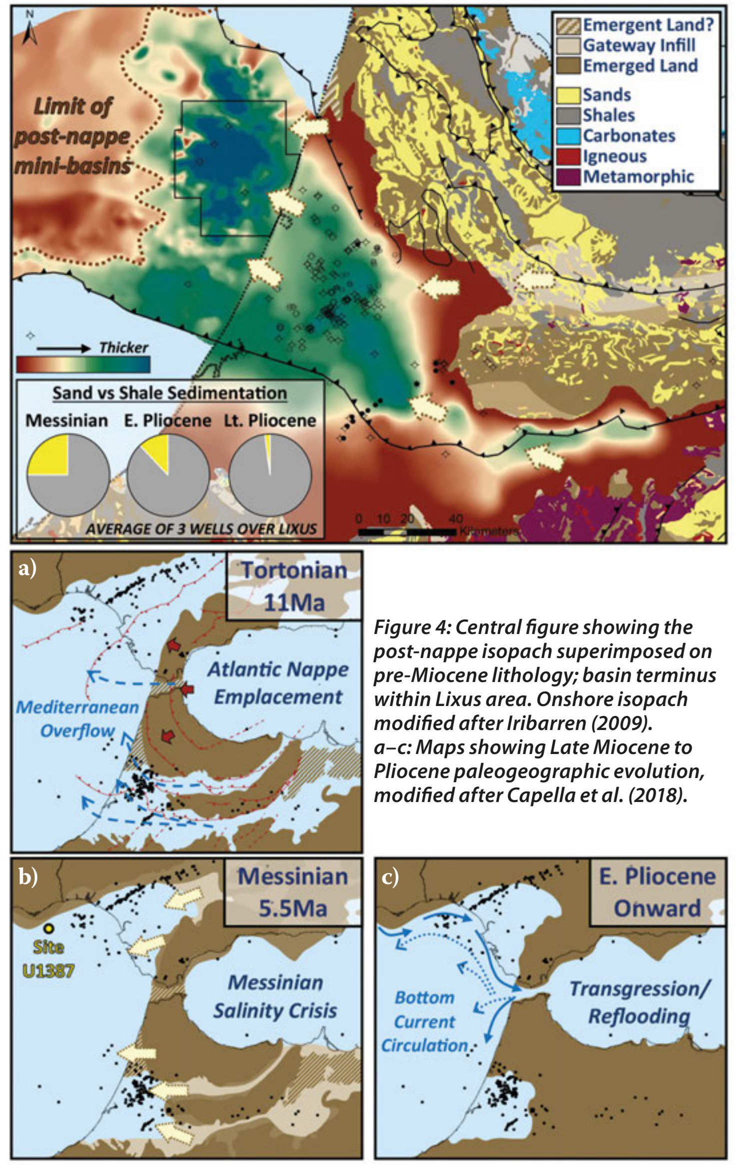


Figure 4: Central figure showing the post-nappe isopach superimposed on pre-Miocene lithology; basin terminus within Lixus area. Onshore isopach modified after Iribarren (2009). a–c: Maps showing Late Miocene to Pliocene paleogeographic evolution, modified after Capella et al. (2018).

Clastic Source and Reservoir Distribution

The Alpine orogenic event led to the emplacement of the Pre-Rifaine Nappe, an allochthonous unit that reached the Atlantic in the Late Miocene (Figure 4). Well data suggests that emplacement was complete by the Late Tortonian (Figure 4a). During this period, the Atlantic–Mediterranean marine gateways, also referred to as the Betic and Rifian corridors, allowed throughflow of marine waters (Capella et al., 2018). Current direction through these gateways and the Straits of Gibraltar, which was also open at this time, was controlled by westward propagating tectonics.

