

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



MATURE FIELDS:
Teamwork at Rangely

geoexpro.com

EXPLORATION
**Iraqi Kurdistan:
All in the Timing**

RESERVOIR MANAGEMENT
Avoiding Reservoir Souring

GEO TOURISM
The Ross Sea, Antarctica



Visit TGS at
PROSPEX
Booth 39

See energy defined. **UK Continental Shelf**

With 58,300 km² of 3D data, you can build quite the empire.

Our 3D UKCS database covers 58,300 square kilometers from the Faroe Islands to the Atlantic Margin to the Southern North Sea. You can gain insights to emerging frontier areas like never before. Plus TGS data is integrated with the richest well-data sets and advanced interpretation technologies. When building your license round strategies and exploration plans, you need the right data, in the right place, at the right time. Get it all with TGS. Contact us today.

See the energy at TGS.com



GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

CONTENTS Vol. 12 No. 6

This edition of *GEO ExPro* focuses on North-West Europe, the Middle East and Mature Fields

COLUMNS

- 5 Editorial
- 6 Market Update
- 8 Regional Update
- 10 Update
- 14 A Minute to Read
- 18 Licensing Opportunities
- 30 Recent Advances in Technology: Supercomputing for Beginners II
- 38 GEO Profile: Mahmoud Abdulbaqi – Dedicated to the Industry
- 48 History of Oil: The Petroleum Gulf
- 78 GEO Tourism: The Ross Sea, Antarctica
- 82 GEO Education: Back to Source Rocks
- 86 Exploration Update
- 88 GEO Media: An Education in Oil
- 90 Hot Spot: Texas
- 92 Global Resource Management

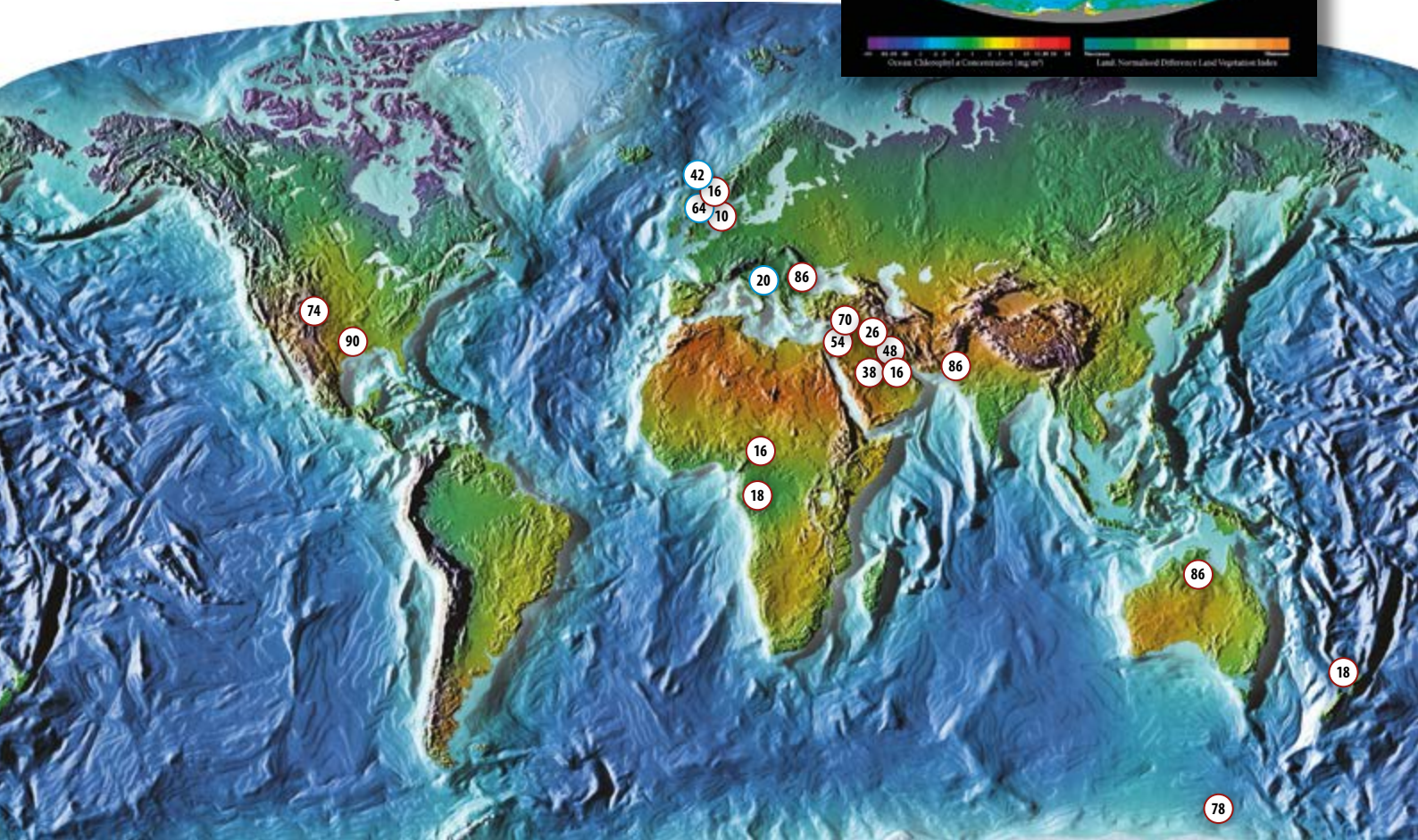
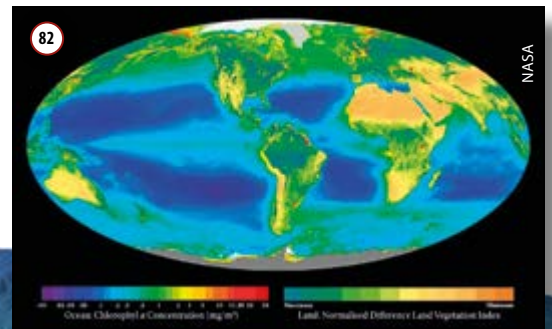
FEATURES

- 20 Seismic Foldout: Croatia's 2016 Licence Round
- 26 Cover Story: Iraqi Kurdistan – It's All in the Timing
- 34 Geology: Black and Blue
- 42 Seismic Foldout: The East Shetland Platform
- 54 Exploration: The Triassic Margin Play
- 60 Reservoir Management: Avoiding Reservoir Souring
- 64 Seismic Foldout: UK Continental Shelf
- 70 Exploration: Lebanon – The New Levantine Exploration Opportunity
- 74 Mature Fields: Teamwork at Rangely

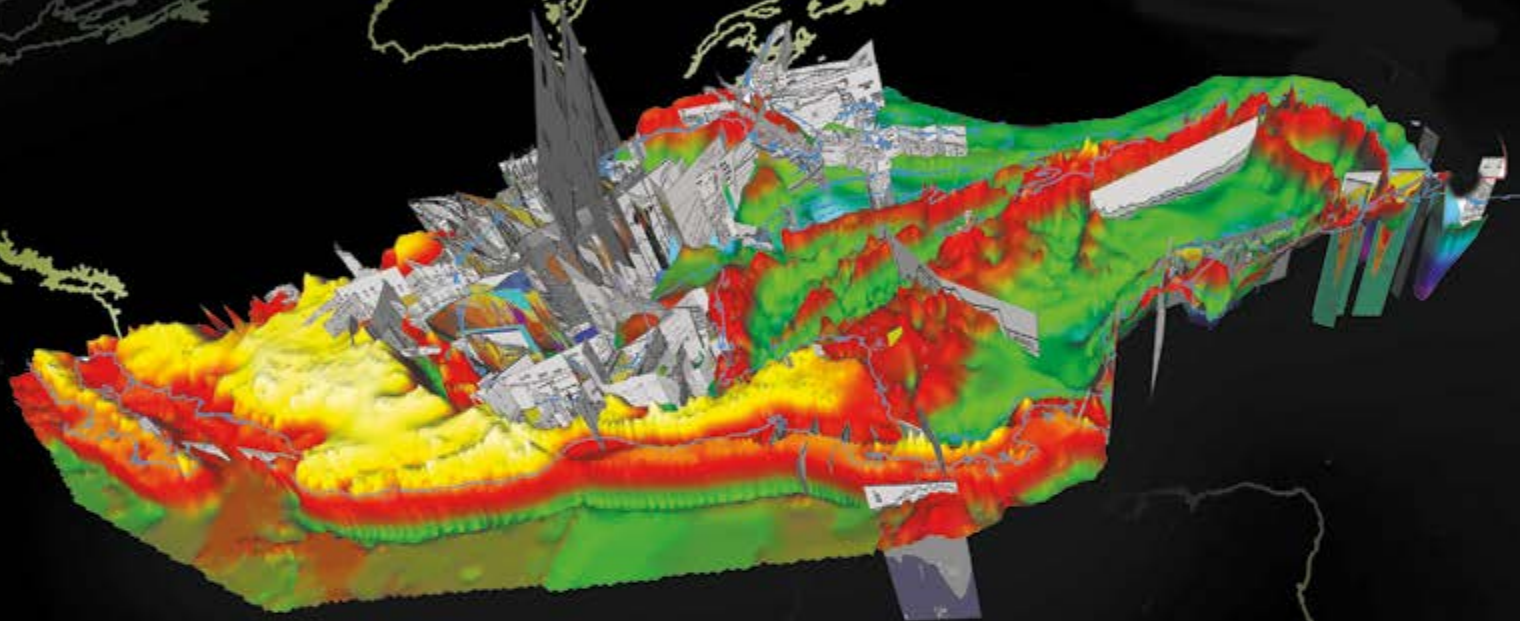


The Levant Triassic margin is a significant but underexplored frontier play.

The distribution of phytoplankton in the oceans is a key component of the carbon cycle and thus instrumental in source rock distribution.



Joining up the exploration process



*Replica of original published data

Unlocking a region's full hydrocarbon potential requires a comprehensive understanding of subsurface structure. The Neftex Regional Frameworks Module delivers unique, isochronous depth grids for key stratigraphic surfaces, bringing vital insight into mega-regional depth structure trends.

As the first Neftex offering deliverable in Landmark's DecisionSpace® Geosciences software, the module provides a robust framework into which proprietary data can be dynamically added. This forms a powerful basis for essential play analysis on a regional scale.

Support faster, more integrated exploration

Contact us today:

Website: www.neftex.com

Halliburton | Landmark: www.landmarksoftware.com

Email: enquiries@neftex.com

Tel: +44 (0)1235 442699

LinkedIn: [linkedin.com/company/Neftex](https://www.linkedin.com/company/Neftex)

Neftex • 97 Jubilee Avenue • OX14 4RW • UK

HALLIBURTON

Landmark



The Lifeblood of the Industry

There is a lot of depressing news out there. Shell, Marathon, Anadarko, Husky Energy, Chesapeake... just a few of the O&G companies which posted poor third quarter results. Virtually every day an exploration or service company announces layoffs, and freezes on recruitment and salaries are commonplace. Meanwhile, the number of new drilling permits issued by the Texas oil and gas regulator plummeted by more than half in a year. If the oil price continues to be depressed for some time, there seems to be little left to cut without impairing long term stability and safety.

But there are always two sides to every story. As Thomas Smith explains on page 90, the drop in drilling permits in Texas has actually been accompanied by an increase in production, as companies learn to drill more efficiently. Norway's recent offshore round received applications from 43 companies, about the same as the previous, pre-slump offering, while two significant discoveries have reportedly been made in the now very mature waters of the UK North Sea. In the eastern Mediterranean there is a lot of excitement over ENI's discovery of an estimated 30 Tcf of gas in a previously overlooked play offshore Egypt. There still appears to be an appetite for exploration.

According to analysts Richmond Energy Partners, exploration activity this year is down by more than 40% and commercial success rates have fallen to 24%, with only one in five technical exploration successes being deemed a commercial success in some areas. As we all know, the present slump in the industry is partially due to a glut of hydrocarbons in the system – so in the present climate do we stop exploring? Or do we keep looking and try to get better and more efficient at finding oil and gas? It would appear that the slowdown in activity means that now is a good time to pick up acreage, as companies divest and fewer of them are chasing the opportunities.

Don't give up on exploration. It is the lifeblood of the industry. ■

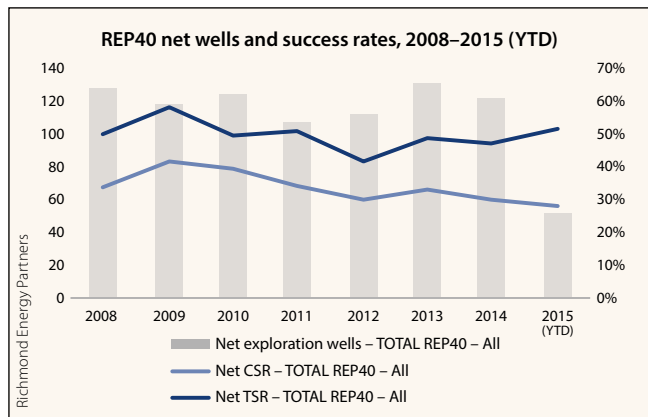


Jane Whaley
Editor in Chief

IRAQI KURDISTAN: IT'S ALL IN THE TIMING

Faulted and folded Upper Cretaceous layered carbonates near Sulaymaniyah in Iraqi Kurdistan. The region is thought to hold about 45 Bbo, and understanding its complex structural history is key to unlocking its potential.

Inset: Colorado's Rangely field has been producing for over 70 years – and still going strong.



Net wells and commercial versus technical success rates, 2008-2015 (YTD), based on Richmond Energy Partners' benchmark group of 40 active mid and large cap explorers.

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

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: Jon Gutmanis
Inset: Thomas Smith

Layout: Bookcraft Ltd.
Print: NXT Oslo Reklamebyrå

issn 1744-8743

© 2015 GeoPublishing Limited. Copyright or similar rights in all material in this publication, including graphics and other media, is owned by GeoPublishing Limited, unless otherwise stated. You are allowed to print extracts for your personal use only. No part of this publication may be reproduced, stored in a retrieval system, or transmitted in any form or by any means electronic, mechanical, photographic, recorded or otherwise without the prior written permission of GeoPublishing Limited. Requests to republish material from this publication for distribution should be sent to the Editor in Chief. GeoPublishing Limited does not guarantee the accuracy of the information contained in this publication nor does it accept responsibility for errors or omissions or their consequences. Opinions expressed by contributors to this publication are not necessarily those of GeoPublishing Limited.

The Train Has Left the Station

How long will Saudi Arabia continue flooding the market with cheap oil? And can it reclaim its strong position as a swing producer?

Saudi Arabia is expected to maintain its low-price strategy until it has achieved its goal of regaining market share. This could take a long time. But I think it is too late to fend off the competition from shale oil and new fuel sources over the long term; the train has left the station.

OPEC'S Plan?

OPEC's mission is to coordinate and unify the petroleum policies of its member countries and ensure the stabilisation of oil markets in order to secure an efficient, economic and regular supply of petroleum to consumers, a steady income to producers and a fair return on capital for those investing in the petroleum industry. So it was a major surprise in November last year when it decided to shift its strategy from being a dominant cartel to focusing on market shares. This shift contributed to changing the pricing dynamics in the market as a whole, triggering a 40% fall in oil prices. It is difficult to see that this drop was in line with OPEC's goal of a fair and stable price for producers or investors in the oil market. The shift also fuelled uncertainties over Saudi Arabia's future role as a swing producer.

OPEC can boost its revenues by cutting production; this will imply a marked rise in oil prices as supply/demand elasticity is low over the short/medium term. Over time, however, high prices will encourage non-OPEC producers to ramp up production again, dampen demand growth and weaken the competitive position of oil compared with other energy sources. Even so, Saudi Arabia does not appear to be quite ready to abandon its market share strategy yet.

After a year of punitively low oil prices, OPEC members can soon reap some of the rewards. US shale oil production is showing signs of a slowdown. But I do not believe that OPEC is done. Most likely the cartel is looking for a more lasting effect. As a result of the short investment-production cycle, shale production will quickly return to the market as soon as prices tick higher again. OPEC must consequently maintain its market share strategy until high-cost producers like Russia, Norway, Canadian oil sand and deepwater/ultra-deepwater wells with long investment-production cycles are squeezed out of the market. That will take time. Then prices will have to stay low for an extended period.

Irreversible Trend

The historic agreement between Iran and the West this summer could also make it more difficult for Saudi Arabia to resume its role as a swing producer near term. The agreement is set to help lift the sanctions imposed on Iranian oil production. This will allow the country to boost production, and investment in new capacity will help to further expand production in the years ahead. Iraq, Saudi Arabia and Iran are political rivals, making it unlikely that the first two will hold back large volumes of their oil to allow Iran to boost its production. This could trigger a price war between these rival producers and help cap oil prices over the medium term.

The transport sector accounts for approximately 55% of the world's oil consumption, and oil-based fuels have in effect been shielded from competition. OPEC's production control has contributed to a decade of rising oil prices; this has in turn triggered the development of new fuel sources and new battery technology. In future, oil-based fuels will therefore face intensifying competition – also in the transport sector.

As I see it, this trend is irreversible and will impact oil consumption growth longer term. This will gradually change our oil dependence and reduce the power of OPEC. ■

Thina Margrethe Saltvedt

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

Move2016 is coming



Be ready to upgrade
this December

Faults can make or break your prospect

New modules for understanding faults, not just
in space, but also in time:

New to 2D & 3D Kinematic Modelling:

Non-Planar Trishear

New algorithm implemented in 2D
Move-on-Fault and the Construct
Horizons from Fault

Horizon from Fault Tool

Improved interactive interpretation
including variable displacement

Thermal Subsidence Modelling

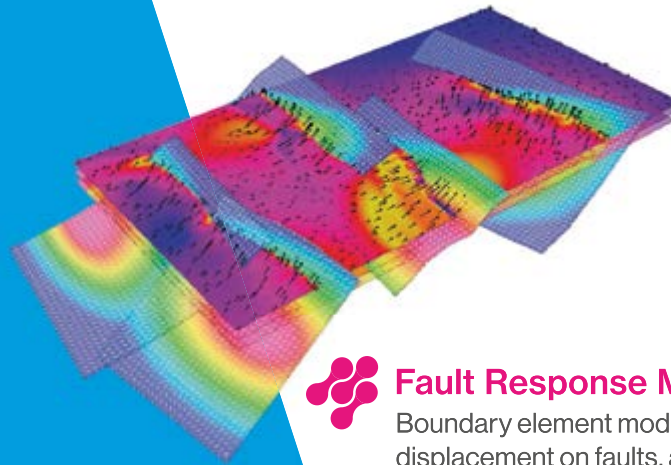
More accurate sequential restorations
of passive margins

Compaction Tool

Improved workflow for decompaction
of growth sequence strata

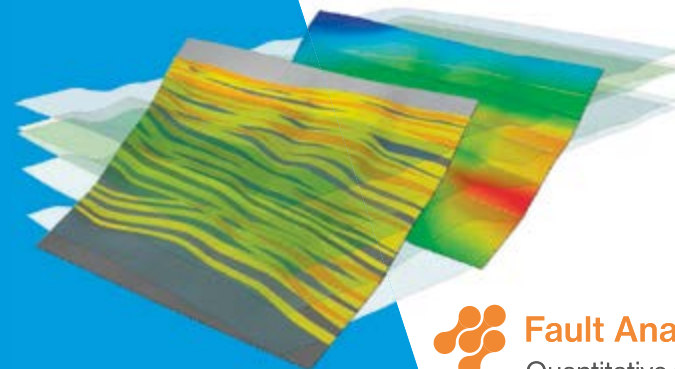
Software Compatibility

Move Link support for Petrel 2015
Support and compatibility for Windows 10



Fault Response Modelling

Boundary element modelling to simulate
displacement on faults, and geomechanical
analysis of surrounding fracture systems



Fault Analysis

Quantitative analysis of fault
throw, juxtaposition and seal
through geological time

Move2016 will be released in December 2015.
For more information please visit www.mve.com/move-latest
T: +44 (0)141 332 2681 E: info@mve.com

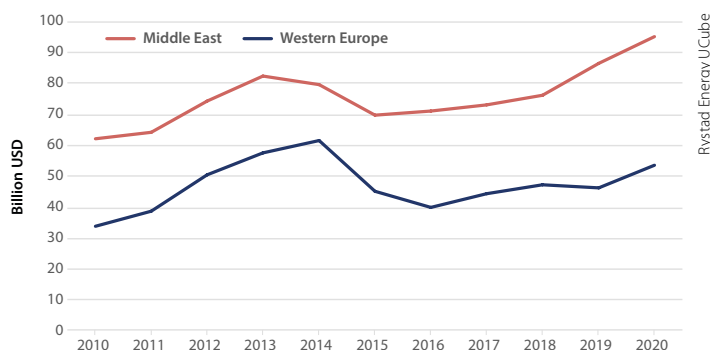
© Midland Valley 2015.



Markets Behaving Differently

The Middle East – one of the most stable E&P markets

The Middle East is the largest producing area within the E&P industry, with a total production of around 41 MMboepd in 2015, while Western Europe is the largest offshore market in terms of spending. These markets are expected to behave differently during the current downwards cycle.



Upstream investments (excluding exploration) for Middle East and Western Europe.

