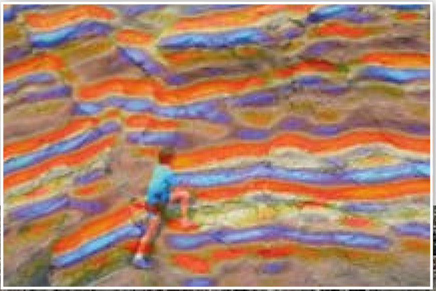
VOL. 16, NO. 4 – 2019

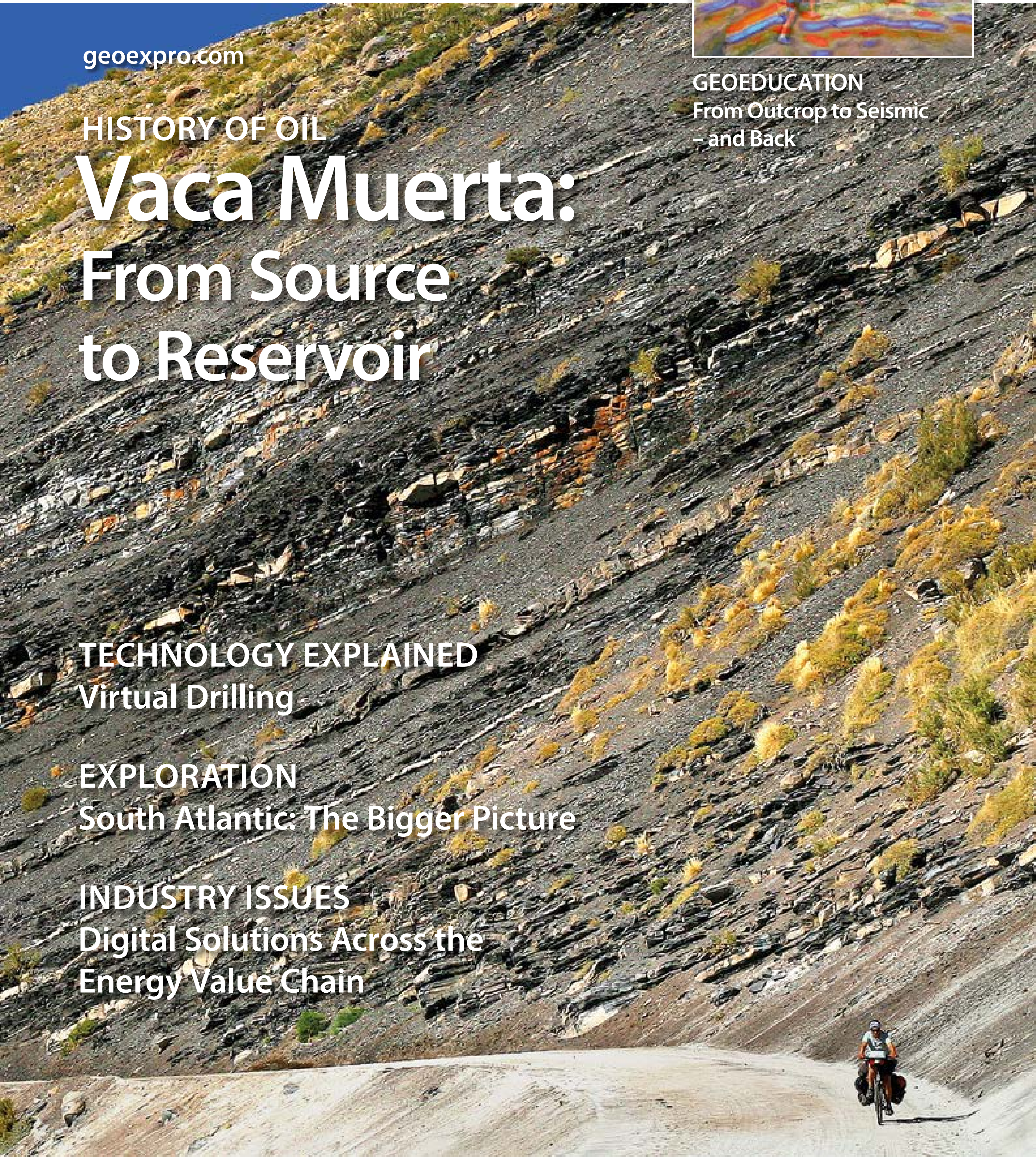
GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



geoexpro.com

GEOEDUCATION
From Outcrop to Seismic – and Back



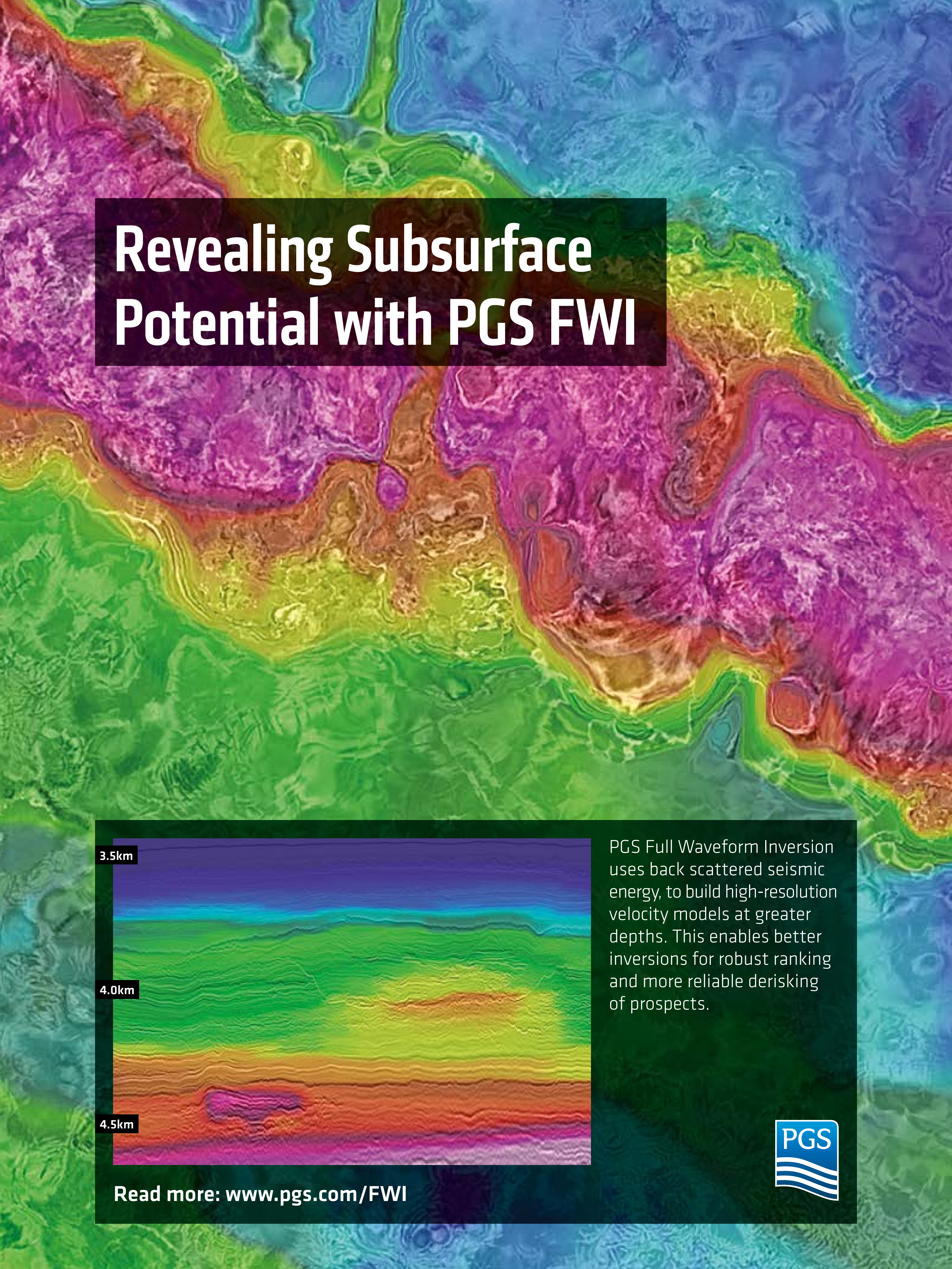
HISTORY OF OIL

Vaca Muerta: From Source to Reservoir

TECHNOLOGY EXPLAINED
Virtual Drilling

EXPLORATION
South Atlantic: The Bigger Picture

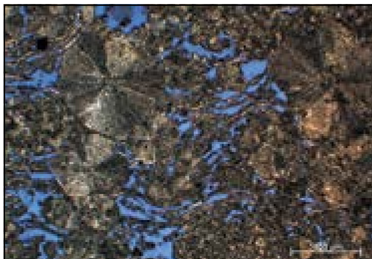
INDUSTRY ISSUES
Digital Solutions Across the Energy Value Chain



Revealing Subsurface Potential with PGS FWI
3.5km
4.0km
4.5km
PGS Full Waveform Inversion uses back scattered seismic energy, to build high-resolution velocity models at greater depths. This enables better inversions for robust ranking and more reliable derisking of prospects.
Read more: www.pgs.com/FWI
PGS

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



28

The enigmatic Cretaceous lacustrine carbonate reservoirs of offshore Brazil.

32

What role should the oil industry take in the transition to a zero-carbon energy system?

SEG

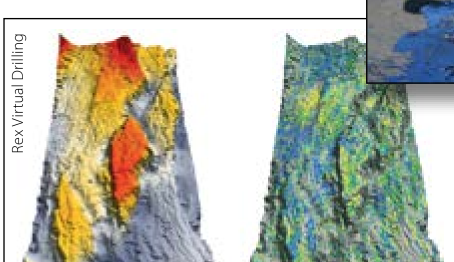
34

EVOLVE: developing the fearless explorers of the future.

Tim Daley

60

Trinidad's La Brea tar pit, the largest tar pit in the world.



Rex Virtual Drilling

78

A novel seismic DHI technology uses resonance and dispersion to indicate for liquid hydrocarbons.

Contents

Vol. 16 No. 4

This edition of *GEO ExPro* focuses on South America and Deepwater Exploration; Interpretation Software; the Energy Transition.

Making the Impossible Possible

In 2,450m of water, Shell's Perdido is the world's deepest spar, and the second-deepest oil and gas production hub.

The technological advancements continually being made throughout the E&P industry are amazing.

Take deepwater drilling as an example. We first tried drilling away from dry land in 1896, using wooden piers extending hundreds of meters into the Californian Pacific and pile drivers to drill into the seabed. For a very young industry, this was an adventurous move. By 1947, drilling had moved to specially built fixed platforms or towed barges, using sophisticated rotary rigs, well out of sight of land. In 1954 the first jack-up rig arrived in the Gulf of Mexico: a novel design which would eventually be able to drill in water 90m deep.

The next major innovation was the semi-submersible, in which the floating rig relies on anchors to keep it steady in the water. These are very stable in rough conditions – just what was needed as the industry moved into the unpredictable waters of the North Sea and deeper Gulf of Mexico in the second half of the 20th century. As drilling progressed into even greater depths like, for example, the South Atlantic off Brazil and West Africa, dynamic positioning ensured the rig remained stationary enough for the drilling riser pipe to pass through many meters of water and not be in danger of breaking.

Developments in seismic technology kept pace with the move into deepwater, with broadband and variable azimuth acquisition methods playing a significant role. Marine 3D seismic became routinely available in the mid '90s, illuminating the geology of previously inaccessible regions.

The Stones field, operated by Shell in around 2,900m of water, is the world's deepest oil and gas project, while at 3,400m, Uruguay's Raya-1 well holds the record for the deepest water depth ever drilled for oil and gas. It is a record I confidently expect to be exceeded before long.

Wherever the industry finds a challenge, great technological minds come up with a solution.

The most pressing challenge facing us now is the energy transition. I, for one, have every faith that this vibrant, innovative industry will be at the forefront of resolving it. ■

Jane Whaley
Editor in Chief

VACA MUERTA: FROM SOURCE TO RESERVOIR

The extensive Vaca Muerta shale formation has long been known as a prolific source for many fields in the vast Neuquén Basin, but now has a new role as reservoir, making Argentina the only country outside North America to have full-scale shale production.

Inset: How to develop an awareness of some seismic interpretation pitfalls through proper modeling of seismic images.

GEO ExPro

www.geoexpro.com

GeoPublishing Ltd
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
+44 20 7937 2224

Managing Director
Tore Karlsson

Editor in Chief
Jane Whaley
jane.whaley@geoexpro.com

Editorial enquiries
GeoPublishing
Jane Whaley
+44 7812 137161
jane.whaley@geoexpro.com
www.geoexpro.com

Sales and Marketing Director
Kirsti Karlsson
+44 79 0991 5513
kirsti.karlsson@geoexpro.com

Subscription
GeoPublishing Ltd
+44 20 7937 2224
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
kirsti.karlsson@geoexpro.com

GEO EXPro is published bimonthly for a base subscription rate of GBP 60 a year (6 issues).
We encourage readers to alert us to news for possible publication and to submit articles for publication.

Cover Photograph:
Main Image: Olivier Galland
Inset: Isabelle Lecomte

Layout: Winslade Graphics
Print: Stephens & George, UK

issn 1744-8743

Scan me

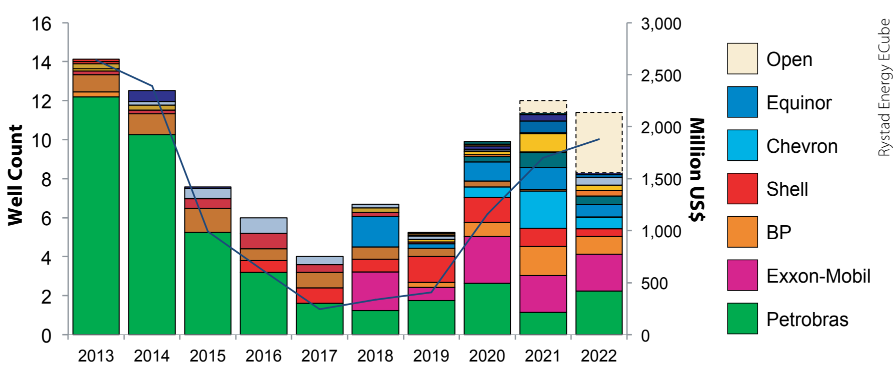
Brazil: Majors Chase Pre-Salt Riches

Brazil is on the verge of a revival in exploration activity in deep waters, driven primarily by oil and gas majors in the pre-salt of the Santos and Campos Basins. Drilling through thick salt domes poses various geotechnical challenges, but the high success ratio, large resource volumes and impressive recovery rates so far have attracted investments from deep-pocketed E&P companies.

Brazil held four pre-salt bidding rounds for production sharing contracts in 2017 and 2018; 13 exploration licenses were awarded, with several majors picking up acreage. These rounds raised an impressive $4.4 billion in signature bonuses, around 80% of the total exploration investments made in Brazil in 2017 and 2018.

Over the next three years the exploration drive in the pre-salt play is going to shift away from national oil company Petrobras towards the majors, as they will cover close to 50% of the pre-salt exploration drilling from 2020 to 2022. Numerous high impact wells are also on the cards.

ExxonMobil will be extremely active in the pre-salt going forward, having applied to drill up to 22 pre-salt wells in the Santos and Campos Basins, including in the Uirapuru and Tita blocks it acquired in previous pre-salt rounds. UK supermajor BP has revived its position in Brazil over the last two years, paying signature bonuses of ~$400 million for the four licenses it acquired. It plans to drill three wells in the Pau Brasil block it operates, the first scheduled in August 2020, and a further six in the Alto de Cabo Frio Central block, plus one in the Dois Irmaos block. The company had been optimistic about its Peroba block well, targeting 5.3 Bboe, but it unfortunately failed to encounter commercial hydrocarbons.



Number of net exploration wells and exploration expenditure on pre-salt assets in Brazil.

Chevron has made a return to Brazil through its recent pre-salt round wins in the Tres Marias and Saturno blocks, while Shell has taken stakes in five licenses in the last four pre-salt rounds, operating in three of them. Shell and Chevron ambitiously plan to drill up to five wells on Saturno, the first expected in January 2020. Shell will also drill five wells over the next two years in the Alto de Cabo Frio West and Gato do Mato South blocks. Both companies won stakes in Brazil's 14th and 15th concession rounds in the vicinity of the pre-salt polygon where a drilling campaign is planned in 2021.

The 6th pre-salt licensing round, scheduled for November 2019, will feature four blocks in Santos and one in the Campos Basin and is expected to raise close to $2.1 billion in signature bonuses. Petrobras has already registered its preference to hold a 30% stake in three of the blocks on offer, but the round provides ample opportunity for international players to raise their positions in Brazil. All the blocks on offer are close to the big pre-salt discoveries, increasing hopes for exciting new finds in the region. Further pre-salt rounds are lined up for 2020 and 2021. ■

Vishruthi K Acharya, Analyst, Rystad Energy

ABBREVIATIONS

Numbers
(US and scientific community)

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

Liquids
barrel = bbl = 159 litre
boe: barrels of oil equivalent
bopd: barrels (bbls) of oil per day
bcpd: bbls of condensate per day
bwpd: bbls of water per day

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

Dominican Republic First Round

Plenty of potential in fourteen blocks.

The Dominican Republic has just announced its first licensing round, which concludes in December 2019. Fourteen blocks are available onshore and offshore; with a flexible contract and an attractive investment environment, the nation is set to open up the Caribbean to new exploration opportunities.

The geology of this frontier region is even more reason for investors and operators to be attracted to the Dominican Republic. Features of the basinal setting include:

- Subduction of the North America plate below the Caribbean Plate.
- Strike-slip, convergent structures produced by strike-slip displacements and transpressional accretion of crustal fragments (Mann and Lawrence, 1991).
- Thrust belts developed on both sides of oceanic island arcs.
- A north-verging accretionary prism lying to the north of the Eastern Greater Antilles arc.

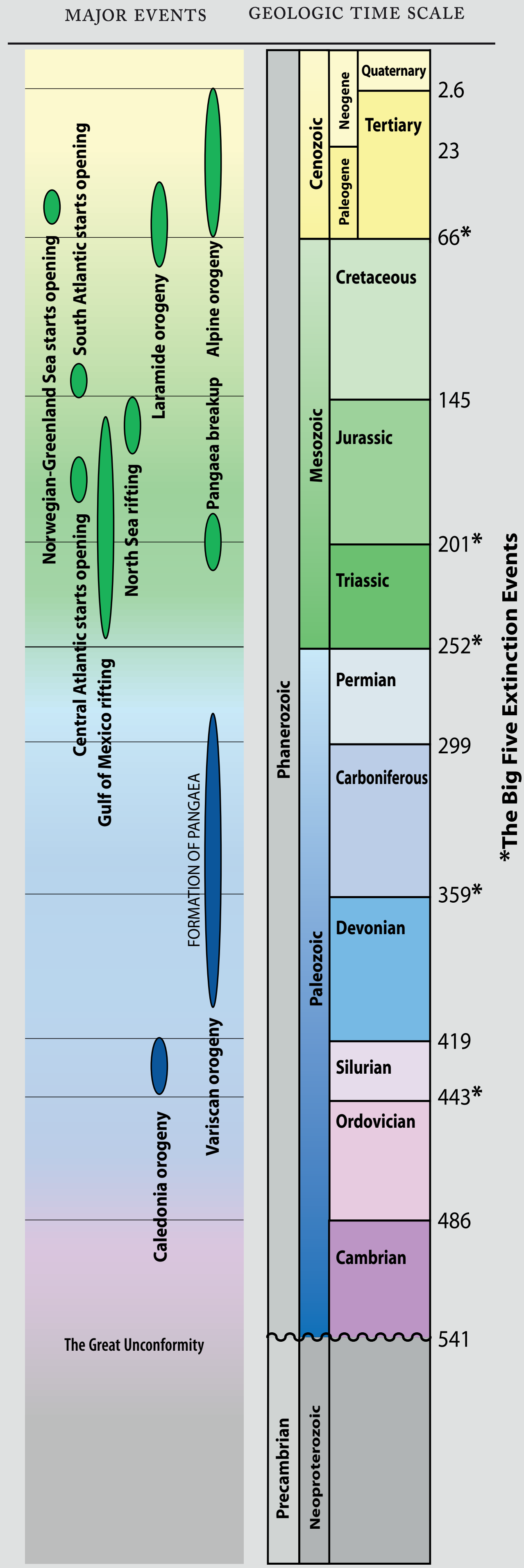
The presence of crude in the Dominican Republic has been known for decades, as evidenced by the black gold that oozes out of a pit in Charco Largo, Azua, in the south of the country. Three onshore Neogene clastic basins have been the focus of petroleum exploration, and oil seeps led to a well being drilled at Higuerito as far back as 1905, reportedly producing about 40 bpd of oil, although sustained production was not obtained until 1927/8 by Texas Co.

The Dominican Republic occupies the eastern 5/8ths of the island of Hispaniola, in the Greater Antilles archipelago of the Caribbean region. It is the second largest Caribbean nation by area, and third by population. Its capital, Santo Domingo, is home to approximately three million people.

With temperatures averaging 26°C/78.8°F and wide climatic and biological diversity, the Dominican Republic has long been a favorite with tourists from all over the world. In addition, it is an attractive and desirable country for international investment.

On offer are fourteen blocks in four basins, a combination of on and offshore, with a maximum size per block of 500 km^2 onshore and 2,500 km^2 offshore. Onshore, six blocks are available in the Cibao Basin, three in the Enriquillo Basin and one in the Azua Basin. The four offshore blocks are all located in the San Pedro de Macoris Basin.

Interested companies will be able to nominate new exploration areas and/or propose changes to future blocks on the back of success in this round. Flexible contract terms allow operators to adapt the exploration strategy during the term of the contract. *(See www.geoexpro.com)* ■

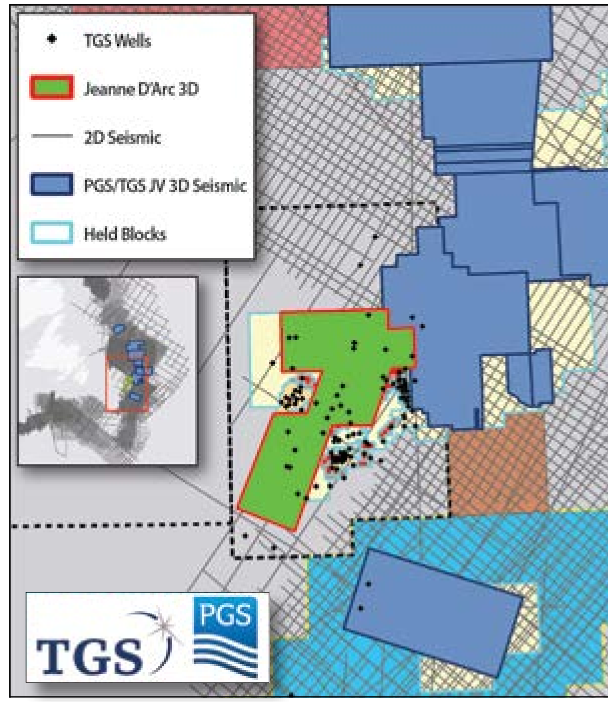


Jeanne d'Arc HD3D survey

TGS and **PGS** recently announced a joint multi-client **High Density 3D project** in the **Jeanne d'Arc Basin** offshore Newfoundland, **East Canada**. The project will cover approximately 5,000 km^2 and is the first comprehensive high resolution 3D dataset to be acquired within this mature basin, which is a large asymmetric half-graben trending north-north-east, lying about 300 km east-south-east of the capital of Newfoundland, St John's.

The PGS vessel *Ramform Atlas* has commenced acquisition, utilizing its high-resolution Geostreamer® technology, and is expected to complete in late Q3 2019. The survey has been designed to cover multiple Exploration Licenses, Significant Discovery Licenses and sections of the open acreage included in the November 2019 bid round.

Following this ninth consecutive season of data acquisition in offshore East Canada, the PGS/TGS jointly-owned library will have more than 189,000 km of 2D GeoStreamer data and approximately 56,000 km^2 of 3D GeoStreamer data. An expansive well log library is also available in the region, along with advanced multi-client interpretation products that will improve play, trend and prospect delineation. ■



New EAGE Energy Transition Group

The **European Association of Geoscientists and Engineers (EAGE)** launched a new **Special Interest Group (SIG)** at its Annual Conference and Exhibition in London this summer. This new community is dedicated to **decarbonization and the energy transition** and its aim is to promote knowledge and develop skills among geoscientists and engineers working with technologies involved in these topics. This covers both the geoscience and engineering aspects of surface and subsurface decarbonization including CO_2 sequestration and the advancement of renewables such as geothermal energy production.

The inaugural session was held during the EAGE conference and attracted about 50 interested attendees, who listened to excellent talks from industry specialists, such as Philip Ringrose from Equinor, who talked about decarbonization and zero-emissions trajectories, and Karin de Borst, who explained Shell's quest to put carbon back underground.

One participant commented: "This is a topic that should start to be part of the conversation more frequently. It is also interesting because it can enable the conversation about decarbonization pathways from different sectors, industries, countries, by building a holistic view of what energy transition is and how to create a network for knowledge and experience sharing which can be translated into programs and actions." Another participant said "It was relevant. I liked being in a room full of passionate people wanting to improve our businesses!"

The SIG is open to all EAGE members and is looking for interested volunteers to form a committee to start working on new events, support decarbonization-related initiatives and knowledge sharing. See the EAGE website for further details. ■

Believe in Future Discoveries

With the opening of the **fifth licensing round**, the **Faroe Islands** are inviting oil companies to explore for hydrocarbons on the Faroese Continental Shelf. This round is being held simultaneously with the 32nd UK round and the terms, conditions and licensing system have been adjusted to those of the UK.

The Faroese Continental Shelf contains great potential and prospects, which are waiting to be further explored, and with only nine wells drilled the area is still underexplored. A working hydrocarbon system has been proven and the area on offer is likely to contain possibilities for hydrocarbons in intra- and pre-volcanics reservoirs (Rosebank and Laggan/Toremore analogs respectively), possibly trapped by extrusive lavas.

Additionally, potential prospects such as the deep Anne-Marie structure, below TD of the Anne-Marie well, which encountered 350m of gas, also remain untested.

Interested oil companies will receive a complementary data package, which includes all relevant data from the area on offer. ■

Superfast 3D Seismic Geometry Analysis

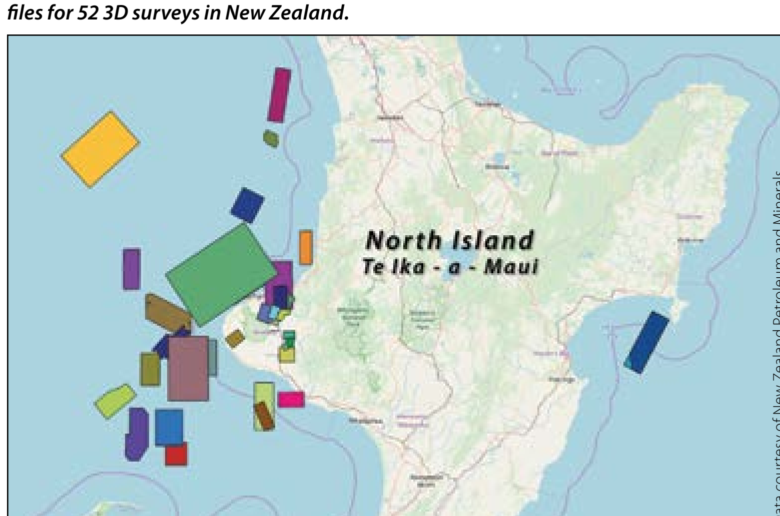
Troika International recently launched a utility that can, within seconds, report key parameters about a **3D post-stack seismic dataset.** The company's new **GEOM** software provides a superfast geometrical quality control check that can potentially save hours of expensive data loading time.

Acquisitions, mergers, joint ventures and multiclient projects mean that 3D datasets are routinely exchanged between E&P operators, service companies and national data stores. The size of surveys continues to grow, both through the increasing extent of new projects and the merging of existing datasets, resulting in data volumes of several terabytes that even the most powerful computer and data storage systems require a long time to upload. Reliable quality control of these datasets is essential to maintain the integrity of company databases and accurate uploading to E&P software platforms.

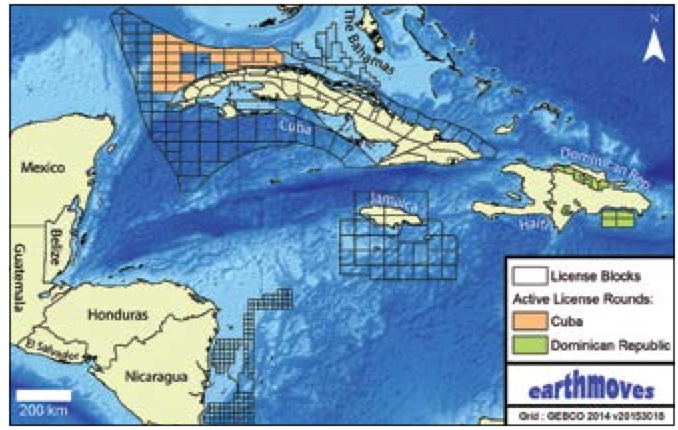
The GEOM software provides important information such as x/y coordinates of corner points, survey azimuth, bin dimensions, trace count, and an outline surface coverage image. It analyzes textual headers and can export the header definitions for integration into other software applications and provide shapefiles for visual display or input to GIS applications.

The cost to acquire and process a 4,000 km² 3D deepwater survey is in the order of $25 million and typically results in a post-stack dataset of around 150 GB. The GEOM software performed preliminary quality control of a volume of this size in around 12 seconds on a 32 GB RAM PC running Windows 10. The software can also identify errors in header and positioning data, mitigating the chances of incorrect information being input to an organization's database. ■

Troika International's GEOM software took ten minutes to analyze and create shape files for 52 3D surveys in New Zealand.



The Caribbean Hots Up!



The **Caribbean** currently offers an unprecedented number of hydrocarbon exploration opportunities, with active license rounds in **Cuba** and the **Dominican Republic**; plus extensive open acreage available for direct negotiation across **Jamaica**, **Honduras**, and **Nicaragua**. Farm-in opportunities are also available in **The Bahamas**.

The complex tectonic history of this relatively underexplored region has produced numerous hydrocarbon plays, with reservoirs ranging from Oxfordian Norphlet Formation aeolian sandstones and Cretaceous limestones, to Tertiary foreland basin clastics. Subduction and oblique collision during the Late Cretaceous to present day has produced a series of docked island arcs with thrusted Jurassic carbonate platforms and ophiolites, creating many potential structural traps.

Recent work on the Nicaraguan Rise indicates that the Eocene Punta Gorda Formation is a potentially prominent source rock, reaching up to 600m in thickness, with TOCs ranging from 0.85 to 3.4 wt%. An Aptian to Albian-age bituminous limestone also has oil-generating potential in this region. Recent onshore seep discoveries from Cretaceous sources confirm the presence of an active petroleum system on Jamaica.

Mounting research and increased accessibility will further encourage the development of this emergent region. **Earthmoves' Northern Caribbean Digital Atlas** provides a detailed analysis on the northern Caribbean's geology and hydrocarbon potential; visit the Earthmoves website for further details. ■

Meet the Entire Upstream Value Chain

AOW

Networking at the Cape Town Waterfront.

For a quarter of a century, **Africa Oil Week** has been the meeting place for the continent's most senior E&P stakeholders. The 26th edition of the summit, taking place in **Cape Town** this November (4–8) looks set to be better than ever. Over 1,500 senior delegates are attending this year, including representatives from supermajors, IOCs, geophysical companies and oilfield service providers. More than 22 ministers and 20 NOC bosses will also be joining via the growing VIP and Ministerial Program. Together, delegates will be setting out the future direction of the continent's upstream oil and gas sector, making deals and building lasting relationships at the summit's daily social functions.

The conference is also welcoming **top students** of geosciences and petroleum from six pan-African universities. These students represent the future talent pipeline of the industry and Africa Oil Week is proud to support them.

Does Africa Oil Week sound like it could be of value to you? Join us by visiting the AOW website. ■

Faster, Cheaper and Fit-for-Purpose

For several years now, the **unconventional sector** in North America has been striving to make the cost savings required for profitable production whilst still drilling P90 wells. To do this, most operators are in 'factory mode', drilling and completing tens or hundreds of wells per year. Reservoir quality data is therefore at a premium as its collection is severely limited by the speed of drilling, the number of wells being drilled, and the tight budget constraints required for profitability. So how do you get the mineralogy, TOC, RHOB, RHOM and porosity that allow you to accurately calculate rock mechanical properties to feed into drilling and completions programs? The answer: you maximize the value of your cuttings.

For the past five years **Chemostrat Inc.** has been developing tools to squeeze these data from cuttings samples in the Permian Basin. Using X-ray fluorescence, Fourier transform infrared and water immersion porosimetry, and proprietary Chemostrat workflows, they can mimic a completions log at a tenth of the cost of running a quad combo downhole.

Chemostrat is applying these years of experience and learning to unconventional plays around the world, including Argentina, MENA, China and Russia. The company will be at **AAPG ICE 2019** in Buenos Aires to discuss with local operators the application of these techniques in Argentina, where it will now also be possible to acquire the data needed for unconventional reservoir quality assessment, even when a play enters 'factory mode'. ■

Vaca Muerta

How a Source Became a Reservoir

Argentina has the second-largest shale gas and fourth-largest shale oil reserves in the world, almost all reservoired in the Vaca Muerta Formation in the vast Neuquén Basin. This black shale has been known and exploited as a source rock for over 100 years, but in a potentially game-changing event, the first exports from the Vaca Muerta itself were delivered in June this year.

CARLOS MACELLARI and JANE WHALEY

None other than the famous naturalist and geologist Charles Darwin was the first scientist to make observations about the black shales he found in the High Cordillera of Mendoza, from which he collected a number of fossils back in the 1830s.