Increased uplift rates across the Alpine belt and the resulting closure of these gateways caused a major increase in clastic sediment supply to the Atlantic basins in the Messinian (Figure 4b). This termination of ocean circulation triggered the Messinian Salinity Crisis in the Mediterranean and allowed Atlantic basins to

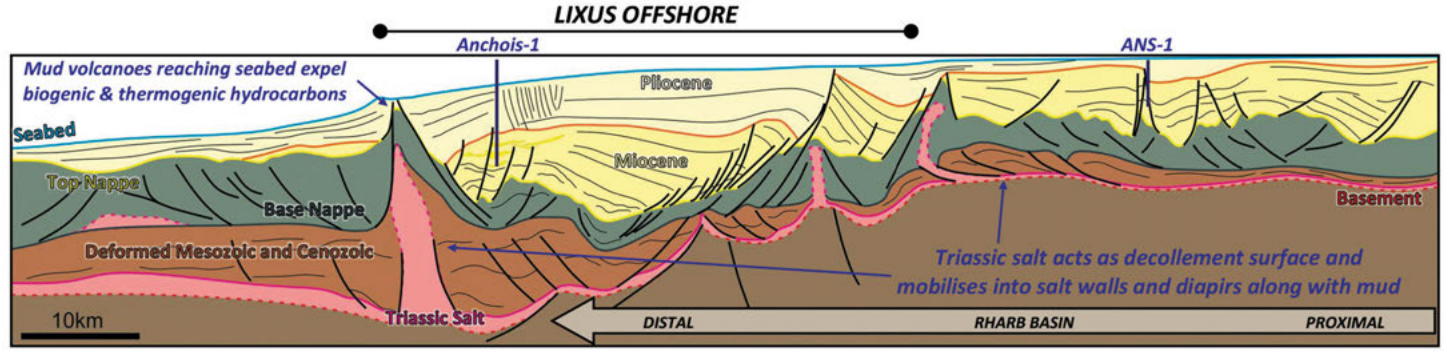


Figure 5: Cartoon schematic cross-section through the Rharb Basin demonstrating the variable post-nappe sediment thickness and internal architecture of Lixus mini-basin walls.

access greater clastic sediment supply shedding off from the growing orogen.

When the Gibraltar Straits reopened in the Early Pliocene (Figure 4c), renewed circulation of Atlantic–Mediterranean bottom currents caused a gradual shift from sand-rich turbidite to mud-rich contourite deposition by the Late Pliocene. This depositional system is mirrored in the Gulf of Cadiz, as confirmed by research drilling at Site U1387. The distinctive Early Pliocene Unconformity marks this reflooding as a regionally extensive, erosional event.

The magnitude of sand supplied into the basin by the orogenic wedge during this tectonic evolution is supported by wells drilled on-block that penetrate the Upper Miocene–Pliocene (Figure 4, inset pie charts). Biostratigraphy data in these wells also confirm the deposition of turbidite systems in a distal, deepwater setting. Through mapping of regional data, it is evident that this area marks the terminal point of deposition into the basin.

Data Analysis and Prospectivity

Correlation of seismic, well and outcrop data across the entire Rharb Basin clearly shows that the Lixus area is an extension of the proven onshore oil and gas producing basin. Larger resource potential exists offshore owing to a combination of the greater accommodation space and the distal setting, leading to the deposition of thicker and more aerially extensive reservoir bodies (Figure 5). Feeder systems that originate from the onshore supply mature clastics into lower slope to basin floor channel and fan deposits in the offshore domain. Channel systems can be seen clearly on spectral decomposition maps (Figure 6), where sands show a strong contrast against background shales on the frequency spectrum. Brightening on spectral decomposition not only aids mapping of sand fairways but also provides geophysical evidence of the presence of gas, as demonstrated at the Anchois discovery. Using spectral decomposition as a tool in facies identification and to map the distribution of reservoir systems has been very powerful compared to the use of conventional seismic amplitudes alone.