The Middle East is the largest producing region in terms of liquids and the third largest in terms of gas, where current production is 28.6 MMbpd and 55 Bcfpd, respectively. Liquid production is expected to grow by 0.8 MMbpd in 2015. This production growth is mainly derived from the redevelopment of old fields in Iraq and the growth of mature fields in Saudi Arabia.

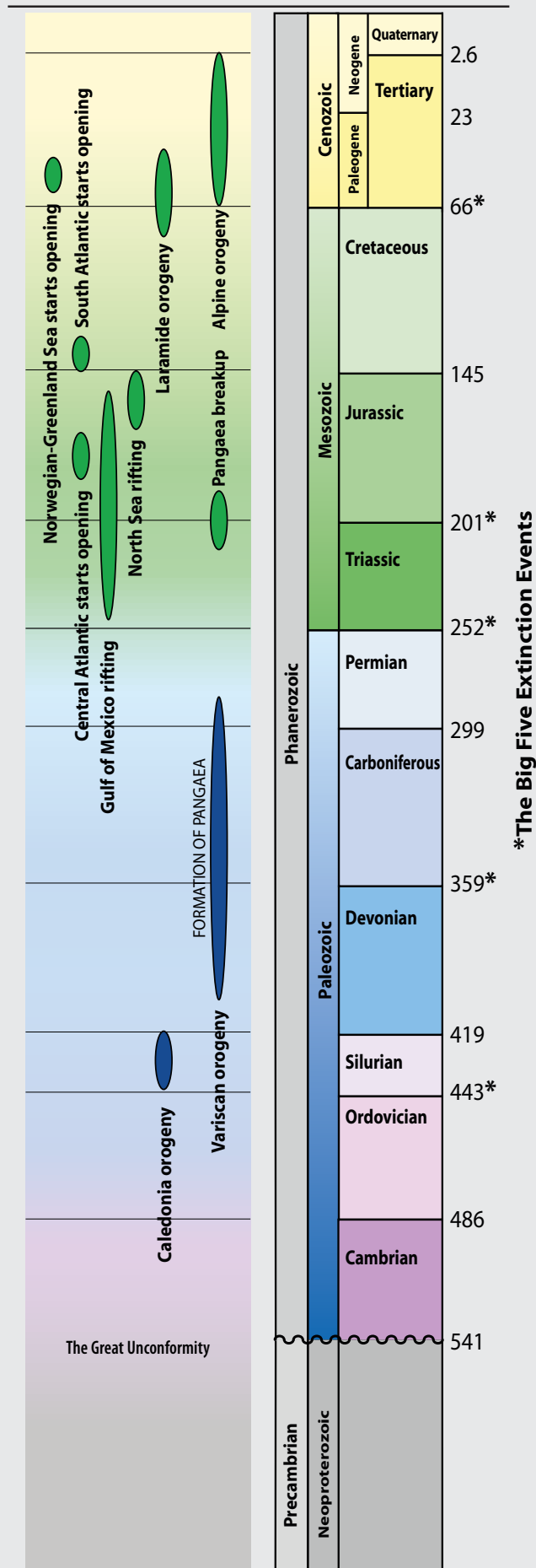
Until 2020 the Middle East is expected to continue to grow at an average pace of around 0.5 MMbpd per year, with Iran as another key driver. The lifting of sanctions against Iran will probably result in the return of international oil companies, where the focus will be on redeveloping mature, oil-producing fields. In terms of investments, the Middle East has been relatively resistant to lower oil prices. Total investments in 2015 are expected to be down by 13% compared to 2014, compared to a global average of 23%. One interesting observation is that despite the drop in oil prices Saudi Arabia's rig count is up 25% in 2015 when compared to 2014.

Different Reactions

Western Europe cannot compete with the Middle East when it comes to production. The region is expected to produce 3.6 MMbpd of liquids and 23 Bcfpd of gas in 2015. For 2015, the liquid production is estimated to increase by 150 Mbpd, but for the rest of the decade it is believed that production will be flat. On the activity side, total investments will fall by around 30%. There are several reasons for this decline, but some key explanations include completion of development projects, lower unit prices and fewer maintenance investments.

The development and reaction of the Middle East and Western Europe to low prices are quite different. Middle Eastern activity levels have been robust and production is projected to increase, whilst in Western European production is expected to remain flat going forward. One of the key reasons for the resilience of the Middle East, even in a low oil price environment, is the number of large mature fields with high potential at a relatively low cost. ■

Espen Erlingsen, Rystad Energy

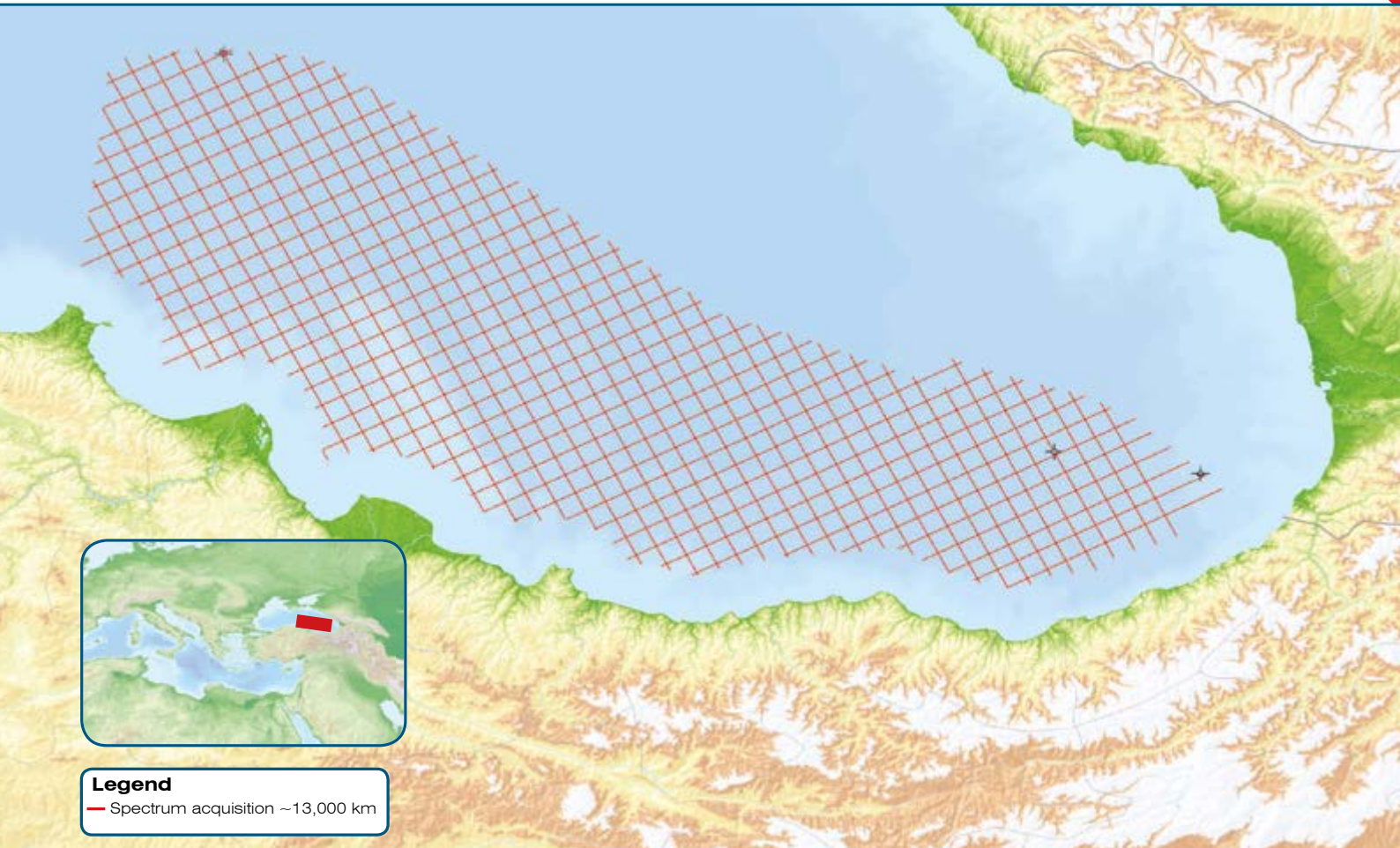


*The Big Five Extinction Events

NEW
ACQUISITION
2015

Covered: East Black Sea

2D seismic over under-explored basin with world-class source rock



Spectrum continue to enhance their reputation for producing exciting new data in underexplored basins, with their latest acquisition in the Turkish East Black Sea.

Despite the East Black Sea basin being similar in size to the Gulf of Mexico, only 3 exploration wells have been drilled here. Large areas of open acreage exist with very little modern data coverage, with a proven source rock (Maykop Fm.) and oil shows in wells which demonstrate a working petroleum system in the area.

In total 13,000 km of long offset 2D data is to be acquired, with broadband processing applied. Acquisition is expected to be completed during Q1 2016, with processed PSTM data available in Q2/Q3 2016.

+44 1483 730201
@mc-uk@spectrumgeo.com
spectrumgeo.com



Endgame for the North Sea?

There are many concerns but also possible opportunities ahead.

Chess theory allows for an *opening*, a *middlegame* and an *endgame*. The boundaries are somewhat blurred but if we take the literal interpretation of the endgame as starting when 'there are only a few pieces left on the board' then the North Sea has not entered the endgame proper just yet. Nevertheless, as the industry celebrates its 50th anniversary (see *GEO ExPro* Vol. 12, No. 5) the rate of decommissioning (removal of the 'pieces') is expected to accelerate, with Wood Mackenzie predicting that 140 of the 330 fields in the UK North Sea may close in the next five years. And this scenario is predicted to play out even if oil hits \$85 a barrel.

The Wood Review emphasised the need for industry to focus on maximising economic recovery from the UK Continental Shelf (UKCS) and called for the establishment of a decommissioning strategy to realise that goal. Consequently, a number of the larger decommissioning schemes to be delivered in the next five to seven years (e.g. Brent, Miller and Thames), will act as flagship projects that will provide insight for the industry.

To help facilitate the process Oil & Gas UK has been tasked with providing an annual review of activity and expenditure. The *Decommissioning Insight 2014* report found that in 2013, £470 million was spent on decommissioning, with a forecast of £14.6 billion expenditure from 2014 to 2023, 43% or £6.3 billion of which will be concentrated in the central North Sea. The largest expenditure is well plugging and abandonment (44% or £6.4 billion).

The offshore decommissioning process within the UKCS, Norway, The Netherlands, Denmark and Germany is governed by the Oslo Paris Convention ('OSPAR'), which states that all installations must be totally removed unless there are safety and/or technical limitations which mean that leaving the structure (or part of it) in place is permissible. Within this framework countries also apply their own internal legislation.

The UK government handles decommissioning on a case-by-case basis, negotiating with stakeholders and monitoring activities. It also has a mechanism for initiating the decommissioning process and of protecting funds set aside for the purpose. The principal legislation in the UK is the Petroleum Act (1998), Part IV of which merges provisions of the 1987 Petroleum Act and several other acts.

Removal And Disposal

Decommissioning is the process of removal and disposal of an installation at the end of its productive lifespan. Four stages of the process are recognised: 1) options are evaluated via a formal planning process; 2) the operator stops production, plugs wells and makes them safe; 3) removal from the site of all or part of the installation; and 4) the disposal of those parts which have been removed. Decommissioning is time-consuming – the Maureen platform took from 1993 to 2001 (eight years) before it was ultimately decommissioned.

Options for removal of installations include: **Total removal** of everything on or above the seabed, with the site reinstated to original conditions; **Partial removal**, e.g. the 'topside' is removed, while the substructure is left in situ; **Sinking in situ**, where the installation falls to the seabed, and; **Leave in situ**, where the installation is cleaned and made safe, to be converted for re-use by other fields or for marine research, for example.

A stumbling block has been what to do with the disposal of the removed infrastructure. Options include scuttling in deepwater; onshore recycling or disposal in licensed waste disposal sites; and 'rigs to reefs', requiring cleaning up of the installation before it is used in situ or elsewhere as an artificial reef habitat for marine life. Platforms in the Gulf of Mexico and Malaysia have been used in this way.

Into the Unknown

Although the legal and regulatory framework in the UKCS is fairly well established, it is worth highlighting that there may well be more questions than answers in the North Sea decommissioning endgame proper. There remain questions of 'residual liability' for infrastructure left wholly or partly in

place and around the provision of the 'decommissioning relief agreement' and how that could impact the public purse.

HSE concerns around ageing assets in the North Sea appear to be growing as companies are falling behind on maintenance to essential equipment. According to the *Financial Times*: 'In the second half of 2014 platforms were on average 8,000 man-hours behind schedule on their maintenance programmes to "safety-critical equipment", compared to an average of 2,000 man-hours at the beginning of 2009... essential repairs are not being done, potentially endangering safety'.

Decommissioning will signal the end for some and herald the beginning of an opportunity to others. With an increasing number of lucrative projects available, some of the more 'traditional' exploration and production companies are turning their hand to decommissioning activities; after all, they have regional experience and knowhow. The real endgame may be some way off but opportunities to promote pawns into queens should not be overlooked.

References available online. ■



Rig to reef decommissioning.

Will Thornton

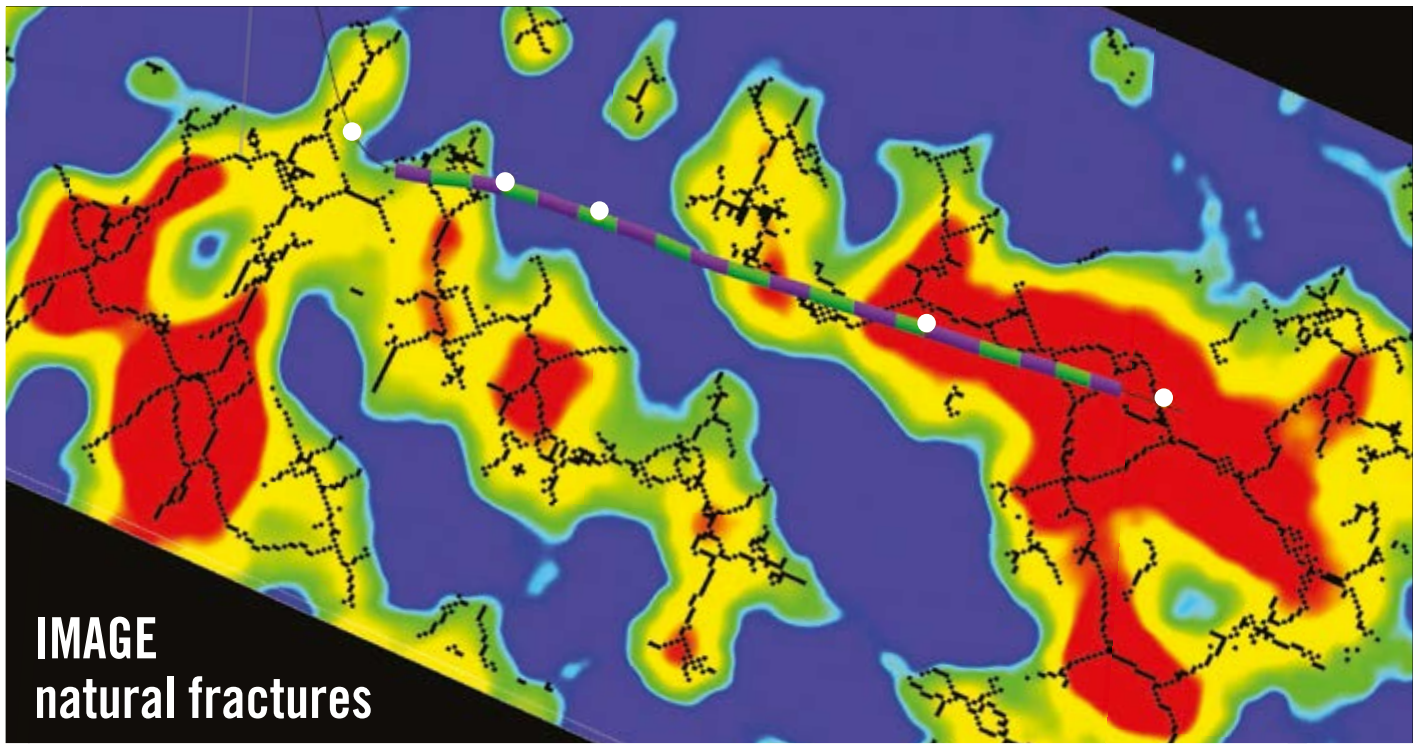
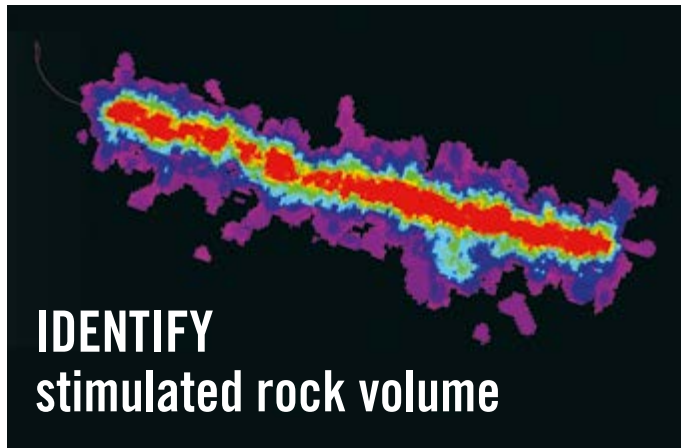
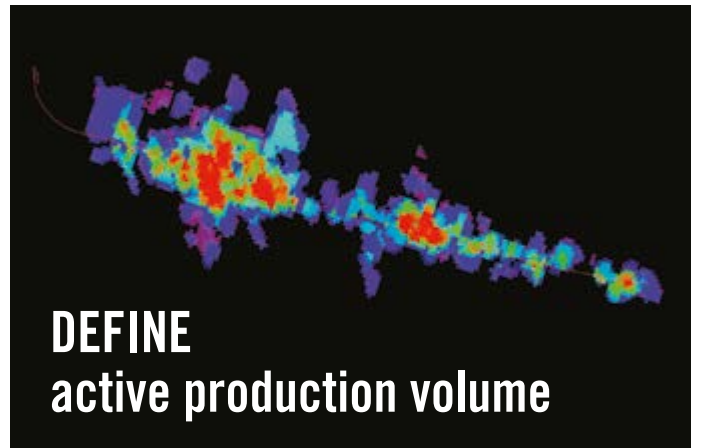


IMAGE
natural fractures

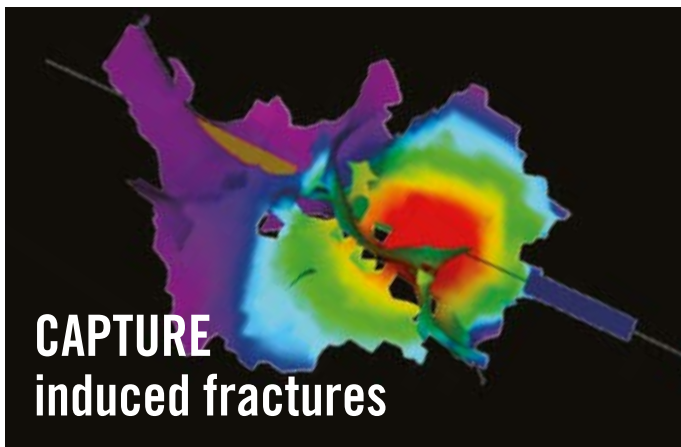
This is AMBIENT Seismic.



IDENTIFY
stimulated rock volume



DEFINE
active production volume



CAPTURE
induced fractures

Global Geophysical's innovative approach to ambient seismic provides direct imaging of acoustic activity in the subsurface. This allows us to identify areas or zones that are acoustically active due to natural fractures, hydraulic stimulation or production-related activities. Our ambient seismic results can be presented as 3D attributes, as discrete volumes of acoustic activity or as Tomographic Fracture ImagesSM.

For more information:
www.globalgeophysical.com/AMBIENT or
 Contact us at AMBIENT@globalgeophysical.com

Global Geophysical Services
 tel +1 713-972-9200 www.globalgeophysical.com



An Overlooked Petroleum System

Is it possible to generate hydrocarbons over the oceanic crust?

DAVID RAJMON, GeoSophix and VSEVOLOD EGOROV, Consulting Geoscientist

In petroleum exploration, the concept of hydrocarbon generation on the continental crust is completely accepted. However, modelling exercises demonstrate that, if the source rock is present and a sufficient amount of sediment is deposited, it is possible to generate hydrocarbons over the oceanic crust. Accumulations in the Niger Delta, and recent discoveries offshore East Africa represent real life examples of this possibility.

Expanding Exploration

In recent years, the offshore search for oil and gas has moved from shelf to deep and ultra-deep water. New discoveries both expanded areas of economic interests and brought them to the edges of the continental crust. One of the common tasks at the early stages of exploration is mapping of the continental-oceanic boundary. This boundary is delineated based on different geophysical measurements such as seismic, gravity and magnetics. They revealed that the continental-oceanic boundary is actually not an abrupt, but rather a transitional zone. These methods often fail to outline it accurately due to many assumptions and ambiguities in the interpretation of observed features; however, they provide a quite reliable estimate of sedimentary thickness.

Why is the continental-oceanic crustal

transition considered very important? Embedded in regional exploration workflows is generally a strong preference for prospects to be located on the continental crust. The main logic in this rule of thumb for many explorationists is that the continental crust generates 10–100 times more radioactive heat per volume than the oceanic crust and, therefore, ensures a sufficiently warm thermal history of source rocks within a sedimentary section to mature and generate hydrocarbons.