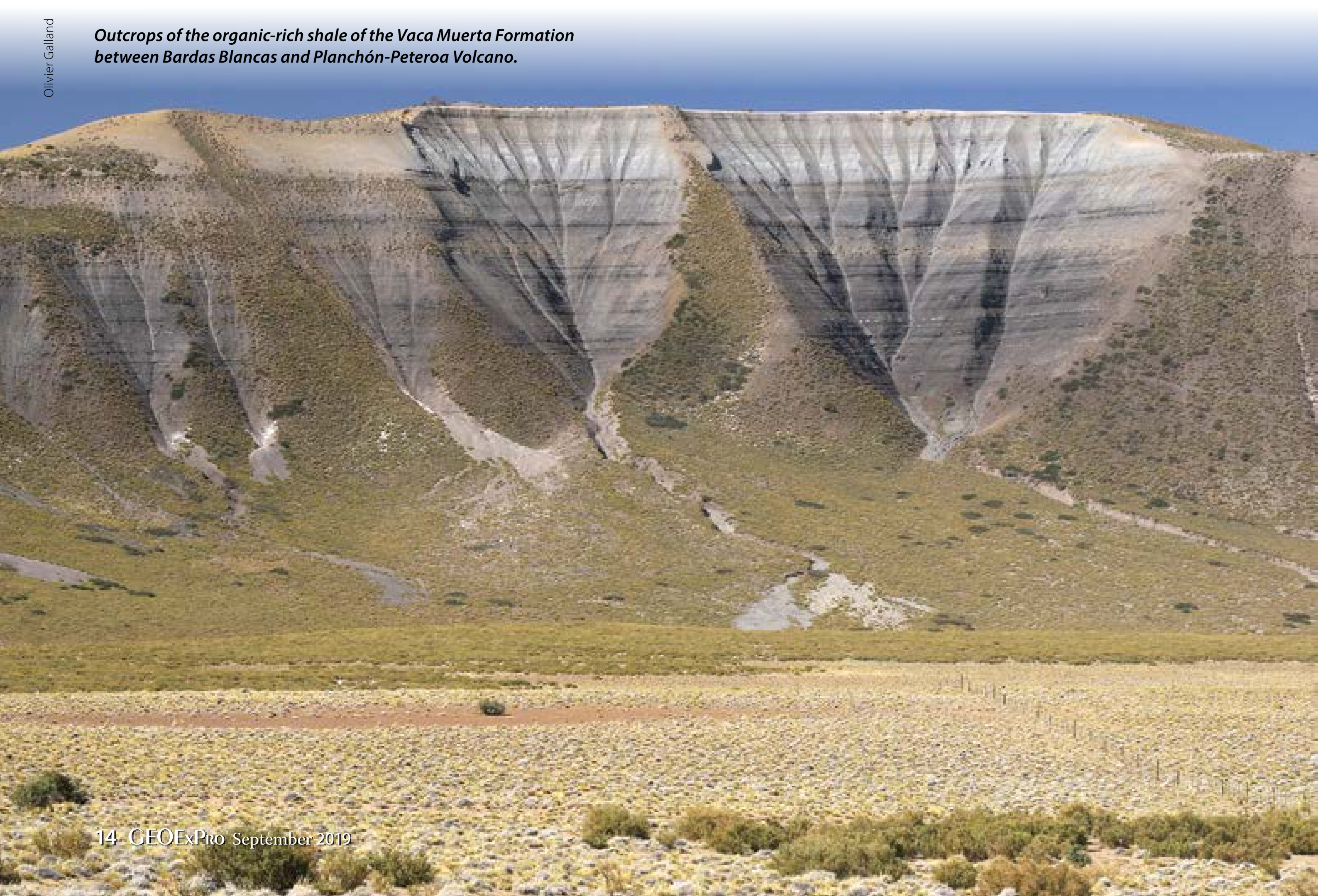
It was not until towards the end of the 19th century, however, that the significance of the color of these shales was realized, when Guillermo Bodenbender, who geologically mapped much of Argentina and can be considered one of the 'fathers of Argentinian geology', realized that the shales contained oil. In 1892 he reported that rocks he had found in the Salado River Valley were "very bituminous and almost completely impregnated by kerosen, which has been found in liquid state in the central cavity of an ammonite…"

A source rock had been identified.

In 1931 American geologist Charles Weaver officially defined the Vaca Muerta Formation and described it as comprising black shales, marls and lime mudstones. It was he who named it the Vaca Muerta (Dead Cow), after the mountains (the Sierra de la Vaca Muerta), where these rocks are outcropping.

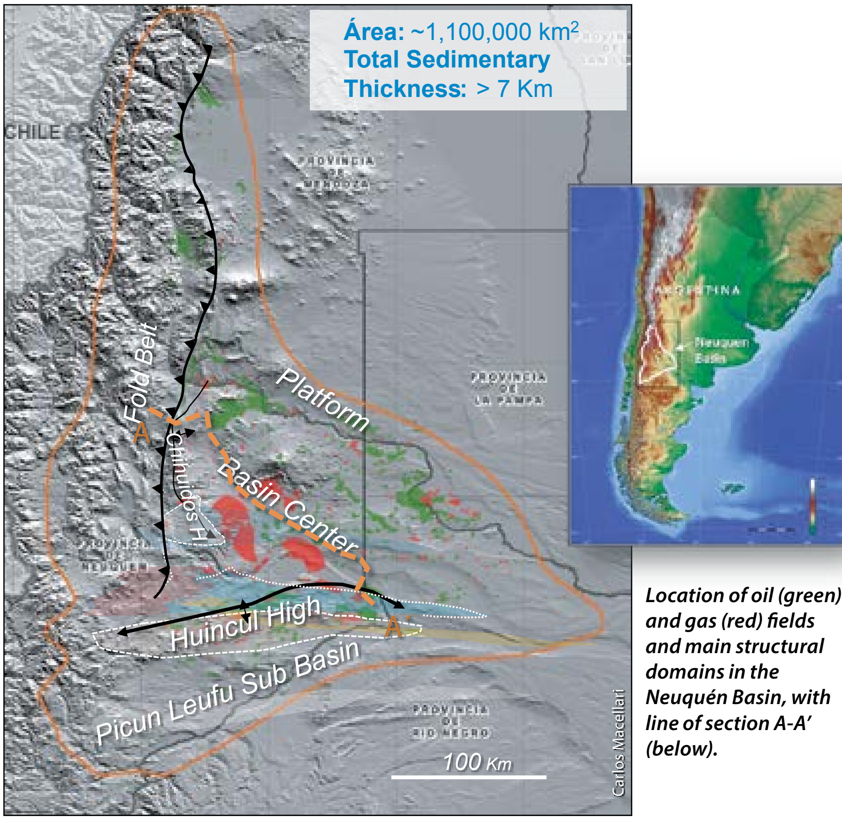
The Dead Cow Formation

The Vaca Muerta Formation underlies much of the Argentinian Neuquén Basin, which contains a near-continuous Upper Triassic-Lower Cenozoic succession covering about 100,000 km^2



Olivier Galland

Outcrops of the organic-rich shale of the Vaca Muerta Formation between Bardas Blancas and Planchón-Peteroa Volcano.



Location of oil (green) and gas (red) fields and main structural domains in the Neuquén Basin, with line of section A-A' (below).

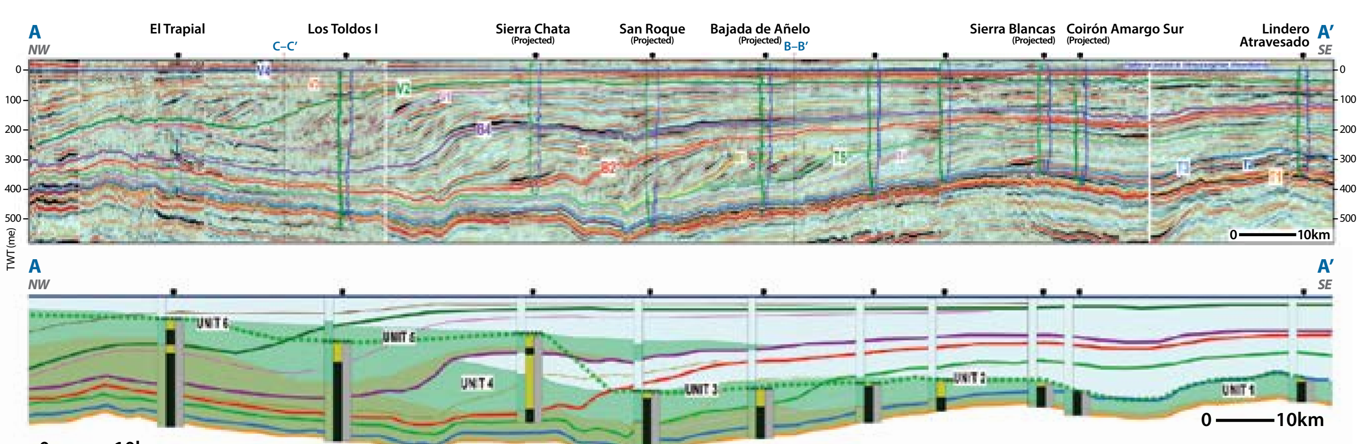
with a total sedimentary thickness of over 7 km. It developed as a back-arc basin in Mesozoic times in the western margin of South America. In the Early Jurassic there was a widespread shallow marine incursion over the basin area and broad depocenters filled with continental and marine siliciclastic, carbonate, and evaporitic sediments. This was followed by a widespread transgressive-regressive sedimentary cycle during the Tithonian-Berriasian with the deposition of dark organic-rich mudstones, marlstones and limestones, including the Vaca Muerta Formation. This is overlain by the Lower Cretaceous Quintuco-Loma Montosa Formation, which forms the largest oil-producing carbonate depositional system in the Neuquén Basin.

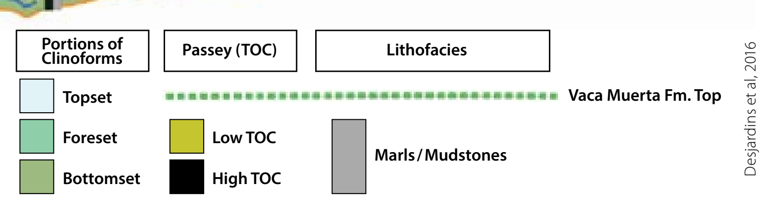
Source Becomes Reservoir

The first oil field in the Neuquén Basin, Plaza Huincul, was discovered in 1918. Over 4,500 exploratory wells have been drilled since then and about 14.4 Bboe of conventional resources have been discovered in the basin, including the giant Loma La Lata Field, found in 1977, which has 10.5 Tcf of gas reserves.

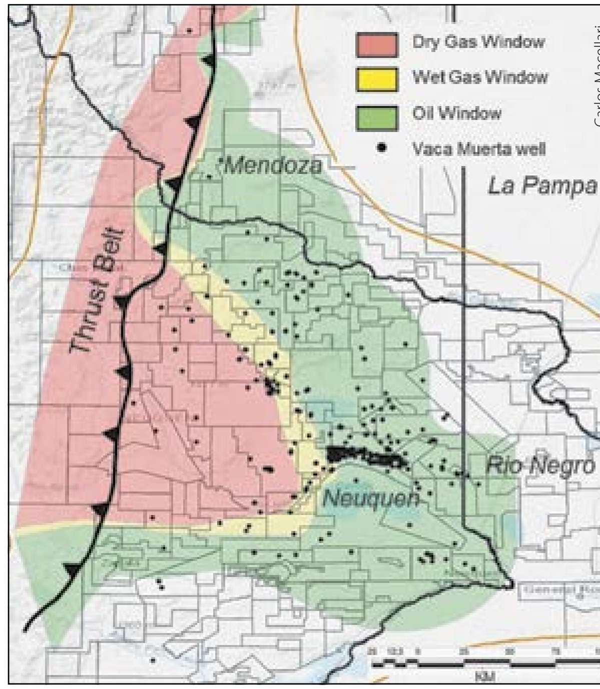
The Vaca Muerta has been known for many years to be the very effective source rock for most of these fields in the Neuquén Basin, feeding into reservoirs that range in age from Late Triassic to Late Cretaceous, with seals in the Jurassic and Cretaceous. Due to the formation's vast areal extent – over 30,000 km² – and variable thickness and overburden, the Vaca Muerta has produced a range of hydrocarbons, including low GOR liquid hydrocarbons, volatile oils, gas/condensate and dry gas. Three distinct hydrocarbon generation windows can be geographically identified in the basin: the north-western part of the basin contains mostly dry gas, while wet gas and oil appear further south and east.

However, when researchers looked again at the Vaca Muerta Formation, with its wide areal extent and ideal burial depth at between 2,000 and 3,500m, they realized that it must have generated a much larger volume of oil than the amount which appeared to have been expelled to overlying reservoirs – so where was the rest? In fact, it has been calculated that only about 20% of hydrocarbons generated in the formation have been expelled, primarily because the overpressure





The Quintuco-Vaca Muerta system is organized in an array of depositional sequences in which proximal facies prograde toward the north-west. (For location of section see map above.)



Vaca Muerta maturity zones in the Neuquén Basin.

barrier (0.75 to 0.85 psi/ft) formed by the overlying Quintuco Formation has helped to retain the hydrocarbons within the Vaca Muerta.

The Vaca Muerta Formation has thick, organically-rich sections between 30 and 400m thick, allowing multiple navigation horizons; plus excellent porosities, ranging from 4 to 16%; and TOCs as high as 17%, particularly towards the base of the unit, which represents the maximum flooding level of the basin. In addition, the unit is overpressured and has a relatively low percentage of clay, making this rock ideal for hydraulic stimulation. These are all excellent properties for an unconventional shale reservoir. The formation has therefore now become the primary target for hydrocarbon exploration in the Neuquén Basin, which is, it is interesting to note, three times the size of the Permian Basin in the USA.

In addition, the long history of conventional exploration means the infrastructure is in place to rapidly assess and exploit this region for shale development.

Vaca Muerta as a Reservoir

Although not officially targeted, there were hints of the Vaca Muerta's potential in some conventional legacy wells. Over the years more than 130 wells had been drilled which had tests or cores in the formation, and the first conventional well to produce oil from the Vaca Muerta was Filo Morado 25, which delivered 533,000 barrels from fractured Quintuco-Vaca Muerta rocks between 1991 and 1995.

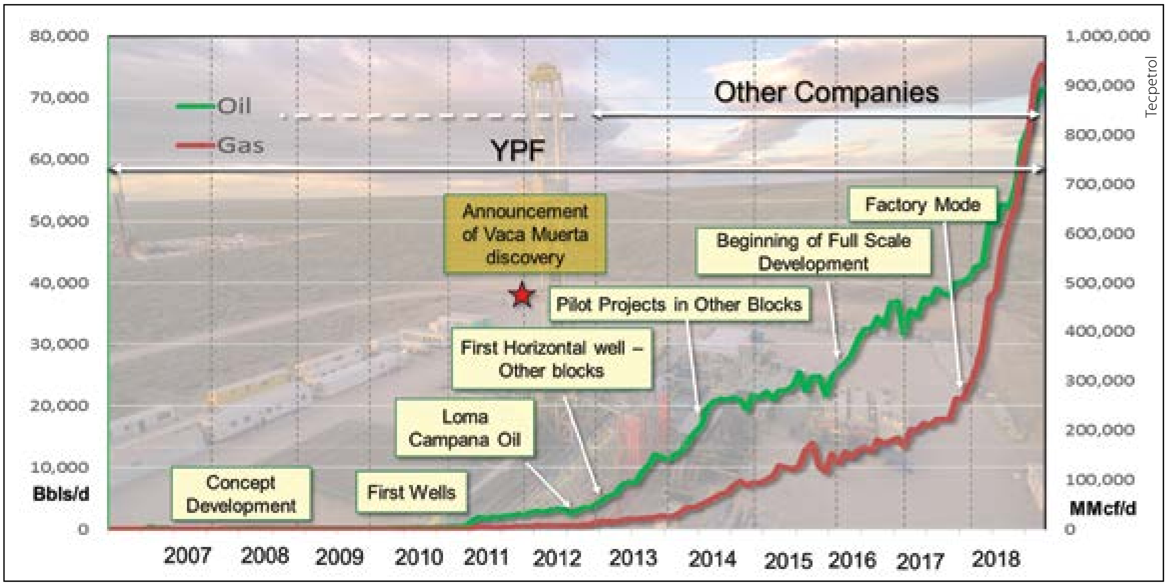
The EIA had also pointed out the unconventional resource potential of the Vaca Muerta in its 2013 World Shale Gas and Oil Resource Assessment. In this it suggests that the risked recoverable amount of gas in the formation could be 307 Tcf, with resources of 16.2 Bb oil and oil condensate.

Work by Repsol YPF in the giant Loma La Lata gas field first brought attention to the unconventional possibilities in the Vaca Muerta. In 2009 the company drilled PSG.x-2, which was the first well in Loma La Lata designed to test for shale gas in the Vaca Muerta, but it discovered oil in the overlying Upper and Lower Quintuco. In 2010 Repsol YPF had gas traces in LLLK.x-1, which targeted karstic features in Lower Quintuco, but after poor results the well was deepened to the Vaca Muerta where it found shale gas. LLL-479, in the northern area of the Loma La Lata field later the same year, similarly targeted the Lower Quintuco but when that proved dry the well was re-entered and found oil in the Vaca Muerta; this was the first discovery of shale oil in Argentina.

Exploration of the Vaca Muerta as a reservoir really started in 2011 with Soil.x-1, the first well drilled to actively evaluate shale oil potential. It successfully produced from the formation after five fractures, which was hailed throughout Argentina as a major breakthrough for the country.

After initially drilling predominantly vertical wells, since 2016 the majority of wells in the Vaca Muerta have been horizontal (190 out of 194 in 2018), with the average lateral length increasing from 1,000m in 2014 to 2,200m in 2018, while

Outcrop of naturally fractured Vaca Muerta shale.



Main events in the discovery of Vaca Muerta as a reservoir. Production from this unit has increased dramatically in recent years.

the average estimated ultimate recovery per horizontal well has also increased considerably, from 218 in 2013 to 872 Mboe in 2019 (GiGa Consulting, 2019).

It is now thought that the unconventional resource potential of the Vaca Muerta is 91 Tcfg and 14.3 Bbo.

First Exports Achieved

Operators in the Neuquén Basin undertook several pilot projects and brought five projects into development, before production ramped up dramatically at the beginning of 2018 as activity increased into full development.

Initially, YPF was the main company involved in the Neuquén Basin unconventional play, but from 2012 it was joined first by Chevron and then by other major exploration companies including Total, Shell, and Exxon Mobil. They were later followed by local companies such as Tecpetrol, PAE, Pluspetrol, Pampa and Vista. In particular, Tecpetrol led the way in showing the tremendous gas potential of the Vaca Muerta, when in a single year the company managed to drill over 60 wells in its Fortin de Piedra Block, building extensive facilities to ramp up production from zero to 550 MMcfpd, making it the largest gas field in Argentina. This represents 10% of the gas produced in the country and was due to a large extent to the incorporation of industrial management know-how and a 'factory' mode approach to production. Today, a total of 82,000 bopd and over 1 Bcfpd is being produced from Vaca Muerta wells, which has dramatically changed the energy spectrum of the country.

All production from the Vaca Muerta unconventional reservoirs was used locally until recently, but production has been increasing enough that, in June 2019, two cargoes from the formation, one of light oil, the other of liquefied natural gas, were exported, foreshadowing what officials say will be a steady flow of shipments by the end of the year.

Changing the Energy Spectrum

The start of oil and LNG exports and the increasing volumes of gas available for domestic use, all stemming from the unconventional reservoirs of the Vaca Muerta Formation, mean that Argentina is the only country to have full scale shale production outside North America. It has yet to become as efficient as the North American shale plays, but can take advantage of the great technological advances which have been made in those fields to short-cut the learning curve.

Considering the recent announcements of future developments by most operators, it is clear that this upward trend will continue, heralding an important shift in the energy balance and economy of Argentina. ■

The Central Processing Facility at Fortin de Piedra, operated by Tecpetrol.

Latin America:
From Shallow Shelf to Deepwater

How we got where we are – and where we are going.

ROG HARDY
Editor, NVentures Latin America Exploration Report

Explorers first stepped out from prolific onshore basins into shallow water just after World War II, using simple 'trendology' supported by early seismic and gravity datasets. Plate tectonics and seismic stratigraphy supported by huge integrated geophysical datasets have since guided industry out to ultra-deepwater, yielding billions of barrels in a quest that will continue until we are in a post-carbon world.

Trendology Wins on Shelf

Stepping out from giant onshore fields in south Louisiana into geologically contiguous strata in the shallow-water Gulf of Mexico (GoM) was the industry's first logical move offshore. Being an easy mobilization distance from the US GoM, Mexico's Tampico area (the Golden Lane extension) and Salina Basins, plus the Gulf of Paria and Atlantic Columbus Basin of Trinidad, were all early beneficiaries of these new engineering capabilities, resulting in major shallow-water shelf discoveries in the 1950s and early '60s. These successes were maximized by rapidly improving seismic reflection technology, but the foundation of these early discoveries was 'trendology'.

As offshore exploration became a global pursuit, industry expanded the effort in Latin America and the Caribbean (LAC), but failure or less than stellar early success was the result on the shallow shelf outboard of more marginal or less geologically continuous onshore production in Cuba, the northern margin of South America, Suriname, Peru's Talara Basin, and several basins offshore Brazil and Argentina. Something more was needed.

Technology Wins in Deepwater

Teaser results (outside the core GoM) from continental shelf drilling across the region then led to strong interest in the deepwater. IOCs were able to start de-risking these new frontiers utilizing data from DSDP and ODP programs, along with valuable new plate tectonic and sequence stratigraphy models. Combined with large-scale 3D and ever-improving deepwater production technology, this enabled focused and highly successful deepwater campaigns in Brazil's Campos and Santos Basins and more recently in Guyana, while extending the Perdido Foldbelt trend from the US to Mexico.

Frontier exploration is a risky game, however, as all this geotechnical rigor has yielded fairly high profile failures in Cuba, Barbados, Caribbean Nicaragua, Suriname, north-east Brazil and Uruguay, plus marginal or gas-only success in Colombia, Venezuela, Trinidad, French Guiana, north-central Brazil and the Malvinas (Falklands).

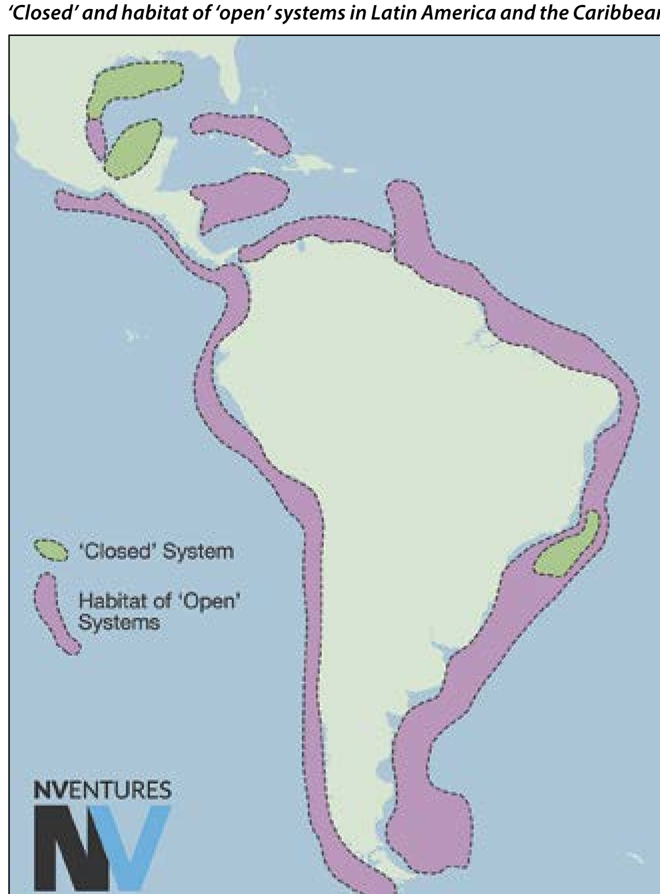
A Tale of Two Systems

With all the activity of the last sixty years the producimg petroleum systems that have yielded major success in LAC fall into two general families that can be informally termed 'open' and 'closed'.

'Closed' systems are highly structured with super seals and readily definable traps and boundaries on seismic data. In LAC these are Mexico's Salina-Sureste Basin and Brazil's Campos-Santos, and to a lesser extent the US-Mexico Perdido Foldbelt and Brazil's Sergipe-Alagoas. These basins have been shown to be prolific and relatively low risk, and have yet to reach their peak for production.

The hydrocarbon habitat in 'open' systems, conversely, are usually not obviously structured, with poorly defined boundaries on seismic, best characterized by the recent Guyana Stabroek trend. (Locally they can be highly structured, as along the Caribbean margin, including shallow-water Trinidad.) Vast regions possibly harboring accumulations in 'open' systems remain barely touched by the drill bit, from deepwater Barbados to Argentina on the Atlantic side, and higher risk Mexico to Tierra del Fuego on the Pacific side. A major campaign is presently underway within IOCs and NOCs to focus in on Stabroek look-alikes using large geophysical datasets, including multibeam for seep detection. This will result in establishing new producing provinces, but at the present industry pace some large productive complexes may go undiscovered while we move to that post-carbon world. ■

'Closed' and habitat of 'open' systems in Latin America and the Caribbean.



Deepwater Santos Basin:

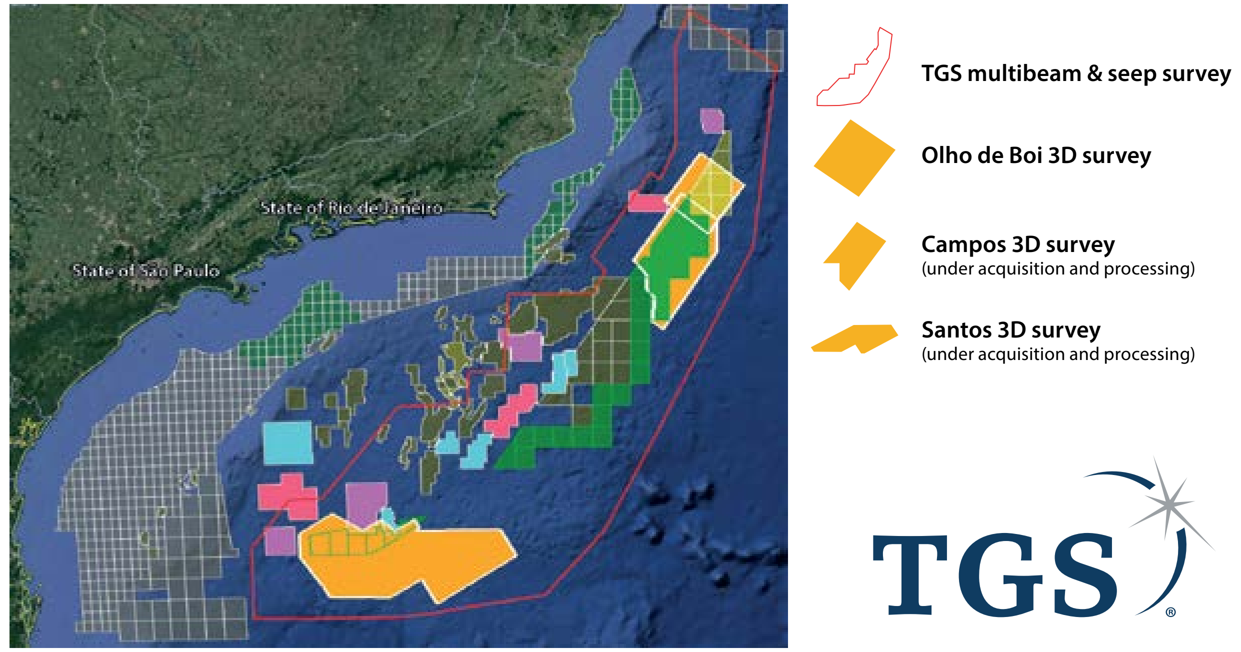
Extending the Pre-Salt Play Outboard

Fast-track RTM PSTM (Salt Flood 1) line (below) through a part of the Santos 3D seismic volume, showing well-developed sag-phase carbonate (main Santos pre-salt reservoir) and syn-rift structures (horsts, grabens and half-grabens) beneath the salt. (A) marks a basement horst, against which the salt seems to have rotated.

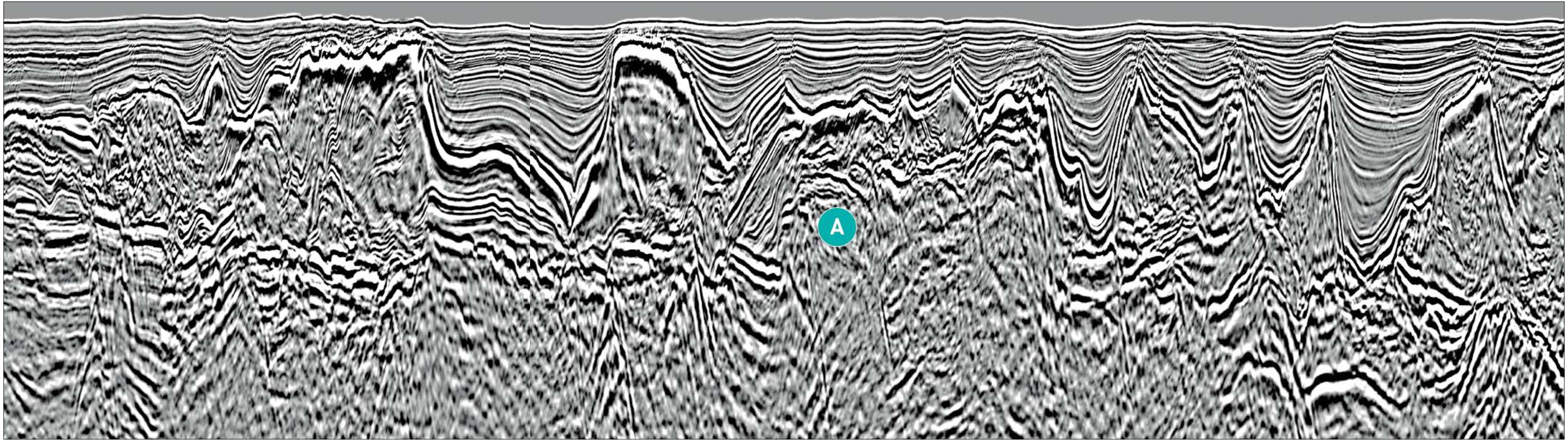
Why did we acquire 3D multi-client seismic in the outboard South Santos? Because it is prospective!

TGS (acquisition years 2000–2001) and Spectrum (acquisition years 2012–2017, now TGS) have acquired long-offset 2D seismic surveys over most of the Santos and Campos Basins, from near shoreline to the abyssal plain. Large four-way dip closures (4WDCs) at base-salt level were mapped on the latest Spectrum 2D seismic (Spectrum, 2018) in the southern Santos Basin that suggested the possibility of large structurally defined pre-salt traps. Seismic facies indicators, as mapped in the TGS (2013) seismic facies and play fairway analysis project, suggested the presence of both the main K46–48 (Barra Velha Formation) reservoir and the presence of syn-rift structures that may contain source rock kitchens. The combination of these factors provided encouragement to proceed to acquisition of 3D seismic.

TGS is therefore acquiring a 22,700 km^2, high-resolution multi-client 3D seismic survey in the outboard Santos Basin, Brazil. 3D Kirchhoff and Reverse Time Migration (RTM) pre-stack depth migration (PSDM) are being undertaken to produce a more accurate velocity model, enhance event placement and improve salt boundaries and subsalt imaging. In this article we look at results from fast-track processing (Salt Flood 1) to see the enhancement of imaging of pre-salt structures and potential reservoirs over the previously available 2D seismic. We present here initial observations on a fast-track RTM sub-volume of the Santos 3D, which support the presence of large, untested four-way dip closures in the pre-salt carbonate reservoir layers.



TGS



Huge Potential in Undrilled Southern Santos Basin

The prospectivity of the deepwater outboard Santos Basin is revealed by new 3D seismic.

CIAN O'REILLY, JAMES KEAY, JIANLI SONG, GRISELDA MARTINEZ, SEUNG YOO, TAEJONG KIM, ERIC NEWMAN and PEDRO ZALAN; TGS

With a daily oil production in the region of 2.6 MMbo (ANP, 2018), Brazil is among the ten largest oil producers in the world. Just under half of Brazilian oil production comes from the pre-salt carbonate reservoirs of the Santos and Campos Basins. Production from sag-phase and syn-rift (Aptian and Neocomian) reservoirs dates back almost to the start of exploration and production in the Campos Basin, where Neocomian vesolitic and fractured basalt and Barremian coquinas were put into production in the Badejo and other fields. However, significant exploration of, and production from, the pre-salt Lower Cretaceous carbonate reservoirs of the Santos and Campos Basins did not occur until the 2006 discovery of the giant Tupi/Lula field in the Santos Basin and the 2008 development of the pre-salt carbonates in the Campos Basin Jubarte field. Further discoveries of pre-salt fields in the Campos Basin (some below extant fields in Late Cretaceous to Miocene turbidite sands) followed, including the Parque das Baleias fields from 2010. Production from the Lula and Sapinhoa fields in the Santos Basin began in 2013, and other fields have followed, including Carioca/Lapa (2016) and Franco/Buzios (2018).

Fast-Track Volume Available

A fast-track sub-volume (3,370 km^2) of the Santos 3D volume is now available for inspection before the upcoming license rounds. This sub-volume shows only a small portion of the larger study area, but it is sufficient to validate the main findings of the 2D seismic surveys:

- there are large four-way dip closures at base-salt level;
- the seismic facies indicate the presence of the Barra Velha Formation beneath the salt;
- syn-rift grabens and half-grabens containing potential source rocks flank the structural highs.

Regional Setting and Exploration Activity

South America and Africa were part of Gondwana until separated by Late Jurassic-Neocomian rifting, when horst and graben structures developed in trends roughly perpendicular to current coastlines. In both Brazil and Angola, a transition is seen from proximal fluvial-alluvial clastic-dominated facies to widespread deposition of lacustrine facies. Shallow water lacustrine carbonate reservoirs developed locally on or around horsts, whilst coeval organic-rich shales (associated source rocks) accumulated in the grabens and half-grabens. The end of major rifting is marked by a regional angular unconformity, with carbonates and shales infilling the late syn-rift to sag basins. Increasing salinity of the lacustrine environment culminated in deposition of thick salt, which ended with the start of seafloor spreading and the resulting opening up of the restricted rift basin. Late Aptian-Albian shallow marine carbonates were deposited on the salt. Platform carbonates and their deepwater equivalents dominate the Albian–Cenomanian. The Upper Cretaceous to Tertiary is mainly characterized by siliciclastic deposition.

Initial development of the pre-salt play in the Santos Basin focused around the northern and central areas inboard of the Outer High of the Santos Basin, including Libra/Mero and Franco/Buzios in the north; Iara, Tupi/Lula, Jupiter and Pau Brasil in the centre; and Sul de Guara and Peroba in the south. The primary reservoir for these fields is a high porosity and permeability sag-phase carbonate facies (K46-48: Barra Velha Formation) sealed by the overlying salt. This usually presents as horizontal to low angle, low-frequency, good to moderate continuity, high amplitude reflectors (TGS, 2013). There is usually little to no evidence of major faulting of this formation in most of the Santos Basin.

Bioclastic limestones (Itapema Formation/coquinas), at the top of the major rift phase and in the lower part of the sag basin, are a potential secondary carbonate reservoir. They are typically present as stacked banks of reworked shelly fragments deposited along lake margins and are found in deep to shallow lacustrine environments. The corresponding seismic facies is moderate to good amplitude, moderate continuity, parallel to sub-parallel (TGS, 2013). Coqueiros reservoirs have been reported as oil-bearing at Seat and Pão de Açúcar in the Campos Basin, and in the Mero, Buzios and Lula fields in the Santos Basin. The main source rock for the

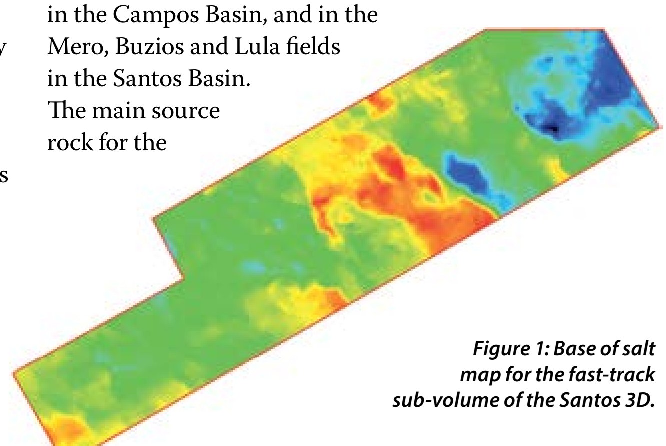


Figure 1: Base of salt map for the fast-track sub-volume of the Santos 3D.