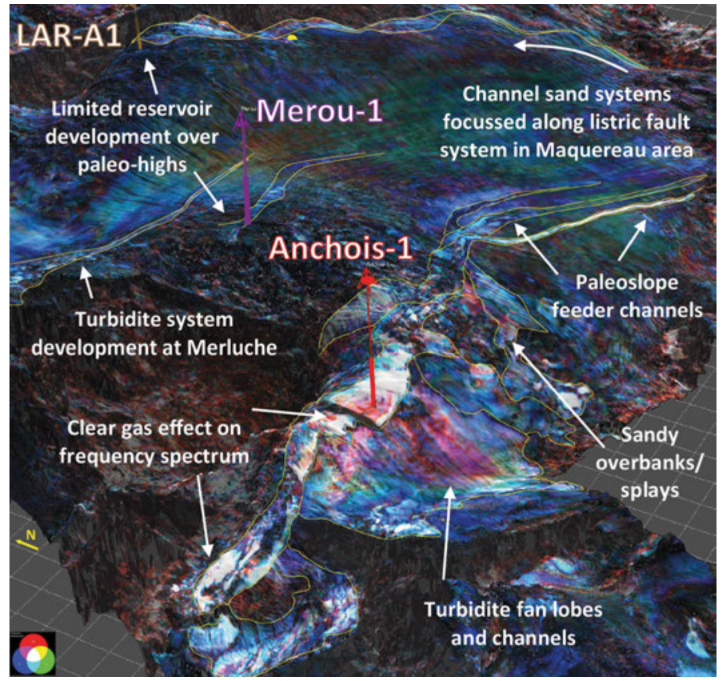
Restoration of depositional environments, achieved by combining these observations with isopach reconstructions, was also key to understanding how the sands entered the basin and were distributed within different mini-basins. For example, a basin entry point is interpreted at Turbot, with a sand-rich succession thickening against the easternmost basin-bounding growth fault of the Lixus mini-basin (see Figure 2). Extensions of this system can be tracked around the basin edge to the north, through the Maquereau prospects area, where thick sands have accumulated along this fault system as accommodation space has opened during deposition. Subsequent inversion due to reactive mud tectonics has created trapping geometries.

Petrophysical analysis of well data proved that the Miocene sands have excellent reservoir properties, with up to 30% porosity and >1 Darcy permeability. Well-to-seismic ties demonstrate that these gas-bearing sands, mapped as soft (trough) events, show increase in full-stack amplitude response and strong class III AVO anomaly on offset stacks. These properties, along with other qualitative attributes such as flat spots, velocity push-downs and low frequency wavelets, are found in mapped prospects, but absent in proven water-bearing sands. The well-seismic calibration of proven gas-bearing sands at the well location has proven invaluable in de-risking remaining basin prospectivity.

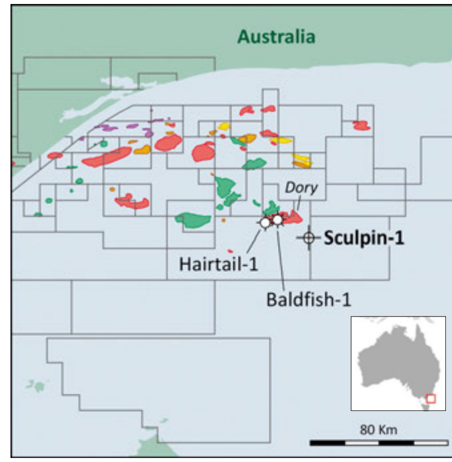
Recent PSDM reprocessing of the vintage dataset is further de-risking discovered and prospective resources within the proven Miocene gas play, as well as opening new play systems for gas in the Pliocene and for oil in the sub-nappe section through the significant improvements in deep imaging. With proven resources ready for commercialization and long-term growth opportunities through a diverse set of exploration plays, the high potential of this area is only just starting to be fully resolved. ■

References available online.

Figure 6: Spectral decomposition at reservoir level draped over the regional structure map highlighting distribution and extent of Miocene reservoirs.



The Elusive Deepwater Gippsland Gas Prize



ExxonMobil have recently completed a three-well drilling campaign on **VIC/P70** offshore **Gippsland Basin**, south-east **Australia**. The first two wells, **Baldfish-1** and **Hairtail-1**, were reported dry in 2018, whilst the latest well **Sculpin-1,** is expected to be reported dry, with no announcement to the contrary. Sculpin-1 was drilled to about 4,700m in an Australian record-breaking 2,239m of water.