Neglected in this reasoning, however, is the fact that the thermal history of a basin is a function of not only basement heat flow history, but also sediment thermal properties and depositional history. Although the overall thermal history of sediments deposited on the oceanic crust tends to be cooler than over the continental crust, it does not automatically prevent source rock maturation.

Modelling Results

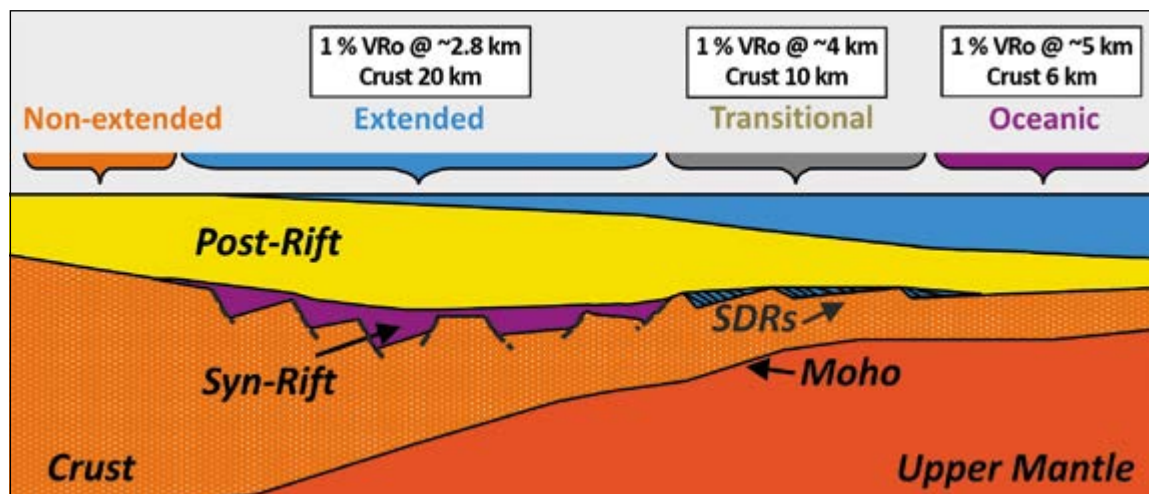
To illustrate this point, several models were constructed investigating the impact of crustal type and crustal and sedimentary thickness on hydrocarbon generation. The first geological scenario is a basin with a rifting period during 100–90 Ma and a continuous siliciclastic sedimentation to present-day (similar to the Equatorial/South Atlantic margin). Three models were derived to evaluate

hydrocarbon generation over thinned continental crust of 20 km in thickness, 10 km-thick transitional crust, and 6 km-thick oceanic crust. Total lithosphere thickness was maintained at 100 km. The results of basin modelling indicate, for example, that over the thinned continental and oceanic crust, the potential source rocks would reach their maturity of 1% VRo (mid-range of oil window) at present-day depths of ~2.8 km and ~5 km, respectively. These estimates support the presence of sufficient heat flow for hydrocarbon generation in areas of thick sedimentary deposits over the oceanic crust such as those found along East Africa and Atlantic margins.

Another considered geological scenario is a young rift basin with forming oceanic crust such as the Red Sea with a high present-day heat flow, where 1% VRo is calculated at ~3.5-km depth.

As the thickness of a sedimentary package is usually mapped with high accuracy, the numerical integration assuming different crustal types and depositional history should be constructed early in, and throughout, the exploration workflow. Illustrating this approach, our exercise and real world examples prove that opportunities for hydrocarbon discoveries over the oceanic crust should not be overlooked! ■

Modelling results from a typical rifted margin show that a source rock can mature over oceanic crust and generate hydrocarbons at ~5 km depth (mid-range of oil window). SDRs: seaward-dipping reflectors.

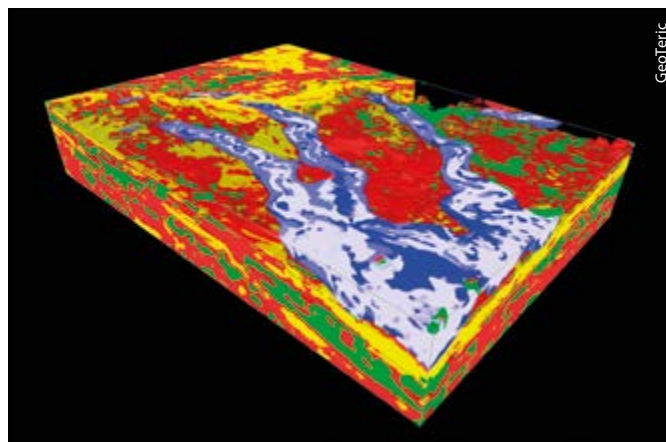




Broadband HDFD

There has been a significant growth in the use of broadband seismic acquisition in the industry's attempt to better image the geology of the subsurface. Important structural and stratigraphic features are visible in much higher quality through obtaining a broader bandwidth, and this has created a pressing need for high resolution analysis techniques that are compatible with the complex waveforms of broadband data.

Amidst the options available to interpreters, software such as **GeoTeric's Broadband HDFD** is suitable for **High Definition Frequency Decomposition** that is **applicable to both broadband and conventional data**. Their Broadband HDFD utilises patented, advanced frequency splitting techniques developed for the complex waveforms of broadband seismic data, and provides a high definition description of the geology which is otherwise not visible. It provides illuminating and informative results, leading to a more precise delineation and extraction of



the geological features from the data.

This level of software is required to not only enable interpreters to understand reservoir heterogeneity, but reduce time and increase business value in a critical time for the industry. ■

NAPE Goes Global – At Home

Our goal at NAPE is to bring the upstream oil and gas industry together. We are taking steps toward further achieving that goal by implementing changes to our international component at **NAPE Summit**, 10–12 February 2016, in Houston. International prospects will no longer be featured in a separate exhibit but instead will be integrated alongside the domestic booth spaces on the main expo floor. Now companies that deal both in North America and around the world may showcase domestic and international opportunities from one centrally located booth.

Additionally, we are expanding our traditional NAPE Business Conference into the **NAPE Global Business**

Conference, which will highlight international topics and feature speakers presenting worldwide forecasts. The most heralded expansion aspect is the addition of a prospect preview theatre located on the exhibit floor featuring a full day of international prospect preview presentations – a must-attend opportunity for international players.

NAPE Summit provides a unique opportunity to network with global colleagues with wide-ranging interests and expertise. For 2016, we anticipate over 35 countries being represented. For international investors and decision makers, NAPE represents an unparalleled venue for making connections and exploring opportunities. Come to NAPE. Where deals happen. ■

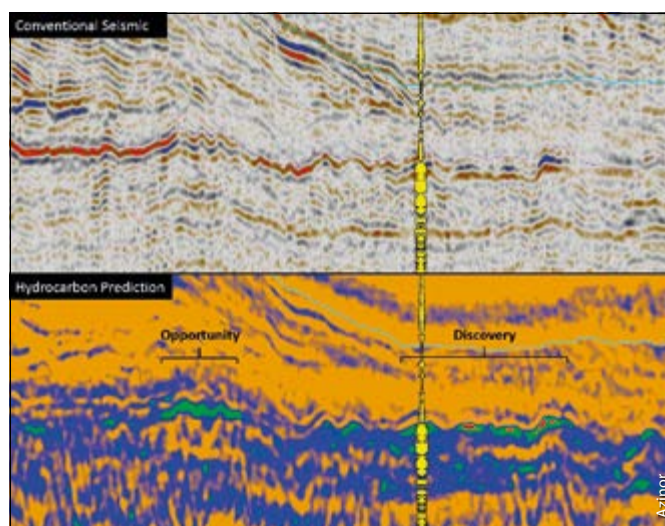
Leveraging Technology and Techniques

A revival of activity on the UKCS needs to be married with high success rates of significant discoveries, and for this we need to leverage the latest generation data – broadband seismic – and quantitative prediction techniques to provide a better understanding of the subsurface.

UK explorer **Azinor Catalyst** is making significant early phase investments to exploit technology and data to find the remaining UK giants. Fewer wells will be drilled but those undertaken will have a higher **Chance of Success (COS)**. Within eighteen months Azinor Catalyst has built a portfolio of 12 licences and identified 250 MMb of net risked resources via access to 90,000 km² of convention seismic, but more importantly squeezing the information out of its 16,000 km² of broadband seismic. Ownership of such a seismic library in one basin is second to only a few majors and a sure sign of commitment to future UKCS exploration.

To extract the maximum value from these seismic libraries, quantitative exploration and development (QED) best practices are being used alongside seeding new initiatives in R&D. QED no longer can be expected to sit outside the conventional workflow. Its application brings value

throughout the subsurface interpretation and provides an improved solution which can quantifiably impact the COS and generate material returns for shareholders. Azinor Catalyst is a member of the Seacrest Capital group of companies. ■



TASK FRONTERRA GEOSCIENCE IS A WORLD LEADER IN THE INDEPENDENT PROCESSING, QUALITY control and interpretation of borehole image and dipmeter data. Some of our employees have been working with borehole image logs since imaging was first introduced!

Whether you have just acquired a modern borehole image, or need to reprocess, or even rescue vintage data, **TASK Fronterra** have the experience to help.

VINTAGE DATA RECOVERY

Are you overlooking a valuable asset?

- Independent data processing and quality control of dipmeter and borehole image logs.
- Vintage data recovery and re-processing.
- Recovery and digitisation of vintage borehole image and dipmeter computations data from prints and data listings.
- Re-interpretation of vintage data using 21st century interpretation techniques!
- Delivery of results using **TASK Fronterra's** unique *attitude*® software for data interrogation and visualization.

A GLOBAL FOOTPRINT - OFFICES IN NINE LOCATIONS ACROSS EUROPE, AMERICA, THE MIDDLE EAST AND ASIA PACIFIC. COMPLIMENTARY EXPERTISE TO ASSIST CLIENTS IN THEIR UNDERSTANDING OF MATURE RESERVOIRS, CARBONATES, DEEP-WATER FIELDS AND UNCONVENTIONAL HYDROCARBONS, ESPECIALLY SHALE GAS WITH OUR INTEGRATED SHALE GAS WORKFLOW

Borehole Image and Dipmeter Data Processing and QC

TASK Fronterra
Geoscience

C O N V E N T I O N A L A N D N O N - C O N V E N T I O N A L R E S E R V O I R S

ABERDEEN • CAIRO • DENVER • HOUSTON • MIDLAND • OKLAHOMA CITY • PERTH • TULSA • VIENNA
KETTOCK LODGE UNIT F CAMPUS 2 ABERDEEN INNOVATION PARK BALGOWNIE DRIVE BRIDGE OF DON ABERDEEN AB22 8GU UK
TEL: +44 (0)1224 357250 www.taskfronterra.com

GeoConvention 2016

GeoConvention
Calgary - Canada - March 7-11 **2016**
OPTIMIZING RESOURCES

With low commodity prices and an ever changing economic and business environment, it is imperative that the industry optimize the way in which it operates. Whether enhancing recovery methods, finding the optimal path for a horizontal well or maximizing the return of capital employed, Optimizing Resources, the theme for GeoConvention 2016, is key to success.

Please join us and contribute as speaker, exhibitor or sponsor.



**MARK YOUR CALENDAR:
GeoConvention 2016 is March 7-11!**

In recognizing the business environment which we are operating in, **GeoConvention is pleased to offer heavily discounted delegate rates for the 2016 program!**

New for our 2016 program, in addition to the technical program and exhibit floor at the Convention Centre, **we will be hosting an offsite component at the Lake Louise Inn** – check out geoconvention.com for details!

**EARLY BIRD REGISTRATION
NOW OPEN!**

www.geoconvention.com



Africa Stratigraphic Harmonisation

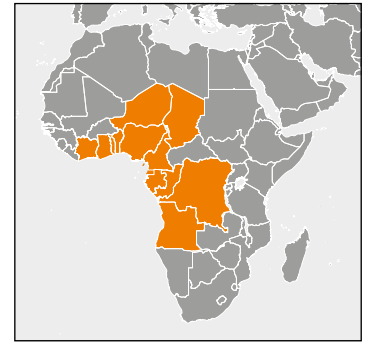
TGS and the African Petroleum Producers' Association (APPA) have signed a Letter of Intent to create a harmonised regional stratigraphic framework for key petroleum-producing sedimentary basins onshore and offshore sub-Saharan Africa. The decision to commission this study was taken to recognise the trans-border nature of many of Africa's hydrocarbon-bearing sedimentary basins and to foster effective cross-border geoscientific data exchange between APPA member countries.

The project will involve the compilation, interpretation and normalisation of geological and geophysical data from all member countries within the study area. The resulting data will be used to build a revised stratigraphic scheme using harmonised nomenclature for each of the Intracratonic, Gulf of Guinea and West Africa Zones.

Exploration companies should save time and money as a result of this project through rapid access to a regional data set and interpretation which consolidates understanding

of regional geology, thereby fast-tracking understanding of basin development and shortening exploration cycle time. It will provide a standardised nomenclature and a homogeneous framework for play modelling and exploration work and the means to technically evaluate new opportunities throughout the region.

TGS is seeking expressions of interest from potential project sponsors to commence work on this multi-client study as planned in Q1 2016. Organisations that participate early will be involved in the final selection of data used in the project and have access to the product sooner than their competitors. ■



Countries covered by the APPA project.

Delivering Positive Change

Now in its 13th year, the annual DEVEX Conference will focus on the theme of **delivering positive change to reduce costs and maximise production**. Despite the severe backdrop there continues to be a great deal of good and interesting work being carried out and the conference will explore this in detail and will give delegates the chance to get involved.

There have been several changes made to increase the quality of the conference for delegates. It attracts some of the best technical presentations from the industry and academia, all of which aim to educate and inspire. Back

by popular demand will be expert-led masterclasses for enhanced learning plus our Young Professionals event, and Core will be on display. There will be opportunities for the supply chain to present their technologies to the Operators in the form of one-to-ones and pitching sessions. As ever, this conference will provide a great networking opportunity for all – so join the debate!

The conference will take place on 18–19 May 2016 at the Aberdeen Exhibition and Conference Centre (see www.devex-conference.org for further details). ■

Forties at Forty

On 3 November 2015 a **major North Sea milestone** was reached: it is 40 years since oil was first produced from Forties Alpha and transported via the Forties Pipeline System to the onshore terminal at Cruden Bay in Scotland.

Discovered in October 1970, in-place reserves for the **Forties** field were estimated to be in the region of 4.6 Bbo with oil reservoir in Upper Paleocene stacked sands of the Forties Formation. This was the first major oilfield development in the UKCS, so it was not until September 1975 that production started, with the field officially inaugurated by Queen Elizabeth II in November.

Production peaked at 500 Mbopd in 1978, declining to 77 Mbopd in 1999, by which time Forties had produced 2.5 Bbo and had nearly 60 producing wells. In 2003, with production down to 45 Mpd, operator **BP** sold its 97% stake to **Apache**, who began an ambitious re-evaluation and development programme, reviving production to more than 60 Mpd

by 2005. Forties was estimated to contain 144 MMboe of remaining reserves when Apache acquired it, but the company has since recovered more than 230 MMboe and added critical infrastructure to extend the field's life expectancy by more than 20 years (see *GEO ExPro* Vol. 7, No. 3). ■

The new Forties Alpha Satellite Platform bridge linked to the Forties Alpha platform.





Rebirth of Exploration

Belief that the oil price will not change wildly up or down is key to longer term decisions about the future so that companies can plan with some degree of confidence. A bear market offers tremendous opportunity for those with foresight and technical knowledge; while the dust settles and costs of E&P come down, opportunities at significantly better value are on offer.

Independent statistics show that historically after a 40% fall in seismic and rig costs and some price stability, a more positive A&D (Acquisition and Divestment) upstream deal flow is likely to resume. Based on the current trend, this could happen by the end of Q1 2016 – perfectly timed for **APPEX**

Global in March 2016. With global demand pretty certain to continue increasing, there appears to be less of a gap to close for current demand to catch up – evidence that stability may not be so far off.

In anticipation of this optimistic outlook, the AAPG is delighted to invite you to participate in APPEX Global in London, with its theme of the '**Rebirth of Exploration**', where the usual high quality of APPEX delegates, including many senior global A&D decision makers, is expected. We look forward to seeing you there.

For more information see www.aapg.org/global/europe/events. ■

DEVEX 2016

DELIVERING POSITIVE CHANGE
TO REDUCE COSTS AND
MAXIMISE PRODUCTION

18 & 19 MAY,
ABERDEEN EXHIBITION AND
CONFERENCE CENTRE

The 13th Devex Conference will showcase subsurface and well technologies, case studies and best practices for oil and gas industry professionals.

Devex 2016 will include
 Innovative Technical Presentations
 Expert led masterclasses
 Core display
 Young Professionals Event

DEVEX 2016 ORGANISERS



PARTNERS



Partnership opportunities available!

For further details on the event programme,
 partnership opportunities and how to get involved,
 visit www.devex-conference.org
 or contact devex@mearns-gill.com

Africa Leading a Small Licensing Revival

KEN WHITE

Gabon

11th Offshore Licensing Round Opens

Gabon's 2016 offshore bid round was formally opened on 27 October 2015 by his Excellency, Minister for Petroleum and Hydrocarbons, Mr. Etienne Dieudonné Ngoubou, at the Africa Upstream conference in Cape Town. This 11th Licensing Round is focused on five highly prospective deepwater blocks, which will be promoted by a series of road shows, starting in Libreville on 24 November, followed by Paris on 26 November, Singapore on 30 November and Houston on 3 December 2015. The round will be open for five months starting on 27 October 2015 and bids can be submitted from 15 February 2016 onwards, but by no later than 31 March 2016. Pre-qualification for the bid round will require the

purchase of a minimum amount of seismic data.

In preparation for this offering CGG launched a new multi-client survey programme to acquire 35,000 km² of BroadSeis™ 3D data over both the latest available and already awarded deepwater blocks offshore Gabon, together with 9,900 km of 2D data over the country's ultra-deepwater offshore area. The first phase of the programme, covering almost 25,000 km², started in the fourth quarter of 2014 and ran for seven months. It will enable better imaging of this exciting and underexplored area, and covers areas down-dip and adjacent to recent pre-Aptian salt discoveries such as Leopard, Diaman, Ruche and Tortue. ■



Congo

Offering Eight Offshore Blocks

Following formal ratification of the new petroleum code by parliament, HE Jean-Marc Thystère Tchicaya, Minister of Hydrocarbons, opened the Republic of Congo 2016 Licence Round at the Africa Upstream Conference in Cape Town on 27 October 2015. The round comprises eight deep and ultra-deepwater blocks and five onshore blocks in the Coastal and Cuvette Basins. The Minister said results of bids made for the blocks offered would be made known on 31 May 2016. The region is thought to contain oil concealed below a layer of salt and may possibly hold reserves comparable to the billions of barrels found in fields off Brazil.

The new petroleum code, which updates the existing 1994 law, was approved by the cabinet in March. Based on a model production-sharing contract, it stipulates that state oil company Société Nationale des Pétroles du Congo (SNPC) is the holder of the mining title in each case, with the right to bring in local and international partners. ■

New Zealand

2016 Block Offer Meeting Some Resistance

Consultation on the 2016 Block Offer closed on 30 October and once again it has proved a divisive issue. The proposal incorporates four offshore areas with a total proposed acreage of 537,632 km². Currently this comprises 1,185 km² in the onshore Taranaki Basin, with the remainder spread over the offshore Pegasus and East Coast Basins, Northland-Reinga Basin, Taranaki Basin, the Great South Basin and the Canterbury Basin. It is hoped to launch the round in March 2016.

While Auckland Council plans to accept the overall Block Offer, some local boards will oppose the plan due to environmental concerns, and remain far from satisfied that enough is being done to protect Auckland's natural and physical resources. Auckland Council officials are recommending councillors approve the offer subject to conditions to minimise the impact on the environment: essentially, the same position it has adopted in previous years. The council is calling for the government to change the proposed Taranaki Basin area to start further offshore (at least 12 nautical miles) as a precaution, so that it avoids the North Island West Coast Marine Mammal Sanctuary. ■

A PERFECT FIT

Seismic + Non-Seismic



NEOS Adds Seismic Imaging to Its Multi-Physics Toolkit

Following our recent acquisition, some of the best and brightest minds in seismic imaging have joined the NEOS team. Continuing to do what they do best, the NEOS Seismic Imaging Group will deliver stand-alone processing and imaging services, including advanced onshore depth imaging in some of the most challenging regions in the world. But it doesn't stop there. Our strengths in multi-physics imaging align perfectly and we will be teaming up to change the way the industry explores. Incorporating seismic attributes into our proprietary predictive analytics methods and undertaking multi-physics inversions is just the beginning. Together we offer a truly complete portfolio of subsurface imaging solutions to our clients.