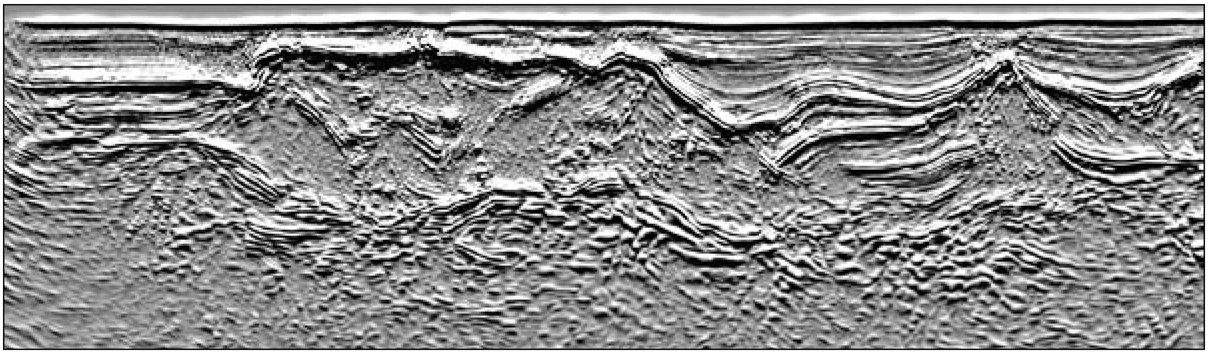


Figure 2: Dip view through a minor structural high in the fast-track sub-volume of the Santos 3D.

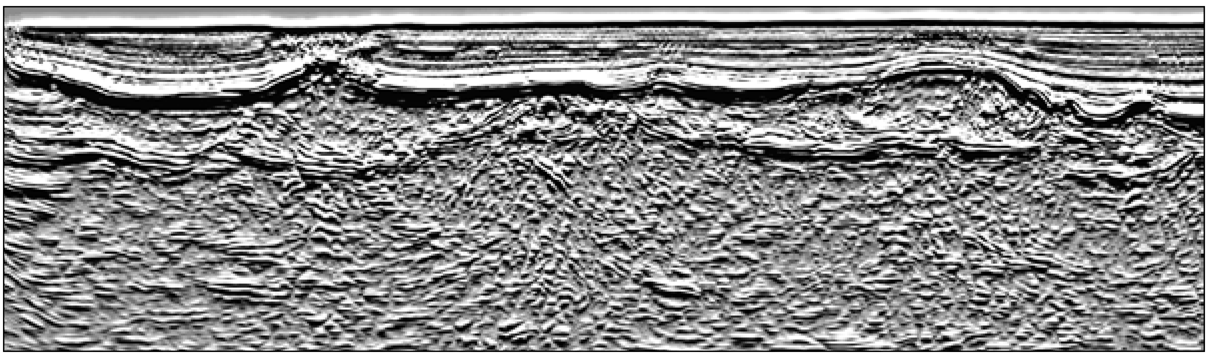


Figure 3: Dip view through the major structural high in the fast-track sub-volume of the Santos 3D.

Santos Basin pre-salt fields occurs in the lower syn-rift (K36).

As these early discoveries have matured to producing fields, exploration has moved south and east into more outboard areas. Exploration interest has been sustained by improved understanding of the environment of deposition of the main pre-salt reservoir (the Barra Velha Formation), by extensive 3D seismic surveys, including the Santos 3D discussed here, and by innovations in the licensing regime, such as frequent licensing rounds and permanently offered blocks. Three exploration rounds in 2018 raised record bid amounts, lifting expectations for three more licensing rounds (Concession Round 16, Pre-Salt Production Sharing Contract Round 6 and the Transfer of Rights Surplus round) for which public bidding is scheduled for Q4 2019.

Complex Salt and Faulting

The evaporite sequence is seen to comprise both ‘stratified’ and diapiric sections, signifying the presence of not just halite but additional evaporite minerals (e.g. anhydrite, carnallite, tachyhydrite). The presence of this ‘dirty salt’ requires that a common offset RTM (COR) be applied to update the salt body velocity. Complex internal deformation (thrusting and folding) is evident in the salt sequences. A feature of particular interest in much of the study area is the apparent large fault-throws at base of salt level. This is not an anomalous feature of the present study area: similar features have been noted in the PSC Round 5 Saturno and Dione prospects (Petersohn, 2018). These faults appear to have normal throws, with kilometers of offset, often larger at the pre-salt level than in the underlying syn-rift level. This suggests that syn-rift faults were re-activated during or very shortly after Late Aptian salt deposition. Note in the seismic foldout how reflectors in the hanging-wall salt (A) onlap the plane of the fault with high angle. This may suggest a significant degree of local rotation within the evaporite sequence caused by fault movement and/or salt dissolution.

Figure 1 shows a map of the Base-Salt horizon throughout the fast-track sub-volume. It shows a series of small north-west to south-east trending four-way dip closures flanking a major high, also trending north-west to south-east. Much larger four-way dip structural closures have been mapped on the Spectrum (now TGS) 2D seismic data throughout the study area (Spectrum, 2018). Seismic facies criteria (see above; TGS, 2013) outline the Barra Velha Formation immediately under the salt and confirm its minimum thickness throughout the fast-track sub-volume to be greater than 200m. In much of the fast-track sub-volume the Barra Velha Formation unconformably overlies the syn-rift succession. On the structural highs, it appears often to unconformably overlie basement.

A Brief Overview

This has been a brief review of a fast-track sub-volume that constitutes a little more than an eighth of the greater TGS-Spectrum Santos 3D; any comments on such a small and intermediate sub-volume are necessarily limited. However, analysis of this data does support the findings of the 2D seismic data that large structural closures at Barra Velha Formation level are present throughout the project area, together with flanking grabens and half-graben areas filled by syn-rift sediments (prospective kitchen areas and secondary coquina facies secondary carbonate reservoirs). These findings support the prospectivity of this entirely undrilled area of the southern Santos Basin and are essential viewing for any companies interested in the upcoming PSC 6 and future license rounds.

References available online. ■

The Future of Exploration

Can a CSEM-supported exploration program increase the chance of success for a prospect portfolio by distinguishing between low and high saturation commercial hydrocarbons?

VALENTE RICOY and FRIEDRICH ROTH; EMGS

When defining an exploration strategy, the following points need to be considered:

- Does the acreage contain several seismic amplitude-supported prospects and objectives?
- Have false positive seismic DHI wells been drilled in the basin?
- Is the seal affected by faults?
- Does the seismic suffer from acoustic wipe-out, suggesting fluid escape or gas attenuation?
- How can associated subsurface risk be managed and mitigated?

This article addresses these issues and explains how a CSEM-supported exploration program increases the chance of success by distinguishing low saturation accumulations from commercial volumes and assessing the top seal potential.

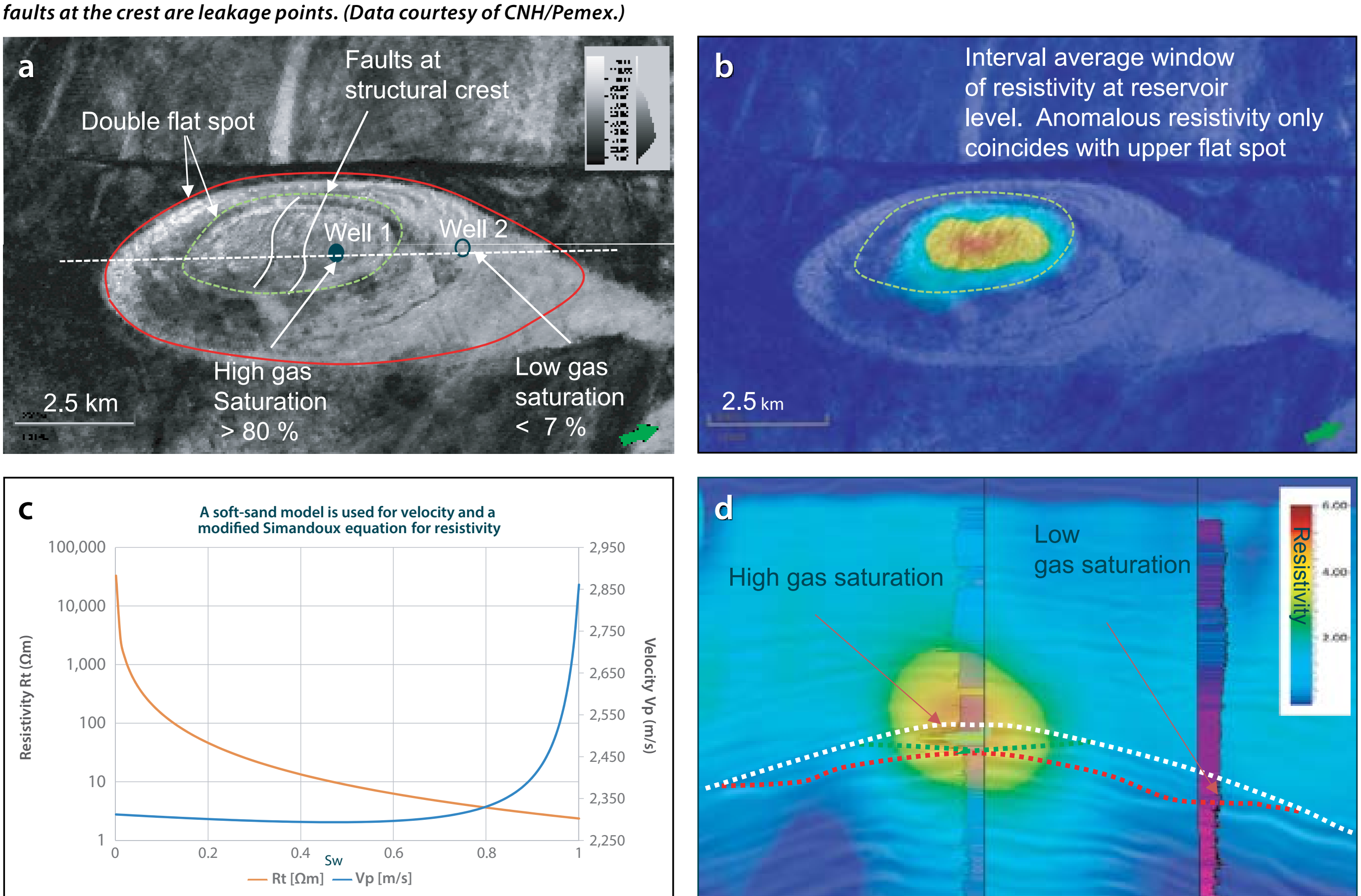
Why is Success Rate So Low?

Exploration statistics remind us of the poor commercial success rate, standing at about 12% worldwide (Westwood Global Energy, 2019).

Diving deeper into well results, it has been noted that a major cause of exploration failures is poor understanding of seal and charge. Numerous dry or sub-economical wells have been drilled based on seismic direct hydrocarbon indicators (DHIs), which fail to distinguish between different reservoir fluid content. Low saturation fizz gas and high saturation gas accumulations typically have an identical anomalous seismic amplitude and amplitude variation with offset (AVO) expression. This ambiguity results in frustrating exploration campaigns where false seismic DHI plays have been drilled over and over again. This problem is well recognized by the industry (Wojcek et al., 2016; Cross et al., 2008) and it calls for a solution to obtain additional information about reservoir fluids to further de-risk exploration elements.

The industry's efforts to improve the understanding of reservoir fluids have mainly focused on advanced seismic evaluation techniques, such as

(a) Seismic amplitude map reveals the presence of a double flat spot highlighted by the red and green lines. Faults are present at the top of the structure, suggesting possible leakage points. (b) Interval average map of resistivity associated with the target level. Anomalous resistivity only coincides with the upper flat spot. (c) Plot for water saturation (Sw) vs. seismic velocity (Vp) and resistivity (Rt). Vp is very sensitive to the presence of hydrocarbons in the system but cannot distinguish high vs. low Sw. Resistivity, however, is sensitive to low Sw. (d) The structure was drilled twice: well 1 at the crest encountered high gas saturations and high resistivity; well 2 down dip encountered low gas saturations (< 7%) and no resistive anomaly. The integration of information allowed the operator to discriminate high vs. low saturation prospects. Furthermore, it suggested that the faults at the crest are leakage points. (Data courtesy of CNH/Pemex.)



multi-component seismic, pre-stack processing and ocean-bottom cable seismic acquiring s-waves, all with the aim of unraveling the daunting fizz gas problem. However, even with these approaches, the issue of distinguishing fizz gas from commercial hydrocarbon accumulations still haunts the exploration outcome in many basins around the world. In other words, the value of obtaining additional seismic information may be very limited in view of the saturation uncertainty.

Integrating Technologies Brings Results

If the industry wants to address the ongoing problem of hydrocarbon saturation and increase the exploration success rate, a subsurface measurement independent from seismic should be integrated with the seismic observations. Resistivity from CSEM is a natural choice for this, as saturation is the primary driver for the resistivity of a good quality reservoir with considerable volumes in place. Moreover, as shown in the figure below left, the saturation dependence of reservoir resistivity exhibits the opposite behavior to seismic reservoir properties and allows us to distinguish low from high hydrocarbon saturation.

Recent exploration activity has reignited interest in deepwater settings with a renewed focus on Tertiary siliciclastic turbidite environments. An exciting number of amplitude-supported leads and prospects have been identified from seismic in various offshore frontier basins, including Trinidad and Tobago, Colombia, Argentina and the Gulf of Mexico. In all these basins, explorers face the ongoing challenge of differentiating between high and low saturations from the seismic expression.

Close to ten years of experience of using CSEM for the evaluation of Tertiary turbidite plays in the Gulf of Mexico has shown that integration of resistivity with seismic information is the technology solution that is most capable of distinguishing between low saturations and commercial volumes of hydrocarbons. CSEM also provides an enhanced understanding of the reservoir properties that give rise to the seismic DHIs. The power of resistivity is illustrated by the case example in the figure (Escalera et al., 2014). Additionally, resistivity will provide an independent earth measurement of the rock properties associated with the top and lateral seal, allowing an explorer to characterize the rock properties of fluid escape features.

These results from the Gulf of Mexico demonstrate that CSEM can reduce the subsurface risk associated with seismic amplitude-supported prospects, high grading those prospects that are the best drilling targets or, conversely, identifying prospects that should be downgraded.

Returning to our initial list of questions, a key question that is missing may therefore be: has CSEM been considered in your exploration strategy? The integration of CSEM in an exploration program will allow an explorer to de-risk seismic amplitude-supported prospects, differentiating those that contain economic volumes and high saturations from shows or low saturation.

References available online. ■

The Pre-Salt Reservoirs of the South Atlantic

There are wide lessons to be learned from the controversy over the origins of the enigmatic Cretaceous lacustrine carbonate reservoirs of offshore Brazil.

PAUL WRIGHT
PW Carbonate Geoscience

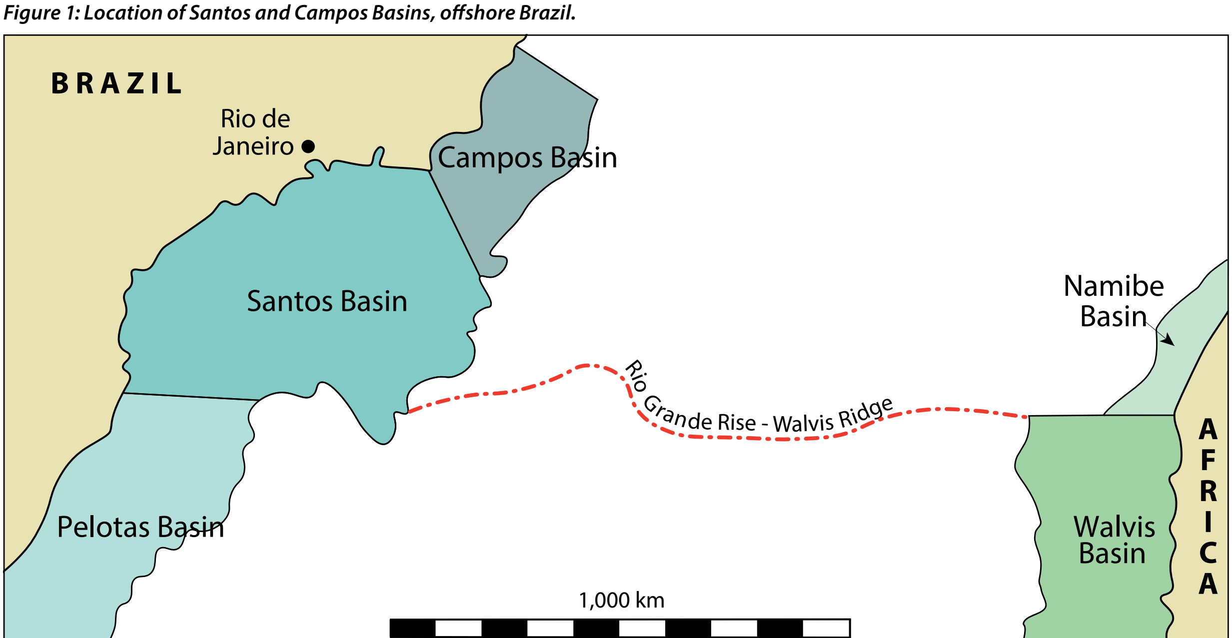
Much of the interest in Brazil's autumn bid rounds will again be on the Santos and Campos Basins with their lacustrine carbonate reservoirs (Figure 1). In the Santos Basin over 30 discoveries have been made in such reservoirs since the Tupi (now Lula) discovery in 2006, with combined recoverable reserves estimated at >30 Bboe in the Cretaceous (Aptian) Barra Velha Formation (known as the 'Microbialite'). Discoveries have also been made in the adjacent Campos Basin, where the same unit is known as the Macabu Formation, and also in the Kwanza Basin, West Africa. The Barra Velha Formation can reach thicknesses of over 550m, with some wells producing in excess of 28,000 bopd. It occurs beneath a cover of marine salt (the Ariri) and represents a later rift-to-sag interval of South Atlantic opening. Deeper in the section are the mainly Barremian coquina (shelly limestone) reservoirs of the Itapema Formation, well documented from the Campos Basin where they constitute the Coqueiros. The Barra Velha and its correlatives represent a lake system that covered an area of at least 335,000 km^2: a similar size to the present-day Caspian Sea.

Carbonate Controversies

Both the Barra Velha and the Itapema carbonates are highly problematic. The Itapema reservoirs are coarse shell deposits 10s to 100s of meters thick, clearly seen as clinoformal features on seismic. The overall settings for the Itapema were relatively deep, stratified lakes similar to those of present-day East Africa. The shells, mainly bivalve mollusks, produce both inter-shell and mouldic porosity through the dissolution of the original shell material. There is evidence that some of these units represent deposition in the shallower parts of the lakes, whereas others were deposited or redeposited in deeper water. What is especially challenging about these hydraulically concentrated shell masses is that we see nothing like them anywhere else in the geological record, in either marine or lacustrine settings. The lakes were periodically highly alkaline at times and the remarkable concentration of shells raises questions regarding the ecology of these mollusks. Such high concentrations might imply unusual feeding strategies such as the bivalves having symbiotic algae (utilizing light like some species of bivalves, corals and foraminifera, for example) or even chemo-symbionts using CO_2.

While debate continues over the origins of the coquina reservoirs, the main controversy relates to the Barra Velha and its equivalents. The implications of the different interpretations for this unit are quite fundamental in terms of both exploration strategies and reservoir modelling. Unlike the Itapema, which was clearly associated with relatively deep lakes during active rifting, the Barra Velha was deposited during the latter stages of rifting but shows clear evidence of syn-depositional control on stratal patterns. Localized deformation continued through the later 'sag' phase.

Figure 1: Location of Santos and Campos Basins, offshore Brazil.



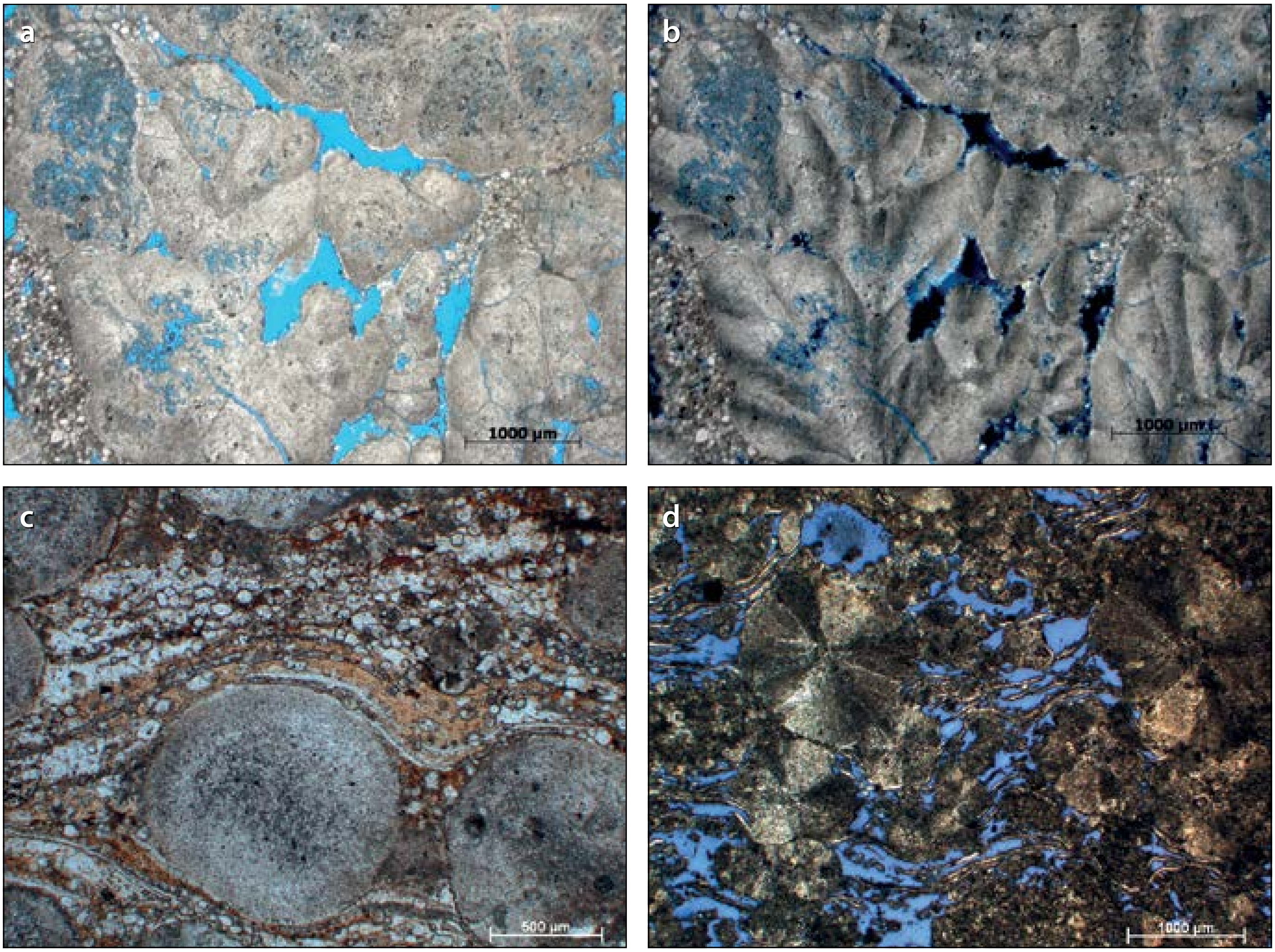


Figure 2: Main components of the Barra Velha reservoirs. (a) Calcite shrubs with inter-shrub porosity (blue) and some mouldic porosity within the shrubs. (b) Same image under cross-polarized light with distinctive sweeping extinction patterns reflecting the fibrous microstructure. (c) Spherulites set in a talc-stevensite matrix within which are dolomite crystals and elongate bridge-like dolomites. (d) Spherulites with pore spaces, with dolomite crystals and bridges, after the dissolution of the stevensite; the internal structure of the spherulites is clearly seen in cross-polarized light.

The Barra Velha carbonates are very simple in their composition. They consist of just two main primary components (Figure 2): millimeter to centimeter-sized crystalline, fibrous calcitic shrub-like structures resembling features found in present-day abiotic travertines (thermal spring deposits); and millimeter-sized spherulites made of fibrous calcite. Both types are commonly reworked, resulting in much reduced reservoir quality, but in their original growth positions, they can be porous and constitute the most widespread reservoir facies. However, the in-situ examples can also be non-reservoir if the carbonate features occur within magnesium-silicate matrices (talc-stevensite).

What is unique about these reservoirs is that some of the clays, which initially formed as gels precipitated out of the lake waters and were deposited on the lake floor, later dissolved to produce a previously unrecorded type of mouldic porosity. In addition, some microbial carbonates occur but represent very little of the formation in terms of thickness. Although many academic researchers have interpreted the spherulites as probably microbial in origin, to date no actual evidence has been presented to justify that conclusion.

Also present, especially on structural highs, are very well sorted carbonate sands, formed on wave-influenced shorelines, spits and fan deltas. Finely laminated carbonate muds formed as thin units during deepening events in the lakes caused by increased run-off, bringing in fresher waters as indicated by fish and invertebrate remains. In deeper parts of the lakes somewhat different laminites, locally microporous, were also deposited, associated with turbiditic carbonates. There are meter-scale cyclic packages with thin fish-bearing laminites, overlain by in situ spherulites, overlain by in situ shrub units (Figure 3). These have been interpreted as reflecting freshening and deepening of the shallow lakes by run-off to produce the laminites, followed by evaporation, a view supported by geochemical studies using C and O stable isotope analyses as well as thermodynamic modeling. The occurrence of what was originally stevensite suggests the pH of these alkaline lakes likely exceeded 10, and the surprising rarity of microbial carbonates implies that the pH may have been even higher during the evaporation phases.

Two Models Hypothesized

Devising a geological model has

proved difficult because there are no known modern or ancient analogs. Figure 3 is an attempt to show how these unusual reservoir rock types might relate to each other due to the interaction of active faults, wave action and evaporation of the highly alkaline lakes. To add to the complexity, the porosity system, effectively controlled by clay dissolution, is unique in the geological record.

Why should the Barra Velha and its equivalents be so unique when there are many carbonate-bearing rift successions in the geological record? The extreme thinning of crust during the opening of the South Atlantic may have led to exhumation of the mantle, creating hydrothermal conditions linked to serpentinization, although there is no geochemical evidence for elevated temperatures in the lakes and $^{87}Sr/^{86}Sr$ data does not indicate a significant input from the alteration of the mantle or ocean basalts. More intriguing is the possibility that the extreme alkalinity in the lakes was due to high CO_2 input, derived from the mantle.

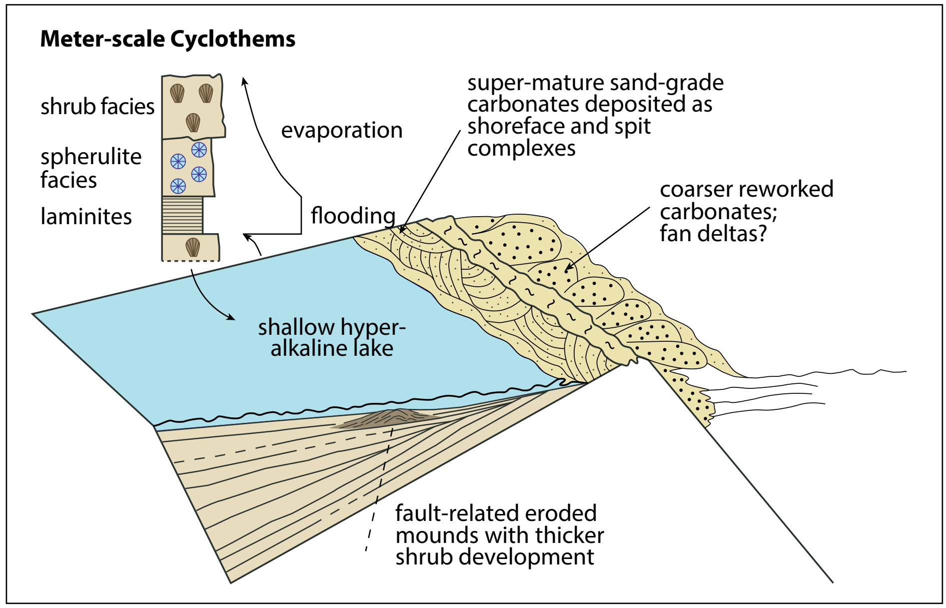
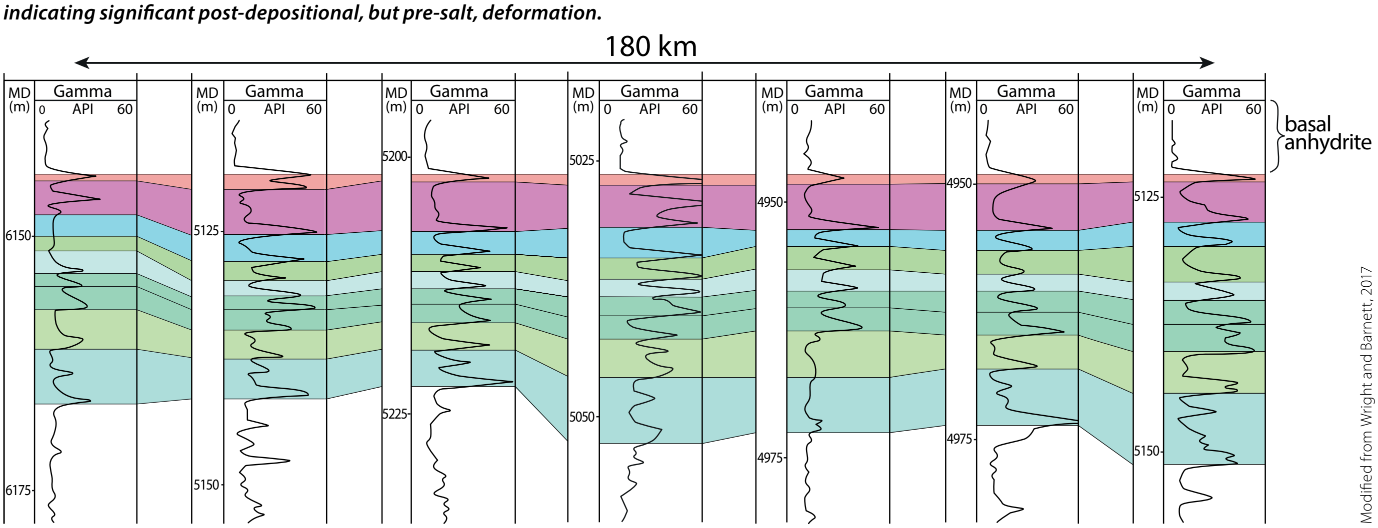


Figure 3: Shallow lake geological model for the Barra Velha Formation based on a tilt-block setting. On the gentler dip slopes localized wave-dominated shorefaces developed with possible spit complexes, as seen in the Great Salt Lake in Utah. Coarser sediments accumulated on the scarp slopes. Meter-scale cycles developed locally as the shallow lakes expanded with increased rainfall, followed by evaporation, when the carbonates and magnesium-silicates formed. Mound-like features occasionally developed in Santos Basin. (Based on multiple sources including Barnett et al., 2018.)

The current controversy over the Barra Velha Formation involves two distinct interpretations. The first was the 'top-down' microbialite-platform model. This uses seismic data to identify high relief platforms with seemingly hundreds of meters of relief, which have been compared to present-day and older marine carbonate platforms. The attribution of the Barra Velha carbonates to a microbial origin has led to some companies making direct analogies with the high relief Carboniferous marine microbial platforms of the Pre-Caspian basin in Kazakhstan, where marine carbonate platforms are differentiated into margins (commonly the preferred targets for exploration) and protected interior facies. Some companies have developed reservoir models based on this concept, but there are no analogs for the key rock types in the Barra Velha and, as stated earlier, there is currently little evidence for the carbonates being largely microbial.

The alternative 'bottom-up model' for the Barra Velha was based on the recognition that no viable analogs have been identified. The strategy was to start by understanding the basic components making the reservoir rock and assessing them using basic science, such as establishing the chemical

Figure 4: West-east correlation across the Santos Basin showing the unit at the top of the Barra Velha Formation known as 'Lula's Fingers'. Its thickness varies from 20.8 to 28.5m (mean 24.3m), within which 9 gamma-defined cycles (mean thickness 2.7m) can be identified. These comprise shallowing-upwards cycles defined by basal laminites. These cycles are well sampled and the facies are very similar in all wells, and include a range of unequivocally shallow water sediments. Even though these cycles were deposited at comparable water depths they are now separated by over 1 km of vertical relief, indicating significant post-depositional, but pre-salt, deformation.



conditions in which the unusual mineral suite formed, combined with integrating crystal growth data. At all times during this process, which took nearly three years, multiple interpretations were deliberately sought, modified and rejected as more data allowed a clearer understanding of the chemical environment. Only once the fundamental controls were understood, the main conclusion being that the Barra Velha formed in shallow lakes, was the seismic data evaluated; without information on lacustrine carbonate seismic facies or marine analogs, the seismic-first approach was considered unjustified. In addition, running de-risking workflows on the seismic features also showed little likelihood that they were analogous to marine carbonate build-ups. Many high relief features were subsequently interpreted as reflecting post-Barra Velha, pre-and syn-Ariri deformation. Correlations of 'Lula's Fingers', a package in the uppermost 30m of the formation characterized by a series of prominent spikes on the gamma log, proved critical. The carbonates in this interval contain a series of very distinctive cycles, including all the typical Barra Velha rock types as well as clear microbial carbonates and reliable water depth indicators proving a very shallow water origin. However, these cycles, correlatable for 180km across the Santos Basin, were affected by hundreds of meters of differential local displacement prior to the main phase of salt deposition (Figure 4).

Important Challenge in Interpretation

Does this difference in interpretation matter? If the platform model applies, and because most production comes from these highs, the lows between them should lack the shallow lake reservoir facies, being relatively deepwater deposits. But if the lows are simply down-thrown shallow lake deposits, they will also contain reservoir-prone rock types, and could be prospective under the right conditions. In terms of reservoir architecture, the differentiated platform model envisages likely changes in reservoir quality across a platform top, whereas the shallow, evaporitic lake model implies potentially very widespread facies continuity. The presence or absence of the magnesium clays is another critical issue to consider when exploring for and developing reservoirs in the Barra Velha.

In summary, the highly unusual composition of the lacustrine carbonate reservoirs in the South Atlantic are especially challenging, and many uncertainties still remain. Interpreting these reservoirs has presented a challenge to the accepted wisdom based on marine carbonate analogs and has required a bottom-up approach relying on first understanding the chemistry of extreme lake environments, which were heavily influenced by highly thinned crust and the effects of the mantle, and then seeking a wider range of explanations for the seismic features.

Resolving this controversy has huge implications for future exploration and development programs in the wider region.

References available online. ■

The Oil Industry and Public Perception

The oil industry is the target of sustained negative pressure, essentially calling for production to cease immediately. What should it do?

HAMISH WILSON

The argument against the industry is simple, emotive, and has a scientific basis: burning hydrocarbons contributes directly to rising greenhouse gas levels and global warming. In addition, the well-known 'oil curse' in developing countries has caused both social and environmental damage. In these instances, as is the case with global warming, the industry is often perceived by the public as not being held adequately accountable; there are few sentences or fines, and businesses seem to continue to operate as before. From this view, it is easy to see why the industry is seen as 'evil' and faces a vocal, growing opposition.

To compound the issue, the case for the defense of the oil industry is nuanced and requires consideration of the trade-offs inherent in living in an industrial society. People choose to drive their cars, heat their homes, and fly thousands of miles for holidays, without necessarily investigating and understanding the environmental consequences of their lifestyles.