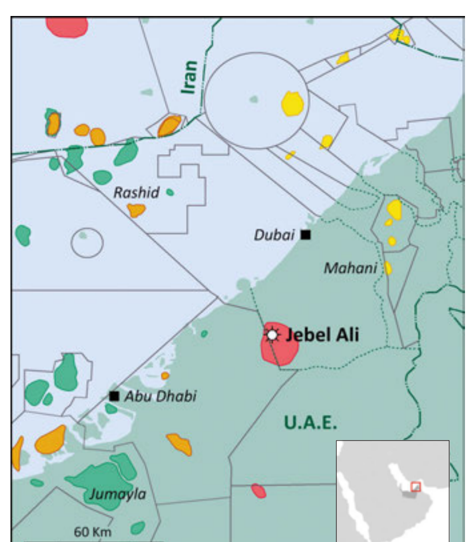
ExxonMobil were hoping to build on the Dory gas discovery of 2008 in the north of the block, although the location of Sculpin-1 further south in the block suggests a step out from this play. Apache originally drilled Dory 1 in 2008 and found 30m gas in good quality reservoir in the Latrobe (Upper Cretaceous) Group, before the well was plugged and abandoned as sub-commercial. Liberty took that license and ExxonMobil bought P70 in 2017 for an undisclosed amount, with press reports talking about potentially 2 Tcfg at Dory. Failure here could be attributed to structure as depth conversion plays a role over a subtle trap; Dory and other prospects do not 'close' in time due to deepening water and deep canyons at the water bottom, and large velocity variations in the carbonates above the target Latrobe group. The stratigraphic nature of the Latrobe nearshore and shoreface sands with fluvio-deltaics also poses challenges for trapping and seal. The jury is out on whether the block will deliver on multi-Tcf promises, and whether Dory is a big enough fish for ExxonMobil to go ahead and develop. Indeed, rumors already circulate that this will be one of many assets subject to ExxonMobil's global divestment strategy. ■

Mixed Results in the Rhine Graben

Neptune with partner **Palatina GeoCon** are testing oil at **Schwegenheim-1** in **the German Rhine Graben**, but not from the main target Triassic Buntsandstein Formation, which is the reservoir in the nearby **Römerberg-Speyer** oil field. Römerberg, believed to contain 150 MMbo in-place, was discovered by accident in 2003 whilst drilling to a geothermal target. Instead, two shallower secondary targets, of undisclosed age but speculated to be in the Upper Trias or Lower Tertiary, have been production tested in Schwegenheim-1, with a gross total of 1,500 bo being produced to a local refinery.

The well was drilled to 2,600m and took 53 days to drill. It is yet unclear if the discovery will be commercial, a similar situation to Rhein Petroleum's Steig-1 2019 discovery which recovered a total of 4,000 bo from an Oligocene reservoir in the Rhine Graben. These two wells, plus drilling in the north of Germany by Neptune, such as at Adorf, demonstrate that exploration drilling is feasible in this part of Western Europe. ■

Jebel Ali Gas Bonanza



In February, the **UAE** announced the significant discovery of 80 Tcf of in-place shallow gas resources, named **Jebel Ali.** The resources lie within an area of 5,000 km^2 between Saih Al Sidirah in Abu Dhabi and Jebel Ali in Dubai. **ADNOC** drilled more than 10 exploration and appraisal wells to establish the discovery. The field is potentially the largest global gas discovery in the last 15 years, with the exception perhaps of the Rovuma Basin gas discoveries offshore Mozambique.

News of the discovery came on the back of ADNOC and Dubai Supply Authority (DUSUP) signing a strategic cooperation agreement to continue to explore and develop the shallow high-quality organic gas resources between the two emirates in a joint project. The shallow nature of the resource will also mean that the development costs of gas production are lower than exploiting Abu Dhabi's sour gas resources.