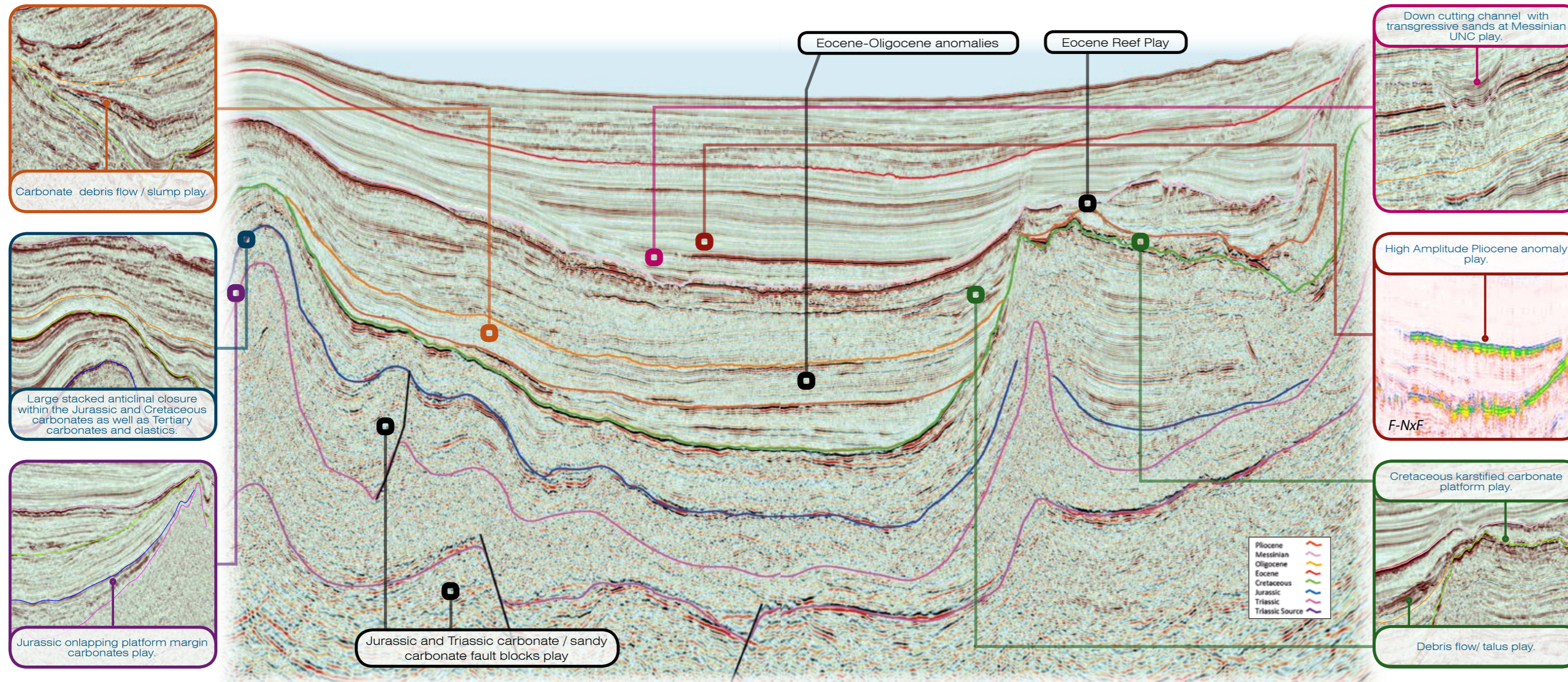
Seismic + Non-Seismic. A powerful combination.

Croatia's 2016 Licence Round

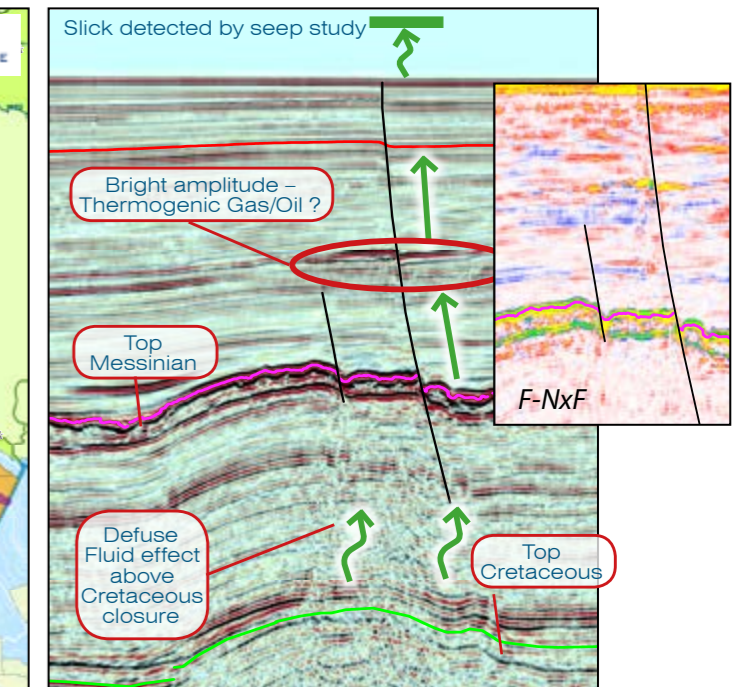
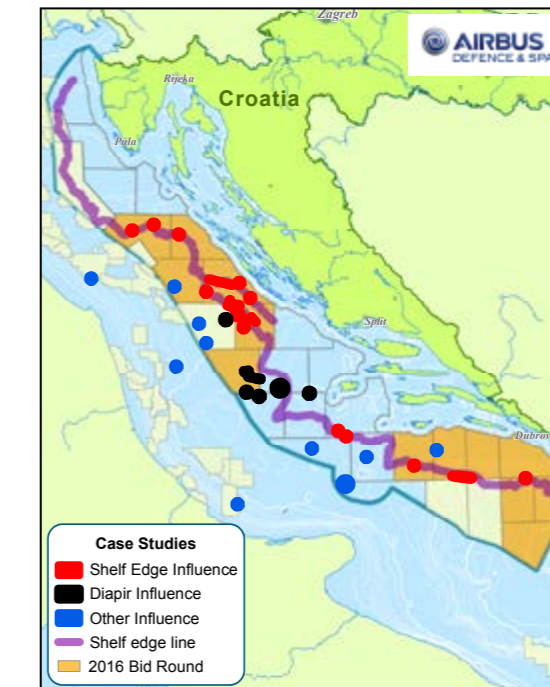
A second bite at the Big Apple

Croatia's first licence round ran through 2014 with an expectation of highly competitive high work-commitment bids and with the world oil price at over \$100 bo. Multiple strongly competitive bids were indeed submitted by IOCs for over 15 of the blocks on offer; however, with the disruption and uncertainty in 2015 caused by the unexpected collapse of the world oil price, it is perhaps no surprise that most of the offered low-hanging fruit remains on the tree.

Yet Croatia's oil and gas licensing authority (AZU) is coming out fighting, with a plan to open a new licence round in Q1 2016 offering 13 offshore and 6 onshore blocks, with expectations that recognise the realities of exploration business today, and opportunities to deliver extraordinary value from oil in shallow water, located at the heart of Europe. It is time for a second bite at this apple.



Multi-Client seismic coverage offshore Croatia.



Well data, seep study and seismic data suggest hydrocarbons offshore central and southern Croatia are from the Triassic source and are **thermogenic not biogenic**. This is in contrast to the northern section of Croatia where the hydrocarbons are post-Cretaceous and biogenic in origin.

Lead Type	Number of leads	Indicative lead values Oil (mmbb)				Indicative lead values Gas (bcf)				Relative Size	Potential Play Type Reserves - Oil (mmbb)				Potential Play Type Reserves - Gas (bcf)			
		P90	P50	Mean	P10	P90	P50	Mean	P10		P90	P50	Mean	P10	P90	P50	Mean	P10
Cretaceous Fan	1	8	66	190	524					Only	8	66	190	524	0	0	0	0
Cretaceous Karstified Lmst	1	8	43	86	223					Only	8	43	86	223	0	0	0	0
Cretaceous Platform Margin	9	12	44	68	159	109	494	891	2240	Largest	36	132	204	477	327	1482	2673	6720
(Cretaceous cored) Tertiary Anticline	8	11	40	60	138					Average	11	40	60	138	0	0	0	0
Eocene Debris Flow	1	5	24	43	107	18	87	167	426	Only	5	24	43	107	18	87	167	426
Eocene - Miocene Anomaly	1	68	382	814	2156					Only	68	382	814	2156	0	0	0	0
Eocene Reef	1	5	30	72	193					Only	5	30	72	193	0	0	0	0
Jurassic Fault Blocks	19					148	774	1563	4056	Average	0	0	0	0	148	774	1563	4056
Jurassic Platform Margin	1					109	494	891	2240	only	0	0	0	0	109	494	891	2240
Mesozoic Anticline	35	58	319	673	1764					Largest	464	2552	5384	14112	0	0	0	0
Messinian Channel	12					8	51	126	337	Average	0	0	0	0	80	510	1260	3370
Oligo - Miocene slump	1	2	12	24	63	5	30	70	186	Only	2	12	24	63	5	30	70	186
Oligo - Miocene Anomaly	5					10	87	287	783	Largest	0	0	0	0	25	217.5	717.5	1958
Permo Triassic	20					5	28	61	159	Average	0	0	0	0	100	560	1220	3180
Plio Quaternary Anomaly	90					70	604	1924	5246	Largest	0	0	0	0	210	1812	5772	15738

Indicative potential lead recoverable (un-risked) resource estimates and total potential by play type.

Stunning Potential Offshore Croatia

ANNA MARSZALEK,
ASHLEIGH HEWITT,
KARYNA RODRIGUEZ
and NEIL HODGSON

Integration of seismic, well and potential field data has led to a better understanding of the petroleum system of the Adriatic Basin.

The Adriatic Basin is a prolific hydrocarbon province with a number of producing gas fields in both Croatian and Italian Adriatic waters. Chasing oil plays on the Croatian margin has been hampered by the imaging of the legacy seismic data, preventing accurate prospect and source rock distribution identification.

High quality seismic data acquired in 2013 has allowed Spectrum to evaluate the petroleum prospectivity offshore Croatia by combining seismic with well and potential field data. This evaluation has led to a number of breakthroughs in the understanding of the petroleum system of the Adriatic Basin. Insights into the spatial distribution maturation history of the Upper Triassic source rock, and the variability and distribution of Mesozoic carbonate platform margins that provide the primary prospective reservoirs allow the calibration and assessment of risk factors for these elements of the hydrocarbon system. Additionally, they have been used to make potential resource estimates of the numerous leads identified in the open acreage.

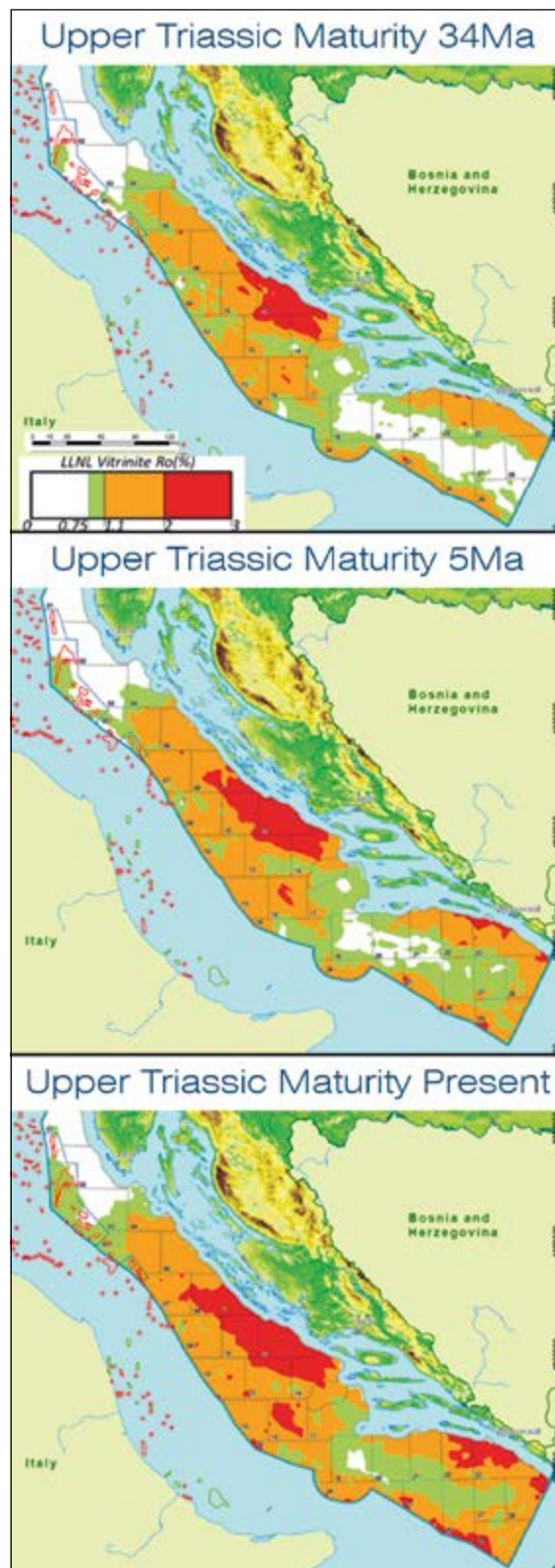
Source Rock and Modelling

The proven oil source rock in the Croatian Adriatic is the Upper Triassic 'Burano Formation' equivalent encountered by the Vlasta-1 well in 1986. Recent retrospective studies of core and cuttings from this well by INA have demonstrated the presence of black organic-rich carbonates with type II Kerogen of algal origin. These sediments were deposited in restricted sabkha 'intertidal' environments in syn-rift grabens formed during the breakup of Gondwana. Such syn-rift restricted grabens also provided the salt-reflux basins depositing thick Triassic salt that have subsequently controlled the depositional environments of the ensuing Mesozoic sequences.

The Triassic source rock at the base of the Mesozoic carbonate platforms was rarely visible on legacy data. However, the long streamer and record length of the 2013 data allows imaging of a deep intra-Triassic reflector that represents the source rock level and therefore allows estimation of the burial history of the Late Triassic source rock.

After mapping the intra-Triassic, top Jurassic, Early Cretaceous, Late Cretaceous, Eocene and Oligocene reflectors, time grids were used with well data and stacking velocities to create a set of depth grids that were combined with well data heatflow maps as input into a basin modelling study. Focussed on the Triassic source rock, hydrocarbon generation and

Upper Triassic maturity maps.



migration have been modelled across the Croatian margin, correlating migration to the timing of trap formation in each of the basins offshore Croatia.

The idea that the Triassic source rock generated oil throughout the Tertiary until the present day is also supported by surface oil seeps from optical satellite data.

New Carbonate Reservoir Plays

It has long been understood that the Adriatic Basin is dominated by a thick succession of shallow to deepwater carbonates deposited through Mesozoic to Palaeogene times. These sequences provide the main hydrocarbon reservoirs and are overlain by Cenozoic clastics providing competent mudstone topseal.

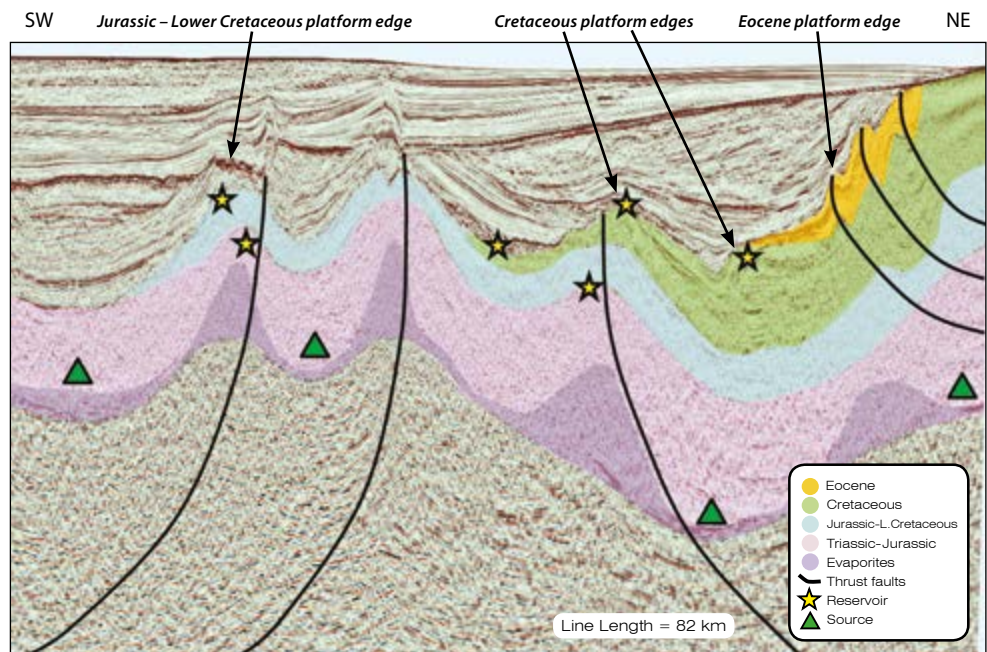
During the evaluation of the 2013 seismic, tying in all available well data and focussing on the mapping of seismic character of platform and distal facies, it became clear that the carbonate margin on the Croatian side exhibits different behaviour to the aggradational margins of the Italian Adriatic. In the Central Croatian basin, multiple eastward stepping carbonate platform edges are identified, providing a range of potential high porosity targets. This previously unrecognised back-stepping platform in the Croatian Adriatic is probably a result of a halokinetically driven platform instability and intra-salt wall pod formation and subsidence.

The Prize

Over 200 leads have been identified offshore Croatia. These are characterised into groups of play types based on structural or stratigraphic closure, age and lithology:

Anticlines: A number of large closures have been created by differential subsidence over geostationary or inverting mobile salt walls and diapirs. These structures have been intensified and rejuvenated by Dinaric inversion during the formation of the Oligocene foredeep of the eastern Croatian offshore area. Inversion tectonics in a north-west to south-east orientation combine with reservoirs in the Cretaceous shallow to deepwater carbonates, and Eocene to Miocene carbonates and siliciclastics.

Stratigraphic: Several Cretaceous–Pliocene play types can be identified on the seismic data as carbonate slumps or debris flows as well as siliclastic/carbonate fan turbidites emanating from the shelf and reworked anticlines. Some of these exhibit high amplitude seismic signatures that could indicate hydrocarbons. A potentially exciting play, unexplored in the northern Adriatic, is the ‘Messinian clastic play’, a sandstone deposited on the Messinian unconformity



Back-stepping Mesozoic carbonate platform, central Croatian Adriatic.

during the post-Messinian transgression. This provides the reservoir for the adjacent Patos Mirenza Field in Albania, one of the largest onshore oil fields in Europe.

Platform Carbonates: There are numerous structurally closed buried carbonate platforms or platform margins which are expected to have enhanced porosity due to fracturing, dolomitisation and karstification. These are seen in the Jurassic through to Eocene.

Basinal Carbonates: In several places along the margin, tight structuring from salt or westward vergent thrusting has generated fairways of significant prospectivity with reservoirs that are likely to be in the distal or deep basin carbonate setting. Whilst some remobilised materials in a talus or turbidite setting may provide reservoir, the key element to success is likely to be fracture density and connectivity.

Pre-Salt Structures: There are a large number of Permo-Triassic and Jurassic shallow marine sandy limestones in tilted fault blocks and horsts. The reservoir is expected to have porosity of 5–10% as recorded in similar depth wells.

Unrisked resource potential is estimated for these play types and presented on the tables in the foldout as largest or average-sized examples as well as estimated cumulative numbers for each category.

Croatia is set to launch its second licence round in Q1 2016. With the availability of modern seismic we can image and model the Triassic source and identify over 200 leads with potentially stunning potential. The Croatian offshore could be Europe’s next large oil province in the very near future. The exploration world has changed since the first round left the prize fruit uneaten – now is the time to have a second bite at the apple.

References:

Wrigley, R., Hodgson, N., and Esestime, P., 2015. *Hydrocarbon potential of the Adriatic Basin, offshore Croatia.* ■

Leaders in natural resource location



Sedimentary basins covered by Getech's 32 Regional Reports

Getech's *Regional Reports* provide focussed assessments of the exploration risks and opportunities in the world's frontier and underexplored basins.

Our latest *Regional Reports*

Tectonic Evolution of Mexico



Detailed mapping of the regional structural framework and crustal architecture, based on Getech's unique gravity and magnetic data, constrains a fully tested plate model which reveals the tectonic evolution of Mexico.

Tectonics and Source Rock Potential of the Southern Caribbean Margin



If you are exploring for hydrocarbons in the Caribbean waters of Venezuela and Colombia then this *Regional Report* from Getech will give you the tools to better understand the basis for, and impacts of, the differing tectonic models of the Caribbean.

Getech's *Regional Reports*

Fuelled by our extensive data and powered by *Globe*, our flagship New Ventures platform. The cost effective solution in Plate-to-Prospect exploration.

For further information contact Getech:

Getech, Leeds, UK +44 113 322 2200
info@getech.com

Getech, Houston, US +1 713 979 9900
www.getech.com/regional-reports



Iraqi Kurdistan: It's All in the Timing

Understanding the complex structural history of the Zagros is key to unlocking the potential of Iraqi Kurdistan.

ABDULLAH AWDAL and JON GUTMANIS, GeoScience Limited

The Zagros fold and thrust belt of Iraqi Kurdistan is a prolific petroleum province with several large-scale producing oil and gas fields. The region is under active exploration and hence production is expected to rise over the next few years.