In an ideal world, hydrocarbons would not be necessary to fuel these lifestyles – indeed, progress is being made towards creating this reality. Developed countries' national grids increasingly carry renewable-generated electricity, and the decarbonization of transport can be seen on the horizon. Steps are being made in optimizing efficiency for air travel, and in reducing residential demand. Despite this, most hydrocarbon alternatives are new, immature, and not yet economically viable.

We have to acknowledge that we live in an 'oil age' in which society enjoys the benefits of abundant low-cost energy. The oil industry is currently the engine on which our economies run, yet society does not like or want to acknowledge that fact. The perception of oil corporations as the 'bogeymen' does not help in an informed debate about the choices facing society in planning our future energy needs. In fact, is the oil industry simply a convenient scapegoat?

Managing Supply and Demand

There is little independent journalism presenting an alternative, holistic opinion. Points that need to be made include the fact that the globe continues to demand hydrocarbons (IEA). Reduced production from existing oil fields creates a shortfall, even if global demand is reduced to limit carbon emissions to achieve the 2°C target. Oil companies must continue to search for low-cost oil and gas to prevent the social disruption that will result from demand outstripping supply.

There are also ethical dilemmas in prematurely curbing the use of oil. The main driver for the growth in energy demand comes from China, India and Africa. Who will take the blame for a failure to provide the energy to support these growing economies? The major oil and gas discoveries of the recent past have been in Guyana, Senegal, Mauritania, Egypt, Cyprus and South Africa: all countries in need of the economic boost that comes from oil and gas production. Without compensation, we cannot demand they forgo the right to develop and advance as we already have.

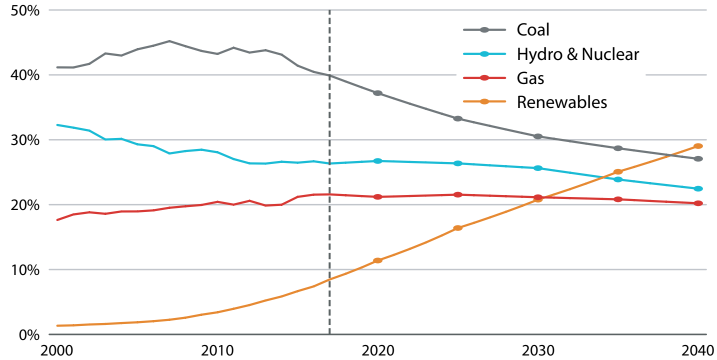
With natural technological and economic barriers to innovation, the displacement of oil by renewable energy will not happen fast enough to mitigate climate change. Thus, the focus for public action on climate change must be to reduce our demand for energy. This requires the combination of legislation, new technologies and changes in behavior.

Take Action – and Risks

The case for the oil industry to act and join a 'coalition of the willing' was well made recently by Nick Butler in the *Financial Times*; the oil industry is part of society and now society is expecting the oil industry to change – but how?

Managing the transition to a zero-

Sebastian Dooris



BP Statistical Review of World Energy 2019

In BP's evolving transition scenario, only in 2040 will renewables be producing more primary energy than coal or gas.

carbon energy system requires the rational analysis of all elements in the energy mix, including social behavior. Despite the flaws of the oil industry, singling out one industry as 'the bad guy' does not help in this analysis – as seen with the public perception pariah status of the nuclear industry.

In the face of overwhelming pressure from public opinion, the industry is in danger of losing its legitimacy and, despite rational arguments to the contrary, may have its activities curtailed. Therefore, oil companies and their investors must be seen to take action. Doing nothing, citing 'the world needs hydrocarbons', is the wrong response.

The energy transition is underpinned by a radically different suite of technologies. Decentralized energy generation is becoming more important, with consumers owning generating assets like solar panels, wind generators and heat pumps. The energy landscape is undergoing a paradigm change from capital intensive power stations connected to consumers via a grid, to distributed energy generation and consumption nodes with the grid as a back-up. Owners of power stations and national grids wish to protect their revenue streams and are reluctant to embrace the new paradigm.

The oil industry skill set of major project delivery and risk management does not fit easily into this coming transition. To date, those oil companies that are investing more in renewable energy are following a traditional major project route through important wind farm or solar projects; major power generation assets feeding the grid. This fits the oil industry capital deployment skill set.

However, a more transformative role for the industry would be to drive the change in consumer behavior through innovations in business models and new technology. It is only through engaging with the consumer that the oil industry can expect to change public perception and win back its legitimacy. One limitation to the deployment of new renewable technologies and business model innovations is a lack of risk capital. The oil industry has a role to play here. Investments on the scale of a new frontier exploration program, put into renewable energy, would be transformative, making an impact far greater than the value of the capital itself – and at a lower risk than wildcat exploration.

A Clear Signal

Taking a leading role in the promotion of decentralized energy generation would be a clear signal to the public and investors that the industry is taking action; it needs to earn its legitimacy and not be afraid of promoting the actions being taken.

In this context, the oil business should be considered an integral part of our economy, working alongside the renewable industry to effect the energy transition while continuing to drive economic growth. Responsibility for informing the public about the complexity of this transition falls to the leadership of both the oil and renewable industries.

Is there scope for a forum on this issue, bringing together all stakeholders to influence both press and policy makers? Many oil industry professional organizations are interested in this idea, and bodies representing the renewables sector and the wider public should also be supportive. Could this help change public perception? ■

Evolving the Future Workforce

A virtual internship for students and early career professionals where everybody contributes and everybody learns.

MIKE FORREST, Technical Advisor, SEG EVOLVE

E &P;
V alue Creation: align with company's strategies and goals;
O nline Collaboration: team members, teams, mentors, and EVOLVE leaders;
L eading Edge Technologies: 3D datasets and key wells;
V irtual Internships: use of the cloud and video technology;
E xtensive Mentoring: key strength of EVOLVE.

The E&P industry is facing major changes due to the departure of many experienced professionals, resulting in limited or non-existent access to mentors for new hires and early career staff transitioning from the academic to the business world. Universities rightly focus on theoretical foundations and principles, but have limited time to teach the practical exploration technical and business workflows used by oil companies.

The Society of Exploration Geophysicists (SEG) is addressing this challenge with the multidisciplinary EVOLVE student program to 'Develop the Fearless Explorers of the Future'. This program has the important attributes shown in the box (right).

EVOLVE's ultimate objective is to prepare students for jobs in the energy industry. Each 'Fearless Explorer' team of four to six students with backgrounds in geology, geophysics, petrophysics and reservoir engineering work together reviewing a technical dataset to recommend the best investment opportunity in their assigned area. EVOLVE is non-competitive and as a result everybody contributes and everybody learns. The program is coordinated technically by Allen Bertagne, from the SEG EVOLVE office in Houston, reporting to Tom Agnew, SEG Associate Director, Programs. Technical support is provided by Jesus Nevarez, a University of Houston graduate, advisors Mike Forrest and Jennifer Thompson, as well as many other experienced mentors.

SEG EVOLVE started in 2015 with a pilot program. Halliburton is the founding sponsor and continues to strongly support the program, including providing access to the Halliburton Landmark DecisionSpace Platform, delivered via the Cloud. Ten university teams from US, Canada, Europe and Latin America participated in 2018 and the program was expanded to 20 international teams this year, with the activities being undertaken from mid-January to the end of May to conform to college semesters.

Technical Workflow

In early January, EVOLVE teams are assigned one of several public domain datasets, currently from the Gulf of Mexico, Dutch North Sea and New Zealand. Software is provided either via the Halliburton Cloud, including the Decision Space software, or local installation of Schlumberger's Petrel or IHS Markit's Kingdom. Key tutorials are provided by IHRDC and delivered via Landmark's iEnergy platform, and Rose & Associates teaches a half-day risk analysis course.

Following an individual Project Kickoff meeting in January, each team conducts a literature review and gathers data, with the goal of understanding the petroleum geology of their assigned area in order to prepare a detailed plan to allow them to identify the best investment opportunity within the area. This is followed by the mid-project presentation in March to review seismic regional and prospect mapping, integrate regional geology studies and well data into their interpretation, and to propose a detailed work plan for the second phase. The final presentations are made in May to an 'Executive Committee' focusing on the recommended best

SEG

Allen Bertagne guiding the team from Perugia University.

investment opportunity, supported by key technical and economic data.

The program has no prepared answers: the emphasis for students is not the 'right answer' but on using available data to think carefully and ask the right questions. Students are encouraged to gather and integrate any and all data they can find for their project area.

Collaboration is important. The E&P work force has changed from experts working in silos to geologists, geophysicists and reservoir engineers working together as subsurface teams to share knowledge and learning across technical and business boundaries, considering the entire E&P life cycle to ensure optimal execution. EVOLVE training is an introduction to collaborating in teams to maximize learning.

> *"Students gain exposure to real world data, top class mentors, industry leading software and critique and direction that no other industry/academia program can provide. This phenomenal learning experience is unmatched in any earth sciences industry program."*
>
> ***Dean Mento, P.G.***
> *Senior Petroleum Geophysicist;*
> *EVOLVE Mentor*

The Technical Coordinator continues working with the teams over the summer in preparation for two half-day sessions at the SEG Annual Meeting where participants present their investment opportunity and also discuss their learnings from the year. Each team makes a 15-minute prospect presentation to an international audience during the oral sessions and hosts a poster session to discuss their detailed work and conclusions with other professionals. They also participate in a student panel discussion to answer questions from the audience and give industry leaders recommendations for the future.

The Value of Mentors

Mentors play a key role in EVOLVE in every phase of the program. The Technical Coordinator holds bi-weekly virtual sessions with every team in a global team meeting, where progress is reviewed and suggestions made. Students often make impromptu informal presentations at that time, exchange ideas among themselves, and share sources of useful data.

Students are free to ask the mentors and other teams questions on most topics via the SEG Basecamp website, except anything related to their specific prospect. Mentors send the teams technical papers about geology/geophysical technical issues and case histories and make personal visits to some universities for discussions with the teams and their faculty advisors. Finally, up to 15 mentors attend the mid-project and final team presentations either in person at the EVOLVE Houston office or via video communication.

Many of the EVOLVE mentors are proficient in the use of the software being used and so are able to give specific workflow suggestions, or on certain occasions even "grab the mouse, and drive." Mentors do not 'know the answers' in advance, so observing how they think and develop their own approach is invaluable to the students.

EVOLVE is more than just technical activities and learning. It also strives to develop the human traits required to be a successful explorer, while having fun along the way. Personal meetings allow for customized exchanges and allow the mentors to gain an understanding of student competencies and remaining gaps.

This real-world experience includes learning the basic technology beyond a student's primary college major,

> *"EVOLVE has been a fantastic program that helped me realize how beautiful and engaging this hunt for oil can be. I put this program in my resume, and this summer, I landed an excellent internship, and I am working with a great international team on an offshore development project. The EVOLVE program is well known now, and professionals from the industry are taking it seriously as proper training for young professionals."*
>
> ***Alexandru Badescu,***
> *Petroleum Engineering Student,*
> *Montanuniversität Leoben;*
> *EVOLVE Participant.*

Mentors exchanging ideas on student prospects during the final project presentation.

Mike Forrest with members of the team from Cambridge University.

building teamwork and dividing job tasks, and making timelines to accomplish team goals in the assigned timeframe. Collaborative learning with real technical data provides a lasting impression and learning experience for the students. Perhaps most importantly, lifelong bonds are formed.

EVOLVE Long-Term Vision

SEG plans for 20 university teams to participate in 2020. Application information will be available in early October, 2019 and teams will be selected in early November. The focus is on geology, geophysics, rock physics and engineering masters students, but PhD students and 3rd and 4th year undergraduate students can apply. Active participation of the university faculty advisor is essential. Universities and students interested in participating should visit the SEG website.

SEG intends increasing EVOLVE to 40 multidisciplinary university teams from around the world during the next two to three years, and is also encouraging universities to award course credits to participants. It wants to add additional comprehensive datasets from several areas worldwide and increase technology application learning from enhanced datasets.

The organization is also keen to train oil and service company young professionals through this scheme by introducing an Early Career Professional (ECP) EVOLVE in 2020, aimed at employees with less than ten years' experience. This program will use the datasets and training processes described above, over a six-month period, with participants spending about 25% of their worktime on the project.

The SEG and SEG Foundation are seeking additional industry partners and sponsors, including individuals, to financially support EVOLVE, guide it, and ensure the program continues to succeed (details available on SEG website).

The training and practical experience that EVOLVE offers both students and young professionals will be essential if the industry is to meet the major energy challenges that lie ahead. These future professionals will be well prepared for a successful career involving complex subsurface, economic and human elements and, over time, they will indeed become the fearless explorers of the future! ■

'Ask the Students': a panel discussion where teams field questions from an audience of professionals.

Digital Solutions across the Energy Value Chain

Cloud computing is changing the traditional E&P business and transforming workflows.

JANE WHALEY

"I have never seen a situation in the oil and gas industry that the use of cloud computing could not improve," says Arno van den Haak, Head World Wide Business Development, Oil & Gas for Amazon Web Services, a company that has been working in this field since 2006, long before most people had heard of the concept. Amazon Web Services (AWS) is its own company within Amazon.com and is the world's most comprehensive and broadly adopted cloud platform. "Having built the enterprise infrastructure system to regulate the huge number of transactions which Amazon.com undertakes every minute, the company realized it had a unique skill set to offer to other industries which deal with large datasets, such as health, finance, manufacturing, public services – and, indeed, oil and gas," Arno explains.

AWS has grown fast in those 13 years, and there is now no industry segment, from public sector and retail to academia and non-profit organizations, in which it is not involved. In fact, most of us use AWS in our everyday lives without realizing it; for example, whenever we watch Netflix, or use banking or ride sharing apps, we are utilizing products which are run through the company's cloud-based services.

Working Backwards

AWS approaches business challenges through a 'working backwards' process which helps customers innovate. "The pattern in the O&G industry has been for people or companies to develop solutions independently and then approach customers and try to make these solutions 'force-fit' each individual implementation," Arno says. "At AWS, we spend time understanding what the significant business challenges are and how we can solve the client's needs, before 'working backwards' to discover what the solution could look like, and then picking the right technology to do it.

> *"Most companies write the software, they get it all working, and then they throw it over the wall to the marketing department, saying 'here is what we built, go write the press release.' That process is the one that's actually backwards."*
> ***Jeffrey P. Bezos***
> ***Founder and Chief Executive Officer, Amazon.com, Inc.***

"The benefits of this process are that we can work on a very clear problem where the solution can have an immediate business impact. An important aspect of this process is developing what we call the MLP (Minimal Lovable Product!); working backwards allows you to quickly experiment and explore a number of solutions until you know you have the right one. With the cloud you can innovate easily, cost effectively and

Gerd Altmann/Pixabay

quickly, getting feedback through it to iterate around a solution to ensure you have the right one for that particular issue. Then you focus on the chosen 'MLP' and build out from there.

"The working backwards process permeates everything we do in AWS. It drives our innovation and data centers to help us come up with new solutions, improve our operational performance and reduce costs to our clients."

Hindsight to Foresight

To see the advantages of cloud computing in oil and gas, let's look at a couple of industry examples.

The first involves E&P major Shell. The company had realized that its explorationists were spending 70% of their working day just looking for the data they needed before they could start working on it: a waste of both their time and their experience. The solution was a cloud-based 'data lake' where all data, structured and unstructured, were accumulated along with the relevant metadata. This enabled the geologists and engineers to access data across different functions, allowing them to incorporate additional information that they did not traditionally use, which they found led to new insights and solutions. "The beauty of this was that not only had this organized data lake helped exploration, but Shell now had a platform that allowed it to run all kinds of machine learning as the data lake has become the foundational piece," Arno explains.

"Shell has seen a threefold improvement in the effectiveness of its machine learning through using the AWS platform," he continues. "It realized that this was a solution that changed the way the company looked at the industry in a truly transformative way, so Shell decided to open it up to a consortium of companies in the industry, creating the Open Subsurface Data Universe (OSDU) that is being administered through the Open Group.

"This is what we see time and time again," he adds. "When people start using the cloud and begin to experiment, they notice the benefits and synergies and identify more and more ways to use it."

Arno cites another example of the use of a data lake to solve a very specific problem for an operator working in the Permian Basin who was running thousands of beam pumps and needed to reduce the mean time between failures. "In just about four weeks we were able to create a data lake that incorporated both historical and ongoing production data. Based on this, we were able to build machine learning models that allowed the company to predict, with a two-week notification period, when the equipment was likely to fail – with 98% accuracy.

"This shows how you can harvest all that old data that you have been sitting on for years, and turn it into meaningful information that can drive successful business outcomes. We describe this process as going from hindsight to insight to foresight. You not only understand what has happened, but you have the insight to understand why it has happened and the actionable knowledge to prevent it from happening again."

Connected Value Chain

The oil and gas industry has a long and complicated value chain stretching from upstream, midstream and downstream to retail

Arno van den Haak is Head World Wide Business Development, Oil & Gas for Amazon Web Services.

and trading, and a large element of the work involved is done by organizations outside the large oil companies. Many believe that this is where digital transformation can offer considerable value. In fact, a recent report by McKinseys suggested that the value of AI alone in supply chain management for O&G is in the region of $400 bn, while a World Economic Forum study suggests the value of digital transformation to the industry to be as much as $1.5 trillion.

Arno agrees that one of the most important things cloud computing can offer the oil and gas industry is that it can connect right across this value train, from E&P to the petrol pump. "The O&G industry traditionally takes a rather 'silo' approach to the use and storage of data," he explains, "but what we are seeing is that with the tools and services available through the onset of the cloud we are able to bridge those silos; this is true digital transformation, allowing us to change the workflows dramatically to increase productivity."

As Arno explains, the example described above in the Permian Basin demonstrates how using cloud data in one part of the operation can spread the advantage through the value chain, as the operator in question can now go back to vendors and suppliers and share the value of an optimized supply chain, driving value for everyone.

High Performance Computing

"One of the areas where we are seeing how the cloud is transforming the industry is in high performance computing," Arno says. "We have an example from Germany, where an oil and gas company had been taking about 100 days to run 100 simulations, but by using the nearly unlimited compute power of the cloud, this was brought dramatically down to just four days.

"Another example of how high-performance computing is really changing the way we look at development is the ability to use this huge compute capacity to create different optimization algorithms," he continues. "Working with a number of academic organizations in the UK, for example, recently we were able to double the NPV of an existing development plan using these new algorithms, taking into account 30 equally-probable geological models. What's more, the total cost of the cloud computing needed to make this dramatic improvement was less than the cost of a single day of an external consultant's time. This demonstrates the fact that on-demand cloud-based IT resources with a 'pay as you go' model via the internet are available at a reasonable cost to everyone, from large E&P companies to small independents, service companies and consultants.

"Whether you are a billion dollar company or a start-up, you have the ability to use the same resources, on demand; this is really leveling the playing field across the industry. In fact, we have found that when start-ups begin by using the cloud, they see the benefits and stay with the cloud as they grow, providing them with agility and flexibility at the lowest cost."

The New Normal

The benefits of cloud computing and digital solutions within the O&G industry are constantly growing, Arno believes. "People are seeing the benefits coming to them not just through lower costs, but also from the agility and elasticity of the cloud, and the ability to innovate and leverage the on-demand services.

"More importantly," he adds, "the use of machine learning can be seen to support geoscientists in their day to day work. Using machine learning for interpretation around salt bodies or to automate horizon and fault picking, for example, reduces the time spent on these sometimes tedious tasks, allowing the geoscientists to spend more time innovating and being creative. I think this is transformational for the industry; we are not seeing these tools replace our geoscientists and reservoir engineers, just giving them more time and making them more efficient and augmenting their skills.

"This is a growing trend," Arno says. "Two or three years ago the questions were about 'if' and 'why?'; now it is simply 'how fast can we move to the cloud?' The speed at which companies are shifting to building applications in the cloud and using machine learning is accelerating fast and the network of users and partners is constantly growing.

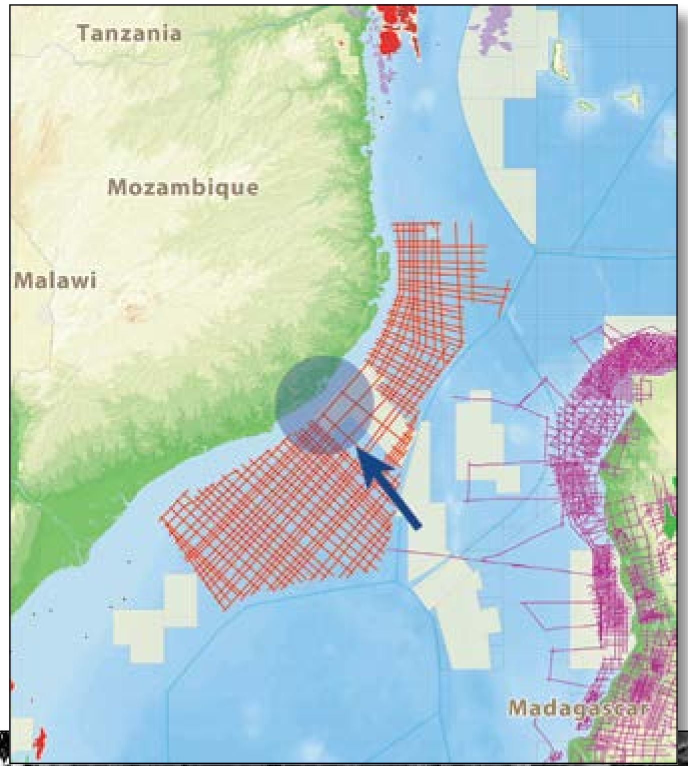
"In oil and gas, as in other industries, using the cloud has become the new normal." ■

The AWS 'Snowballl' captures raw seismic data and allows for some field processing before quickly ingesting the data in the AWS cloud. This eliminates the need for tape, thus transforming the seismic acquisition workflow.

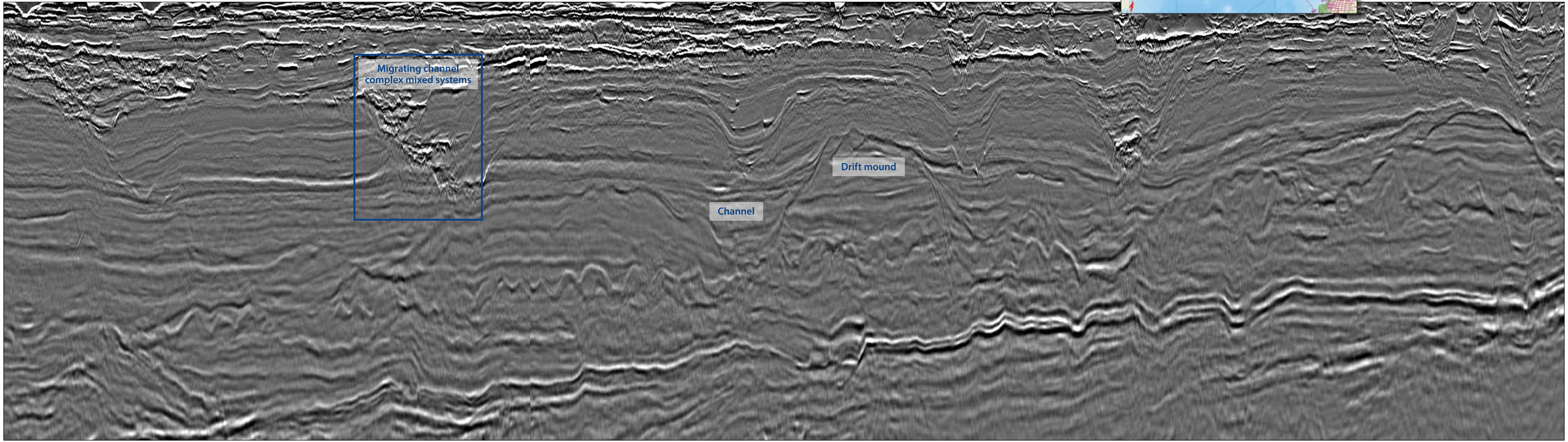
2019 Bid Round Treasures Exposed by Ocean Currents

The identification and evaluation of the hydrocarbon potential of hybrid depositional systems.

According to Rystad, exploration in deep water locations have already contributed half of the discovered volumes in the first six months of 2019. In this key setting for future exploration, coast-parallel bottom currents and gravity processes are common along continental margins. The interaction of these processes can build large mixed/hybrid (turbiditic-contouritic) depositional systems which have only just been recently identified and have now begun to be studied in more detail. A number of prolific discoveries have been associated with these hybrid systems and several more are now being recognized in modern long-offset seismic data.



Location of the Angoche Basin and Spectrum 2D seismic lines.



2018 PSTM strike line located in the Angoche Basin offshore Mozambique, showing different styles of hybrid systems. The presence of large drift mounds is interpreted as indicating that drift currents are the dominant process.

Drifting Towards 2019 Bid Round Treasures

Mixed/hybrid deepwater turbiditic-contouritic depositional systems are only just beginning to be understood, but show great potential.

KARYNA RODRIGUEZ and NEIL HODGSON, Spectrum

Several prolific discoveries have been associated with hybrid turbidite-contourite systems, of which the most notable is the Rovuma Basin offshore Mozambique (Maba Complex). Another significant hydrocarbon accumulation with clear seismic indications associated with a mixed system is the deepwater confined channel Barra/Moita Bonita complex (>3 Bbo in place) in the Sergipe Basin, Brazil.

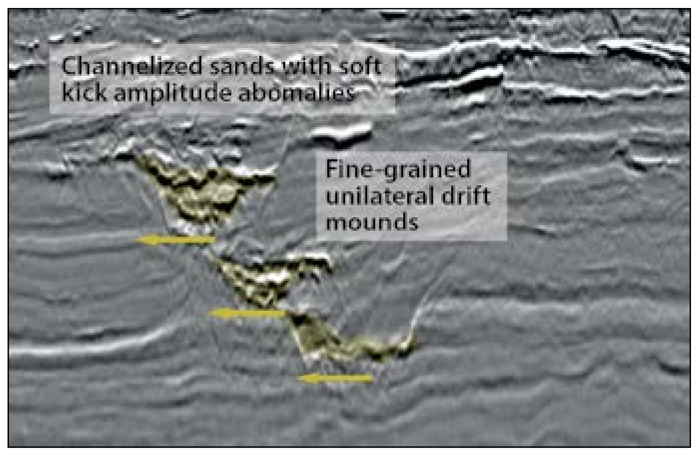
Identification of these systems relies on the recognition of a series of diagnostic criteria derived from the integration of available understanding (Sansom, 2018) and comparison with direct observations from well-established proven systems. Hydrocarbon potential evaluation includes the analysis of probable source rocks, reservoir and traps. Potential source rocks can be identified using a systematic frontier basin methodology which integrates plate tectonic reconstruction, paleographic setting, seismic character, any available well and outcrop data, and source rock characterization (Eastwell et al., 2018). To de-risk reservoir presence and quality, both depositional system features and seismic character can be used. The trapping mechanism is usually provided by the depositional characteristics of the hybrid system.

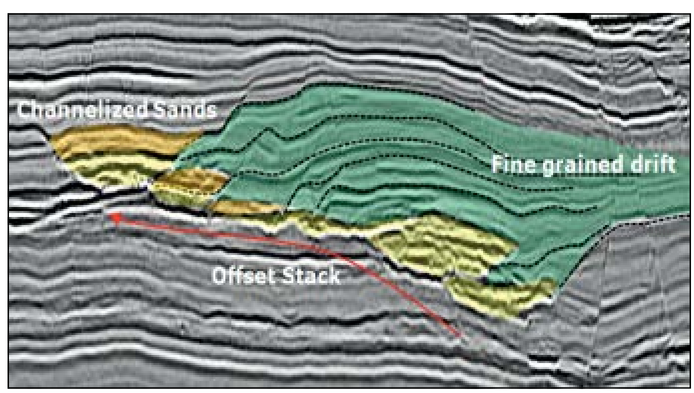
Angoche Basin, Offshore Mozambique

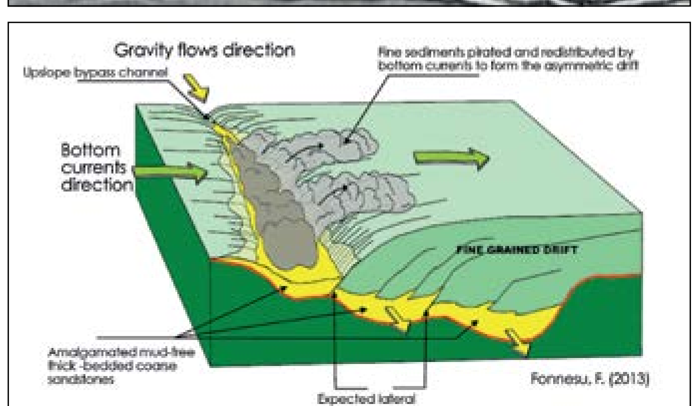
To the south of ENI's over 85 Tcfg Mamba Complex lies the Angoche Basin. Here, long-offset 2D seismic data acquired in 2017/2018 has revealed a series of hybrid turbidite-contourite systems with confined to weakly-confined channels, as well as a series of migrating channel complexes, all flanked by impressive drift mounds. The model put together by Fonnesu (2013) shows how the gravity flow moves sediment down the turbidite channel while the drift current winnows the channel in a direction perpendicular to the coast, depositing a unilateral drift mound on the flank of the channel. Counter-intuitively, the channels migrate against the current direction, which might be a characteristic of more contourite-dominated systems. This process results in enhanced reservoir quality (net/gross up to 90%) in the channels and an overlying effective seal provided by the fine-grained drift mounds.

The block nomination process for the next bid round offshore Mozambique will commence later in 2019 and the significant potential indicated on the new seismic data, together with clear indications of present-day oil generation, should make the Angoche Basin very competitive.

Mozambique: Strike line from the MOZ2D-17 survey showing a migrating channel stack in a hybrid system in the Angoche Basin, which is very similar to the one demonstrated by Fonnesu et al., 2013. (Reproduced with permission from Denis Palermo)

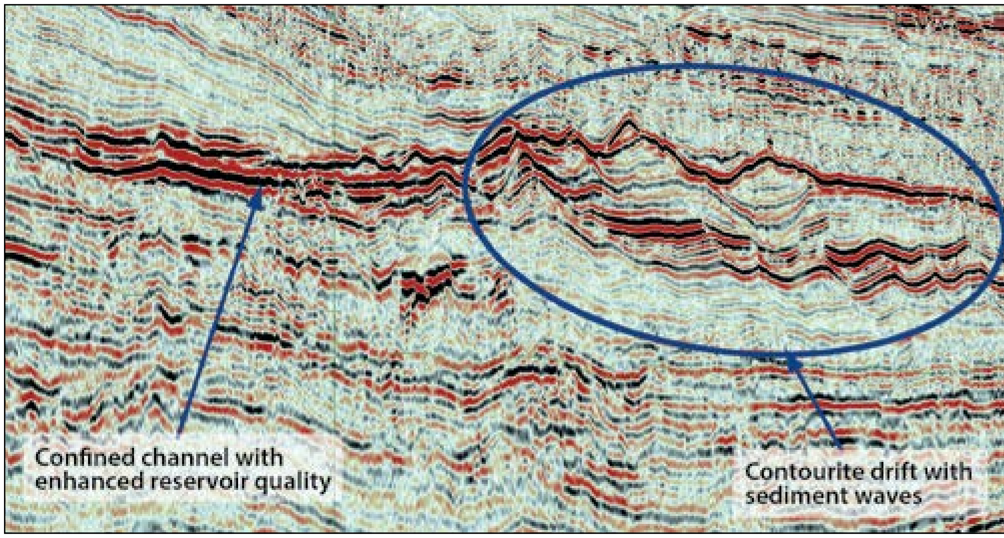






Sergipe: Multibillion Barrel Hybrid System

The Sergipe Basin on the north-eastern coast of Brazil has seen an astonishing rejuvenation in exploration effort and oil success. In 2010 Petrobras found the Barra Field and subsequently made several more significant discoveries in Upper Cretaceous to Lower Tertiary turbidite channel sandstones in the deeper water of the basin, with total reserves of over 3 Bbo. Despite clear seismic indications that contourite drift features seem to play a key role in the success of this petroleum system, these have received little attention.



Sergipe: PSDM through a Barra well showing clear evidence for contourite drifts.

A depth seismic section through one of the Barra wells shows a clear contourite drift downdip of the confined channel, indicating the presence of drift currents during the deposition of this mixed system. It is possible that the winnowing of this channel by perpendicular drift currents is largely responsible for the excellent reservoir quality associated with these sands.

The Sergipe Basin currently has several offshore blocks on offer through the 1st Open Door Bid Round. There are indications of a widespread hybrid system extending into the open blocks on offer. Understanding the distribution and nature of these depositional systems is key in the evaluation of these open blocks.

Argentina Basin: A Turbidite-Dominated Hybrid System

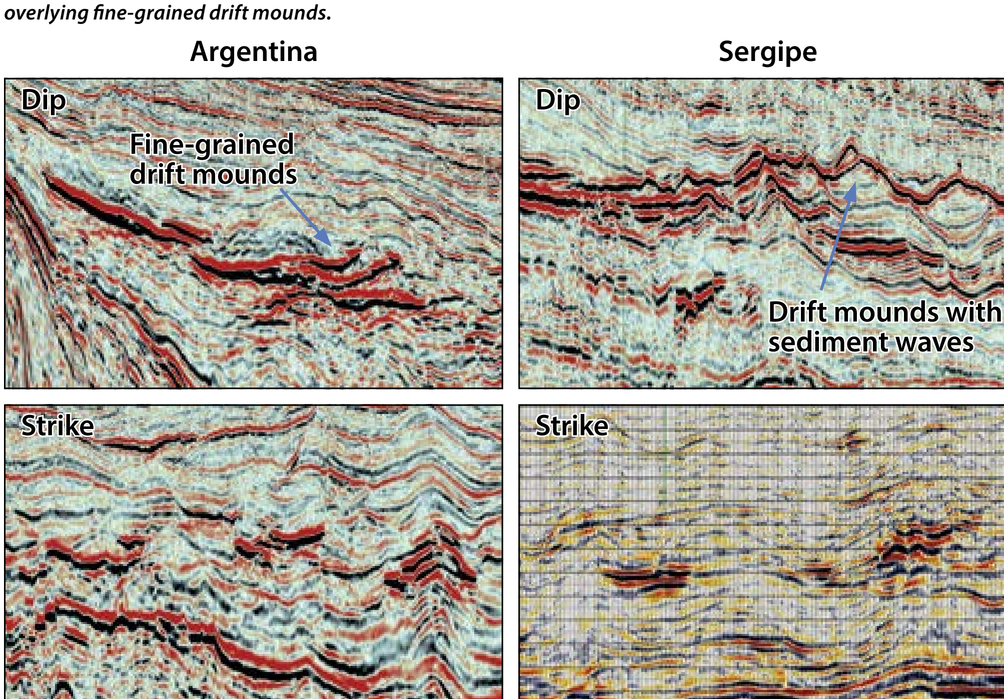
An extensive long-offset 2D seismic survey was acquired in 2017–2018, mainly to assist in the evaluation of the very successful first offshore license round in Argentina. A detailed source rock analysis identified a high quality potential source with sufficient burial depth to generate hydrocarbons. This source rock is overlain by numerous Cretaceous and Cenozoic stacked, confined turbidite channel complexes influenced by drift currents. One of these systems shows an AVO-supported high amplitude anomaly which can be mapped over a very large area. The system is very similar to Sergipe, but extends over 5,700 km^2, three times the size of the Sergipe anomaly, and indicates that there could be an accumulation holding as much as 9 Bbo.

Great Exploration Potential

Mixed/hybrid deepwater turbiditic-contouritic depositional systems, often located in relatively frontier basins, are only just beginning to be understood. Modern 2D seismic is proving to be an essential tool in identifying these systems and performing a hydrocarbon potential evaluation.