Both conventional and unconventional drilling and completion technologies and methods are being used by ADNOC to access this gas. In addition, the number of drilling rigs required will be reduced by utilizing horizontal drilling and hydraulic fracturing, which in turn will facilitate the best productivity rates. ■

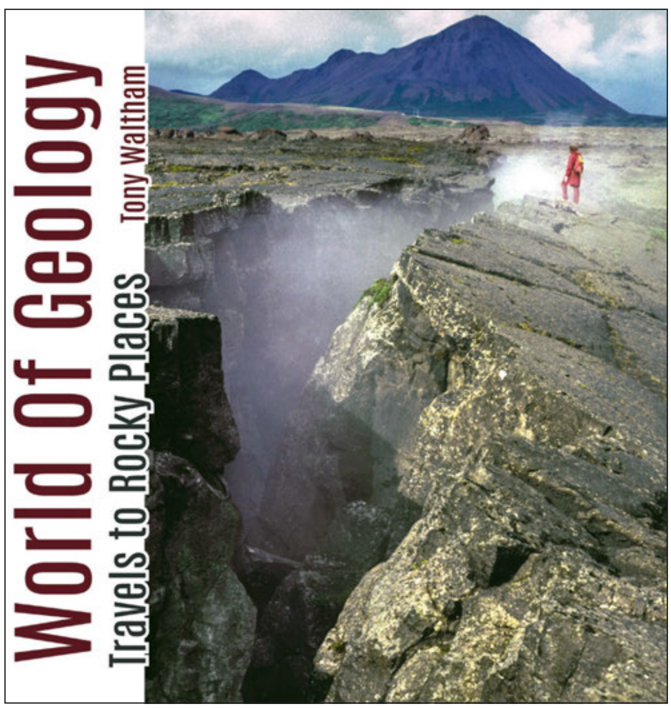
Travels to Rocky Places

JANE WHALEY

World of Geology: Travels to Rocky Places
Tony Waltham
Whittles Publishing

Like many other geologists, retired university professor Tony Waltham has spent much of his life traveling the world, recording his journeys with some stunning photographs.

A selection of over 100 of his images have been compiled in an excellent new book, called *World of Geology: Travels to Rocky Places*. It has a simple but effective format: following a brief introduction, which includes an introduction to geology for the uninitiated, each photo is displayed on a single page, while the opposite page has a description of the image and the stories behind it. Geology features strongly, of course, written in a straightforward style, easily understood by the non-specialist but with plenty of interesting information for the geoscientist – but there are also many personal anecdotes, little bits of history and other items of general interest.



Interesting Range of Photos

The photos in the book encircle the globe, from Patagonia at the tip of South America to Spitzbergen inside the Arctic Circle, and from New Zealand through Africa to Alaska. Some of the places visited are probably on every geologist's bucket list. We admire the spectacular Niagara Falls; Myvatn in Iceland, where you can stand with a foot on either side of a diverging plate boundary; the magnificent Tangariro volcano in New Zealand; Petra's wonderful banded red sandstone; and many, many more.

There are also photos of beautiful places that I will add to my bucket list, including many in some little-visited parts of Asia. Places like the Gangapurna Glacier, "tucked away in the remote northern side of the Annapurna Range," which is about 6 km long and descends nearly 4,000m before it melts away, edged by textbook moraines. Or the beehive-shaped sandstone hills of the Bungle Bungles in northern Western Australia; or the vertical limestone cliffs of the El Chorro Gorge in southern Spain with its vertigo-inducing walkway; or the granite laccolith at the Chilean Torres del Paine, to name just a few. Tony avoids the obvious photogenic scene, preferring, for instance, a close-up view of exfoliation on the famous Half Dome in the Rocky Mountains rather than the more classic image of the mountain's steep face. A keen caver, many of his best photos are taken inside caverns.

Man and Nature

Among the most interesting images in this book are those that remind us of how important geology is in everyday life – and also how we must remember that fact, and the problems that ensue if we don't. These were the images and stories that I found most fascinating.