Reservoirs are primarily fractured carbonates at a variety of stratigraphic levels, with different fracture intensity mainly controlled by mechanical stratigraphy, the structural position of the regional thrust-related anticlines, and present day in-situ stress.

The Zagros fold and thrust belt in Kurdistan can be divided into four distinct structural zones. From the

north-east hinterland to the south-west foreland these are known as the Zagros Suture, the Imbricated Zone, the Highly Folded Zone and the Foothill Zone. The Imbricated and Highly Folded zones are characterised by major surface-breaching, mainly south-west-verging thrust-related anticlines, whereas major folds above blind thrusts characterise the Foothill Zone. The trend of fold axes varies from north-west to south-east in the Zagros to west-north-west to east-south-east in the Taurus Mountains. The structural style of the Zagros fold and thrust belt in Iraqi Kurdistan is characterised by both thin- and thick-skinned tectonics.

Fractured Reservoirs

A reservoir fracture is a naturally

occurring macroscopic discontinuity in rock due to tectonic deformation or pressure solution mechanisms. Natural fracture systems can have a variety of effects on reservoir performance and well rates, which must often be predicted long before they are evidenced in production data. In folded rocks, the existence of a pre-fold fracture network contributes to a mechanical anisotropy of the strata that apparently controls the subsequent fracture development during folding. In his book *Geologic Analysis of Fractured Reservoirs*, Ronald Nelson has introduced a classification of reservoirs based on the porosity and permeability of both rock matrix and fractures. Based on this classification, most fractured reservoirs in Iraqi Kurdistan are either Type II, where fractures provide the essential permeability, or Type III, where

Steeply south-west-dipping limb of a typical anticline in the Highly Folded Zone west of Sulaymaniyah.



fractures contribute to the permeability of an already producible reservoir.

The fractured reservoir units in Kurdistan are found in rocks spanning in age from the Neogene, such as the Jeribi Formation, to the Triassic, which includes the Kurra Chine. The most common fractured reservoir units in Kurdistan are the Pila Spi Formation (Paleogene), the Cretaceous (Shiranish, Bekhme, Kometan and Qamchuqa), the Jurassic (Najmah and Sehkaniyan/Mus), and the Kurra Chine (Triassic). Study locations across wide areas of the Kurdistan Region contain excellent surface outcrops of these important fractured reservoir units, exposed in large-scale fractured periclinal (four-way closure anticlines). Quantitative characterisation of fracture networks measured in these outcrop analogues, combined with sub-surface data, provides the basis for robust discrete fracture network models, which can be used to predict both flow performance and recovery factor for these reservoirs.

Mechanical Stratigraphy

The term 'mechanical stratigraphy' implies that the rock consists of layers that have different mechanical responses to stress, because they have different strengths and different elastic moduli. In simple terms, layers dominated by clay or shale accommodate strain in a ductile manner, while stronger layers such as limestone or cemented sandstone can accommodate higher levels of strain and therefore deform in a more brittle manner. The result is that, in a layered sequence, fractures initiate in certain layers, while adjacent layers are either unaffected or less affected by such brittle structures. Fractures are typically stratabound and span the thickness of the mechanical layer and commonly abut the bounding stratigraphic horizons.

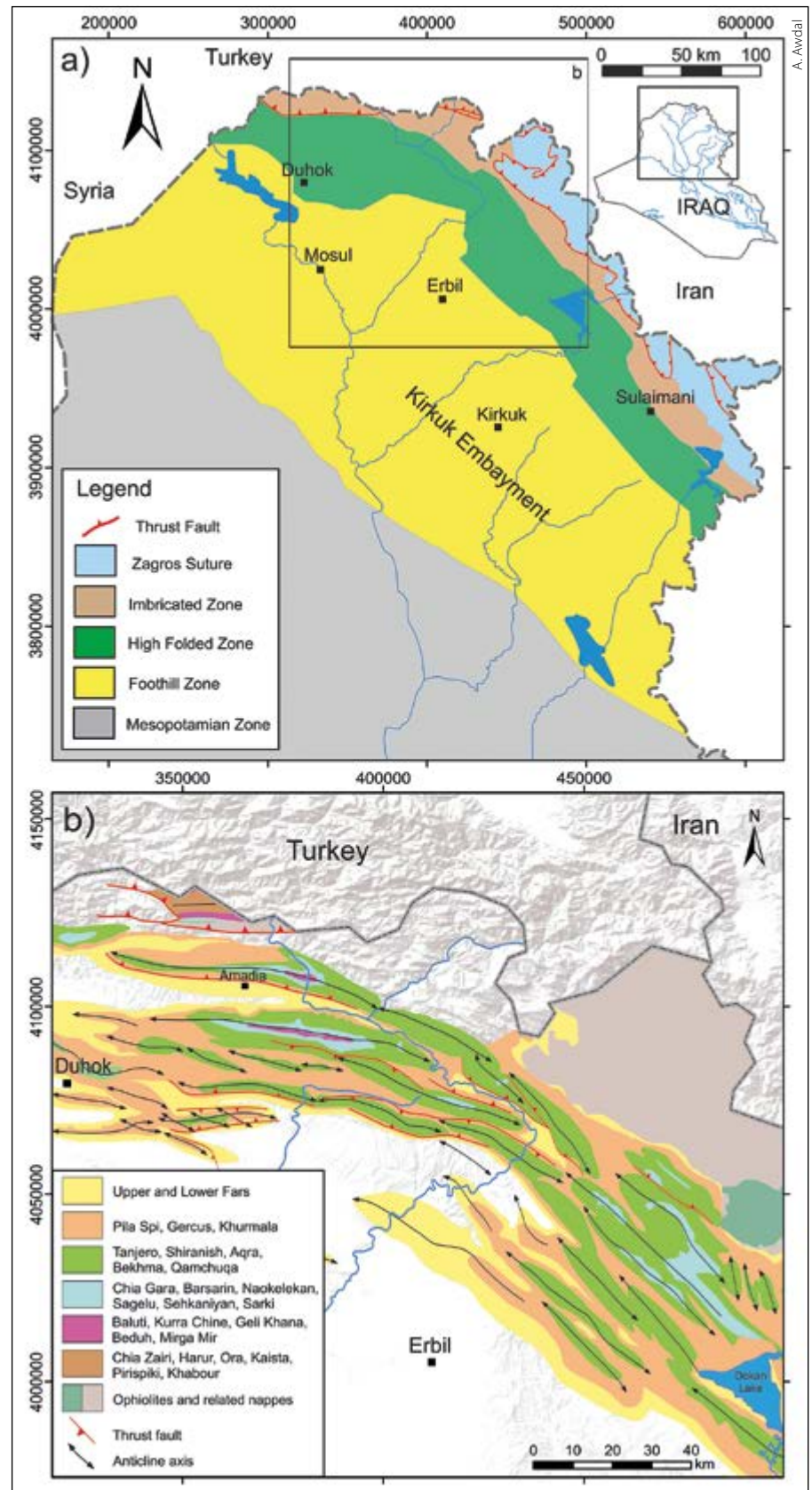
In addition, a proportion of fractures develop into larger scale structures that cross the bed boundaries and may be tens of metres in length and height. These are referred to as 'fracture corridors' and, for those with offset, 'sub-seismic faults'. They are important because they can have significant impact on fracture connectivity and thus on well performance.

Structural Style

As noted above, the structural style of the Zagros fold and thrust belt is

characterised by both thin- and thick-skinned tectonics. In addition, it is segmented due to the interaction of

(a) Tectonic map of Iraqi Kurdistan; (b) Simplified geological map of northern Kurdistan showing the anticlinal axes and related thrust faults.



J. Gutzmanis



Stratabound fractures and fracture corridors in the Sinjar Formation (Lower Eocene) near Sulaymaniyah.

the exposure level and variations in active decollement levels along strike. Complex hybrid compressional structures developed, which are the products of earlier thick-skinned faulting and folding, later modified by younger thin-skinned thrusting and folding. The main thin-skinned detachment levels occur in the Lower Fars (Neogene), the Gercus-Kolosh (Palaeogene), the Jurassic, and the Baluti (Upper Triassic). In addition, thick-skinned detachment levels are likely to occur at one or more deeper levels within the Palaeozoic (e.g. Ora Shale). Dip section variation along strike is observed due to decreases in stratigraphic separation across the faults, and systematic shortening varies with stratigraphic level. Most shortening is observed within the Tertiary, and at top-Cretaceous and top-Jurassic, whereas the least shortening is found in the top-Triassic carbonate units.

Depth to the basal detachment is yet to be accurately defined in Kurdistan. The basal detachment layer is commonly interpreted as being detached on the Cambrian Hormuz Salt in the Iranian Zagros. However, it is assumed that the Cambrian Salt pinches out to the north-west of the Zagros and that the fold and

thrust belt in Kurdistan is detached on Ordovician and Silurian shales. In a recent study, the basal detachment is assumed to be in the Ordovician-aged shales or within any other mechanically weak layer overlying the basement. In addition, this study predicted duplexes comprising Triassic and Palaeozoic rocks in the deeper subsurface. However, the prediction of duplexes in Kurdistan needs further investigation. Further complexities can be represented by

decoupling structures. In south-eastern Iraqi Kurdistan, for example, the surface structures are decoupled from the more complex subsurface structures by multiple thrust sheets.

The presence of a strike-slip component is observed in outcrops and documented in the subsurface in the Zagros of Kurdistan. In the Taq Taq field, for example, dextral transpression parallel to a north-west–south-east shortening axis is evidenced by oblique

Fracture pattern in the Upper Cretaceous Shiranish Formation, Highly Folded Zone, east of Erbil.



A. Awdal

2nd Stefan Götz Workshop: Petroleum Geology of Fold and Thrust Belt Provinces Worldwide

May 15th-17th, 2016
Catalonian Pyrenees

Logistics and registration:

Lluís Ardèvol (Chief Geologist, Geoplay Pyrenees Ltd)

Lluís@geoplay.cat

Convenors:

Jon Gutmanis, (Chief Geologist, GeoScience Ltd)

gutmanis@geoscience.co.uk

Jaume Vergés (Researcher, Institute of Earth Sciences, Barcelona)

jverges@ictja.csic.es

Erich Funk (Carbonate Geologist, Oslo)

Erich.Funk@dno.no

A 2-day workshop with associated field trips for oil industry geoscientists. The superb Pyrenees exposures and workshop venue provide a relaxed forum for the exchange of knowledge.

See www.geoplay.cat/
www.geoscience.co.uk
for information

Call for
Contributions

Deadline
31/01/16



slip slickensides on faulted drill cores. In addition, the top reservoir map derived from interpretation of 3D seismic data suggests that a set of parasitic folds trending east-north-east to west-south-west is present across the axis of the anticline. These features are interpreted as oblique minor folds related to a steep dextral fault striking north-west-south-east, parallel to the anticline axis.

Structural Inheritance

Structural inheritance is only occurring at specific levels of sequences undergoing contraction. Inherited pre-orogenic deformation structures oriented perpendicular to the shortening direction can be reactivated during foreland flexuring.

Some anticlines in Kurdistan formed as a result of reverse movement on pre-existing normal faults during the Late Miocene-Pliocene compression of the Zagros. Others, however, may be formed by inverted half grabens. Inversion has placed Cretaceous basinal facies of generally poor reservoir quality in structurally elevated positions, whereas shelf carbonates with higher reservoir potential tend to be located in synclinal areas representing former footwalls. These anticlines are also characterised by relatively simple structural closure of the shallow stratigraphy, with a structurally more complex underlying section due to restoration of the graben by inversion to its pre-late Cretaceous structural configuration. Furthermore, basement

blocks are possibly involved in the thick-skinned tectonic phase and there is most likely reactivation along some of the pre-existing late Cretaceous extensional faults. Reactivation and stress reorientation around basement faults is also suggested along the Iranian Zagros fold and thrust belt. The best producing wells in some fields, such as Gachsaran, are thought to be located close to north-north-east-trending basement faults.

Summary

Hydrocarbon reservoirs in the young and seismically active Zagros fold and thrust belt of Kurdistan sit within generally complex structures that are 'stress sensitive'. In addition, they often

have complex facies distributions and diagenetic histories related to phases of extension prior to the late Cretaceous to Tertiary inversion when structural inheritance and reactivation of fractures become important. Understanding the relative timing of trap formation, porosity development and hydrocarbon charging is essential – 'it's all in the timing'. This requires a multi-disciplinary G&G approach to produce robust constraints on reservoir modelling, plus close liaison with reservoir engineers in the simulation process. In this way, uncertainties and risk in developing these challenging reservoirs can be minimised.

A full list of references is available online. ■

Upper Cretaceous fractured carbonates in the north-east limb of the Ranya Anticline, Highly Folded Zone, east of Erbil.



A. Awdal

Supercomputers for Beginners PART II

LASSE AMUNDSEN, Statoil,
MARTIN LANDRØ and BØRGE ARNTSEN, NTNU Trondheim

Energy companies need ever larger computers. This article is the second of three articles giving an introduction to supercomputers. Here, we look at the design of parallel software.

Most supercomputers are multiple computers that perform *parallel processing*, which is well suited for modelling, simulating and understanding many complex, real world phenomena. Historically, parallel computing has been considered 'the high end of computing', referring to high capability and high capacity computing, communication and storage resources. It has been used to model difficult problems in many areas of science and engineering. Today, however, a greater driving force in the development of faster computers is provided by commercial applications that require processing of large amounts of data in very advanced ways.

Embarrassingly Parallel Solutions

In parallel computing the problem is divided up among a number of

processors. The figure opposite shows the basic computer layout.

The art of parallel programming is identifying the part of the problem which can be efficiently parallelised. In many cases this can be straightforward and simple, such as in the processing of seismic data. Seismic data consists of a (large) number of records, and very often a single or a small number of records can be processed independently.

A simplistic example of this kind of processing is the application of various filter operations. The problem is solved by distributing a small number of records to each processor which performs the filtering. This is usually referred to as an *embarrassingly parallel solution* and, as the name suggests, does not require much sophistication, but a surprisingly large number of problems can be solved by

Beta: Software undergoes beta testing shortly before it's released. Beta is Latin for 'still doesn't work'.

Unknown

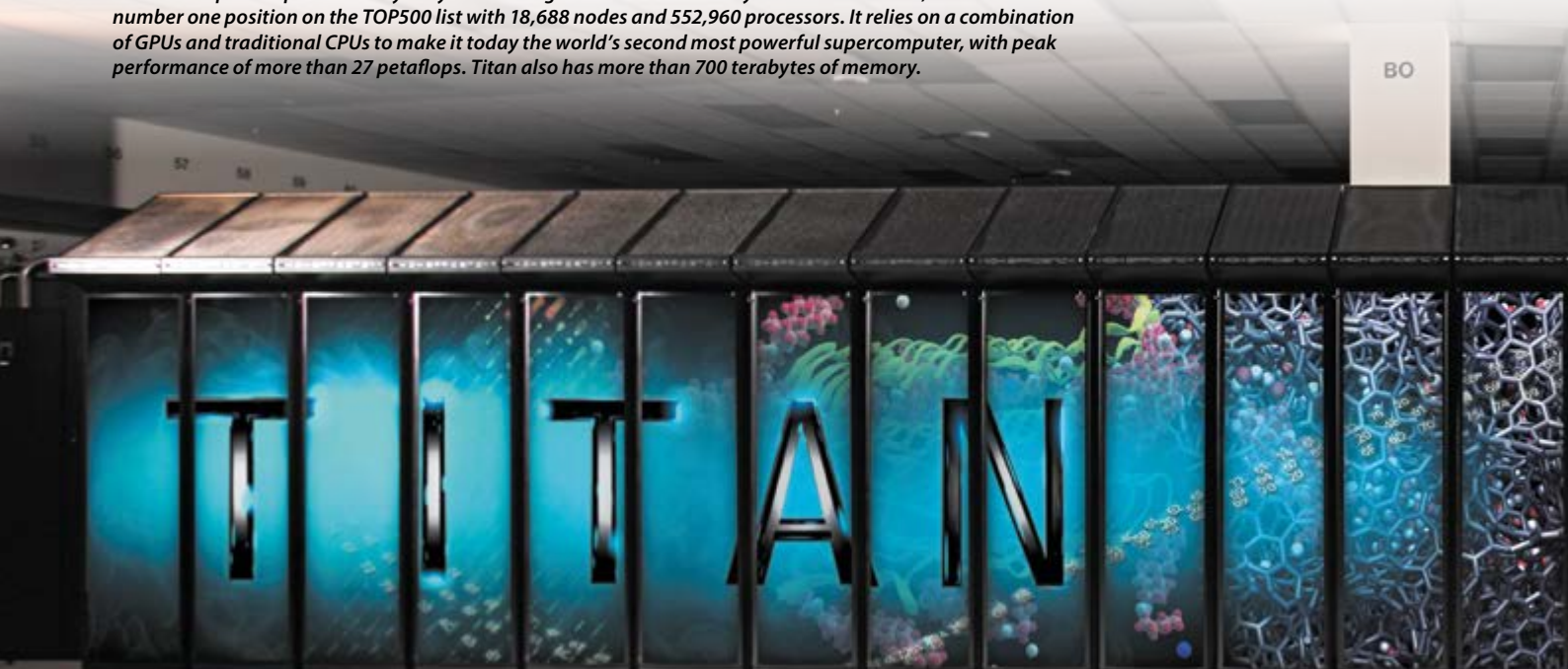
this approach. The gain in computer time needed to solve this kind of problem can be measured by the *speedup*, which is the ratio of computer time needed to solve the problem using a single processor to the time needed to solve the problem on N processors. For embarrassingly parallel problems the speedup is largely equal to the number of processors used. If each filter operation takes 0.001 second and we want to filter one million records, then a single processor would use 1,000 seconds, while a small supercomputer system with 1,000 processors would need only one second. This way of solving parallel problems is thus highly efficient and simple to implement.

Message Passing Interface

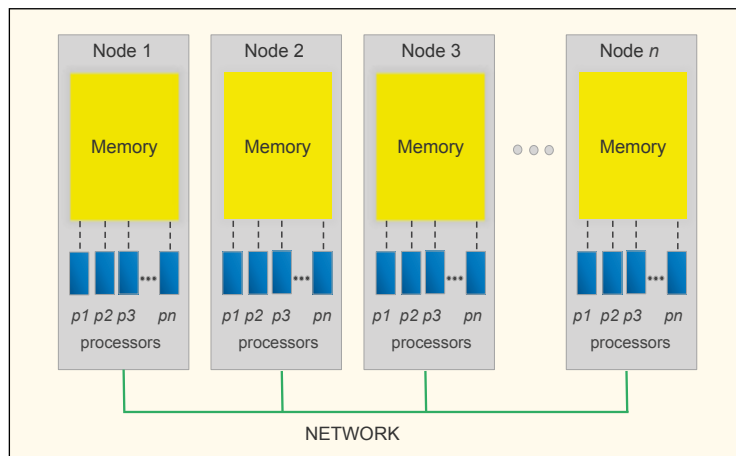
However, in many cases the problem at hand cannot be split into completely

Titan is a supercomputer built by Cray at Oak Ridge National Laboratory. In November 2012, Titan held number one position on the TOP500 list with 18,688 nodes and 552,960 processors. It relies on a combination of GPUs and traditional CPUs to make it today the world's second most powerful supercomputer, with peak performance of more than 27 petaflops. Titan also has more than 700 terabytes of memory.

BO



As a rough simplification, the modern supercomputer is divided up into nodes. Each node may have multiple processors which are the hearts of the node. Each processor has access to memory on its node – but does not have access to the memory on the other nodes. Communication of information can occur between processors within or across nodes. Communication across nodes takes place through a high-speed network, but is usually considerably slower than communication within a node. Data storage has to be accessible from all nodes in order to input and output data. In order to benefit from a supercomputer, the programs need to utilise the resources of multiple nodes in parallel. The network connects the nodes to make larger parallel computer clusters.



independent sub-problems, and some sort of communication must take place between nodes. A common example is a problem where each processor is assigned an independent computation, but where the results from all processors must be combined to form the solution.

A simple example of such a problem is the evaluation of an area under a curve. Numerically, this is usually solved by dividing the area up into small rectangles: computing the area for each rectangle and then summing together all individual rectangle areas. Table 1 shows an excerpt from a C program performing this computation on a single processor. Basically the programmer has used a loop to perform the computation of the area of each small rectangle, starting with the first rectangle and sequentially adding together all rectangles to form the total area.