2019 has already seen significant discoveries in the deep water and this year's bid rounds are ideally placed to target these hybrid depositional systems with already proven success, offering a great future exploration opportunity. ■

Argentina: Comparison of the Sergipe and Argentina hybrid turbidite-contourite systems supported by amplitude and AVO anomalies, indicating huge potential in the Argentina Basin. The seal is provided by overlying fine-grained drift mounds.



From Arrhenius to CO_2 Storage

Part III: A Simple Greenhouse Model

"We dance round in a ring and suppose,
But the Secret sits in the middle and knows."
Robert Frost (1874–1963)
American poet

What would the temperature of Earth be without the atmosphere? By using simple physical models for solar irradiation and the Stefan-Boltzmans law for blackbody radiation, we can estimate average temperatures with and without atmosphere.

MARTIN LANDRØ and LASSE AMUNDSEN, NTNU/Bivrost Geo

An Earth Without Atmosphere

In his paper, Arrhenius stated, without any reference, that without its atmosphere the mean temperature of the Earth would be very different, and significantly less. Let's use a simple Earth energy model to investigate this further.

The energy that keeps any planet warm, including the Earth, comes from the sun. But the Earth needs to send this energy back; otherwise it would become warmer and warmer. The equilibrium temperature of the earth can be estimated by realizing that the incoming energy flux must equal the outgoing energy flux. The incoming energy is the solar irradiance – the total amount of energy per unit time and unit area measured at the Earth. The sun's output energy is not constant. It fluctuates (< 0.15 %) over a course of 11 years, from a relatively quiet state to a peak in intensity; however, the average annual solar radiation arriving at the top of the Earth's atmosphere is roughly S = 1,365 W/m^2. But this energy does not continuously reach each square meter of the Earth's spherical surface. As shown in the figure on the opposite page, the area of the Earth that collects the sunlight is effectively its cross-section. The incoming energy on the cross-section of the Earth is

$$E_i = \pi R^2 \cdot S \quad [1]$$

where R is the radius of the Earth.

The outgoing energy consists of two parts. First, part of the incoming energy is reflected from the Earth's surface. The fraction of the sun's incident radiation that is reflected is called albedo (α), so that the reflected energy is $E_r = \alpha E_i$. Albedo is close to 1 for white surfaces (like fresh snow), and close to 0 for black surfaces (like dark and wet soil). Earth-orbiting satellites measure the Earth's albedo to be $\alpha = 0.33$. Secondly, the Earth's blackbody radiation is also outgoing energy. The entire surface of the Earth emits this energy, which according to the Stefan-Boltzmann law is proportional to the fourth power of its temperature. Then, the energy related to the blackbody radiation is:

$$E_b = 4\pi R^2 \cdot \sigma T^4 \quad [2]$$

Energy balance, $E_i = E_r + E_b$, now gives the temperature equation:

$$\sigma T^4 = (1-\alpha)\, S/4 \quad [3]$$

For the Earth we now can calculate the effective temperature that would exist at its surface if the planet had no atmosphere. We find T = 252K, or -21°C, in fair agreement with Arrhenius's observations.

The Moon, which has a very tenuous atmosphere and no clouds, has an albedo of 0.12. Venus, covered by dense clouds, has an albedo of 0.76. Since the Moon has a similar distance as Earth to the sun, the solar radiation is the same. Inserting Moon's albedo into equation 3 gives the blackbody temperature T = 270K (-3°C). Average temperatures of the Moon's surface have been reported as low as -20°C, but temperatures in different areas vary greatly depending upon whether they are in sunlight or shadow. Daytime maximum temperatures are 387–397K

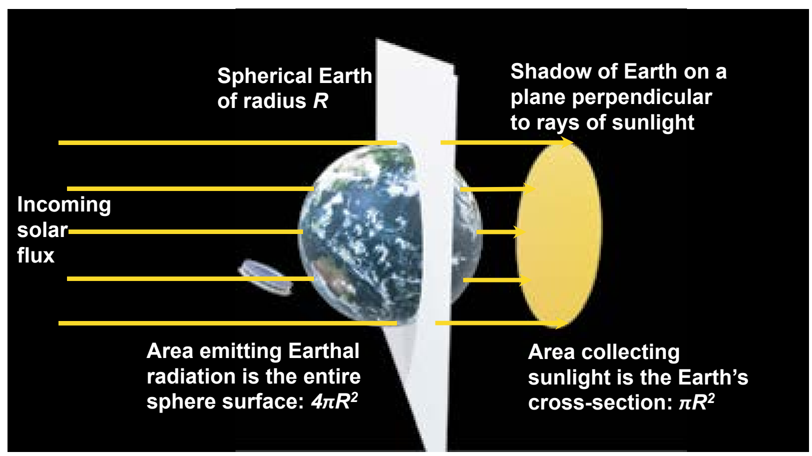
View of the Sun on October 14, 2011 from NASA's Solar Dynamics Observatory, taken at 171 Angstrom, showing the corona and upper transition region of the Sun. The irradiance of solar radiation peaks in the visible wavelengths. About half of the energy is in visible wavelengths below 0.7 µm. The solar spectrum can be approximated by a blackbody spectrum.

(114–124°C) at the equator, dropping to 95K (-178°C) just before sunrise.

A Simple Greenhouse Effect Model

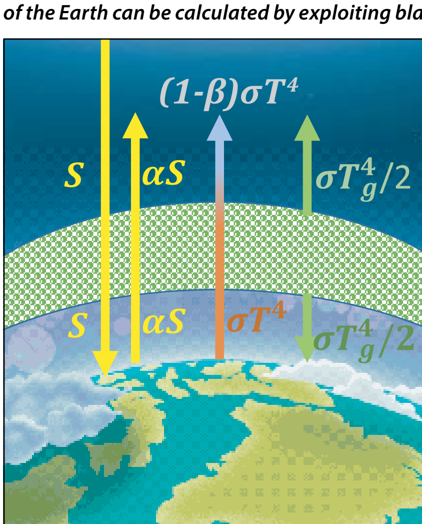
Observe that we have calculated a temperature of the Earth that is (fortunately) much lower than the observed temperature. The reason, of course, is that we have neglected the fact that the Earth's atmosphere contains gases that absorb the longwave radiation emitted from the Earth's surface. Atmospheric absorption gives rise to the greenhouse effect, and thus warmer conditions. The warmest temperature ever recorded on Earth was 70.7°C, in the Lut Desert of Iran in 2005, while the coldest was -89.2°C, at the Soviet Vostok Station on the Antarctic Plateau in 1983. The average surface temperature on Earth is approximately 16°C.

The blackbody curves discussed in Part I and II show that the solar radiance is almost completely separated spectrally



The area collecting sunlight is the cross-sectional area of the Earth, while the area emitting radiation is the entire surface of the Earth.

A simple model of the greenhouse effect. The temperature at the surface of the Earth can be calculated by exploiting blackbody radiation and the physical principle that the incoming energy equals the outgoing energy. The atmosphere is represented as one layer that absorbs β of all Earth's IR radiation; when β = 1 all terrestrial radiation is absorbed. The atmosphere heats and re-radiates half of the energy to space and half back to the surface. In this way, the atmosphere acts like a blanket, causing some of the heat from Earth to be retained.



from the infrared (IR) thermal emission from Earth. This fact motivates a simple but illustrative model showing how the atmosphere warms the surface of the Earth. Let us assume that the atmospheric layer absorbs β% of the Earth's IR radiation. As the atmosphere absorbs this longwave radiation, the layer also warms up. By treating the atmosphere as a blackbody with temperature T_g the figure left shows that the atmosphere must emit radiation through both its upper and lower surface in equal amounts. The model thus assumes:

1. The atmosphere is transparent to solar radiation at all wavelengths $<2\mu m$.
2. The area of the Earth that collects sunlight is its cross-section. The Earth is a blackbody where emission occurs over its entire spherical surface area, so the average radiation at the surface is $S/4$.
3. The atmosphere, which absorbs β% of terrestrial radiation, is a blackbody at terrestrial wavelengths $<2\mu m$.

Again, we exploit the fact that the incoming energy flux must equal the outgoing energy flux. In the following, we drop the area of the bodies that enter the energy calculations. Outside the layer, energy balance yields:

$$\frac{1}{2}\sigma T_g^4 = (1-\alpha)\frac{S}{4} - (1-\beta)\sigma T^4 \quad [4]$$

At the surface of the Earth, the energy balance gives:

$$\sigma T^4 = (1-\alpha)\frac{S}{4} + \frac{1}{2}\sigma T_g^4 \quad [5]$$

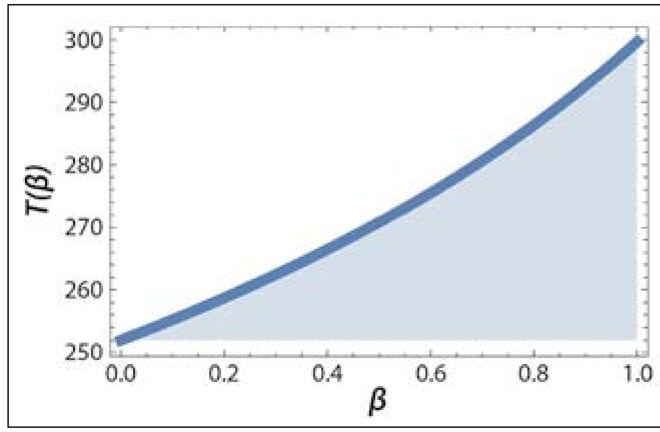
By inserting equation (4) into equation (5), we obtain:

$$\sigma T^4 = \frac{2(1-\alpha)}{2-\beta}\frac{S}{4} \quad [6]$$

$T(\beta = 1)$ = 300K (27°C) is the temperature for a fully IR absorptive atmosphere. $T(\beta = 0)$ = 252K (-21°C) is the temperature for a non-absorptive atmosphere. However, part of Earth's IR radiation escapes directly into space, which allows it to maintain a cool surface temperature. To reproduce today's average temperature of 16°C, we need to select β = 0.844: $T(\beta = 0.844)$ = 289K (16°C).

The model is a gross simplification of the real climate system, but the simple calculations which contain the basic ingredients of the climate system demonstrate that the temperature increases due to greenhouse gases. Furthermore, the temperature is very sensitive to how much terrestrial radiation is absorbed in the atmosphere (β – value).

The blackbody temperature of Venus is found from equation (6) by using Venus's albedo and its solar irradiance S = 2,601 (explained below). We arrive at the chilly temperature of 229K (-44°C). However, the very strong greenhouse effect of Venus' atmosphere changes this temperature to an average of 737K (464°C). The model in the figure on the previous page does not apply to Venus, partly because it has such a dense atmosphere that the assumption that the short wavelength solar radiation reaches the surface of the planet does not hold. The atmosphere, composed of more than 96% CO_2 and 3.5% nitrogen, heats, trapping much of the infrared radiation in the dense atmosphere and thick cloud layers. This trapped radiation heats the lower atmosphere, raising the surface temperature by hundreds of degrees.



Temperature at the surface of the Earth T(β). When β = 1 all terrestrial radiation is absorbed and when β = 0 no terrestrial radiation is absorbed.

Total Solar Irradiance

The total solar irradiance (TSI) is the amount of solar radiation received at the top of Earth's atmosphere. It has been measured since 1978 by a series of satellite experiments to be 1,365 kW/m². Variations of this number have been discovered on many timescales, linked to several physical processes known to occur in the Sun's interior, including the 11-year sunspot (Schwabe) cycle, the 88-year Gleisberg cycle, the 208-year DeVries cycle and the 1,000-year Eddy cycle. TSI provides the energy that drives Earth's climate, so continuation of the TSI time series database is critical to understanding the role of solar variability in climate change.

In 1894 the English astronomer Edward Walter Maunder pointed out that very few sunspots had been observed between 1645 and 1715. This 'Maunder minimum', which featured exceptionally low numbers of sunspots, is known to coincide with the coldest part of the 'Little Ice Age' (ca. 1500–1850) in Europe, North America and China. In these cold years, the Thames River in London froze over during winter, and Norwegian farmers demanded that the Danish king recompensed them for lands occupied by advancing glaciers. On a much longer time scale, over its 4.55 billion year lifespan, it is also known that the sun will increase its luminosity significantly.

We can calculate the sun's surface temperature T_s by using the principle of energy conservation, where the energy on spherical shells centered on the sun is constant. Considering the sun to be a blackbody, the total radiated energy at the surface is $4\pi R_s^2 \bullet \sigma T_s^4$, where R_s = 695,508 km is the radius of the sun. The total solar irradiance is measured at the top of Earth's atmosphere, at a distance R_{se} = 149,600,000 km from the center of the sun. The energy in a spherical shell at this distance is $4\pi R_{se}^2 \bullet S$. The energies must be equal; therefore, the temperature can be solved from the equation:

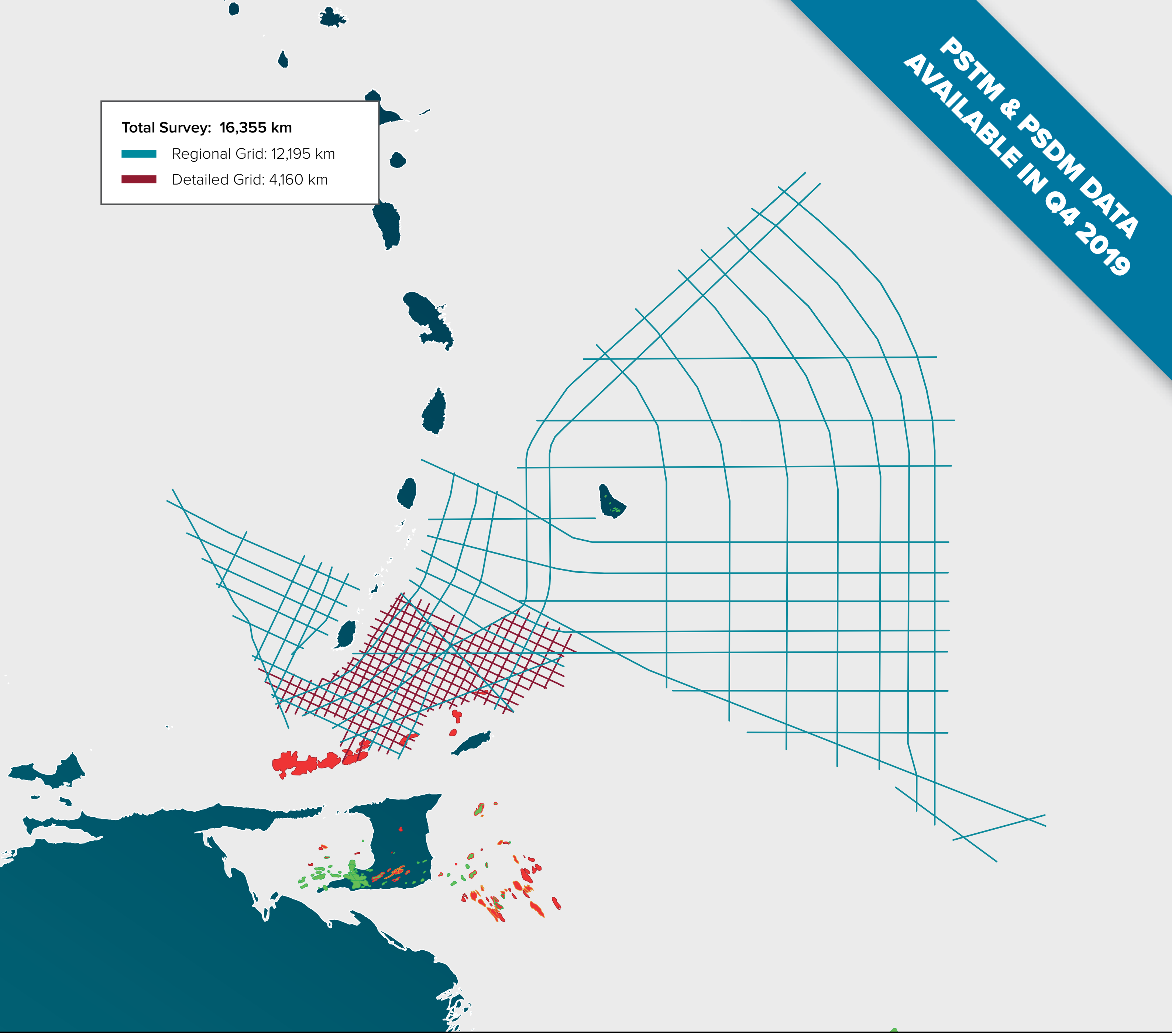
$$4\pi R_s^2 \bullet \sigma T_s^4 = 4\pi R_{se}^2 \bullet S$$

This yields T_s = 5,778K.

Venus is R_{sv} = 108,200,000 km from the sun. The total solar irradiance measured at the top of Venus's atmosphere is

$$S_v = \left(\frac{R_{se}}{R_{sv}}\right)^2 \cdot S = 2{,}601\ \mathrm{W/m^2}.$$ ■

Painting by Thomas Wyke of the Thames Frost Fair in 1682.



CARIBBEAN ATLANTIC MARGIN DEEP IMAGING

MCG is pleased to present the Caribbean Atlantic Margin Deep Imaging survey (CAMDI).

The 16,355 km survey is targeting the highly prospective and underexplored basin along the Southeastern Caribbean and Western Atlantic margin of Northeast South America.

High quality pre stack time, pre stack depth, gravity and magnetic data will be made available upon completion.

Geoex

MCG

A Geoex Company

Learn more at www.mcg.no & www.geoexltd.com

Anomalies Indicate Potential

Vertical CSEM technology identifies new potential for undiscovered volumes around the Gjøa field in the North Sea.

ASLAK MYKLEBOSTAD and SVEIN ELLINGSRUD, PetroMarker

The alignment of the sources in vertical Controlled Source Electro Magnetic (CSEM) technology, combined with source signals transmitted as pulses in time domain, result in a deeper imaging as well as the ability to record near-offset data, giving rise to an increased lateral resolution of subsurface resistivity compared to other CSEM technologies.

Vertical CSEM uses a vertical electric dipole source that is adjustable to the water depth of the actual survey area and a grid of receivers with vertical electric dipole antennas that is dropped in pre-planned positions on the sea floor. The dipole source has two transmitter electrodes, one placed and positioned accurately on the seabed, while the upper electrode hangs below the survey vessel, positioned above the lower electrode by DP2. It is important that the vertical alignment is strictly maintained to obtain the best possible data quality. During pulsing the vessel is stationary and the dynamic positioning of the vessel is used to ensure verticality. The electric current transmitted between the two electrodes is 5,000A and the source signal is pulsed to acquire data in time domain. A typical source signal could be 9s on at 5,000A, followed by 9s off for a listening period. The pulse sequence is repeated for a pre-planned number of stacks to achieve the required signal to noise ratio.

The receivers are equipped with an active verticality correction for the vertical electric dipole sensors (each receiver has four parallel Ez dipoles). They are dropped to the sea floor by gravity and positioned accurately by acoustic signals and then the verticality is adjusted for a potentially tilted seabed. After data acquisition the receivers are released by an acoustic signal and retrieved by the survey vessel. Horizontal sensors complement the recording suite.

One of many important features of the vertical CSEM technology is its application in zones close to existing infrastructure, or so-called 'near zone'. Vertical time domain CSEM is a near-offset technology, with the strongest response being on the receivers closest to the transmitter. A typical offset range could be from 500m to 5,000m. In the near offset, the subsurface layers impacting the pulse signal are narrowly concentrated between the transmitter and its nearby receivers. Most of the vertical energy is therefore used to penetrate the layers of interest and is not passing through geology at far offsets before reaching the target of interest. Another important factor in vertical CSEM is the stationary pulsing. More energy can be transmitted by increasing the pulsing time on each location to optimize signal to noise ratio. The stationary approach also gives more freedom when operating close to existing installations.

Gjøa Area Survey

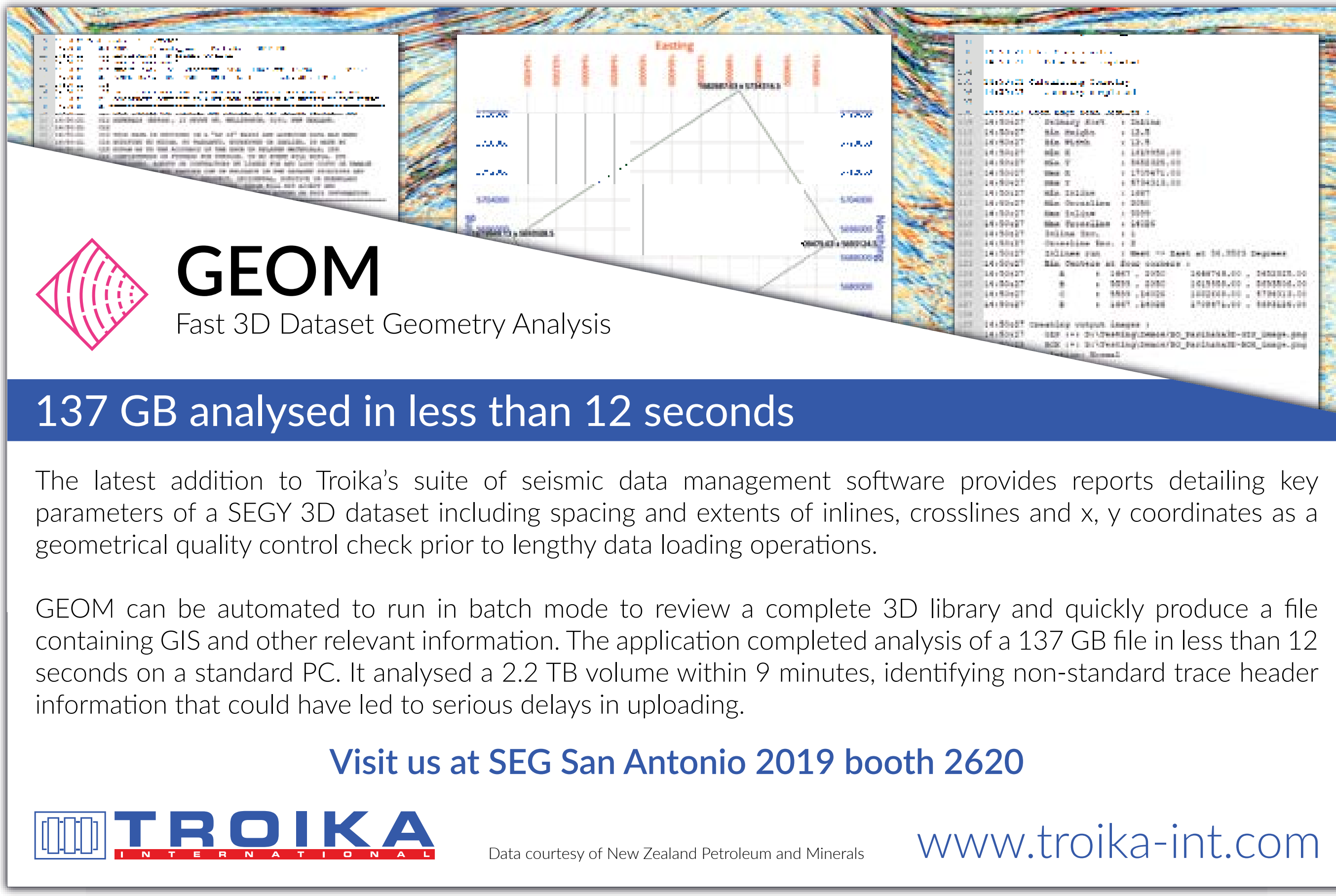
PetroMarker was established in 2005 to develop this marine CSEM acquisition method using 2D surveys, but improved technology and an increased number of receivers mean that it is now possible to acquire 3D data by this method. In 2018 the company acquired 700 km^2 of vertical 3D CSEM data around the Gjøa field in the Norwegian part the North Sea. The survey also covered the Cara discovery, now renamed Duva, located north-east of Gjøa, as well as interesting exploration opportunities to the east and south of the field, as seen on the survey layout map on the following page. The field reached a record high production of 43.8 MMboe in 2016 and this coupled with the Cara discovery in 2016 have increased interest in further exploration potential around the Gjøa area.

The CSEM receivers were laid out in a grid pattern with 1.7 km distance between each receiver location. The source positions were asymmetric between receivers, with a distance of 700m and 1,000m to the closest receivers, getting a richer dataset with more offsets for the inversion. Pulsing strategy was set to 9s transmitting time and 9s listening time, repeated over a period of 67 minutes at each pulsing location. PetroMarker's technology allows for tailormade grids without generating operational issues around infrastructure.

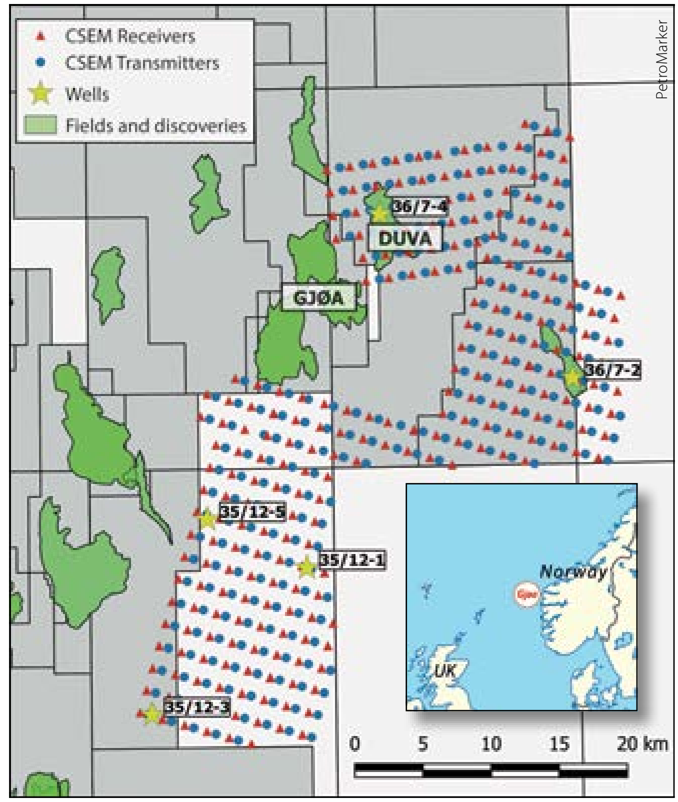
Analyzing Anomalies

There are a couple of dry wells in the survey area that show an absence of any elevated resistivity in the respective drilling

CSEM receiver with active verticality correction.


GEOM
Fast 3D Dataset Geometry Analysis
137 GB analysed in less than 12 seconds
The latest addition to Troika's suite of seismic data management software provides reports detailing key parameters of a SEGY 3D dataset including spacing and extents of inlines, crosslines and x, y coordinates as a geometrical quality control check prior to lengthy data loading operations.
GEOM can be automated to run in batch mode to review a complete 3D library and quickly produce a file containing GIS and other relevant information. The application completed analysis of a 137 GB file in less than 12 seconds on a standard PC. It analysed a 2.2 TB volume within 9 minutes, identifying non-standard trace header information that could have led to serious delays in uploading.
Visit us at SEG San Antonio 2019 booth 2620
TROIKA
INTERNATIONAL
Data courtesy of New Zealand Petroleum and Minerals
www.troika-int.com

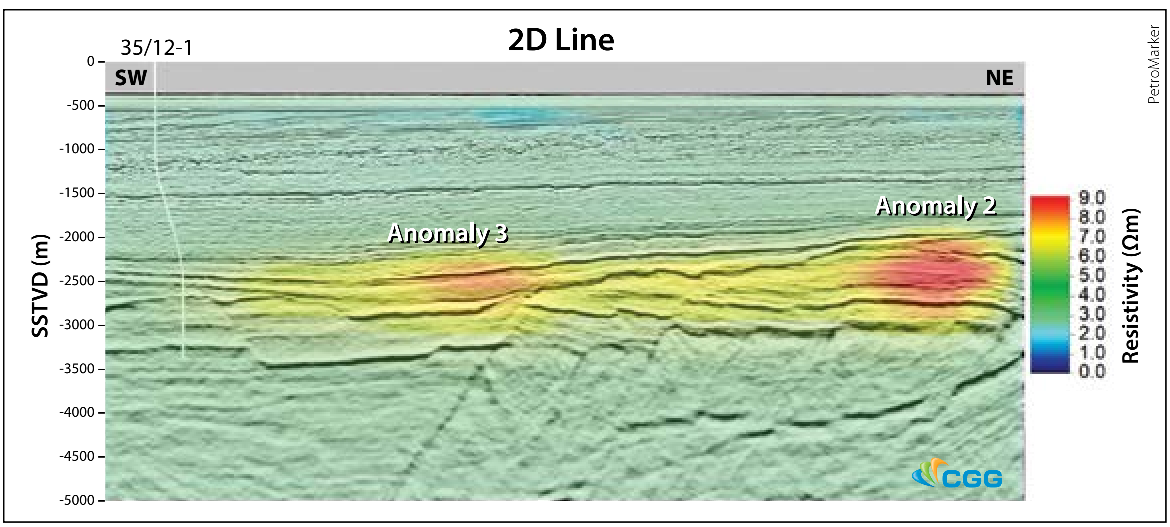

11–12 DECEMBER 2019 | BUSINESS DESIGN CENTRE, LONDON
PROSPEX
2018 INCLUDED
25 countries represented
800+
delegates
20% international
audience
More than 30 Prospectors
promoting 50+ Prospects
Over a quarter of
attendees were
Directors, C-Level
Executives or VPs
VIEW THE
FLOORPLAN &
REGISTER NOW AT
https://prospex.pesgb.org.uk/
PESGB Member | £186
Non-member | £300
PROSPEX
LONDON
PES
Oil & Gas
Authority
#PROSPEX2019
@PESGB

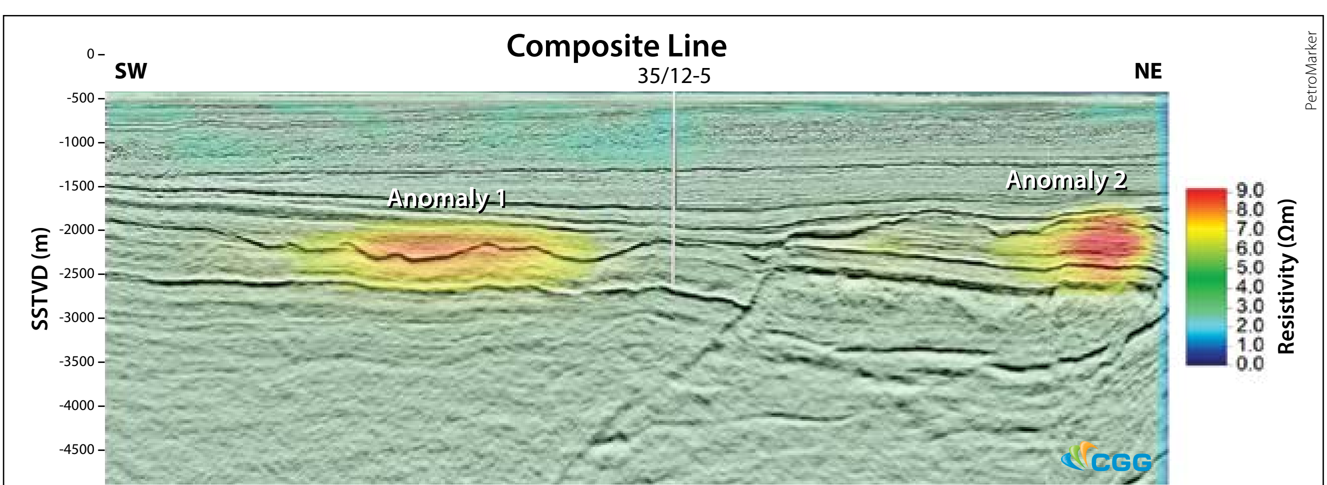


Survey layout map. Gjøa is a producing oil and gas field in the northern part of the North Sea, with the reservoir in sandstone of Jurassic age in the Dunlin, Brent and Viking Groups at 2,200m. The water depth in the area is 360m. Gjøa was the fifth highest producing field on the Norwegian shelf in 2016, according to the Norwegian Petroleum Directorate (NPD). Just 14 km from Gjøa, discovery 36/7-4 Cara was made in 2016. The well proved a 50m gas column and 60m oil column in a stratigraphic pinch-out trap of Agat sandstones. The original volumes were estimated to be between 4.5 and 12 MMm^3 of recoverable oil equivalents, making Cara the second largest discovery on the Norwegian continental shelf in 2016, according to the NPD.

locations, in line with the unsuccessful outcome of these wells. Offset from them, however, three prominent CSEM anomalies stand out from regional variations (Anomaly 1, 2 and 3 in the figures below). The anomalies indicate the presence of additional exploration possibilities in the area, with potential for significant remaining volumes. This view is supported by an analysis of the main characteristics of the three anomalies, including an evaluation of the most likely resistive alternative models.

Of the three observed anomalies, Anomaly 2 exhibits the characteristics that are most commonly observed as resulting from hydrocarbon effects in rotated fault blocks. A clear up-dip termination of the anomaly against the fault is present, with a limited extent in the down-dip direction which may indicate the presence of a fluid contact. In addition, the



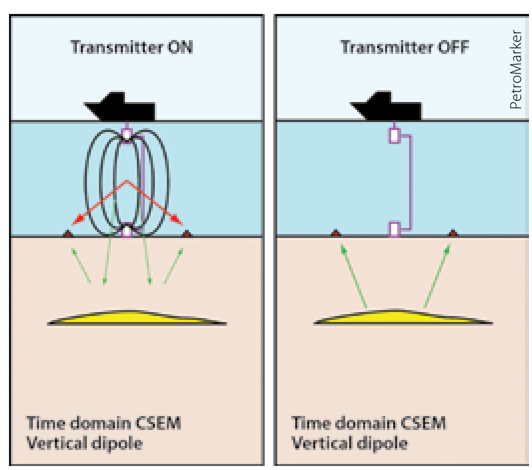


limited down-dip extent also reduces the likelihood that a resistive lithology effect has caused the anomaly, as a sharp lateral lithology boundary with very different resistivities would need to be invoked.

Anomaly 3 shows a similar apparent up-dip termination against a fault; however, no clearly defined rotated fault block geometry is present. At the same time, a distinct geo-body is present approximately 150m below the anomaly, which needs to be considered within the depth uncertainty inherent in the CSEM method. The highest resistivities can be observed in the up-dip location where this body pinches out towards the fault. This lack of correlation between body thickness and resistivity makes a lithology model very unlikely if the implied correlation of seismic feature and CSEM feature is correct.

Anomaly 1 represents a more challenging case as it appears to cross stratigraphic boundaries. However, this does not only represent a challenge for a hydrocarbon scenario, but also for any alternative models to be evaluated. While the juxtaposition of two resistors could represent one scenario, only two intervals with large resistivity contrasts are proven by wells in the area. These comprise the Lower Cretaceous shales and the Heather shales, both of which were penetrated in the nearby well 35/12-1, but no marked CSEM response is observed at the well location.

The Lower Cretaceous shales are the most unlikely alternative model due to the depth difference, primarily because of a thinning away from the well location and the limited overall resistivity contrast. The Heather Formation shales could



A schematic drawing of a source positioned between two receivers.

represent a different model for a juxtaposition, provided that a resistivity increase is postulated. This is primarily due to the more rapid variations in thickness at this level, but it still requires the resistivity placed in the syncline where the Heather Formation shales in this location would be either absent or very thin. Solving this puzzle will probably be the key to properly qualifying and quantifying the anti-model risk and for the more prominent anomalies with more distinct fluid characteristics.