A stunning photo of the Morning Glory hot spring in Yellowstone Park, for example, showed a deep blue pool, but the accompanying text tells us that the photo dates from 1970, and the whole pool is now a dirty mustard color, probably because the delicate balance of water flow, temperature and bacteria has been upset by the coins thrown into the pool. The ship's graveyard in the Aral Sea provides another visual reminder of how easily we can create an environmental disaster; the diversion of its feeder rivers to irrigation schemes turned this vast inland lake into an arid desert.

Some photos, by contrast, remind us of man's ingenuity at attempting to bend geology and nature to our advantage. For about 1,000 years the rice terraces in Batad in the Philippines have climbed up the steep mountain sides, but the accompanying text tells us that this has only been possible because they are faced with local clay dominated by kaolinite, the most stable of the clay minerals. From Cheddar Gorge, a popular picturesque tourist attraction, we have a photo of rock blasting at the top of the ravine, undertaken to prevent landslides into the Gorge along bedding-plane weaknesses.

A Glorious Journey

This is a book any person interested in their natural surroundings would like to have – and since it has soft covers and is only about 15 cm across, it is light enough to fit into a traveler's backpack. A number of the photos were taken several decades ago, so the printed picture quality was sometimes not as good as might be expected, but the interesting range and descriptions more than make up for this.

Tony sums it up in his preface: "Perhaps the whole book is best viewed as a glorious journey of discovery." A journey that I was very happy to join him on. ■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Encouraging Girls Into Geoscience

How can we stop the decline in the number of women studying geoscience degrees? Sarah Boulton and Jodie Fisher from Plymouth University tell us about Girls into Geoscience, a UK initiative aimed at letting female secondary school pupils know more about the subject.

What is Girls into Geoscience?

Girls into Geoscience, or GiG, is an outreach initiative primarily based around an annual two-day event held at the University of Plymouth. Aimed at female students in year 12 (16 to 17-years-old) we welcome all who are interested in geoscience, from those who have studied geology or have some geological knowledge, to those who are completely new to the geosciences.

On the first day we offer an optional field trip, to demonstrate that there are no barriers to female inclusion in the field, whilst the second day consists of talks and workshops, with topics from throughout the geosciences. These sessions showcase the range of geoscience career pathways that are possible across industry and academia, and provide role models for the girls and an insight into the university experience.

Why did you feel there was a need to set this up?

We knew the figures. Women still only make up 22% of the UK STEM workforce, and a similar pattern is seen in the geosciences. At degree level the numbers are better; however, only about 40% of places on geoscience courses are being taken up by women. We wanted to do something to encourage more girls to consider the geosciences, but the final straw came when a prospective student told us her teacher had told her geology was not for girls! This was a mindset we could definitely try to change.

What difference has it made?

Running now for seven years, more than 320 girls have come to our events; some of our first attendees are already embarking on their own geoscience careers and fulfilling their ambitions having completed their university studies. Feedback from attendees has helped us understand the impact of the events, and the difference we have made to the girls, many of whom are the only female on their A-level course, or the only one at school interested in studying the geosciences at university. GiG has given them the opportunity to meet like-minded students and to start to form their own networks, giving them the confidence that they are not the only one interested in geology! We give the girls a chance to see if geoscience is really for them through role models and fieldwork, and our surveys show that 100% of the girls attending would recommend GiG to anyone considering studying the geosciences.

Locally we have also seen an increase in the number of girls on our courses at the University of Plymouth. GiG has also had an impact on our equality agenda. Overall, we are seeing a community of female geoscientists coming together to raise the profile of the geosciences to the wider community.

What are the plans going forward?

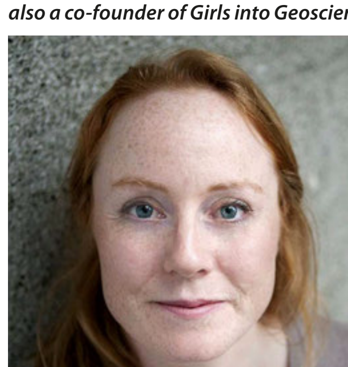
Our initiative has grown recently; Ireland has set up GiG Ireland, running their third event this year, and the University of Glasgow started GiG Scotland last year, while 2020 will see the first GiG Wales event. With links to other international programs we are beginning to see a global network developing.