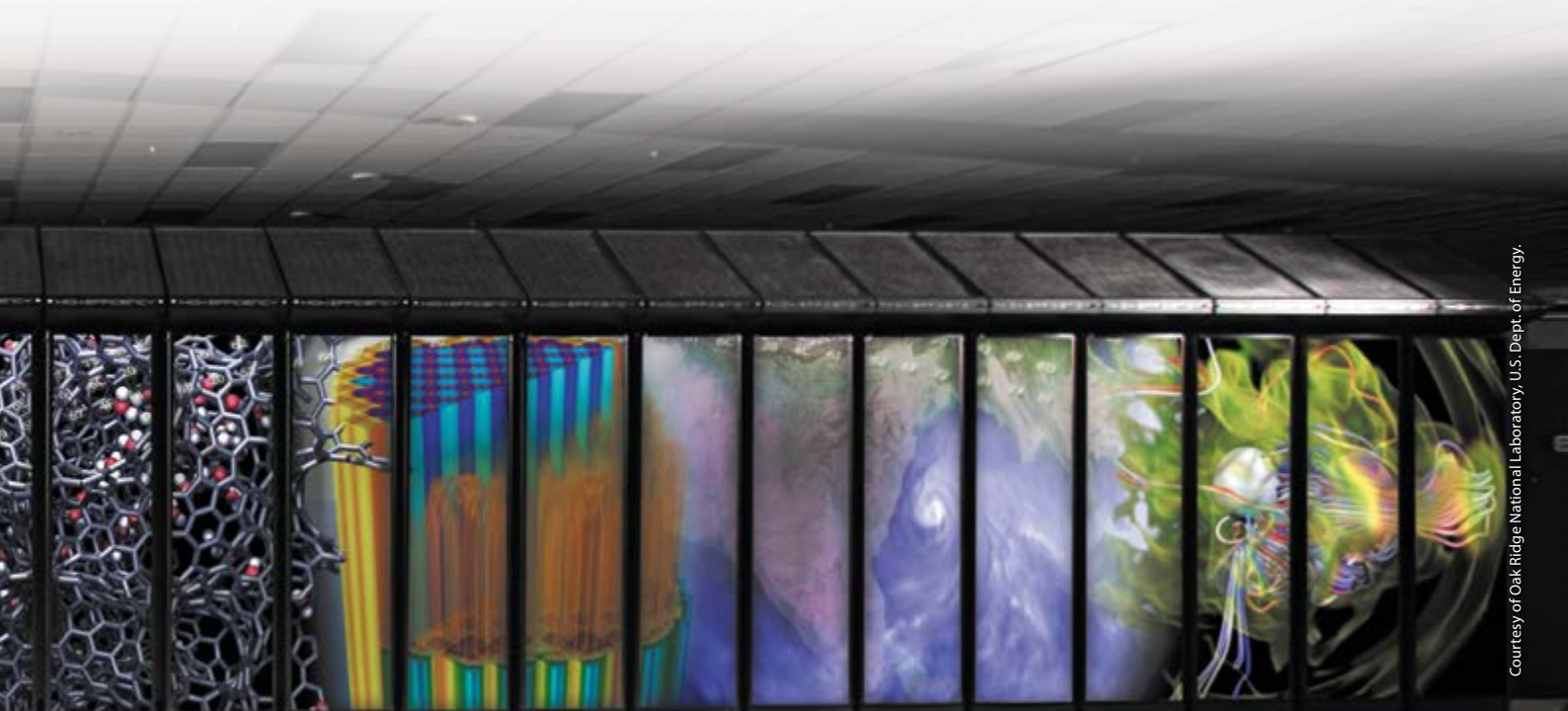
Solving the same problem in a parallel way on a supercomputer with many processors requires some tools not present in conventional programming languages. Although a large number of computer languages have been designed and implemented for this purpose, one of the most popular approaches consists of using a conventional programming language, but extending the language

with a small collection of functions capable of sending and synchronising data or *messages* between processors, a so-called message passing interface or commonly referred to as MPI. It turns out that by using this simple approach a large number of parallel problems can be efficiently programmed.

The example given in the first table can be parallelised by the computer

Table 1: An excerpt from a program written in the C language to compute the area under a curve defined by the function $f(x)=4/(1+x^2)$ in the interval $[0,1]$ using the rectangle (midpoint) method; n is the number of rectangles used and h is the width of each rectangle. The third line is the start of a loop doing the area computation and i is a variable looping from 1 and up to n . The expression $i++$ means that i is incremented by one for each time the loop is executed. The last line computes the final answer, which in this case is the first few digits of the famous number, π .

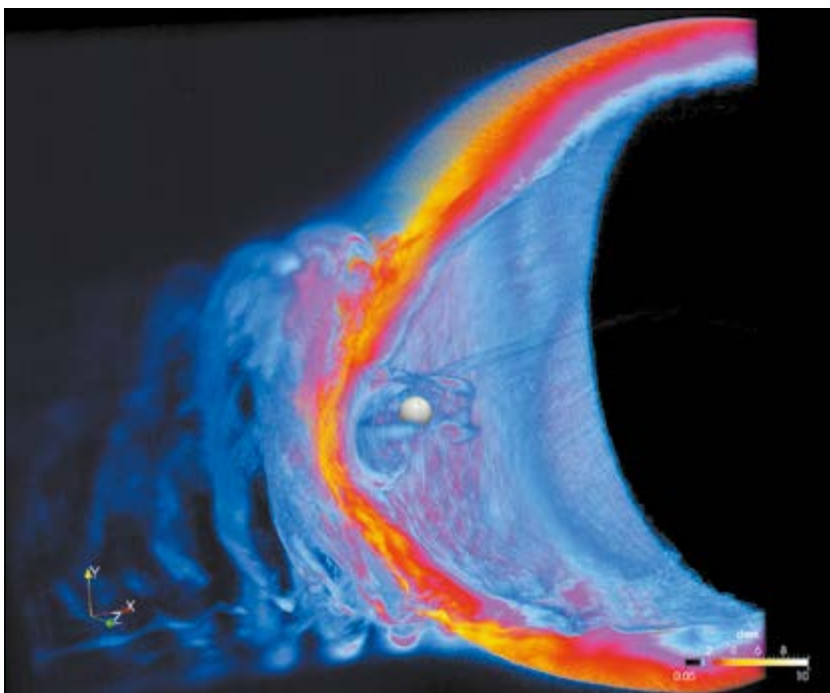
```
n=1000000;
h=1/n;
for (i = 1; i <= n; i++){
    x = h * ((double)i-0.5);
    sum += f(x);
}
pi = h * sum;
```



Recent Advances in Technology

code shown in the second table. We see that the addition of only three lines turns the conventional program into an MPI parallel program. At the start of the computation a copy of the program starts execution on each of the processors we have available. The two first lines are calls provided by the MPI system and provide each of the executing programs with information on the total number of processors (the variable `np`) and a unique number in the range 0 to `np` identifying each processor. Let us assume we have a system where `np` equals 1,000 and that the number of rectangles is equal to one million. The program then works by numbering the rectangles used in the computation from 1 to 1,000,000, and processor number 0 computes the sum of the areas for rectangles number 1, 1001, 2001... and so on up to one million. Processor number 1 does exactly the same, except it computes the sum of the areas for rectangles number 2, 1002, 2002... and so on. When each processor has finished computing their sum, a single MPI Reduce call will combine the sums from each of the 1,000 processors into a final sum. The speedup for this kind of problem is directly proportional to the number of processors used. Running the program in Table 2 using 100 million rectangles on 12 processors gives a speedup of about 11.25, which is roughly what one would expect, allowing some time for overhead. However,

NASA's supercomputing resources have enabled them to exceed previous state-of-the-art magnetospheric models. The figure shows a snapshot from a 3D simulation of the Earth's magnetosphere. The plasma density shows formation of helical structures in front of the magnetosphere. The structures lead to turbulence, which in turn amplifies the adverse effects of space weather on Earth and its technological systems. In this project, a typical simulation ran for over 400 hours across more than 4,000 cores on NASA's Pleiades supercomputer. (Courtesy Homa Karimabadi, University of California, San Diego/SciberQuest; Burlen Loring, University of California, Berkeley).



```
MPI_Comm_size(MPI_COMM_WORLD, &np);
MPI_Comm_rank(MPI_COMM_WORLD, &myid);

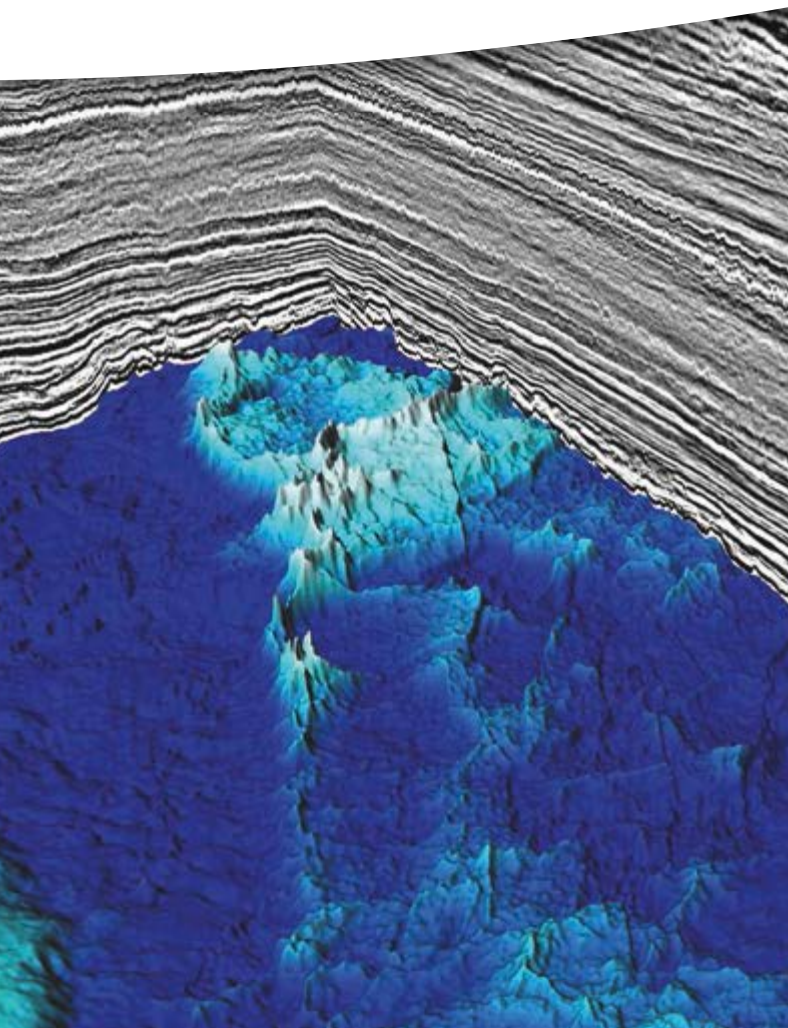
n=1000000;
h=1/n;
for (i = myid+1; i <= n; i+=np){
    x = h * ((double)i-0.5);
    sum += f(x);
}
mypi = h * sum;
MPI_Reduce(&mypi, &pi, 1, MPI_DOUBLE, MPI_SUM, 0, MPI_COMM_WORLD);
```

Table 2: The parallel version of the program shown in Table 1. The two first lines are calls to the MPI system returning the number of processors participating (the variable `np`) and a unique id (the variable `myid`) for each processor. The variable `myid` is a number between 0 and the number of processors. The loop in the fifth line is almost the same as for the program in Table 1, but each processor only computes a subset of all rectangles and stores the resulting sum in the variable `mypi`. The expression `i+=np` increments the loop variable `i` by `np` for each iteration of the loop. The MPI Reduce call in line number 10 adds together all results from each processor and returns this number to processor number 0. In the last three lines, processor number 0 prints the result.

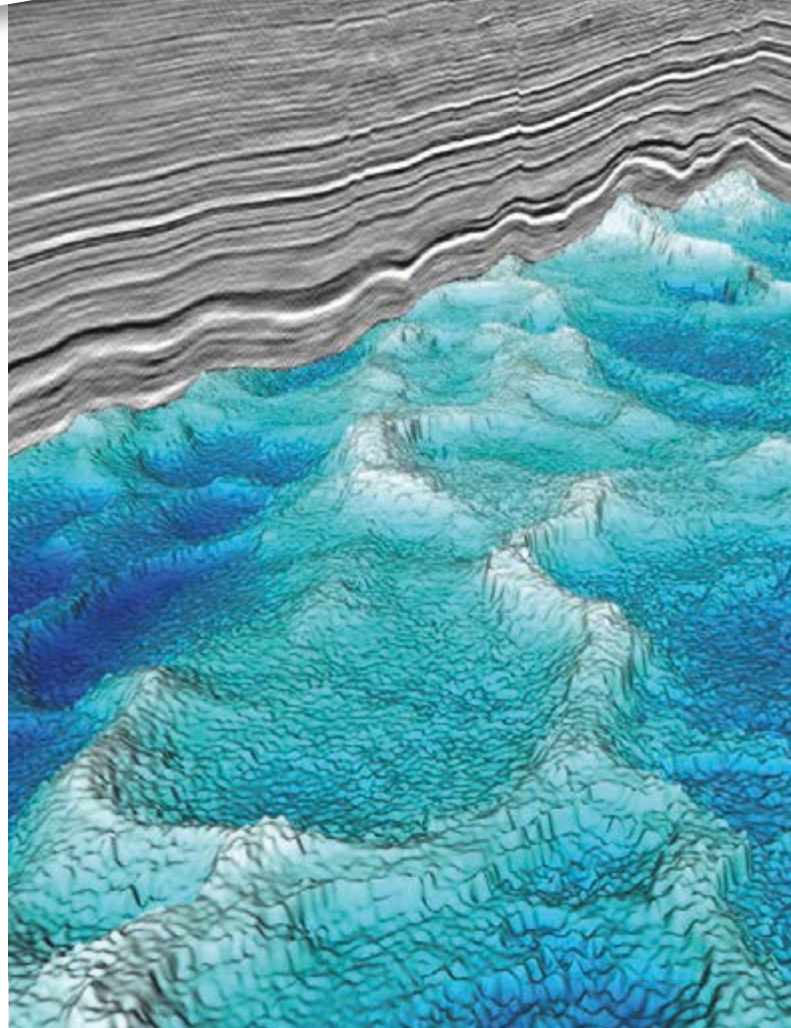
if we increase the number of processors to 120 we will only get a speedup of about 40. This seems puzzling until one realises that 120 processors involve 10 different nodes, since the particular machine used for the test runs is equipped with 12 processors per node. The Reduce call then involves communication between 10 nodes. In general, communication between processors on different nodes takes more time than communication between nodes on the same processor.

Balancing Communication

Not all problems can be split up into independent sub-problems. Often large simulation problems involving the solution of differential equations require large amounts of memory to hold intermediate results exceeding the available memory on each node, or the number of numerical operations is so large that the problem has to be split into smaller parts, or domains, in such a way that each processor is able to deal with each of the domains. This is known as domain decomposition. Each of the smaller domains will usually depend on other domains, and an important issue then becomes the interchange of information at the domain boundaries. Each processor, working on a single domain, requires information from other processors. Hence, some form of communication needs to take place. We have already seen how the MPI system can be used to pass information between processors via the Reduce call shown in the second table. There are in addition a number of calls which can be used to send data from one processor to another. In practice these are relatively easy to use, but the logic and structure of programs rapidly become complicated if the pattern for information exchange is non-trivial. We also learnt that communication between processors on different nodes is expensive in terms of computer time. Hence an important issue is the balance between computing and communication. ■



Q37 and Q29 3D SHarp Broadband Surveys
UKCS



Gohta 3D SHarp Broadband Survey
Barents Sea

The Permian Carbonate Play on the Mid North Sea High and in the Barents Sea

Dolphin Geophysical's Multi-Client data

For further information contact

Ian T. Edwards, ian.edwards@dolphingeo.com | +44 7920 713 587

or Magnar Ullnaess, magnar.ullnaess@dolphingeo.com | +47 9527 69 14



Black & Blue

Using blue sky science data to aid in de-risking black gold exploration.

For nearly 50 years the International Ocean Discovery Program has drilled, cored and measured the earth beneath the sea in search of answers to fundamental scientific questions. Why are companies such as Landmark, a Halliburton business line, interested in this largely blue-sky research programme?

DR. SALLY MORGAN
UK IODP Knowledge Exchange Fellow

Oceans cover more than 70% of the earth, but we still know more about some other planets than we do about the earth beneath the sea. The International Ocean Discovery Program (IODP) and its forerunners have significantly progressed our knowledge of the history and dynamics of earth through a long-standing programme of drilling, sampling, logging and monitoring boreholes across the oceans. Every year a series of two-month long scientific expeditions are implemented, chosen from a pool of hypothesis-driven proposals submitted by the global scientific community. Better understanding of the sub-seafloor will help reveal the internal structure and dynamics of the earth and further enhance our knowledge of climate change, the origins of life, planetary dynamics and geohazards such as landslides and tsunamis.

Similar to IODP, Landmark's Exploration Insights team takes a global and interdisciplinary view in delivering the Neftex Earth Model, which integrates publicly accessible data, including a number of IODP datasets, into an interactive product which facilitates navigation of the earth system through space and time. The model provides an important tool for the hydrocarbon sector in minimising the risk associated with exploration and exploitation of resources.

A Short History of Scientific Ocean Research Drilling

The dawn of plate tectonics theory in the mid-1960s revolutionised the earth sciences, and highlighted the need to better understand marine geology through direct sampling. The Deep Sea Drilling Project (DSDP, 1966–85), established in June 1966, provided a means of doing this, with its programme of drilling and coring operations commencing in 1968. During this phase of the programme significant technological advances related to deep-ocean drilling were also made, including development of a technique to facilitate borehole re-entry.

Since those early years of exploration, DSDP and its successors have contributed significantly to increased scientific understanding of earth history and processes through enabling verification of numerous theories and hypotheses. The Ocean Drilling Program (ODP, 1985–2003), which succeeded DSDP and was marked by increased international collaboration and the introduction of a new, more advanced drillship, the JOIDES Resolution, focused on better understanding the composition and structure of the sub-seafloor. Discoveries during this phase of the programme led to the birth of new disciplines in earth sciences, including the field of palaeoceanography.

The D/V Chikyu at sea off Japan.



In 2003, ODP came to an end, transforming into the Integrated Ocean Drilling Program (IODP1, 2003–13) that enhanced international cooperation and increased capability through the introduction of two new drilling platforms. The riserless vessel *JOIDES Resolution*, hosted by the USA, was joined by a riser vessel, *Chikyu*, hosted by programme partner Japan, both ships being dedicated drilling vessels equipped with permanent drilling and state-of-the-art scientific laboratory facilities. A third platform, known as ‘mission-specific’ platforms, coordinated by a European consortium, contracts especially chosen vessels to meet the specific needs of a particular project. Such needs have historically included operating in ice-covered regions, in very shallow waters such as those off New Jersey and in environmentally sensitive areas.

The International Ocean Discovery Program (IODP, since 2013) is the fourth and current evolution of this scientific programme centred on ocean research drilling, continuing to sample a wide variety of geological formations around the world. An international consortium of 26 countries, including the USA, Japan, UK and numerous European partners, IODP continues to be a multidisciplinary collaboration between scientists, students, engineers, technicians and educators. The programme retains its central aim of extending sub-seafloor exploration, but with an increased emphasis on scientific outputs that are societally relevant. IODP is diversifying by continuing to operate with three platforms and with increased collaboration with industry and other third parties through, for example, co-funded ventures.

Geography, Geology and Data

IODP has undertaken drilling projects across the world’s oceans from the Atlantic to the Pacific, from the Arctic to the Southern Ocean, and beyond. Some studies are centred on the continental shelf and a huge number have taken place in the deep ocean. One of the current programme’s primary objectives is to further our understanding of ice sheet responses in a warming world. High latitude expeditions to both the Arctic and Antarctic in 2018 will make significant contributions to this endeavour.

The breadth of the scientific questions addressed by the programme ensures an equally diverse range of geological formations have been drilled, cored and logged. These include siliciclastic shelf deposits, deep-sea sediments, carbonates and corals, landslide deposits and volcanic basement.

Uniquely, IODP is a legacy scientific programme with data and samples routinely made publicly available after a one-year post-project moratorium. The programme has developed to undertake a set of minimum and standard measurements on every



John Beck, IODP/TAMU

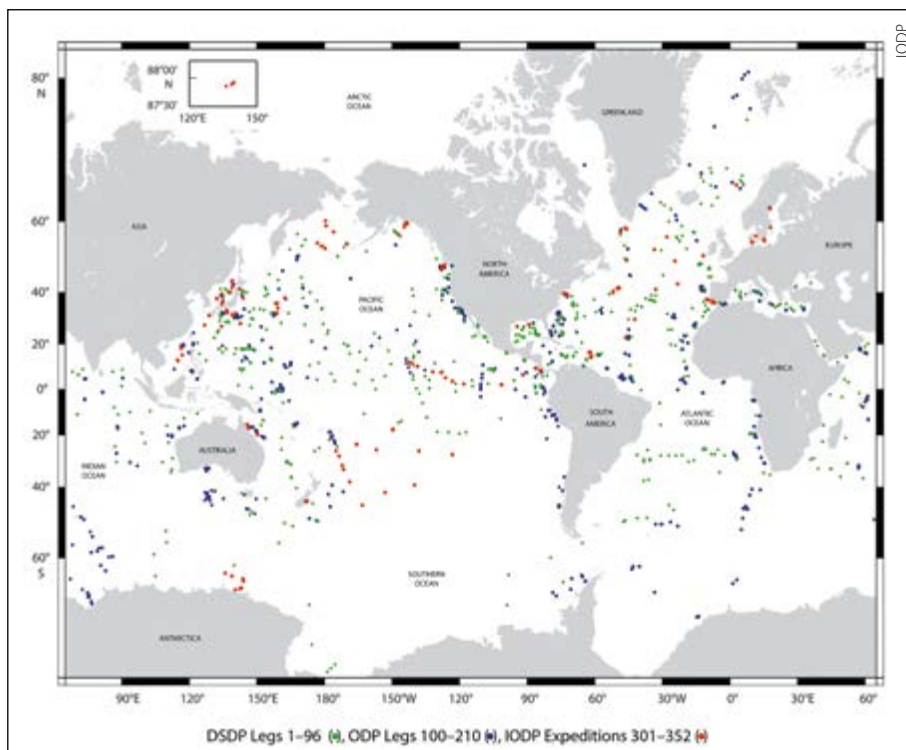
The R/V JOIDES Resolution on site during Expedition 334, Costa Rica Seismogenesis Project.

expedition, regardless of the project’s scientific objectives. These measurements include detailed core description, petrology, structural geology, palaeomagnetism, geochemistry, palaeontology, biostratigraphy, physical properties and downhole measurements, and these are often supplemented by additional project-specific measurements, such as microbiology and borehole monitoring. The combined diversity in geography, geology and data type represents a vast and invaluable public resource.