Acknowledgement

The author wishes to thank CGG for permission to access the BroadSeis - BroadSource seismic data available in the Gjøa area and publish the examples included in the article, and to thank CGG`s Multi Physics team in Milan for the 3D inversion work. ■

South Atlantic The Bigger Picture

HERMANN LEBIT, JEFF TILTON, SRIRAM ARASANIPALAI, PASCAL OLLAGNON; PGS

The timing of continental extension relative to salt deposition and the impact of pre-salt faulting is critical to reservoir formation and exploration success in the South Atlantic. Major advances in broadband seismic data processing offer clearer imaging, allowing a closer look at the elements of the prolific plays and their tectono-stratigraphic boundary conditions.

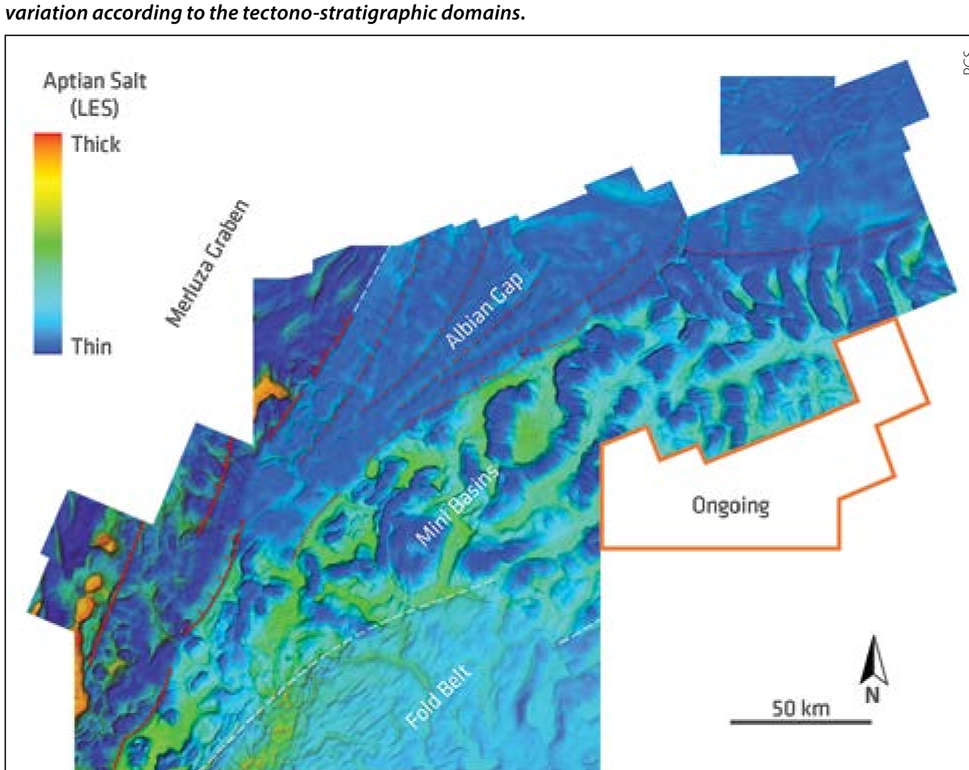
The transition from continental extension to seafloor spreading marks the separation of continents and the development of conjugate passive margin systems. It causes major restorations of the regional tectonic conditions, has wide implications for basin evolution, and affects the formation of petroleum systems. In restricted environments, the continental break-up commonly occurs somewhere close to the period of salt deposition, such as in the South Atlantic basin or the Gulf of Mexico. Unsurprisingly, it is widely debated whether salt deposits postdate or predate the continental break-up. Depending on the timing, salt basins might have formed either separately on each conjugate margin including scenarios with salt deposited on newly formed oceanic crust, or as a large salt basin that has been subsequently split during break-up.

Analysis on extensional faults near the base of salt allows us to narrow down the critical time interval of continental separation and provides insights into the condition during reservoir formation of the pre-salt plays. Key prerequisites for such investigations are high resolution regional-scale seismic products offering reliable and accurate imaging of the base of the salt and the reservoir-bearing sequences below, including their fault-controlled morphology. PGS implement a focused and integrated velocity model-building process, including refraction and reflection Full Waveform Inversion over the entire depth section, rigorously constrained by geological compatibility. High resolution broadband seismic imaging and Least-Squares Migration (LSM) provide high fidelity images of the pre-salt sediment geometries and fault architecture.

Comparing Santos Basin, Brazil…

The pre-salt São Paulo Plateau is a rift-related basement high which contains the regional fairway for the prolific hydrocarbon play associated with pre-salt carbonate build-ups. Based on the salt and post-salt architecture (Figure 1), the plateau region is divided into three tectono-stratigraphic domains. The north-western Albian Gap domain is an approximately 40 km-wide zone of roll-over structures that displaced most of the Aptian layered evaporite sequence (LES) and largely lacks the post-salt Albian carbonates. A system of extensional faults (Cabo Frio Fault) delineates the Albian Gap from the adjacent mini basin domain of thick layered evaporite sequences

Figure 1: Isopach map of layered evaporite sequence across the Santos Basin illustrating the salt thickness variation according to the tectono-stratigraphic domains.



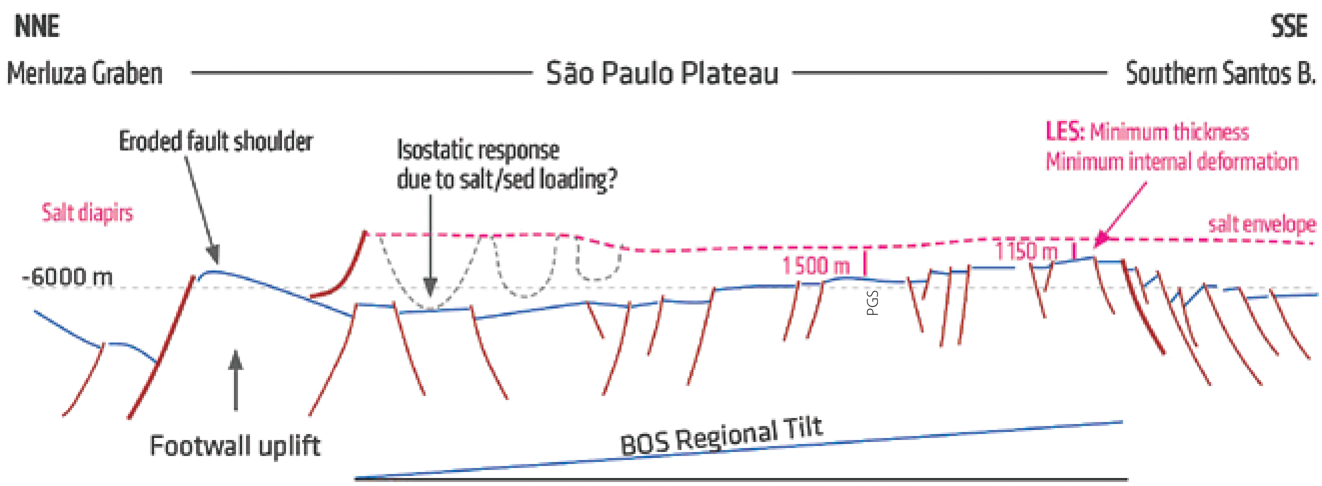


Figure 2: Schematic section through the entire São Paulo Plateau outlining major pre-salt faults and the thickness variation of the LES.

bounding mini basins filled with post-salt sediments. Highly reflective layers of anhydrite and other evaporites within the LES indicate complex internal folding, while rather transparent sections refer to accumulations of intra-formational mobilized halite. The dominance of mini basins diminishes towards the adjacent fold belt domain, which reveals increasingly well imaged folding and diminishing complexity towards the distal section of the São Paulo Plateau.

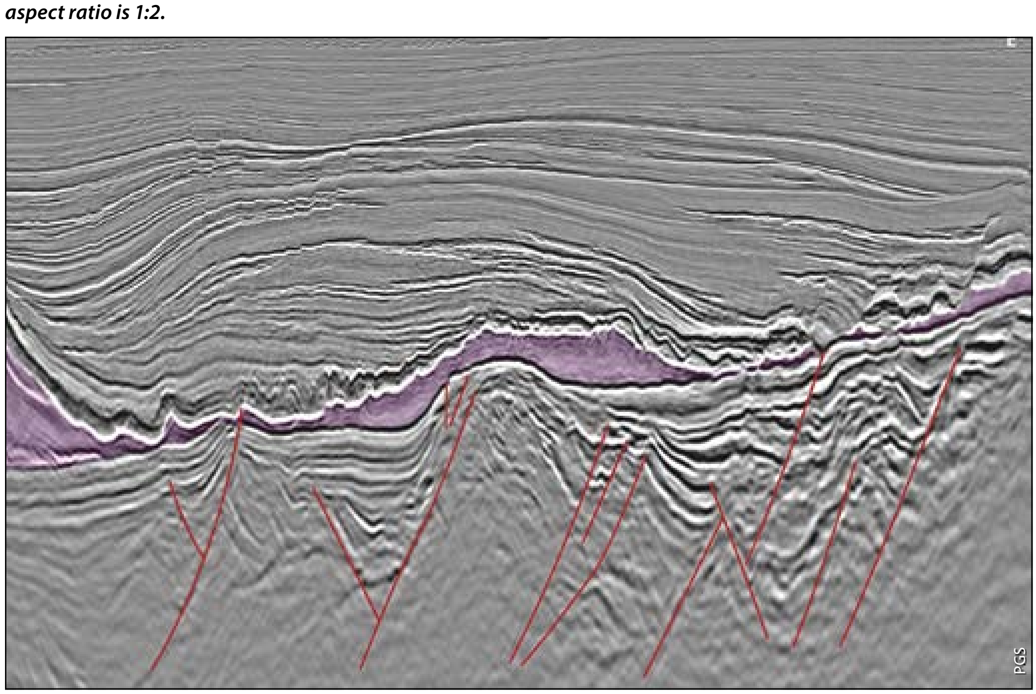
The São Paulo Plateau is bound by normal faults, such as the Merluza Graben system, with fault throws in excess of 3,500m. On the plateau, similar north-north-east to south-south-west trending faults form the basis of major pre-salt hydrocarbon reservoirs. Displacement along these fault systems continued during the deposition of the LES, which accumulated up to 4,000m in thickness at the graben systems, while the São Paulo Plateau received about 1,150–1,500m of evaporite deposits (Figure 2).

A key objective of the PGS regional-scale imaging project Santos Vision, which encompasses more than 49,000 km^2 of broadband 3D seismic, is the reliable and accurate imaging of the base of salt and the reservoir-bearing sequences below, including their fault-controlled morphology. The latter is a major element in play fairway analysis, and a useful guide to define hydrocarbon leads and prospects within the pre-salt play. Constructing an accurate model of the heterogeneous seismic velocity signature within the LES and its cover sequences is essential not only for imaging the pre-salt structural and depositional geometries, but also for assessment of the seal risk for the pre-salt reservoirs.

…to Kwanza Basin, Angola

The West African margin is conjugate to the Brazilian margin and reveals similar architectural elements for the rifted pre-salt section. However, separation of the continents was rather asymmetric and left a significantly wider portion at the Santos Basin than at the West Africa counterpart, including the Kwanza Basin of Angola. These differences are reflected in the visible post-salt architecture. The Kwanza Basin is dominated by a basinward gravitational gradient that causes up dip extension (Figure 3), which is balanced by downdip compression via the salt layer serving as the kinematic detachment. The Santos Basin lacks such a gradient at

Figure 3: West–east seismic section at the Kwanza Basin passive margin illustrating the withdrawn and partially welded salt layer. The pre-salt fault pattern highlights tilted fault blocks with onlapping sag-phase sediments. A subset of the faults affect the salt base that covers locally eroded pre-salt sections at uplifted fault blocks. Image aspect ratio is 1:2.



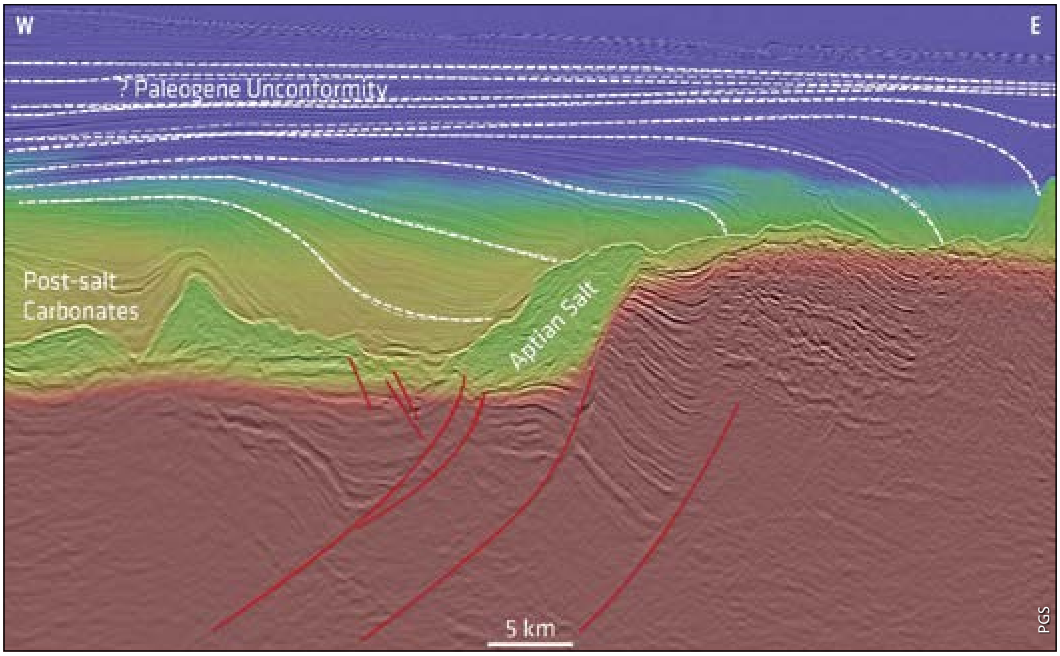


Figure 4: Santos Basin's Merluza half-graben revealing propagation of a post-salt Upper Cretaceous sediment wedge from the graben onto the São Paulo Plateau (Albian Gap). The São Paulo Plateau section displays the effect of footwall uplift and erosion into the rift phase sediments (right-hand side).

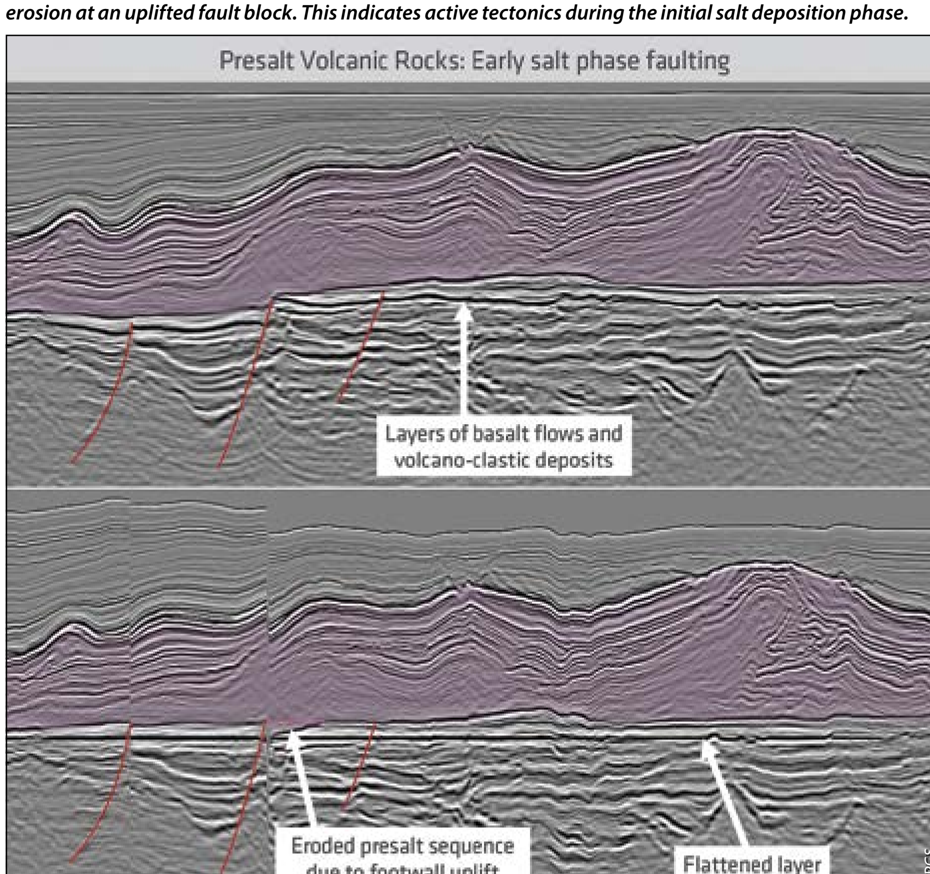
the São Paulo Plateau, where lateral salt movement due to displacement loading is caused by propagating Upper Cretaceous sedimentary wedges (Figure 4).

Timing is Everything

Timing and tectonic context of fault activity at the base of the Aptian salt in the South Atlantic basins affects the development of the pre-salt petroleum system. It has a direct impact on trap formation and hydrocarbon charge, while the prolific carbonate reservoir facies are associated with the fault-controlled paleo-relief, besides using sub-salt faults as proxy for the continental break-up. Rift-related faulting further affects the reservoir fluid due to localized hydrothermal circulation (CO_2; thermogenic gas). In essence, imaging individual fault magnitude and depth scale is critical to mitigate a wide range of hydrocarbon risk elements.

With regard to the Santos Basin, the base of salt has a rugose relief that ranges in depth from 6,000 to 7,000m at the São Paulo Plateau. It is bound to the west by a prominent half-graben system that throws the base of salt down to a depth of more than 10,000m along north-north-east to south-south-west trending normal faults (Merluza Graben, Figure 4). The faults align with the dominant fault system at the São Paulo Plateau where individual fault throw rarely exceeds 500m and this forms the grain of the pre-salt play fairway. Displacement along these faults was ongoing during development of the pre-salt reservoir carbonates and influenced the shallow marine to lagoonal paleo-environment on the São Paulo Plateau. Fault movement continued at least into the early stages of the Aptian evaporite deposition as clearly indicated by the displacements of the salt base (Figures 4 and 5). Well-imaged volcanic layers interbedded with the pre-salt reservoir section

Figure 5: Original (top) and flattened (bottom) pre-salt section highlighting the paleo-relief and localized erosion at an uplifted fault block. This indicates active tectonics during the initial salt deposition phase.



are a useful reference for fault activity and represent initially horizontal layers suitable to restore the paleo geometries. Younger growth strata within adjacent half-grabens indicate post-volcanic fault movement, and talus signatures along fault scars are evidence of exposure during pre-salt carbonate build-ups. Up-thrown fault blocks at the São Paulo Plateau reveal additional evidence of erosion at the top of the pre-salt sequences and a paleo-relief subsequently covered by evaporite deposits (Figure 4). In addition, the high-resolution broadband images reveal a seismic signature that indicates lateral facies changes at the reservoir level when flattened on the volcanic layers.

Large-scale fault displacement along the São Paulo Plateau edges (Merluza Graben) is associated with significant footwall uplift and local erosion down to the rift section (Figure 4). Onlapping sag-phase sediments on the flanks of fault blocks indicate that the formation of the Merluza Graben and São Paulo Plateau was active during the late pre-salt stage and evolving grabens accumulated significantly more evaporite section than the plateau, which resulted in an observable larger salt budget over pre-salt graben structures. The diachronous evaporite deposition were initiated at the deep grabens and later reached the São Paulo Plateau.

The Kwanza Basin reveals a similar faulting history for the pre-salt section, though the overall passive margin setting differs from that of the Santos Basin/São Paulo Plateau. Pre-salt faulting actually affects the salt sequence by offsetting its base. In rare examples (Figure 3) the faulting appears to truncate a thin salt layer, giving the impression that the top of salt was also affected by pre-salt faulting. However, this is a heavily depleted salt section and the imprint on its top might be the result of salt withdrawal.

Faulting was active during the pre-salt deposition and certainly affected the depositional (erosional) environment for the hydrocarbon reservoirs. Fault activity continued at least during the early stages of salt deposition and initiated in the graben structures and local depressions, while paleo-highs were eroded and subsequently covered by the evaporite sequence. Faulting ceased sometime during the deposition of the Aptian salt restoration of the rifted margins falls into this period.

High Quality Imaging Critical

The success of hydrocarbon exploration and production demands high quality seismic images that provide critical subsurface insight into prospective petroleum systems, enable an improved classification of play types, and mitigate the overall prospect risk. Both Santos Vision and high quality 3D GeoStreamer data from Kwanza provide a high level of detail in post and pre-salt imaging. These datasets are ideally suitable for exploration efforts, including prospect maturation and hydrocarbon risk assessment of the pre-salt reservoirs. Innovative technologies such as LSM offer a further leap in enhanced image quality that help to delineate pre-salt fault patterns at very high detail and support confident seismic stratigraphy analysis. ■

Oil Paves the Way in Trinidad

The largest tar pit in the world has a fascinating history and awaits approval as a Unesco World Heritage Site – even if it resembles a somewhat neglected car park!

TIM DALEY

I have been to more spectacular outcrops, I admit. I am in the middle of what seems to be a somewhat neglected car park. The gently undulating black hardstanding is stretched and cracked as though from a long hot summer, yet elongate pools of water are suggestive of a recent rainstorm. I feel curiously isolated in this quiet dead zone, yet the verdant fringe lies only a couple of hundred meters all around. I am standing on a large mineral bed. Oil is a mineral, isn't it?

The Magic Lake

La Brea Pitch Lake (always 'La Bray' in Trinidad) is one of those places an oil geologist has heard of but does not quite know what to expect when they get there. Is it a glorified seep or an environmental disaster? The view on our arrival early one Saturday seems less than auspicious. Seen from the gentle hill above, it looks like a dry lake bed, and the tall reeds and grasses that surround it certainly don't contradict this view. On the far flank, there seems to be some industry – warehouses, pipes and hoppers – but all is quiet today.

Mindful of the advice to avoid hustlers who might take advantage of our zeal to visit at all costs, Shazam and I had waited at the small car park until we saw a guide appropriately attired in an official red tee shirt and Cyrill Billy assigned himself to walk out with us. Of course, so as to justify his appointment, we are shown a faded photograph of an oil-covered man, zombie-like after rescue from the tar and presumed guilty of straying unsupervised from the route. The three of us walked through the curtain of sedge and out on to the tar field, Cyrill Billy recounting his well-rehearsed patter while prodding the ground with an umbrella.

It is like soft tar. Indeed, it is soft tar. But it does not move or rebound and nor does it clag to your shoes. There is no particular odor; nor does it flow except in a few places where the surface

Cyrill Billy prods the tar lake.

Tim Daley

skin is split, causing the gentle exuding of a rich black fudge. None can resist poking and probing at the wound and pulling the tar into extended tendrils of thick, viscous grease. There is a network of fissures that are mostly filled with water, and I am surprised to see the water is clear, with no slick, revealing schools of small fish suspended among a desultory fizz of bubbles. And just over there, as the tourist brochure claims, a family of 'Trinnies' (Trinidadians) are bathing, without fuss or demonstration, and presumably seeking the supposed restorative benefit of the sulfurous waters for their skin and bones.

And that's it. The largest tar pit in the world awaits approval as a Unesco World Heritage Site in its quiet unassuming corner of Trinidad while it lays bare the oil history of this land. The magic is in that history: the industry it founded and the unseen thermoplastic properties of this mineral bed. According to Cyrill Billy, the 24 wagons of pitch that the Trinidad Lake Asphalt Company still scratches out from the surface every day and push up the hill for 'refining' are replaced each night and the lake surface healed by inflow. A mine that refills every night; now that really is magic.

Paved with Oil

Despite the economic interest and obvious focus for study, I am a bit unconvinced by the explanation for the pitch lake. It covers an impressive 100 acres or so (40 hectares) and is up to 250 feet (75m) deep, classically portrayed as a bowl shape. I have seen a cross-section, a detached figure I presume comes from an early 20th-century document, which appears to depict where the lake had been penetrated and records its reduction in size between 1893 and 1925. It is probably a breached oil field, now revealed as a massive seep, any light gassy fraction naturally venting away to leave a slow churn of biodegraded bitumen that appears to replenish over time. The proximity and intersection of two large faults is cited as facilitating the up flow, an association with faulting it may have in common with other well-known tar pits, including the identically named deposits in the suburbs of Los Angeles, which lie above the Salt Lake oil field and the 6th Street fault.

Stollmeyer's Quarry: bitumen stained and seeping oil.

But why is a lake the result here? Oil seeps out at the surface all over the world but there are few tar lakes.

There is a small museum which may be open when you visit. We needed to ask for a Mr Carrington, museum curator and key holder, to come and open the center, but it was worth the wait. The display of glossy posters and artefacts is not overwhelming but it is well-presented and features the human history around the lake.

Every reference to the pitch lake is prefaced by the visit of Sir Walter Raleigh in 1595, who used this 'black gold' to caulk his boats on the way to search for El Dorado. Indeed, 'brea' is Spanish for tar, although the indigenous Amerindians use of the word 'piche' is closer to the word adopted by English speakers. The Spanish and then the British became aware of the properties of this flowing tar to smooth over uneven surfaces. A certain John McAdam was making roads in the mid-18th century from tightly packed broken stones, but in 1820 the addition of pitch led to the invention of 'tarmacadam' and a massive increase in demand for the asphalt, which has 'paved' the progress of Europe and America. I read in the museum how the 10th Earl of Dundonald, Thomas Cochrane, provided the money to form the precursor of today's company to develop the field in 1851, but that it was Conrad Frederick Stollmeyer who managed the operation and further experimented with converting the tar into the kerosene known as 'Trinidad Oil'. In the 1920s, more than 1,200 souls were laboring to dig up the lake, but by this time deeper sources of flowing oil were being discovered in Trinidad that would provide an abundant and frictionless source of kerosene and fuel oils.

Quarries to Castles

Stollmeyer: the name rang a bell. He was a German national, an emigrant to America, who when journeying to Venezuela was persuaded to stay in Trinidad by the opportunity presented by the pitch lake. Visitors to the Queens Park Savannah of Port of Spain might have noticed an eccentric mansion of that name, fashioned after a baronial Scottish castle – an ostentatious display of the wealth extracted from the south of the island. But the name also reminded me of a quarry, just a few miles south of La Brea, bisected by the Southern Main Road.

While puzzling over extending the life of the oil fields in south-west Trinidad with Trinity Exploration and Production, I had been invited on a field trip in which we examined the reservoirs exposed at the coast and in quarries. We had arrived at Stollmeyer's Quarry late in the afternoon after a hard day's geo-pondering; here was a great sand body cutting across its flood plain, cross-bedded over its entire 15m height – and weeping oil from its bituminous face. The oil is not the focus of the quarry, the sand being extracted for road aggregate, but the location has been studied as an analog for an oil reservoir and how its resources are compartmentalized by subtle stratigraphic barriers.

Although the pitch lake is more famous, it is oil, and latterly gas, that has energized the Trinidadian economy. Oil company maps are peppered with closely spaced well penetrations and oil fields across the south are depicted as broad, continuous swathes, brushing over the intricacies of complex structures and multiple stacked sandstones. But the overall impression given is correct. Southern Trinidad is very oily. Everything that can hold oil does so and the overfill leaks to the surface.

Lower slopes of San Fernando Hill and the Naparima Formation.

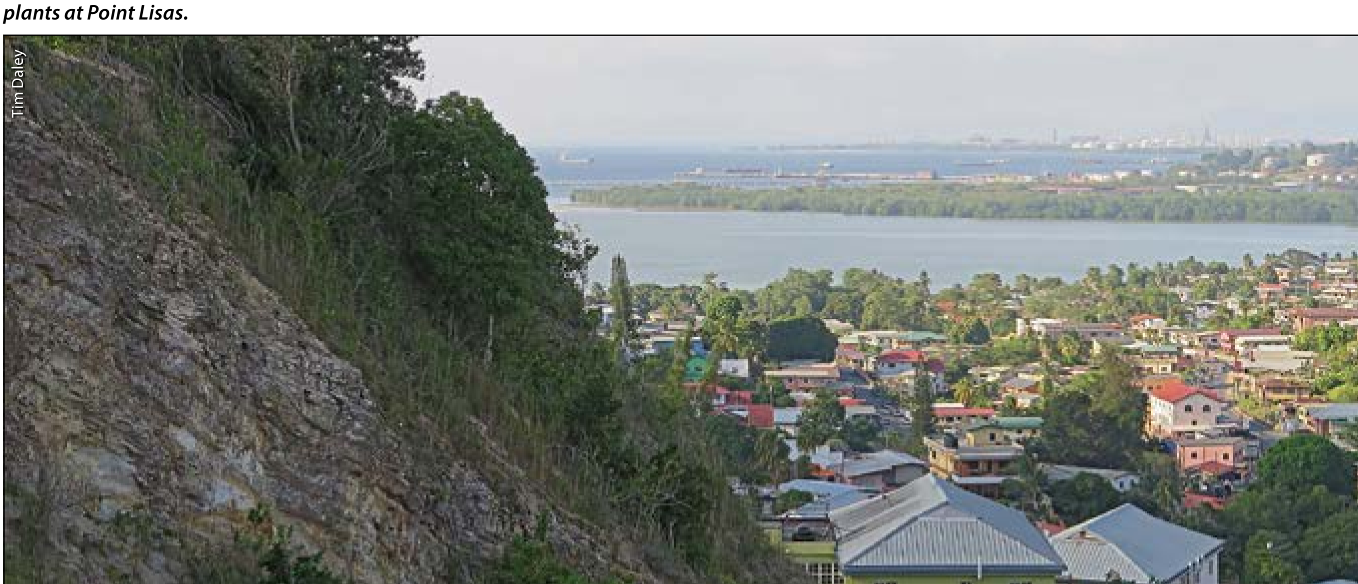
The Source Up a Hill

What is the source of all this oil? An unlikely outcrop of a world-class source rock is the centerpiece of San Fernando, southern capital of the island. A cone of pearly white rock, Naparima Hill, lends its name to the Upper Cretaceous rock formation, age-equivalent to the widespread and prolific Querecual Formation of eastern Venezuela which is responsible for that country's vast oil reserves. This uplifted outlier is the evidence of what lies beneath the Trinidadian oil patch.

When I jogged up the road to the small public park on the upper flanks of Naparima Hill and looked over the town and out across the Gulf of Paria, I did not really correlate the chalky looking cliffs with anything from which oil might have been sourced. But the shaded lower slopes of grey beds held more promise, based on comparison with my personal but unreliable atlas of source rock outcrops. Indeed, type rock descriptions from the Geological Society of Trinidad and Tobago describe bedded bituminous marls and shales while the upper parts are more of a silicified argillite. I should have wielded a pick hammer to expose the unweathered grey rock, and perhaps a whiff of hydrocarbons, but I left that untested honor to a literature search, which suggested 3–5% TOC from sampling.

But the age of abundance is coming to an end and even naturally refilling bitumen mines and super-sourced reservoirs are eventually emptied. One last look from San Fernando Hill shows the former Petrotrin refinery now quiet and unlit since its closure last year. It is being left to the small independent companies like Trinity to extend production life and keep the oil flowing long after the main harvest. ■

The view from San Fernando Hill looking across the Gulf of Paria. We can see the oil loading dock in the mid ground, and beyond that the chemical plants at Point Lisas.



The Zambezi Delta Basin

A Complex Puzzle with Missing Pieces

Until recently, exploration on the African continent had traditionally been concentrated on the sub-Saharan western margin, to the detriment of the east. Proven prolific basins, existing infrastructure, favorable and progressively transparent regulations, as well as analysis of prospective conjugate basins in Brazil, are just some of the factors creating a positive environment for exploration in the western margin.

A USGS report published in 2012 predicted undiscovered mean gas resources of more than 370 Tcfg offshore East Africa. World-class discoveries were made between 2010 and 2013 in the offshore regions of Tanzania and northern Mozambique, revitalizing exploration interest along the East African margin.

The Mozambique Channel has traditionally been the focus of intense academic research, with a number of 2D seismic and gravmag acquisition surveys conducted in recent years. However, the region remains poorly understood. To this end, in 2017 CGG acquired a high-resolution 3D multi-client seismic survey, as well as marine gravmag data, in the outer Zambezi Delta Basin, west of the Beira High (Figure 1). By integrating the seismic and gravmag surveys with data from multiple wells in the area, CGG aims to add fresh insight to the geological understanding of the basin.

Figure 1: Location of the gravmag, 3D seismic survey (green polygon area) and wells analyzed.

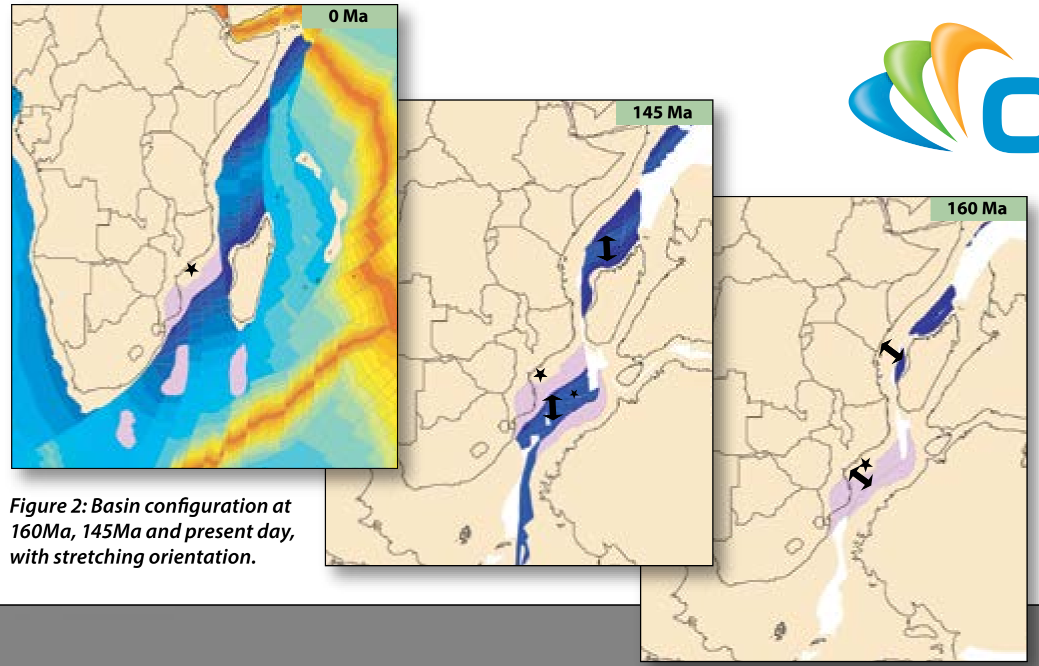
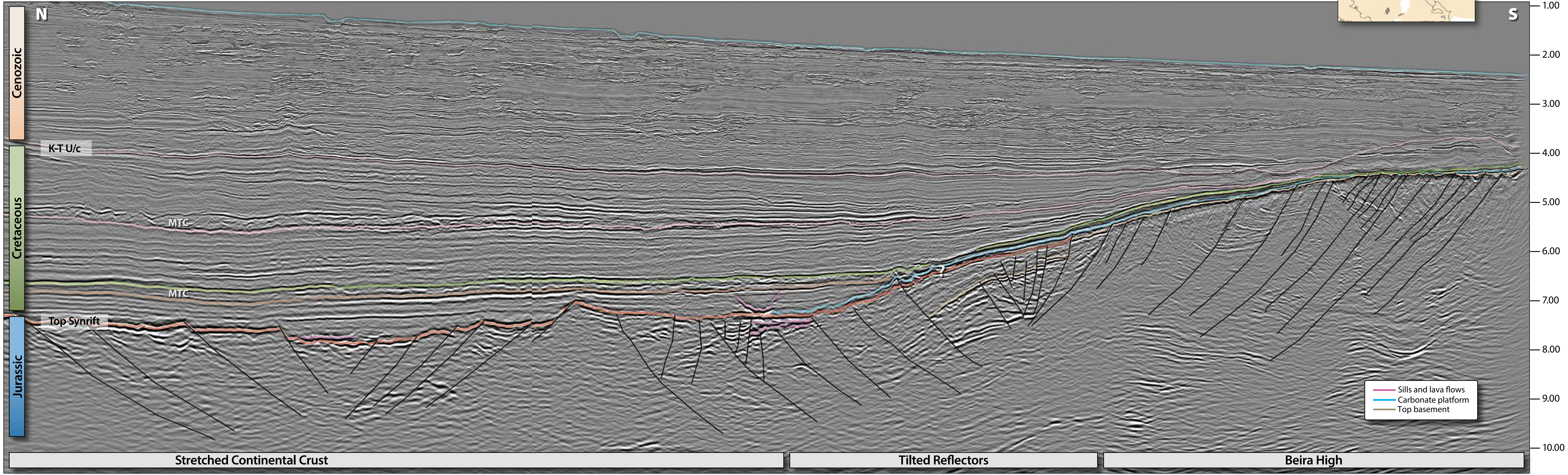


Figure 2: Basin configuration at 160Ma, 145Ma and present day, with stretching orientation.