However, we realize there is still more we can do to break down the barriers that may exist in females when thinking about STEM subjects and careers. Many girls make their career choices by the time they are 14, and gender stereotypes about potential careers are set as early as the age of four. To address this issue we launched GiG Junior last year for girls aged 12–14 to inspire them into STEM and show them where the geosciences could take them. The University of Leicester held the first GiG Junior event last October, and they are planning another event this year.

Is the oil industry discussed at a GiG session?

Earth scientists see themselves as custodians of the planet, but there is no getting away from the fact that for modern life to continue we need the extractive industries and the materials they produce. In recent years the number of students studying geology has fallen, perhaps partly owing to the close links between the subject and the oil industry. We have had a number of women from the oil and extractive industries attend GiG as speakers and role models, who have shown both the diversity of what these industries do but also what they are doing in terms of sustainability. We hope that the students leave the event with an understanding of how earth scientists can be part of the solution across a range of industries. ■

Left: Dr. Sarah Boulton is Associate Professor of Active Neotectonics at the University of Plymouth and is a co-founder of Girls into Geoscience. Right: Dr. Jodie Fisher manages the earth science research laboratories at the University of Plymouth and undertakes workshops and geoscience sessions for schools. She is also a co-founder of Girls into Geoscience.



University of Plymouth, Alan Stewart

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Time to Regroup

Covid-19 is having an huge impact – but are there any positives to the situation?

International Petroleum (IP) Week, the London gathering of the great and good in the oil and gas sector organized by the UK Energy Institute, seems like a very long time ago. How the industry was getting on transitioning to a low carbon economy took front and center stage at the event but coronovirus, or Covid-19, as we are now calling the virus, was the elephant in the room. Predictably enough we missed the Chinese delegation this year but plenty of Italian and Spanish oil folk were traveling. The virus was a threat but containable.

Would IP Week have taken place if it had been scheduled for the end of March rather than February? Almost certainly not. Other industry events are getting postponed or canceled one by one and while not in complete lockdown the sector has moved to tick-over mode.

Positives? More oil is being pumped as producers fight for market share – but carbon emissions are lower than for a very long time as users cut back. In February, for example, China's state-owned refiners announced a cut in refining throughput of nearly a million barrels a day. Major ports such as Shanghai and Shenzhen reported a 20% decline in trade for the same month as labor shortages caused by the virus started to bite.

At IP Week this year, Matt Haddon of the sustainability firm ERM talked about "an old economy, new economy thing." Low carbon priorities, argued Haddon, were producing "the most urgent structural shift that the sector has seen for decades." Oil and gas majors were having to rethink their roadmap and energy provision in all its many forms was very much on the agenda.

With the oil price currently down below $30 a barrel will transition among the majors continue? What can we expect when BP CEO Bernard Looney sets out how the company is going to get to net zero carbon by 2050? The answer, I suspect, is careful, measured progress in a new economy not only shaped by climate change but by the virus and by other nasty bugs which may follow. BP for one is now the world's largest investor in solar energy. Shell is involved in the world's largest pilot project for producing green hydrogen. Equinor believes it can achieve carbon neutrality as early as 2030.

These are strange times but they are times when the industry has a chance to regroup – despite the spat between OPEC and Russia. The global economy may be sick for the moment but this particular patient can prepare for its recovery. ■

Nick Cottam

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Conversion Factors

Crude oil
1 m^3 = 6.29 barrels
1 barrel = 0.159 m^3
1 tonne = 7.49 barrels

Natural gas
1 m^3 = 35.3 ft^3
1 ft^3 = 0.028 m^3

Energy
1000 m^3 gas = 1 m^3 o.e.
1 tonne NGL = 1.9 m^3 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 Sm^3) of oil equivalents

Giant field
Recoverable reserves > 500 million barrels (80 million Sm^3) of oil equivalents

Major field
Recoverable reserves > 100 million barrels (16 million Sm^3) of oil equivalents

Historic oil price