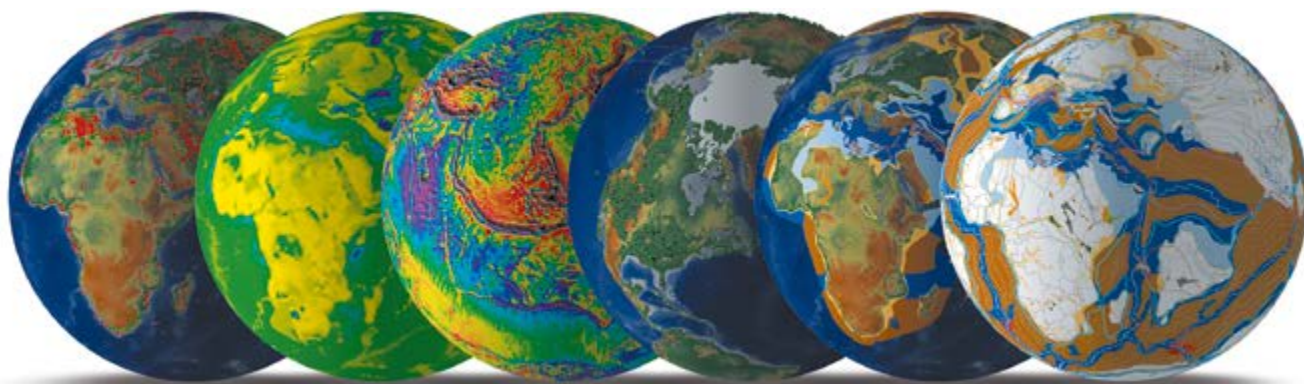
A Model of the Earth

Landmark, like IODP, adopts a multidisciplinary and global approach in its endeavours. The Neftex Earth Model, a database

Location map of sites drilled and sampled by DSDP, ODP and IODP.



IODP



Landmark

Image of Neflex Earth Model.

illustrating the stratigraphic development of earth through both space and time, utilises an array of geological data represented in a sequence stratigraphic and geodynamic framework. It is not only historical, but also predictive. The model is transformative in facilitating understanding of the subsurface, providing scope to help both understand and minimise risk in hydrocarbon exploration and investment activities.

The Neflex Earth Model fully integrates published geoscience data into an interactive globally consistent product delivered via a web-interface which users can supplement with their own data and expertise. The model, comprised of a global grid of petroliferous regions, also includes a library of over 100,000 pieces of literature, which can be rapidly and specifically searched. The data used to populate the model are all public data, accessed from various publishers, national and international data repositories and geological surveys. Mining of these data and ensuring consistency across the datasets is clearly a huge undertaking, especially where numerous sources for a particular data type are used.

The Neflex Earth Model utilises five key IODP datasets: stratigraphy; biostratigraphy; organic geochemistry; physical properties; and downhole measurements. These data provide invaluable constraints on dating plate tectonic processes, being readily incorporated into the geodynamic modelling of past plate motions to better refine palaeo-plate tectonic processes. In addition, the Neflex Earth Model accurately represents palaeoclimate at precise intervals of deep geological time and these attempts at modelling can only be rigorously ground-truthed via the well-dated geochemical proxy data routinely collected by IODP and its predecessors. With its open-access online databases, IODP clearly provides a wealth of information to both the scientific and commercial sectors. IODP has sampled areas that the hydrocarbon industry has not yet drilled, so the IODP datasets are invaluable for populating models such as the Neflex Earth Model, often providing critically unique data-points in certain geographic regions. These unique data-points

are particularly important for providing insight into these undrilled regions, especially as the hydrocarbon sector looks to explore frontier and non-traditional resource environments where subsurface risk is especially poorly understood.

Future for Industry-Academia Collaborations

To date, the relationship between Landmark and IODP has been a relatively passive one, with the Landmark Exploration Insights team utilising the open-source data via the programme's databases and publications. In keeping with the philosophy of IODP, the contribution of the data to the Neflex Earth Model facilitates improved understanding of the earth. In doing this it maximises the use of IODP data for purposes over and above the original projects for which the data was originally acquired. Realising the potential of the IODP datasets and the science arising from expeditions in this way is all-important for securing the future of the programme. Landmark continues to contribute to this goal, not only through utilisation of numerous data types but also through referencing of IODP publications.

Moving forwards, there is clearly potential for enhanced interaction between the two organisations. The highly integrative nature of the Neflex Earth Model and its impressive web-interface are certainly features for IODP to aspire to for improving the accessibility of publicly available data. For now, IODP will continue to generate invaluable and diverse data and samples through its programme of exploration, with expeditions currently scheduled into 2018. ■

Screenshot of the Neflex Earth Model interface.



Landmark

**We offer spectacular
views of Norway.**



We're Rock Solid.



For this year's APA and 23rd licensing rounds, the company to look to is RSI. Our experience in Norway is unmatched. We have worked on more than 660 wells in the region and our experience in the quantitative interpretation of seismic and CSEM is second to none.

Additionally, our interactive regional studies connect you to key petrophysical, rock physics, seismic and AVO data displays, giving you the modeling versatility you need to accurately assess prospectivity and reduce geologic risk.

Whether you're targeting prospects in the Barents Sea, Norwegian Sea, or the North Sea, our team of experts will give you the complete view.

Call RSI, and let's succeed. Spectacularly.

rocksolidimages.com/Norway

HOUSTON | STAVANGER | LONDON | VILLAHERMOSA | SHEFFIELD

Dedicated to the Industry

Mahmoud Abdulbaqi, retired VP of E&P at Saudi Aramco, and one of the founders of the Bahrain GEO series of conferences, tells us about his career and his belief that the way forward for the industry is through finding, educating, training and retaining the right people.

JANE WHALEY

“When I was a teenager, my uncle gave me a present of a book about the Mohole Project – an ambitious attempt in the 1960s to drill through the Earth’s crust into the Mohorovičić discontinuity. I was fascinated by the idea that by drilling such deep cores we could gain an understanding of the earth, and from that day I knew I wanted to be a geologist.”

So explains Mahmood Abdulbaqi, a veteran of 45 years in the hydrocarbon industry, who retired from his role as VP Exploration and VP of Petroleum Engineering and Development for Saudi Aramco in 2005 and is now Chairman of Saudi geophysical company, Argas.

Rising through the Ranks

Mr Abdulbaqi was born in Palestine but when displaced moved many times in his early years, having lived in Lebanon, Syria, Jordan, Iraq, Kuwait and the United Kingdom before he eventually arrived in Saudi Arabia in 1971. He is now a Saudi national.

“I obtained my first degree from the University of Baghdad, which had a very good geoscience programme, with links to the University of Texas at Austin and lectures by senior Iraq Petroleum Company (IPC) personnel,” he explains. “Although I was always interested in the hydrocarbon industry, when I graduated in 1966 it was in one of its periodic troughs and so I worked for a couple of years in engineering geology, on dam construction in Jordan, and also spent three years lecturing in Kuwait. Eventually, companies started hiring again and Saudi Aramco contacted me in response to my earlier application. In 1971 I moved to Saudi where I met my wife and the rest, as they say, is history.”

“My wife also worked for Saudi Aramco for 26 years; she was one of only four or five Saudi professional women in the company in those days, although things have changed a lot since then and there are now thousands of Saudi women working in it.”

Mr Abdulbaqi started as a wellsite geologist, soon rising to be head of his group, and then worked in oilfield development and reservoir geology, before moving to the exploration group in Saudi Aramco’s processing centre near London. His wife took temporary leave from the company and the family joined him in the UK,

living near the famous Kings Road in London.

“However, as they began building capacity in Saudi the processing centre was moved to the Dhahran ‘Expec’ (Exploration and Petroleum Engineering Centre), and in 1986 I became the company’s first non-expatriate General Manager of Exploration.

“Saudi Aramco has grown a great deal since those days,” he adds. “At that time we only operated in Saudi Arabia, producing 4.5 MMBopd; now the company is in China, South Korea, the United States and many other countries and employs over 60,000 people, producing about 10 MMBopd. It no longer just operates primarily in the upstream sector, but is also heavily involved in petrochemicals and refining. It was very exciting to be involved as this growth was happening – I was made Vice President of Exploration in 1991, while we were

developing some of the largest reservoirs in the world. Being in the exploration department is always fascinating, as not only are you finding oil and



Argas

gas, but you are also involved in the geoscience of oilfields and their development.”

During his years with Saudi Aramco, Mr Abdulbaqi held the positions of Chief Exploration Geologist and Chief Production Geologist, was a member of the Saudi Aramco Executive Advisory Committee, the Planning Advisory Committee, and the Board of Directors of the Arabian Drilling Company. He also took an MBA through Columbia University Business School and is a graduate of the Management Program at Georgetown University Law Centre in Washington, D.C. He finally retired from the company in October 2005, by which time he was Vice President of Exploration and Vice President of Petroleum Engineering and Development.

Professional Societies Important

Having been an active member of professional societies like the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Engineers (SPE) since the very start of his career, Mr Abdulbaqi believes they serve a very important function, particularly in encouraging the younger generation. From 1999 to 2002 he served as the first President of the Middle East Region for the AAPG and he was also on the association’s Advisory Council. In 2003, the AAPG gave him the great honour of awarding him the status of Honorary Membership, a rare accolade. He was also the first non-European President of the European Association of Geoscientists and Engineers (EAGE) and is still involved in their student fund activities. He is also a member of the Society of Exploration Geophysicists (SEG).

He was involved from the outset with GEO, the well-reputed Middle East geosciences conference and exhibition, held biennially in Bahrain.

“MEOS – the Middle East Oil Show, sponsored by the SPE – started in 1979”, Mr Abdulbaqi explains. “It featured a few geoscience sessions, and I was involved in those, but we realised there was no proper forum to address exploration topics in the Middle East. I therefore became a founding member of the Dhahran Geosciences Society (DGS) and we soon recognised that we needed our own conference. We talked to the AAPG about setting something up in the Middle East, but they didn’t have the appropriate resources at the time, so we decided we would develop the idea ourselves. MEOS was every two years, so there was an obvious slot in the conference schedule. Bahrain-based Arabian Exhibition Company, which organises MEOS, agreed to organise the exhibition, with DGS organising the conference part, while Saudi Aramco gave a lot of support to the idea and its implementation. Bahrain was the perfect host country.

“GEO 1994 was the first Middle East-based geoscience conference, and I have been heavily involved with it ever since, and still serve on the executive committee of GEO. For me, this is a way of giving back to the industry I love,” he continues. “It’s good fun and I really enjoy working with people, plus I have established great contacts all over the world.”

Preparing the Next Generation

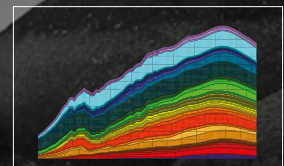
Passionate about the oil and gas industry, Mr Abdulbaqi now

PROVIDING TRANSPARENCY IN THE OIL & GAS BUSINESS

UCUBE

A REVOLUTION WITHIN E&P
BUSINESS INTELLIGENCE

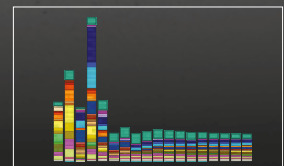
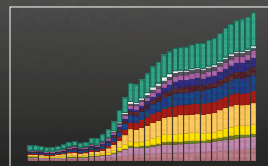
- Field-by-field oil & gas database
- Complete coverage & fully integrated
- 65,000 assets & 3,200 companies
- Reserves, production & financial profiles
- Time span from 1900 to 2100



DCUBE

A UNIQUE TOOL FOR OIL SERVICE
MARKET RESEARCH

- Oil service database based on 65,000 assets from UCube
- E&P spending from all fields & licenses globally
- Total expenditure split by hierarchy of oil service segments
- Oil service market forecast split by geography, operators & projects
- Market forecast to 2030



RYSTAD ENERGY

WWW.RYSTADENERGY.COM

indre.net

expends considerable energy inspiring people to enter it and to develop good exciting careers in all aspects of it.

“As I moved up the career ladder I realised that developing people had become the most important part of the job, taking up to 60% of my time,” he says. “I became particularly interested in ensuring that our young nationals are well equipped to take on more fulfilling roles within the company. We established an excellent programme to aid their development, with connections with prestigious educational establishments such as Stanford University, Colorado School of Mines, MIT, the University of California at Berkley, Imperial College, and Delft University, so we could prepare the younger generation to take over from us.

“That was fun to do, I really enjoy working with the younger generation. I have continued doing so since I left Saudi Aramco: helping young students, finding them placements, and mentoring. Through the EAGE I visited many countries, meeting with students from different nationalities and cultures; I helped establish the EAGE student fund and was active in getting industry donations. I am also involved with the EAGE Geo-Quiz programme at their annual meeting.

“I would like to see the industry continue to grow and expand, but it must be based on solid ground,” he continues. “We need to do more to ensure we are taking on the right people who are dedicated to this industry. This is not just a human resources issue; line organisation has an important role to play and must be integrated into individual training and development programmes. It is, of course, a two-way process, and both the employee and the organisation need to contribute. There are no short cuts in the people business and we must commit time, effort and resources to it even in difficult times to get the best return on our investment. Continuity and commitment from high level people in the organisation – both are important.”

Promoting the Industry

Mr Abdulbaqi feels passionate about the importance of engaging all young people, not just those who are working in the oil industry or involved in studies leading to a career in it. “We should start with our schools and encourage and support science and maths programmes in them.

“In the oil and gas business we don’t promote ourselves well at all. When the industry is talked about, people think of flaring, fumes, pollution etc. – but they need to look at what it does for all of us,” he says. “It provides three-quarters of the energy of the world and we cannot have economic growth without it. Oil and gas provide us with sophisticated petrochemical products like plastics for a huge range of uses, including for modern medical procedures; basically, we need petrochemicals for the well-being of humans. It’s an exciting, high tech industry.

“To get that message across we must interact with young people in our schools and universities at all levels. Saudi Aramco has a very good programme to help this. Youngsters are invited to visit the company’s modern interactive oil exhibit in Dhahran, which demonstrates all stages of the industry. Even the bus transport for school children in the immediate area is provided, while mobile oil exhibits visit schools further away. The students can play and interact with this and learn about the importance of the industry in the process. Saudi Aramco also

has good connections with King Fahd University of Petroleum and Minerals in the Eastern Province and with the research centres of the Dhahran Techno Valley, and was heavily involved in establishing the King Abdullah University of Science and Technology in the Western Province, a graduate research school. Saudi Aramco is still a significant partner.

“In general, as an industry we are not doing a good job of explaining what we do or how we are affecting everyone’s lives in so many ways,” he adds.

Living Life

Although he retired from Saudi Aramco about ten years ago, Mr Abdulbaqi is still working, both as a consultant and as a board member of a number of companies. He is Chairman of geophysical company Argas, which is jointly owned by TAQA of Saudi Arabia and CGG of France. This started as a geophysical acquisition contractor in Saudi Arabia, but now covers the Middle East, in fields which include not just seismic data acquisitions, but also advanced processing, reservoir characterisation, integrated geophysical solutions, gravity and other non-seismic methods. He is also a board member of Houston-based Quantum Reservoir Impact (QRI). He was also recently Chairman of the International Petroleum Technology Conference Board (an annual event rotating between Asia Pacific and the Middle East), and still serves as a member of that board. He seems to have no intention of slowing down.

Just as well, then, that Mr Abdulbaqi and his family love travelling: “Ask me where I haven’t been,” he laughs.

“I like what I do, and when you enjoy your work you have the energy to go on and progress comes naturally,” he explains.

“Some people live life and some just travel through; I like living it!” ■

Mahmoud Abdulbaqi when he was the first non-European President of the EAGE.



A Unique Opportunity

Exploration interest in the North Sea is extending beyond the traditional areas and casting its eye upon frontier plays.

WILLIAM REID and STEFANO PATRUNO, PGS

In this article we will show how the technological advancements of the dual-sensor broad bandwidth GeoStreamer® data reveal a new level of detail, highlighting structures not previously visible. We apply this to the definition of multiple Palaeozoic, Mesozoic and Cenozoic plays in UKCS Quadrants 9, 14, 15 and 16. Upper Jurassic deltaic to marine sandstones are the most important reservoir units on the platform margins (e.g., Claymore, Piper, Tartan), whilst the proven and potential targets on the main East Shetland Platform (ESP) range from Eocene to Palaeozoic in age (e.g., Mariner, Cairngorm).

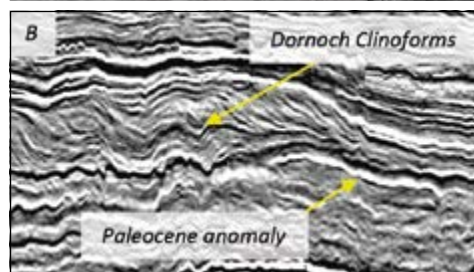
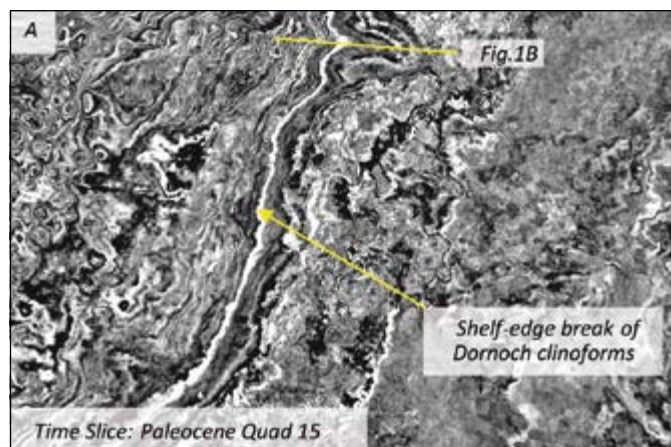


Figure 1. A) Time slices through MC3D-Q152014 (dual-sensor), showing a clear shelf-edge break representing the Dornoch clinoforms. B) MC3D-Q152014 (dual-sensor) west-east-oriented seismic cross-section through the lower Eocene 'Dornoch Delta'. An undrilled additional amplitude anomaly is visible in folded upper Paleocene reflectors, just below the clinoform bottomsets.

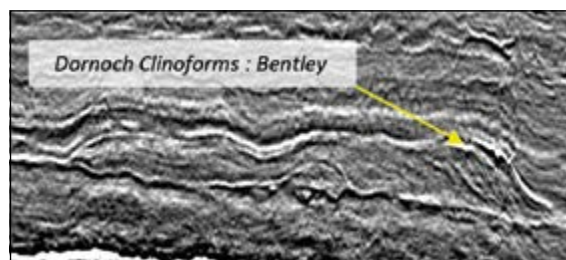


Figure 2. MC3D-BBK2011 (dual-sensor) west-east-oriented seismic cross-section through the Bentley Field (Upper Dornoch Sandstone).

Tertiary Potential

The Tertiary plays on the platform target shallow marine and turbiditic Paleogene sandstones, with key fields within the Dornoch, Lista, Sele and Vale formations (e.g., Mariner, Bentley, Kraken, Yeoman, in UKCS Quads 9 and 15). The high-fidelity of the GeoStreamer data improves imaging and interpretation in the Tertiary reservoir targets (e.g., Dornoch clinoforms, Figures 1–2). The additional undrilled Paleocene prospectivity of the Forties, Balmoral and Heimdal sandstones (Figure 1B) are also clearly identifiable and highlight new potential in this frontier area.

Palaeozoic and Mesozoic Potential

Several hydrocarbon discoveries in the Central North Sea have a working Palaeozoic (e.g. Cairngorm) or Early Mesozoic (e.g., Crawford) reservoir, proving the regional exploration value of these reservoir targets.

Fractured crystalline basement constitutes a reservoir component in hydrocarbon discoveries on the West of Shetland (e.g., Lancaster), Utsira High (e.g., Cliffhanger North, Edvard Grieg) and the eastern East Shetland Platform areas (Cairngorm). The Devonian alluvial 'Old Red Sandstone' forms a reservoir component in several hydrocarbon fields and discoveries, including Clair, Buchan, Stirling, Embla and Alma/Argyll. Buchan and Clair in particular are large fields (respectively, 220 and 1,100 MMboe total recoverable reserves), producing 25–34° API oil.

Carboniferous or Lower Permian Rotliegend sandstones are reservoirs in the Innes and Auk fields, in the South West Central Graben, and a subordinate component in Claymore and Highlander fields (UKCS Quad 14). Upper Permian fractured carbonates represent the main reservoir in Auk and Argyll/Alma and a subordinate component in other large fields, including Claymore, Johan Sverdrup and Ettrick.