Figure 3: Seismic section over the Zambezi Delta Basin with the different geological domains.



Another Piece in the Complex Zambezi Delta Puzzle

Addressing missing gaps with high-resolution gravity, magnetics and seismic data.

JAVIER MARTIN, MADHURIMA BHATTACHARYA and MARIANNE PARSONS; CGG

The structural configuration of the Zambezi Delta Basin provides evidence of a complex regional geodynamic evolution, with multi-phased plate tectonism and reconfiguration. The complexity of restoring the western Indian Ocean to its original configuration lies in the scarcity of M-series anomalies (those observed on the ocean floor and indicating oceanic crust) recorded during the Late Jurassic to Early Cretaceous.

The Zambezi Delta Basin is one of the oldest offshore basins in the East African margin, formed as a consequence of the onset of an Early Jurassic rifting and subsequent breakup of eastern Gondwana. Its two-phase breakup with different stretching orientations triggered the formation of the African-Antarctica corridor, separated from the Somali Ocean by activation of the Davie Fracture Zone during the late Jurassic (Figure 2).

Gravmag Reveals Basin Structure

The area's crustal nature and distribution across the basin was inferred from analysis of the high-resolution gravity and magnetics (gravmag) data and derived attributes acquired by CGG in 2017, which were also modeled in 2D cross-sections. Cross-correlation with the seismic data from CGG's multi-client survey underlines the structural dimension of the basin's geological characteristics.

The Bouguer gravity map shows a low over the Beira High, a north-east to south-west elongated structural feature located offshore that extends for more than 150 km. The horizontal gradient of the Bouguer gravity shows highs along the edge of the Beira High as well as in the north of the survey area (Figure 4a), where a north-east to south-west rifting geometry is observed. Cross-correlating this map (blended with the top synrift structural map) with a seismic section confirms the extensional character of this geometry (Figures 4a and 4b).

The magnetic anomaly map differentiates between two main domains (Figure 4c). The northern domain, which is relatively quiet magnetically, shows low-amplitude non-coherent magnetic anomalies over the deeper basin. Conversely, the southern domain is characterized by two distinct magnetic anomaly orientations associated with the Beira High. One is observed over its northern flank, and the other, a set of north-west to south-east anomalies, within its internal architecture.

The Complete Basin Picture

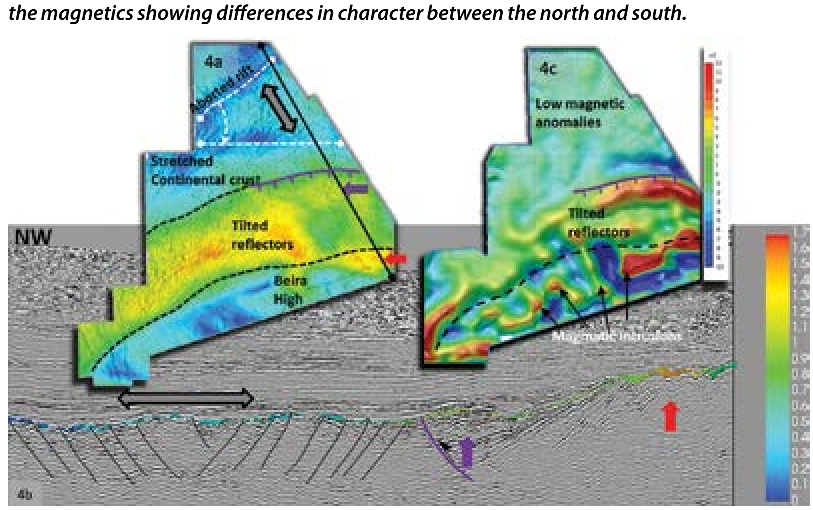
Insight from gravmag and seismic data confirms the continental origin of the Beira High. However, the origin and crustal nature of the northern area has historically been a matter for discussion. The evidence provided in this article suggests a stretched continental origin, with a north-east to south-west aborted rifting geometry located to the north of the survey. The synrift structural map indicates a clockwise rotational component (Figure 5).

Volcanism in the area played an active role in the basin's configuration, with at least three relevant magmatic events identified. Locally, remnant magnetization was identified in the magnetic anomalies within the Beira High, suggesting magmatism during different magnetic pole orientations. The magmatism can be characterized by three separate events, although it would be more accurate to understand these events as part of a continuous evolution of the margin (Figure 3).

Firstly, there was an early Jurassic event, related to the start of regional north-east to south-west rifting. Late Karoo volcanism provided a considerable volume of mafic material along the northern flank of the Beira High. Some authors describe these geometries as seaward-dipping reflectors. However, magnetic depth estimates suggest a deeper origin.

A second event, identified from lava flows and intrusions interpreted on the seismic data, occurred along the north-east to south-west graben structures of the

Figure 4: (4a) Horizontal gradient of the Bouguer gravity map overlying the top synrift structural map. (4b) North-west to south-east oriented seismic line correlating to the Bouguer horizontal gradient anomaly map. The northern extensional area correlates to relative highs in the horizontal gradient of the Bouguer. (4c) A matched filter of the RTP of the magnetics showing differences in character between the north and south.



failed rift morphology. This event could be related to the reconfiguration of stress regimes and rotation during rifting evolution. Stress field orientation developed from north-west–south-east to north–south, favored by the onset of the Davie Fracture Zone and the opening of the Somali Basin. The Beira High acted as a backstop for continued rifting, which shifted south-eastwards with accretion of oceanic crust identified from M-anomalies south of the Beira High.

The third magmatic event is observed as sills in the seismic data, intruding the Early Cretaceous section. These are interpreted as resulting from late crustal readjustments and the reactivation of faults and flexure during the sag phase, resulting from thermal relaxation after the rift axis shifted to the south-east of the Beira High.

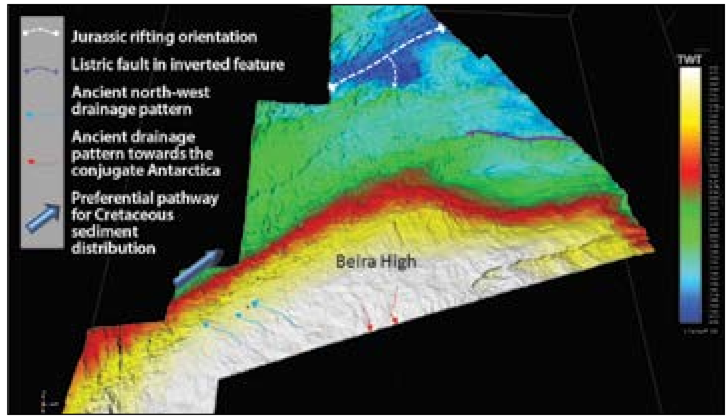


Figure 5: Top synrift structural map showing the configuration of the basin in the Late Jurassic. The Beira High is observed as a positive elongated north-east to south-west oriented relief. The northern area displays a failed rifting geometry. A clockwise rotational component resulting from rifting reorientation induced reactivation of a listric fault and local inversion.

Beira High Influences Sediment Distribution

Seismic data analysis reveals that the configuration and location of the Beira High during Early to Late Cretaceous times played a crucial role as a barrier for sediment distribution and its confinement along the basin. The crustal density contrast between the continental Beira High and the oceanic crust induced a buoyancy effect and a gradual uplift. Simultaneously, conditions for a rimmed carbonate platform were established on the inner western flank of the Beira High and subsequently more than 11 km of Mesozoic to Cenozoic sediments were deposited within the basin. Deep marine channel systems, together with mass flow processes, are the predominant mechanisms for sediment distribution within the basin. Observations from seismic attribute maps provide evidence of a south-west to north-east system of meandering channels developed from the early Cretaceous, which evolved to a west–east orientation during the Late Cretaceous and then a north-west to south-east orientation during the Cenozoic (Figure 6).

The present-day Zambezi Delta has been active since the Early Cenozoic and has a sedimentary thickness of over 4 km. Analysis of the Tertiary channels and their geometry, distribution and orientation variations provides evidence for close interaction between eustatic sea level and the Oligocene regional uplift event (Figure 6a).

Completing the Puzzle

CGG's high-resolution 3D seismic survey further revealed potential prospective structures within the Zambezi Delta Basin. Widespread amplitude anomalies are evident as pinch-outs or within channels in the Cenozoic and Cretaceous sections.

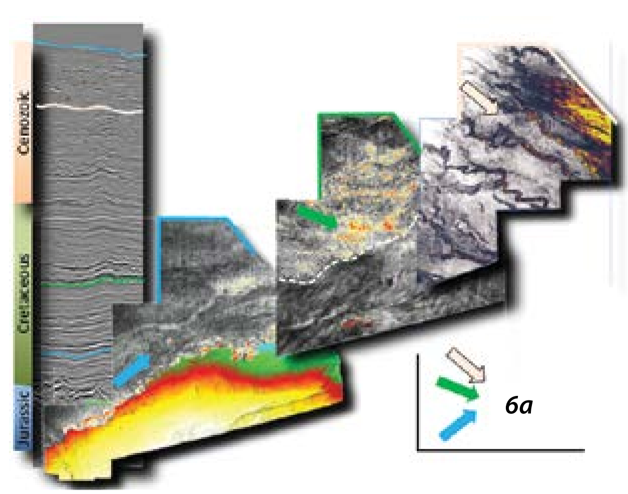
Understanding the initial stages of the basin's tectonostratigraphic evolution is fundamental to infering its hydrocarbon prospectivity. The mid-late Jurassic on the Beira High is dominated by the presence of rotated fault blocks with possible deposition of terrigenous sediments. The resulting carbonate platform would have been conducive for the development of both source rocks and reservoir facies.

The Cretaceous is dominated by the deposition of clastic sequences. The upper and lower Domo shales (Cretaceous source rocks) were deposited during a period of marine transgression and anoxia. The lower Cretaceous reservoirs are represented by the Maputo and the Domo sands. The Late Cretaceous reservoirs are represented by the Grudja Formation, possibly deposited by basin floor fans and channels. The Eocene-Oligocene reservoirs are represented by the Cheringoma Formation. Late Oligocene to Miocene reservoirs are well defined within the Zambezi Delta complex. Potential traps include structural as well as stratigraphic mechanisms (pinch-outs onlapping onto the Beira High, truncations against unconformities and channel fills). Seals will predominantly be intra-formational within the Cretaceous and early Cenozoic section.

Despite the presence of a promising and technically proven petroleum system in place, no significant oil or gas discoveries have been made in the basin. This could simply be a result of low drilling density in such a large basin. Predictions do, however, suggest significant potential in this basin.

References available online. ■

Figure 6: Set of RMS attribute maps from Early Cretaceous to Mid Tertiary. Note the evolution in orientation and morphology of the channels conforming to the intervals analyzed. The Late Cretaceous interval (green maps) shows a prominent mass transport complex (MTC) developed (dashed white line). The MTCs are dominated by localized erosion, possibly turbidity-induced channel systems flowing from west to east. The lighter map shows the orientation and geometry of the deep marine channels related to the dynamics of the Zambezi River during intra Oligocene. (6a): Angle of evolution of the main flowing system for each of the analyzed intervals.



Challenges and Opportunities in Africa

Africa's total proven reserves stand at 125.3 Bbo and 509 Tcf natural gas, 7.5% and 7.1% respectively of the global total. Is the continent's share of the market likely to increase in the near future?

Despite the downturn in oil prices, exploration for oil and gas has continued in Africa, although with a concentration on the 'low-hanging fruit' represented by low risk wells in areas of existing production that would yield rapid results. As a result, total exploration spend in the region dropped to a low point of ~US$5,000 million in 2017, resulting in a big drop in discovered volumes in 2018.

As the oil price recovers, however, there are signs that explorers are getting ready to look further afield in Africa, to frontier areas and new countries, spurred partly by continuing economic growth on the continent.

Average GDP growth for Africa reached an estimated 3.5% in 2018, and is projected to accelerate to 4% in 2019 and 4.1% in 2020. There are also signs that political change is underway in many countries, such as in the Democratic Republic of the Congo, which experienced its first post-independence democratic transition of power late last year, and Ethiopia, which is making great strides towards democracy. Another cause for regional optimism is the ongoing trade talks towards continental political and economic integration, promising to facilitate frictionless trade and bring economic benefits to all.

With economic growth will come an increased demand for energy, and a number of countries are looking to capitalize on that by encouraging exploration companies to their part of Africa through bidding rounds, either underway already or due to open in the near future.

Rosy Picture for Gas

Global gas consumption rose by 5.3% between 2017 and 2018, one of the fastest growth rates since the 1980s, largely driven by the US, China, Russia and Iran. Africa's gas production, meanwhile, grew by 8% in 2017, primarily due to the discovery of large fields like Egypt's Zohr, which alone could meet half that country's demand. This growth in gas production is expected to continue as demand increases, particularly through gas-to-power initiatives throughout the continent. Rapid increases in population, particularly in gas-producing countries such as Egypt, Algeria, Nigeria and Ghana, is one of the key drivers for this growth.

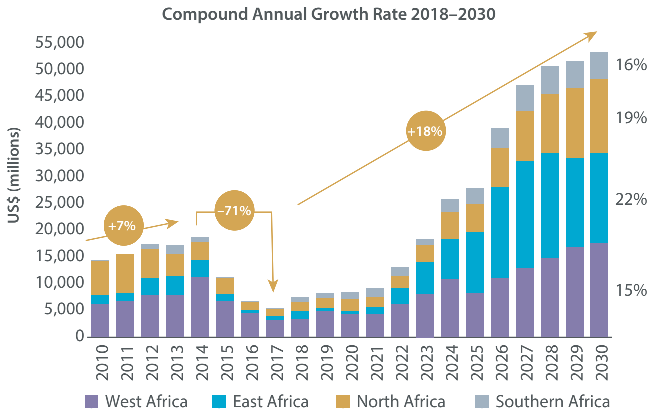
A number of liquified natural gas (LNG) projects are progressing across the continent, such as Eni's Coral South floating liquefied natural gas (FLNG) project in Mozambique and an Anadarko-led LNG project in the same country. A recent agreement between the operators and the governments of Senegal and Mauritania to develop the giant (>15 Tcfg) gas field which crosses the border between the two countries means that the Greater Tortue Ahmeyim FLNG project should be up and running in 2022.

Stranded gas is a target for future exploration, especially near older, declining fields. Efforts being made to reduce flaring, especially in Nigeria, where roughly 15% of gas produced is currently flared, will also bring more gas into the market.

Deepwater Exploration Promising

Deepwater drilling in frontier regions of Africa is on the rise as companies have more money to spend on this high risk/ high reward environment. Some of this will be in already producing countries such as Nigeria, where, for example, FID is expected on the Bonga South West deepwater project very soon. Exploration is continuing in the deep water off Senegal, while Total's recent play-opening deepwater discovery of Brulpadda earlier in 2019, with a reported 1 Bboe resources, has

Rig being repaired in the port at Cape Town, South Africa.



Africa oil and gas exploration spend by region, 2010–2030. Source: Rystad Energy, PwC Strategy&

rejuvenated interest in the deep water offshore South Africa.

A number of countries are offering deepwater and ultra-deepwater blocks in their upcoming bidding rounds. These include Congo Brazzaville, which is offering five offshore blocks in deep and ultra-deep waters in its ongoing licensing round, and Gabon, where last year Petronas announced an oil discovery in ultra-deepwater block F14. The Gabon licensing round includes 23 blocks in deep water.

Several high impact wells due to be drilled in Africa in coming months are in deep water. Total plans a well on Block C-9 offshore Mauritania and another in the ultra-deepwater of the Congo Basin. The company is also aiming to drill the giant Venus prospect off Namibia later this year, with what will be the deepest well ever undertaken on the continent.

Positive Outlook

There is definitely a sense of positivity in the African oil and gas arena, according to a new report released by Menas Associates in conjunction with Africa Oil Week, *Africa Oil and Gas Outlook 2019*, which can be downloaded for free from the Africa Oil Week website. Their experts predict that 2019 and beyond will see an increase in offshore exploration and mega gas finds, along with the development of trans-continental pipelines, gas-to-power initiatives and refining potential.

There are challenges ahead, however, the report points out. Worldwide, continuing US China trade tensions are having a negative impact on the global economy, and with it, foreign direct investment into Africa, while rising US unconventional oil and gas production is also putting pressure on demand for African oil.

Additional strain is being put on the market by regulatory uncertainty as various political and financial trends impact on policy making, while the rise of resource nationalism in some countries might act as a barrier to investment. Corruption and transparency have long been an issue in Africa and the increasingly stringent US and European anti-corruption legislation has made detailed due diligence and transparency essential for success on the continent.

Overall, however, so long as African countries can rise to the challenges inherent in ensuring they remain globally competitive, there is a diverse array of opportunities available across the whole oil and gas value chain in Africa. ■

From Outcrop Geology to Seismic… and Back!

Making new geoscientists better aware of seismic interpretation pitfalls through proper modeling of seismic images.

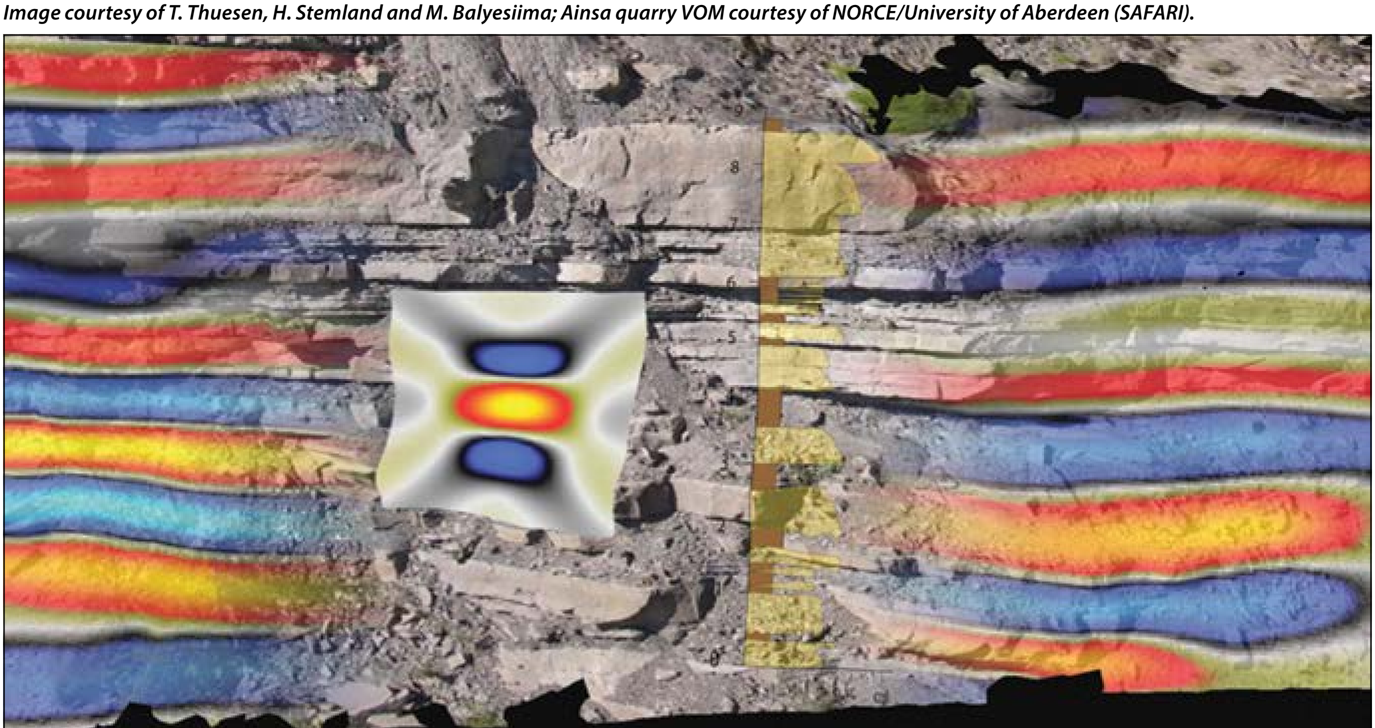
ISABELLE LECOMTE, University of Bergen

When I started studying geophysics, the teacher introducing seismic arrived one day with colored pencils and a bunch of paper rolls; we then laid these over a few tables and discovered our first seismic sections. I was not impressed at the time and thought that interpreting seismic was not going to be for me! Fellow students thought it was fun, while I wondered how on earth one could trust these colored lines we drew, viewing the sections sideways-on to better appreciate continuity. Though PCs at the time were barely available for students, a very few of us got really enthralled, and had fun testing Fortran-like codes on our one computer and discovering modeling and imaging (Claerbout, 1985).

This student experience colored my career, as I realized I enjoyed modeling seismic in various ways, though I stayed away from interpretation. Thanks to working on imaging with colleagues in other fields as a young researcher in the early '90s, I stumbled across the concept of Point-Spread Function (PSF; imaging response of a point scatterer), a well-known key feature of any imaging system, and adapted it for seismic (Lecomte and Gelius, 1998). Using ray-based approaches to compute PSF, we applied the function to simulate seismic images by convolution.

But, as long as I was making my own – simplistic – geomodels, the produced seismic images remained… simplistic. However, in 2014 I joined forces with a geologist in need of seismic modeling for fold models and an expert in digital geoscience making virtual outcrop models (VOM) and software. We opened the way for fun and fast – yet realistic enough – target-oriented seismic modeling of possibly complex/detailed geological models. In recent years this has proved to be in high demand, becoming the 'cherry on the cake' for various young geoscientists spending a huge amount of time collecting field data or making advanced geomodels; they are finally able to see how it looks on seismic (see reference list for examples). Additionally, for

Figure 1: An example of learning about the issues involved in creating models. After logging an outcrop in the field, a multidisciplinary group of students created a geological interpretation of a 3D VOM (Buckley et al., 2019) followed by PSF-based convolution modeling before adding proper elastic properties. Back-projecting the modeled seismic and other elements in the VOM is always insightful, especially on an outcrop with barely 20m height! Image courtesy of T. Thuesen, H. Stemland and M. Balyesiima; Ainsa quarry VOM courtesy of NORCE/University of Aberdeen (SAFARI).



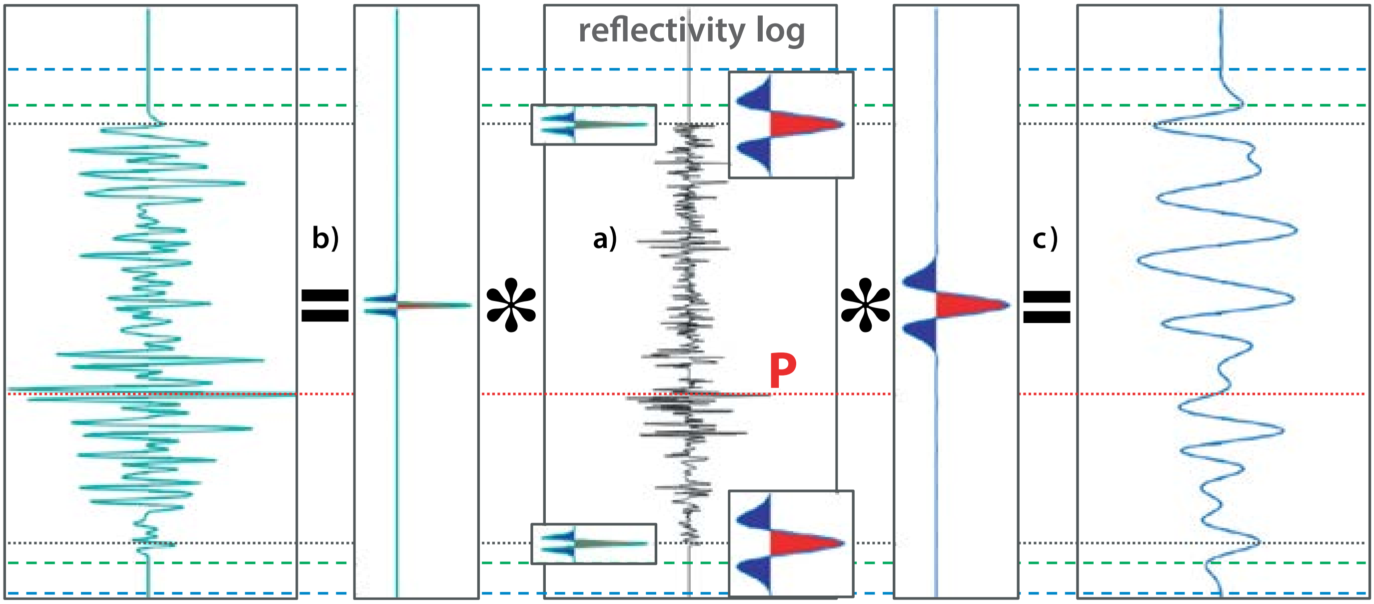


Figure 2: 1D-convolution principle. (a) (truncated) reflectivity log from Lubrano Lavadera et al. (2019). (b) and (c) synthetic seismic traces obtained by convolving (a) with two different wavelets. The dominant frequency in (b) is four times larger than in (c). P, the highest reflectivity peak in (a), corresponds to a seismic peak in (b) but is near zero in (c) due to (vertical) resolution effects.

education and industry training, we can now better teach and illustrate seismic interpretation, using hands-on cases where modeling relates both geology and seismic (Figure 1).

Do Convolution Modeling…

When teaching seismic interpretation, students always get the classic explanation of the seismic trace resulting from a convolution between a reflectivity log and a wavelet (e.g., Simm and Bacon, 2014), a necessary step towards introducing vertical resolution issues. Students can then see how a high-frequency wavelet better matches the detailed input log rather than a lower frequency one (see Figure 2). Though the wavelet automatically applies a smoothing to the dense log, we often upscale the latter due to technical constraints; for example, to reduce the number of parameters in seismic modeling/inversion due to computing costs (but keep the details if you can!). Then comes the quarter-of-a-wavelength ($\lambda/4$) rule of thumb for vertical resolution or tuning thickness. After that, we mention the Fresnel Zone for the lateral resolution issue (cf. Sheriff, 1977), but books often state that this is highly reduced by migration (cf. Lindsey, 1989), yielding a lateral resolution of $\lambda/2$ with modern 3D seismic and is therefore not a problem.

Note that, although vertical resolution issues are still discussed at length and wedge models re-created repeatedly, nobody seems to bother about a lateral resolution that is at least twice as bad as the vertical one.

Thereafter, students are made aware of detectability issues (a combination of size and reflection strength) and told that we can theoretically detect thicknesses down to $\lambda/20 – \lambda/30$. Finally, we add that not all structures will be seen by seismic due to illumination issues; the steeper reflectors, for instance, are seldom imaged even if they have proper contrasts.

But these are all rules of thumb and generalities, based on such things as specific wavelets and using simple models. Students then start to work with modern 3D seismic, with spectacular features like fluvial systems enhanced by attributes/color plays, using the industry-standard software they all want to learn to get a job, and these potential seismic pitfalls are long forgotten. The best way is to let students model for themselves, in a learning-by-doing and visual approach, with interactive tools (gaming-like!) designed for the digital generation to gain insight through modeling.

… But Not Only Repeated 1D!

As teachers, we need to catch our students' attention, and I favor 'fun' models like those illustrated here, as they stick in the mind better. All the figures have animated versions online (see www.geoexpro.com), in order to help people better appreciate not only why they should model, but also to help them stop thinking of 1D convolution and instead do a PSF-based one. These examples also encourage students to bear in mind lateral resolution and its relation to illumination, and to consider the small details whenever possible, even in 3D.

Basically, instead of convolving a reflectivity model trace-by-trace with a 1D operator (wavelet), wrongly calling that a 2-3D convolution, a PSF-based approach takes 2-3D models at once and applies 2-3D PSFs to it (e.g. Lecomte et al., 2003; 2015). The illustrations given here are target-oriented and apply a single PSF per image, designed with just a few key parameters for the sake of simplicity and efficiency, but the concept extends to spatially-varying PSFs estimated for given survey geometries and velocity models (e.g. Jensen et al., 2018). Each example is only briefly discussed and readers are encouraged to make their own analyses. Note that the PSF-based approach used here simulates pre-stack depth-migrated seismic and thus allows direct comparison to actual geology in outcrop.

My Favorite 'Owly' Model

As my university's logo is a good mix of patterns and thicknesses, it can be used as a (fake) 0˚ incidence reflectivity (R_0) input model, the original pixel size upscaled to $1x1m^2$ to reflect seismic sizes (Figure 3a). Utilizing a 20-Hz wavelet and an average velocity of 2 km/s, three seismic-like versions of the logo can be generated: 1D-convolution along vertical lines (3b) and two PSF-based convolutions with (3c) perfect illumination (λ/4 resolution in all directions) and (3d) standard limited illumination (λ/2 lateral resolution with dips steeper than ~45˚ not illuminated). The corresponding PSFs are superimposed in the lower right corner of each image and scaled.

If students first try to guess the original model from (3d), i.e., the most seismic-like version, they fail. When they see (3b) , i.e., 1D-modeled, they identify the logo but this is not a realistic image, showing also some artificial thinning of the steep parts. The illumination needs indeed to be perfect (3c) – difficult to achieve in reality! – for the logo to be identified.

The Man on the Outcrop

Figure 4 shows modeling of an upscaled fault-zone outcrop picture with a man as our fun target and with the same modeling options as above. The top background photo of a man and an extensional fault network is used as input by converting a grey version of the image into Vp values (ranging from 2–3 km/s), Vs and density being given as simple functions of Vp. The original pixel size is upscaled to $1x1m^2$ to reflect seismic sizes, the man on the original picture thus turning into a 'target feature' of about $100x200m^2$. After extracting the 0˚ incidence reflectivity R_0 (see enlarged zone around the target to the left of the man), a 20-Hz wavelet and an average velocity of 2.5 km/s are used to generate three seismic-like versions of the outcrop: (4a) 1D-convolution along vertical lines; 2D PSF-based convolution with either perfect illumination (4b) or limited (45˚ maximum reflector dip) illumination (4c), the latter yielding the background seismic in the lower half of the figure. The corresponding and scaled PSFs are superimposed at the top of the figure, while the enlarged target is plotted at the bottom. R_0 and seismic (4c) are also superimposed on the right of the man.

The Fault Zone for Interpretation

Another upscaled fault zone image (Figure

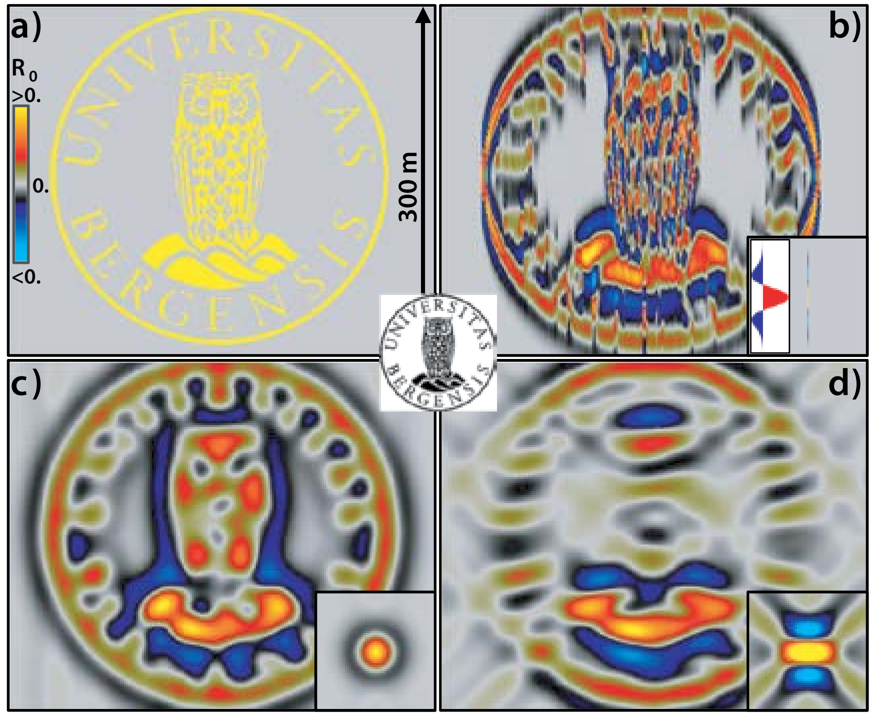
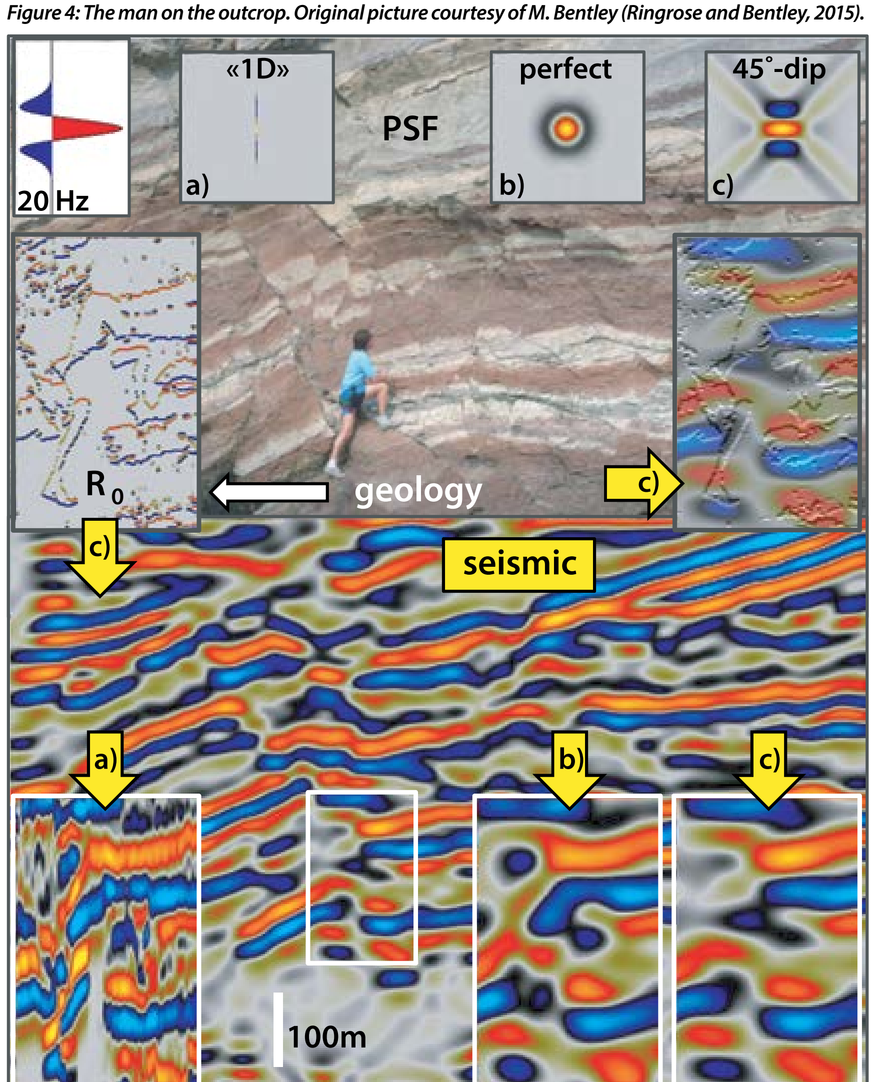


Figure 3: The 'Owly' Model.

Figure 4: The man on the outcrop. Original picture courtesy of M. Bentley (Ringrose and Bentley, 2015).



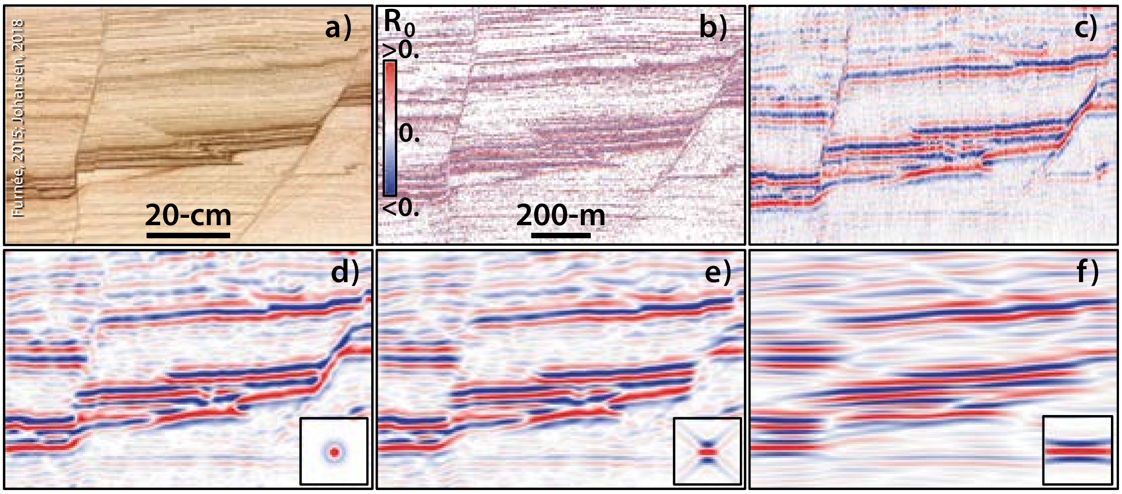


Figure 5: An upscaled fault zone image can be used for classroom interpretation.

5) is used for interpretation in class. A small-scale lacquer peel (5a) from a Tertiary sand-pit is the input model, following a similar procedure to the examples above. Figure 5b is the seismic upscaled R_0 model with a $1x1m^2$ pixel size. The remaining sections are modeled with a 20-Hz wavelet and 2 km/s average velocity: (5c) is 1D convolution; 2D PSF-based convolutions are shown in (5d) with perfect illumination, in (5e) with up to 40˚ and in (5f) up to 10˚ maximum reflector dip illuminations. The corresponding PSFs are superimposed in the lower right corner of each section. Students are given figure 5e with a fake well and a few horizon markers and usually successfully map the near-vertical (left) fault, but the right (~55˚dip) fault is less easily identified due to lack of illumination and lateral smearing, while the near-flat reverse fault in the middle is seldom caught. If the illumination is very bad (e.g. below salt or thin high-velocity layers), as in (5f), an extreme lateral smearing is induced.

Paleokarst Reservoir

The synthetic 3D paleokarst reservoir model of a cave system imbedded in a fractured network (Figure 6) illustrates the interplay of vertical and lateral resolution (Furnée, 2015; Johansen, 2018). The top row shows horizontal slices (XY: $600x650m^2$), while the bottom row shows vertical cross-sections (XZ: $600x135m^2$). The cell size is $5x5x2.5m^3$, each seismic modeling taking 15s total running time on a standard laptop, including reflectivity calculation. The reflectivity R_0 input model (6a) shows the thin, elongated cave pattern; 1D convolution (6b) shows the impact of the vertical resolution alone, inducing some lateral smearing on XY by ghosting the structures above and below, especially at the area circled, while XZ keep the lateral gaps of the reflectivity. By modeling a more realistic resolution pattern with 3D PSF-based convolution (6c) (45˚maximum reflector-dip illumination) the cave is, like seismic, blurred in all directions. All plots are pixelated (without any auto smoothing) to better emphasize the 1-pixel lateral 'resolution' of the 1D convolution.

Avoiding Pitfalls

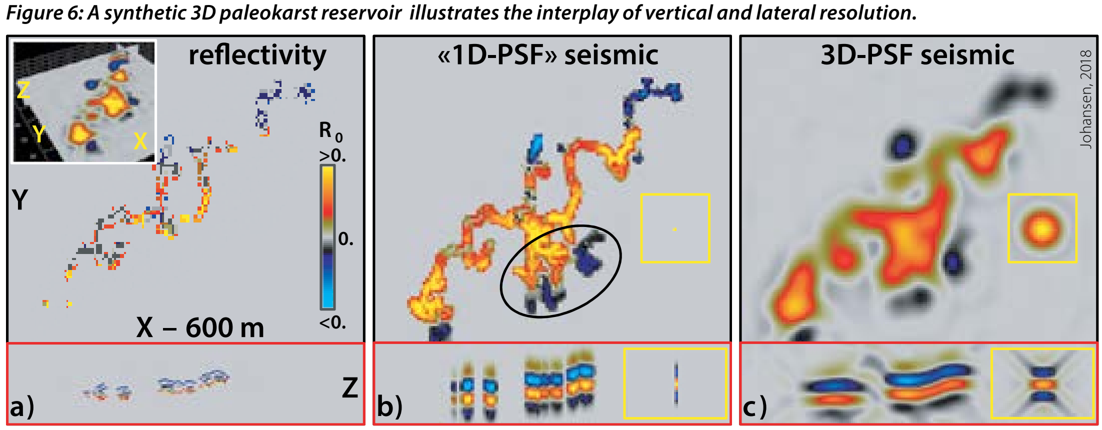
These education-related modeling examples are solely intended to catch the eye of students so that they do not forget seismic pitfalls when later playing with advanced, often black-box, software, where they can be 'blinded' by the beauty of 3D seismic. However, it would be better for them to fully interact with input (detailed) geology and properly modeled (not 1D) seismics, through efficient, integrated, flexible, and visual workflows. Ideally, all migrated seismic volumes should be handed over with their PSF characteristics to allow such modeling-while-interpreting exercises. Furthermore, PSF-based convolution is ideal for any machine-learning processes in interpretation, as such systems need training.

Acknowledgements

I would like to thank the University of Bergen (UiB) for authorizing a seismic distortion of our logo; NORSAR colleagues and NORSAR Innovation AS for the use of SeisRoX provided through an academic agreement; NORCE colleagues, especially S. Buckley, for the use of the LIME software. N. Naumann and University of Aberdeen for VOMs of the SAFARI database and J. Tveranger for the use of the Setergrotta reservoir model as part of our cooperation in the FOPAK project, funded by the Research Council of Norway, Petromaks2 program (#267634). The teachers involved thank UiB and Equinor for the Academia agreement support of the field course in 2017 and 2019.

References available online. ■

Figure 6: A synthetic 3D paleokarst reservoir illustrates the interplay of vertical and lateral resolution.



INDUSTRY LEADING NODAL TECHNOLOGY

AUTOMATED HANDLING SYSTEMS AND FLEXIBLE DEPLOYMENT SOLUTIONS

NEXT GENERATION SOURCE TECHNOLOGY

Virtual Drilling
Challenging Conventional Wisdom

KRISTOFER SKANTZE
Rex Technology Management

A novel seismic DHI technology using resonance and dispersion to indicate for liquid hydrocarbons is making inroads in the E&P industry, successfully identifying oil and predicting dry wells. Could this find the pot of black gold at the end of the rainbow?

When sound passes through a liquid, something interesting happens. The different frequencies which make up the pulse start to separate: a well-known physical phenomenon from photonics that also manifests as rainbows in the sky. When light shines on tiny rainwater droplets, these act as prisms and cause white light's frequencies to separate, forming beautiful colored rainbows. This effect is referred to as dispersion and occurs due to photons exhibiting frequency-dependent velocities through the water. While legend has it that there is a pot of gold at every rainbow's end, rainbows remain merely admired for enhancing the scenery with their spectacular colors.

This prism effect in photonics has its equivalent in acoustics. When sound pulses (analogous to white light) penetrate a liquid-filled reservoir (equivalent to the water droplets) at different velocities, the shape of the sound pulses is altered (as with the different colors of the rainbow). However, this effect, compared to reflection-based attributes, is very minute and therefore not easy to identify, but while these acoustic rainbow equivalents in seismic data may be difficult to see, they offer real black gold – oil – when found.

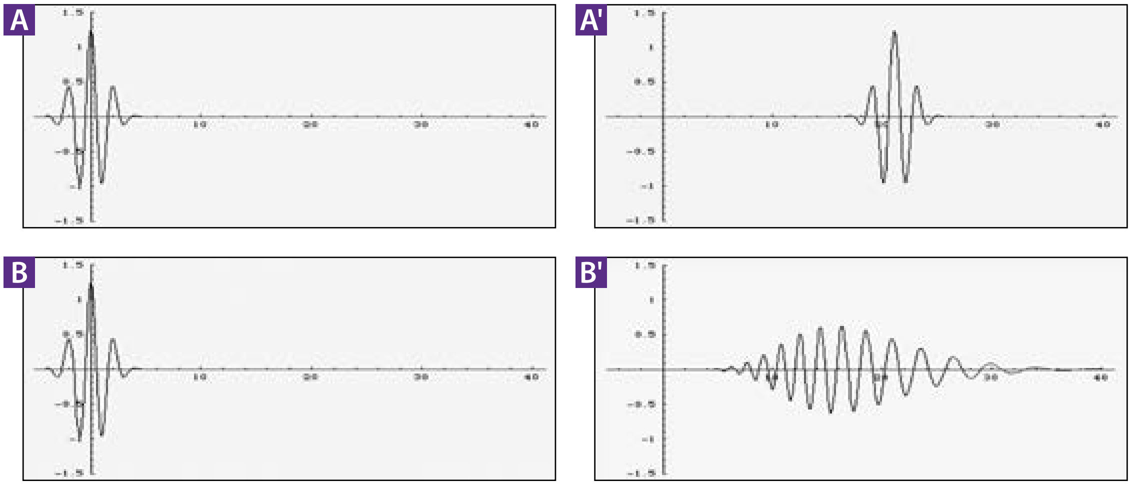
The ability to measure the dispersion effect allows for the identification of liquids in the ground. And since dispersion is a function of reservoir thickness, porosity/permeability and viscosity, identifying strong dispersion events clearly correlates to identifying liquid hydrocarbon-filled reservoirs, while conversely, the absence of dispersion signals in the seismic data suggests a low chance of finding an oil-filled reservoir.

So why are more companies not using dispersion as the powerful Direct Hydrocarbon Indicator (DHI) tool it is? As it turns out, measuring dispersion is rather complex and requires some novel and refined approaches to seismic data processing and analysis.

A Paradigm Shift

Despite modern computer power, better seismic quality, enhanced data processing and improved seismic analytical methodologies, global exploration drilling success rates remain surprisingly low, while discovery sizes are simultaneously shrinking. The seismic industry has worked hard over recent decades to refine seismic reflection and refraction attribute interpretation, achieving higher resolution imaging for improved identification of sediments, facies changes and structures. The arrival of machine learning and artificial intelligence offers exciting and promising new approaches to high multi-dimensional analyses. The use of DHIs is growing; yet their success is still only moderate, with some notable exceptions such as the successful use of amplitude versus offset (AVO) in the Gulf of Mexico. There is no doubt that there is a significant need for an improved and broadened usage of DHIs.

A detailed understanding about dispersion requires the ability to study minute shifts in frequencies. Luckily, access to both



A+A´ illustrates a wavelet propagating through an elastic medium (tight rock); the wavelet remains unaltered. B+B' shows a wavelet passing through a dispersive medium (fluid-filled rock); the wave velocity is now frequency-dependent, leading to a stretched out wavelet. The dispersive effect is more pronounced in a higher viscosity medium such as oil-filled rock over water-filled rock.

computer power and new mathematical models for spectral decomposition are now available. What is possible today in the world of spectral decomposition for oil exploration purposes was not practically feasible even 15 years ago – we are at the inflection point of a paradigm shift. Utilizing a hybrid of spectral decomposition methods, combined with high-performing multi-core computers, permits minute dispersion signals to be identified and analyzed.

Frequency-based seismic attribute analysis is already an integral part in many companies' exploration de-risking toolbox. However, shortcomings in seismic data processing, unsuitable selection of spectral decomposition methods, lack of understanding of spectral decomposition method limitations and the very high computational requirements, have held back the extent of the implementation of spectral decomposition in oil exploration. Red-Green-Blue (RGB) frequency blending is a tool popular for channel sands identification, yet it says little about the actual presence of liquid hydrocarbons.

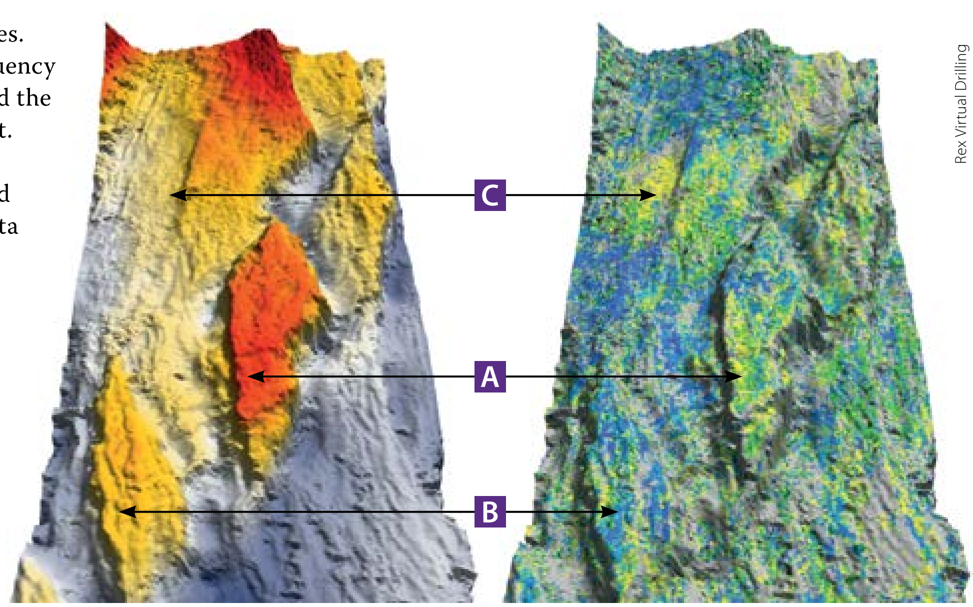
Dispersion as a DHI

A successful approach to identifying liquid hydrocarbons via dispersion requires the use of a hybrid of frequency decomposition technologies. This approach grants high time/frequency resolution, within the constraints and the quality of the original seismic dataset. Once the computationally intense time-frequency decomposition hybrid method has been selected and the data processed, dispersion analysis can be performed.

Frequency dependency with liquid content in a reservoir was demonstrated in the lab as early as 2002 in a SEG paper by Goloshubin, Korneev and Vingalov. Velocity-dependent dispersion needs to be distinguished from frequency-dependent amplitude attenuation, although the two phenomena may at times correlate. For example, a study by Carcione and Picotti (2006) showed that gas saturation and porosity are the main factors influencing frequency-dependent attenuation. There are numerous studies in which frequency-dependent AVO shows its usefulness for seismic interpretation (Wilson et. al., 2009; Wilson, 2010). Several papers suggest the authors have studied dispersions events, when in fact they make no reference to dispersion but instead to frequency-dependent amplitude attenuation events. This distinction is important, since thin beds of gas can cause frequency-dependent attenuation and therefore identifying oil based on such anomalies may be challenging, whereas dispersion signals are less influenced by gas presence.

A more precise analytical tool for liquid hydrocarbon detection is therefore velocity dispersion analysis, since it is less influenced by the presence of thin layers of dry gas. A high-dispersion response has empirically been seen to

An example of additional information obtained by Rex Virtual Drilling (RVD) from Block 50, Oman. A structure map with clearly visible anticlines (left) is draped with RVD results (right). Yellow/green RVD indications represent high/medium dispersion and blue represents lack of dispersion signals. Point A illustrates structural high with presence of dispersion congruent with structure. Point B illustrates structural high without evidence for dispersion. Point C illustrates stratigraphic trap with pinch-outs to the north (up), fault boundary to the east and clear presence of dispersion indications.

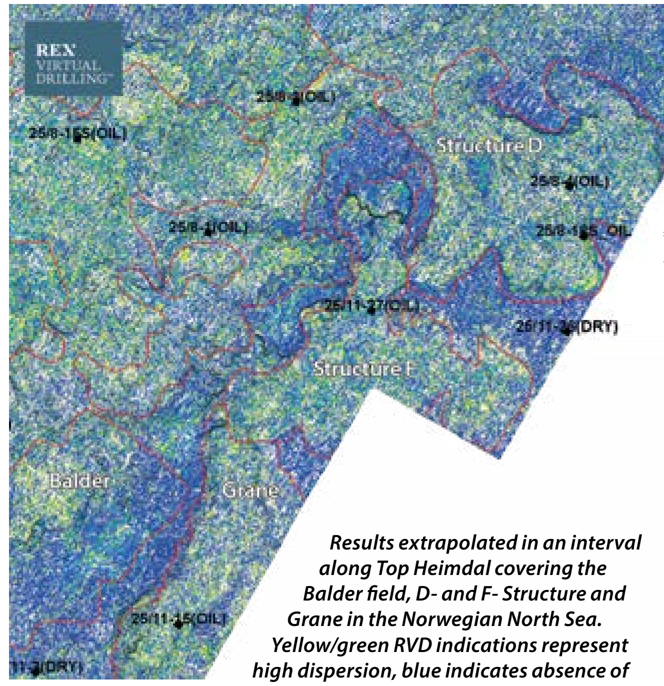


Rex Virtual Drilling

strongly correlate with the presence of liquid hydrocarbons.

By studying velocity-based dispersion, information beyond frequency-related attenuation can be analyzed, thereby increasing the overall geophysical understanding derived from the seismic data. One approach to measuring attenuation and possible dispersion correlation was to analyze reflection-coefficients. A more advanced approach encompasses very detailed frequency analyses in combination with the study of resonance waves. With seismic dispersion signals being inherently weak, high requirements are put on the seismic data quality and in particular, its processing. Any post-stack frequency alteration such as spectral bluing or whitening runs the risk of altering the sought-after frequency information. Too aggressively boosting low frequencies in broadband data may introduce frequency artefacts across the entire seismic spectrum.

In 2009, Rex Technology Management started studying resonance effects in seismic data using the RVD technology. Resonance occurs in any elastic acoustic environment and is known and basically understood, yet greatly understudied. The idea was to use resonance effects to show information about lithologies and the presence of oil, which would otherwise not be seen. The technology had been highly successful, predicting several dry wells in assets that were offered on the farm-in market. In 2015 the technology was fundamentally revamped to combine resonance with advanced dispersion studies to improve the prediction of liquid hydrocarbon reservoirs. RVD today is significantly more accurate and has a stronger ability to identify not only dry wells, but also liquid hydrocarbon reservoirs.



Results extrapolated in an interval along Top Heimdal covering the Balder field, D- and F- Structure and Grane in the Norwegian North Sea. Yellow/green RVD indications represent high dispersion, blue indicates absence of dispersion. Red outlines are field polygons as provided by Norwegian Petroleum Directorate. Note the consistency between RVD indications and polygons, with notable exception in the eastern, undrilled, part of the Balder field which indicates mostly lack of dispersion.

Successful Applications

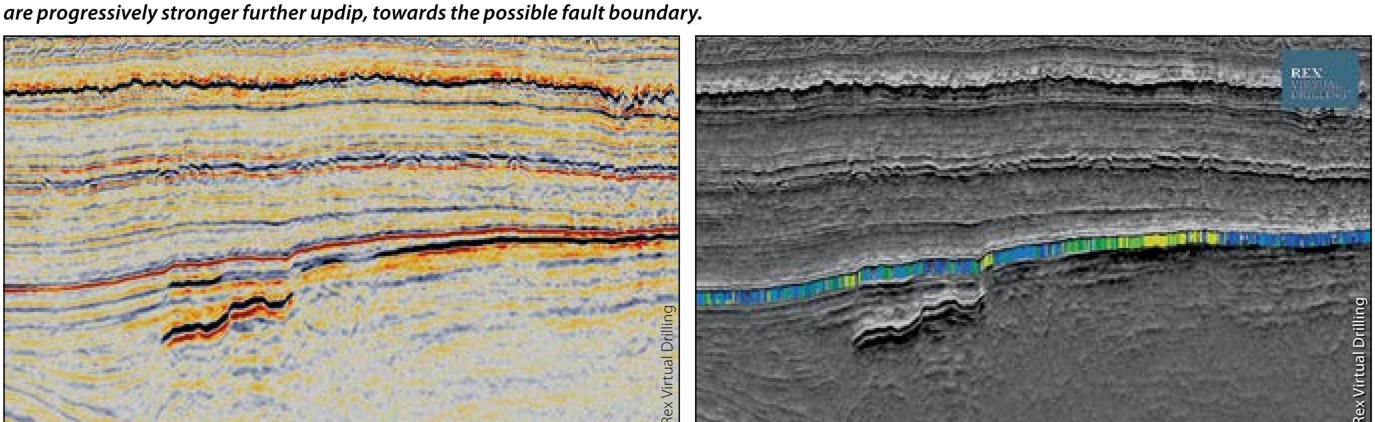
RVD has already been successfully used by a number of companies to find oil and to avoid drilling dry wells. In 2014, the technology contributed to the first ever offshore oil discovery in south-eastern Oman, the GA South in Block 50 by Masirah Oil Ltd, as illustrated in the figure on the previous page. This discovery opened up a new play and also led to the identification of a new source rock in Oman.

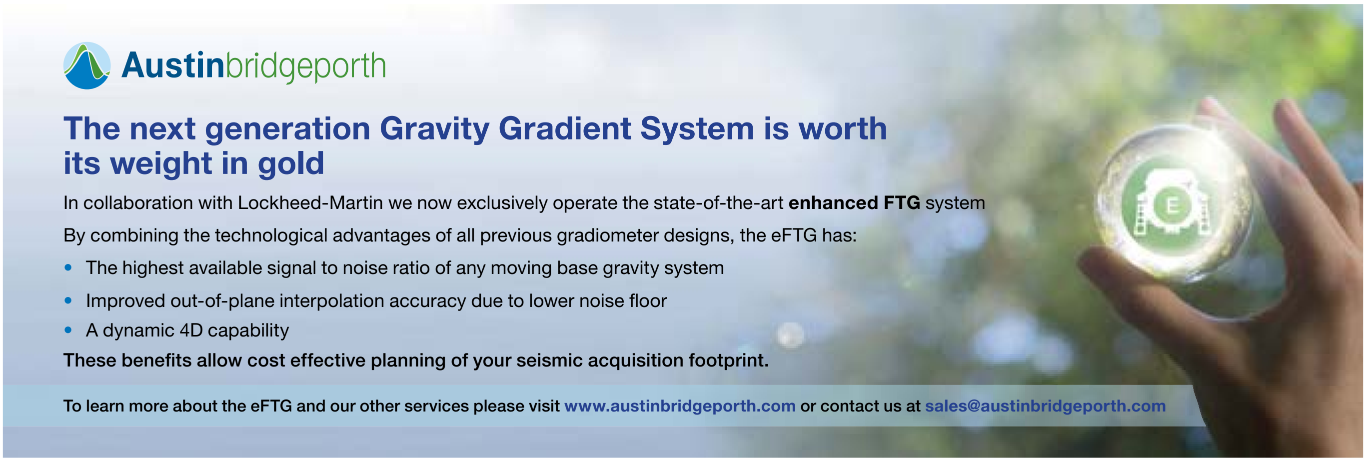
The technology has also been successfully used in the Norwegian North Sea, contributing to the Rolvsnes basement reservoir discovery, in which Lime Petroleum AS participated. The technology adds entirely new information, which contributes to a richer geological understanding: for example, the figure above shows strong dispersive events in the well-known Balder field in the Norwegian North Sea with its complicated injectite reservoirs. The figure below shows a narrow seismic section where identifying the magnitude of the dispersion event adds new and relevant information to be put into a geological context.

This new and bold technology has been extensively tested on a number of wells around the world, successfully finding oil and predicting dry wells. RVD shows that more information can be extracted from conventional seismic data than previously known and that conventional wisdom can be challenged, with remarkable results.

References available online. ■

Seismic section from Norway (left). Same section right with colored RVD indications in interval of main interest overlain on reflection seismic relief background in grey; yellow RVD indications represent strong dispersion, green moderate dispersion and blue weak dispersion. Dispersion indications are progressively stronger further updip, towards the possible fault boundary.




Austinbridgeporth
The next generation Gravity Gradient System is worth its weight in gold
In collaboration with Lockheed-Martin we now exclusively operate the state-of-the-art enhanced FTG system
By combining the technological advantages of all previous gradiometer designs, the eFTG has:
• The highest available signal to noise ratio of any moving base gravity system
• Improved out-of-plane interpolation accuracy due to lower noise floor
• A dynamic 4D capability
These benefits allow cost effective planning of your seismic acquisition footprint.
To learn more about the eFTG and our other services please visit www.austinbridgeporth.com or contact us at sales@austinbridgeporth.com


1–2 OCTOBER 2019 | OLYMPIA LONDON
60%
of attendees were Presidents / VP / Directors / Exploration Managers / Senior Explorationists / Chief / Senior Geophysicists and Geoscientists
Over 250
companies represented at Africa 2017
29%
of the audience was international with representation from: Comoros, Mozambique, Sierra Leone, South Africa, Namibia, Guinea, Congo, Madagascar, Gabon, Nigeria, São Tomé & Príncipe
VIEW THE FULL TIMETABLE & REGISTER NOW AT
https://africa.pesgb.org.uk/
PESGB/HGS Member | £500
Non-member | £576
#AfricaEP2019
@PESGB
AFRICA
E&P CONFERENCE
AFRICA IS BACK
SMARTER
STRONGER
BETTER


JARÐFEINGI
FAROESE GEOLOGICAL SURVEY
5th FAROESE
LICENSING ROUND
The Round closes at noon on November 12, 2019
Faroe Islands – your next discovery?
• The 5th Round is coordinated with the UK 32nd Licensing Round
• Terms, conditions and fees for licences and acreage are similar to the UK´s
More information on www.jf.fo

Transformative Technologies

Bjarte Bruheim has spent the majority of his career introducing technologies that reduce risk and improve efficiencies in the oil and gas business, having been involved at the start of companies such as PGS, EMGS and Axxis GeoSolutions (AGS). He tells us what drives him to keep pushing the technological limits.

As a serial entrepreneur, what drives you to become involved with a new company?
The main driver for me is to be involved in developing leading edge technology. As a manager, I like to see technology and operational experts/employees joined successfully as a team and working together over years and years. In oilfield service the key for me has been to reduce risk and costs by using advanced operations and new technologies.

As a physicist, do you think scientific understanding is important for an industry leader?
An oilfield service company has different phases and, as we have seen, technology will be replaced by newer technology over time. I think for a start-up company within the seismic industry it would be an advantage to have the experience and technical knowhow to evaluate technology's impact on clients' business and be able to pick a team who will be able and experienced enough to develop the technology. Our clients are highly educated and experienced experts and your team must be able to mirror this expertise and see the technology trends.

What are the up and coming technologies in offshore exploration?
In general, a lot of new technologies are developed during a downturn in the industry. The trend within exploration is digitalization of all types of data. New computer power means that the main trend in exploration is to combine and process the data more efficiently and drive more value out of existing data.

You can't go wrong with higher resolution in seismic data and the increasing demand for AGS products in low cost production areas is an example of this trend.

What gap in the market did you see that led you to co-found AGS?
During the few last years I have followed the major technological developments such as channel count and the size of land seismic node surveys. The trend onshore has been towards higher channel counts and larger area surveys. Clients have been asking for these kinds of survey offshore for some time, but the OBN industry has been limited by cost per square kilometer and channel count offshore.

The AGS team had been following this trend and came up with new survey designs, higher channel count and teams with the long-term experience to execute this type of survey. The AGS team, combined with the multi-client sharing model on costs, opened up the market in the North Sea and elsewhere. This was the business idea behind AGS. We are staying on course and together with our clients and partners our aim is to work ourselves into the number one position, leading the development of high resolution/low cost products in this market.

How do you see the energy transition affecting service companies like AGS?
The financial markets show a lack of enthusiasm to invest into our industry. Some of the larger E&P companies use a lot of their cash and resources to be involved in the energy transition. Typically, the drive for new seismic technology has been driven by supermajors, but we see that two-thirds of the cash in the OBN industry so far has come from national oil companies. This is a trend that has given us larger value surveys and one of the largest seismic surveys ever ($1.6 bn), was awarded in 2018 by a national oil company.

The push for cheap gas close to consumers is another trend we are seeing, driving some of the available dollars onshore to the shale industry, particularly in the US and Argentina.

What has been the most transformative technological innovation you have seen in the industry?
The most transformative technology I have seen in oilfield services was the transition from 2D to high resolution 3D seismic. The key technology enabling this transition was Global Positioning Systems (GPS), combined with marine acoustic positioning systems. This high resolution 3D product, powered by supercomputers and high tech work stations, enabled directional drilling and an increase in recovery rates from both new and existing oil fields around the world. Ekofisk, Valhall and Statfjord are good examples of this. ■

Bjarte started his career with Schlumberger after graduating with a master's degree in physics from the Norwegian University of Science and Technology in Trondheim, Norway.


Eirin Bruheim

1st Licensing Round of the Dominican Republic

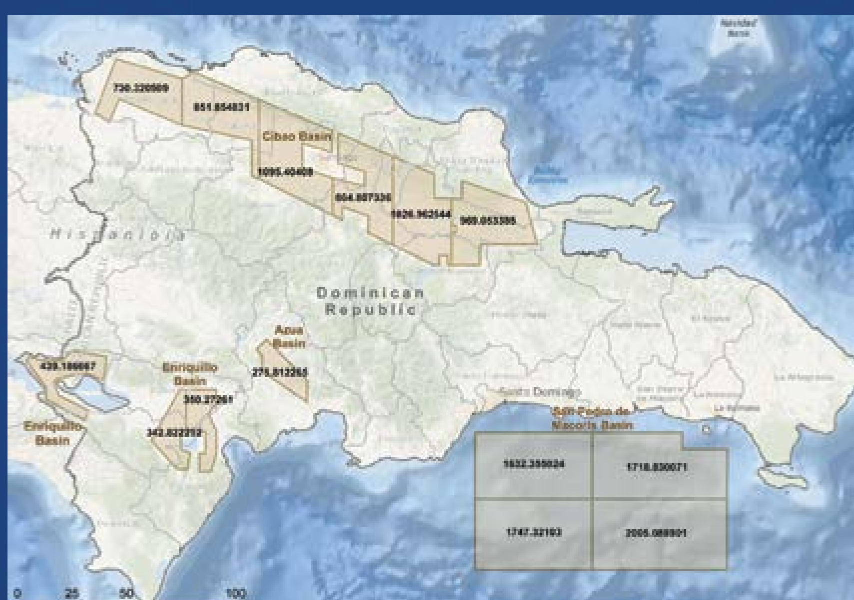
Announced by the Ministry of Energy and Mines

The Dominican Republic forms part of the Island of Hispaniola, and lies within the North Caribbean strike-slip plate boundary zone. During World War II, oil production was achieved in the Maleno and Higuerito fields. Seismic data for the Enriquillo, San Juan and Cibao Basins is held by the Ministry, and recent surface and seismic stratigraphic mapping has clarified the geological story of the area.

The Ministry is offering fourteen (14) blocks, a combination of on- and offshore.
The existing seismic data identifies significant potential prospectivity.

Blocks on offer:

- Cibao Basin – 6 onshore blocks
- Enriquillo Basin – 3 onshore blocks
- Azua Basin – 1 onshore block
- San Pedro Basin – 4 offshore blocks



All information is public and available at www.roundsdr.gob.do

DOMINICAN REPUBLIC LICENSING ROUND

For more information, please contact info@roundsdr.gob.do

The Value of Satellite Data

In an age of so-called untruth, what can satellite imagery do to offset the deficit? Can it add to the evidence that turns speculation into hard fact; that overturns distortion and worse?

Take what has been happening in the Strait of Hormuz as an example. Behind the cat and mouse politics are a series of satellite pictures which show rising inventories of stored crude on Kharg Island, Iran's main export terminal. A message to make Donald Trump smile, despite the tension: sanctions are biting and customers like Syria are finding it harder to get their crude.

Satellite imagery is an accurate overview, an addition to the information flow which different parts of the industry are finding it increasingly difficult to ignore. "The oil and gas sector has long struggled with patchy, time-lagged, and sometimes incorrect information," notes Berend Heringa, an industry analyst with McKinsey & Company. What's more, he adds, in an online post on the topic, this information is gleaned from a variety of sources, some less reliable than others.

So are satellites creating a more level playing field in the industry? In some ways this seems to be the case, as investors and buyers get a more immediate sense of how inventories and capacities are helping to drive the market. If you want to know the extent to which the latest Chinese mega refinery is adding to the country's demand for crude then it may be a satellite which can give you the most accurate, most immediate picture.

In a recent online blog the satellite company URSA noted that Kharg Island crude storage had reached 81% capacity, the conclusion being that Iranian crude exports have been falling faster than production rates. Small wonder then that Syria and China have become such important customers for Iranian crude. The evidence in viewing images of those near-to-full storage tanks is that Iran must cut production or find new customers, not so easy in the face of US sanctions.

In making use of SAR (Satellite Aperture Radar) data from a number of satellite providers, URSA is seeking to demonstrate the market intelligence value of its services. Other companies are doing the same and given that the industry is steering a course through volatile times they may have a point. The value of satellite-based services, notes Berend Heringa, can extend from oil traders working for some of the largest majors to NOC executives trying to improve security.

Whether this can help counter the age of untruth is open to debate. ■

Nick Cottam

NASA-JPL/Caltech

Conversion Factors

Crude oil

1 m³ = 6.29 barrels

1 barrel = 0.159 m³

1 tonne = 7.49 barrels

Natural gas

1 m³ = 35.3 ft³

1 ft³ = 0.028 m³

Energy

1000 m³ gas = 1 m³ o.e

1 tonne NGL = 1.9 m³ o.e.

Numbers

Million = 1 x 10^6

Billion = 1 x 10^9

Trillion = 1 x 10^{12}

Supergiant field

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

Giant field

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

Major field

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

Historic oil price