GeoStreamer enables improvements in seismic imaging in the deeper pre-Cretaceous section and has allowed the interpretation of the Palaeozoic horizons over the entire East Shetland Platform region for the first time, shedding new light on its evolution. Structural closures can now be mapped with confidence. A few of these are shown in Figures 3 and 4 (see page 45). In particular, Figure 3 highlights undrilled Permian mini-diapirs with overlying potentially evaporite-cored Triassic-Jurassic anticlines. Furthermore, significant Permo-Carboniferous mini-basins and large Devonian structures (e.g., fault blocks and faulted anticlines) are clearly interpretable (Figure 4). These features are often truncated by the Base Cretaceous Unconformity (BCU) and sealed by the overlying Cretaceous and Tertiary strata.

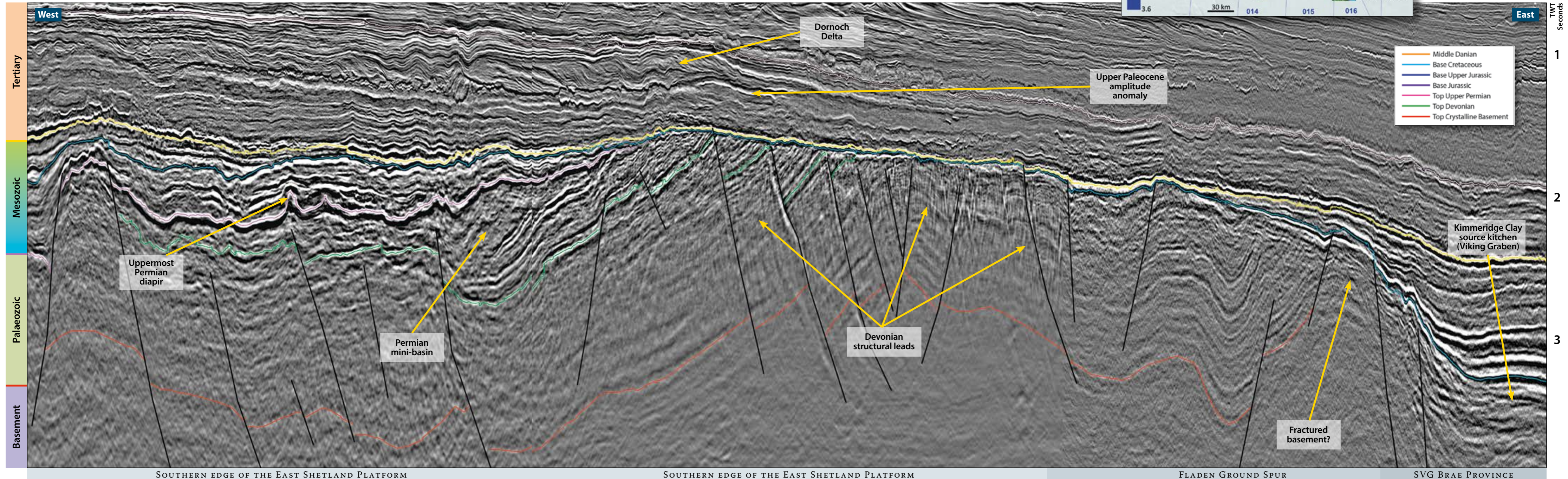
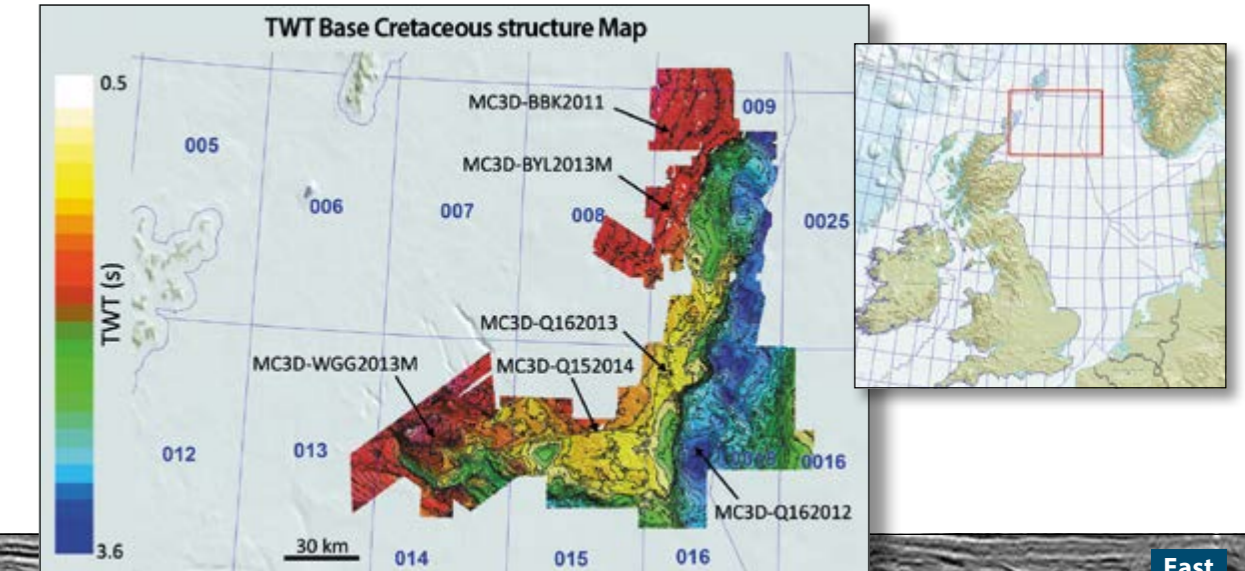
Continued on page 45 ►

The East Shetland Platform

A Clearer Image: Unlocking the Platform Potential

With significant advancements in seismic acquisition technology, it is time to re-visit the East Shetland Platform.

PGS dual-sensor broadband GeoStreamer® data has revealed significant Palaeozoic to Eocene potential on the East Shetland Platform. The section below identifies features which have never been seen in such detail before. With clear structures now seen at depth, this article aims to highlight the key tectono-stratigraphic elements within this exciting frontier area. It furthermore seeks to address some of the questions relating to the long migration pathways of the classical Kimmeridgian source and the viability of a Devonian source rock.



► Continued from page 41

Source Rock and Maturation History

Source rocks for the existing discoveries and additional leads on the platform could be provided by the upper Jurassic Kimmeridge Clay Formation. This unit is, however, thought to be immature over the East Shetland Platform, and lateral migration from the Moray Firth and Viking Graben source kitchens is understood to provide the charge for fields along the platform margins. With questions surrounding long distance migration of this source, additional source potential, possibly from Devonian lacustrine shales, must be considered. The Devonian lacustrine shales are proven in the Inner Moray Firth (e.g., Beatrice Field), and several wells drilled Devonian source rock intervals over the East Shetland Platform (particularly, in UKCS Quads 9 and 14).

The key risks associated with the Devonian source rock are its distribution and the timing of maturity. If generation occurred early on, initial hydrocarbon accumulations might have been breached due to the later complex pre-Cretaceous tectonics. Temperature data from wells and geothermal gradients in geological analogues calibrate respectively the Palaeozoic and the present-day maturity model (Figures 5–6). In particular, Devonian mean geothermal gradients were constrained by post-orogenic extensional collapse analogues (c.f., West Italy, East Africa). Permian evaporites caused a geothermal decline; Jurassic rifting increased the gradient.

Seismically constrained thermal history modelling indicates that the Kimmeridge Clay is thin and at best marginally mature away from the graben axis. Furthermore, the mid Devonian source rock timing of maturation varies semi-regionally, but there are areas (e.g., Q14–15, Crawford area) where peak thermal maturation is believed to have been reached after the Jurassic. This post-dates the uplifting events which could have breached early hydrocarbon accumulations (Figures 5–6).

Glennie (2009) points out that higher sulphur oil is found in major Witch Ground Graben fields, such as Claymore (Figure 5), Tartan and Buchan. He suggests that this either represents a more sulphur-rich Jurassic facies or a contribution from a Devonian source rock. Our analysis of a well close to Claymore (Figures 5–6) suggests that peak maturation of the mid Devonian was reached from the mid Cretaceous, which is compatible with migration into Jurassic structural traps, such as Claymore itself.

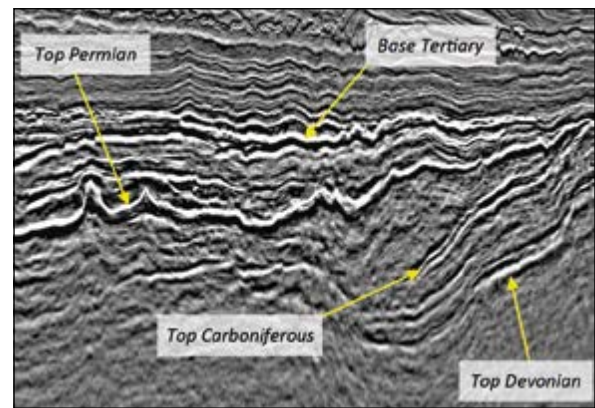


Figure 3. West-east-oriented seismic cross-section through the MC3D-Q152014 dual-sensor, highlighting a Permian mini-basin and associated halokinesis and detachment of Permian evaporites.

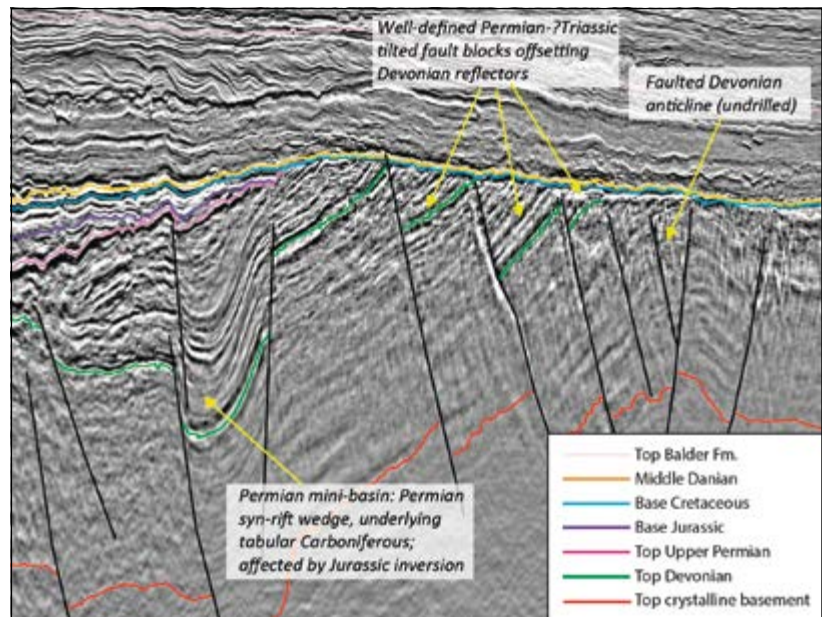


Figure 4. West-east-oriented seismic cross-section through the MC3D-Q152014 dual-sensor dataset, showing large tilted fault blocks associated with an anticline in the Devonian, as well as a faulted Permian mini-basin.

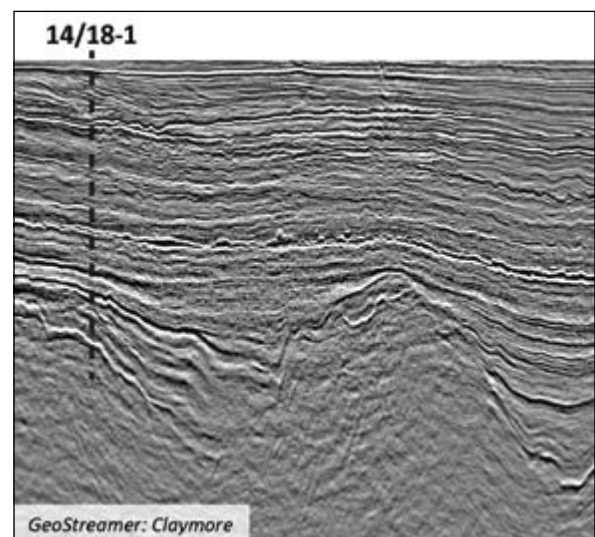


Figure 5. Dual-sensor seismic cross-section (MC3D-WGG2013M) across the Claymore ridge and the 14/18-1 well. Total subsidence curve for this well is shown in Figure 6.

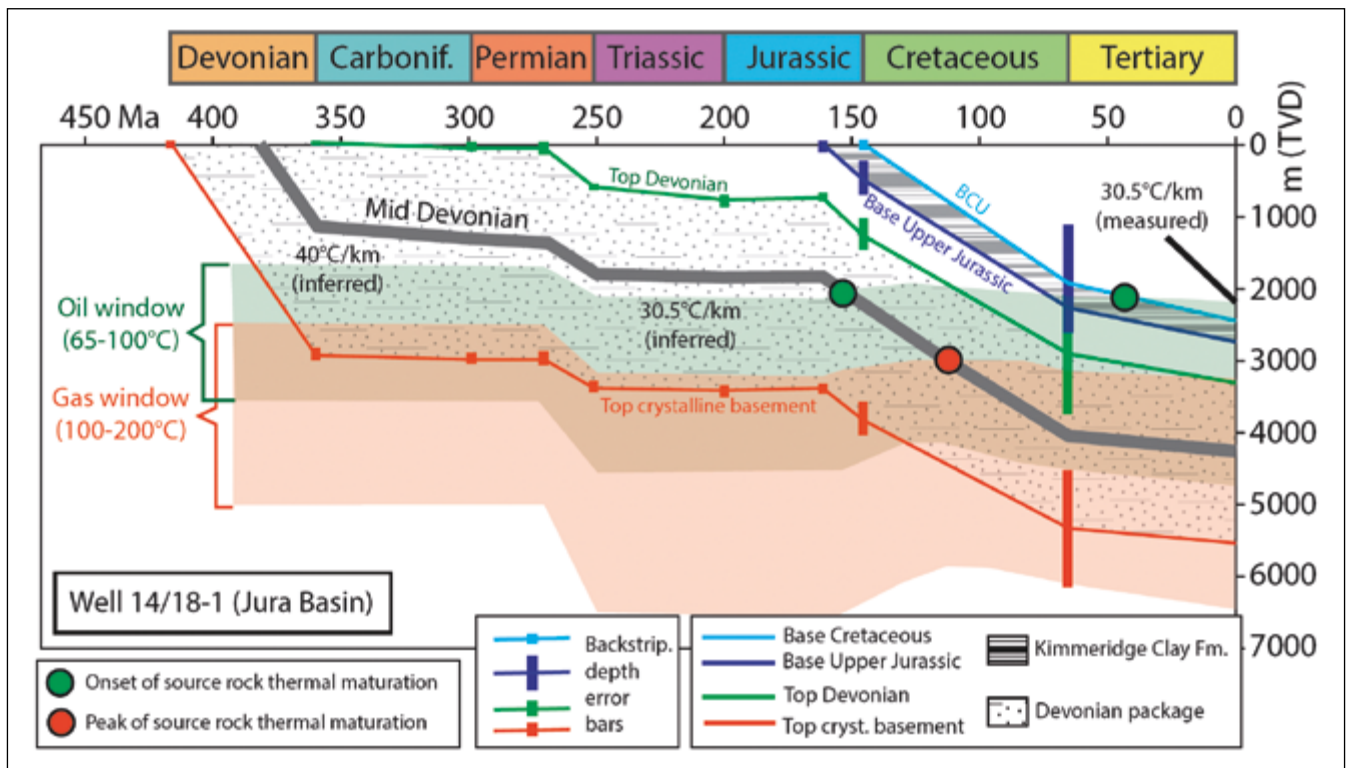


Figure 6. Total subsidence curve below present-day sea level of backstripped 14/18-1 (Figure 5) versus modelled depths of oil and gas maturation windows.

Summary

The East Shetland Platform and the surrounding Central North Sea area have many proven Devonian-Eocene fields and may still contain 1.9 Bbo and 3.4 Tcfg (USGS, 2005). Multiple plays have been identified across the platform area and include Palaeogene deltaic, shelfal and deep-water sandstones, Triassic and Jurassic sandstones, Permo-Carboniferous carbonates and sandstones, fractured Devonian sandstones and fractured basement in prominent structural traps. The Palaeozoic plays, in particular, have been successful in large fields such as Buchan, Clair and Auk, proving these units to be viable reservoirs, producing fields with >100 MMboe of ultimate recoverable reserves.

Potential oil-prone sources in the East Shetland Platform and Moray Firth regions may be provided by Devonian shales (e.g., Beatrice Field). Provisional burial history modelling indicates that the best case scenario (late generation / expulsion) is viable over parts of the East Shetland Platform area, thus reducing the requirement of a long lateral migration from the Kimmeridge Clay source kitchen.

As 76% of the 205 wells penetrating pre-Jurassic units on the platform areas were drilled in the 1970–80s based on vintage seismic data, the East Shetland Platform remains poorly understood. With the acquisition of several recent 3D dual-sensor towed-streamer broadband surveys by PGS, there is now a unique opportunity to view the Palaeozoic reflectors with significantly more clarity (Figure 7). The existing coverage, combined with new 3D GeoStreamer acquisition over Quadrants 3 and 8, is allowing the true geological story and prospectivity to be unravelled. ■

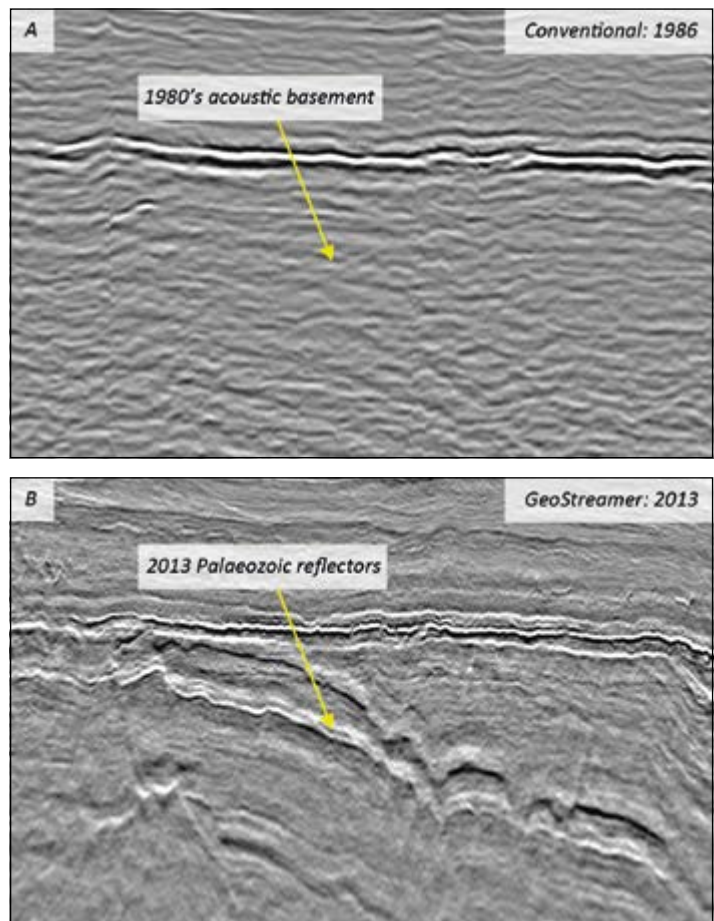


Figure 7. North-south oriented seismic lines across the platform west of the Beryl Embayment, showing a conventional (A) versus GeoStreamer (B) comparison. The significant advances in seismic acquisition technology are highlighted by the sub-BCU acoustic basement (A) becoming well imaged Palaeozoic reflectors (B).



CASPIAN STUDY

GWL invites to participate in the Caspian Study scheduled to commence in **Q2 2016**.

The Study consists of a new **9,685 km** grid of reference lines including **GWL Seismobuoy™** refraction seismic, designed to tie together the major geological provinces and structures of the Northern, Central, and Southern Caspian Sea.

Study Objectives:

- Understand the regional geology of the Caspian basins
- Reveal the major elements of the Earth’s crustal architecture
- Provide high quality deep depth imaged exploration seismic data and refraction data integration
- Provide new insights into the evolutionary model of this region

Reflection:

Streamer 12 000 meters
Recording 50m pop in 18 sec
Source > 5,000 cu in
Energy output > 110 bar-m

Refraction:

Recording instrument **GWL SEISMOBUOY™**
Recorded offsets up to 150 km
Buoy Spacing 2-10 km

Shallow water areas data will be acquired with the help of contemporary high-sensitivity seismic recording systems.

The Program commences in Q2 of 2016 with the first deliverables being available by Q3 of 2017.

Program participants have an opportunity for a technical input and to influence the Study priorities as well as first access to the results.

The Petroleum Gulf

Oil Discoveries off the Arabian Shore

MICHAEL QUENTIN MORTON

The pearl industry, which had once been the mainstay of the Gulf states, was in decline when the first oil was struck on Bahrain in 1932. Discoveries in Saudi Arabia and Kuwait followed in 1938, and Qatar in 1940. It dawned on the oilmen that there was a good possibility of finding oil offshore in the region: the Arabian side of the Gulf has similarities with the Gulf of Mexico, where the modern offshore oil industry began, both having relatively shallow waters conducive to drilling from simple structures or barges.

After a lull during World War II, interest in offshore exploration revived, spurred on by President Truman's proclamation of 1945, which effectively extended US jurisdiction over the natural resources of the subsoil and seabed of its entire continental shelf. Similar proclamations followed in 1949 from the rulers of the Arabian littoral, the Gulf sheikhs, in respect of their own seabed resources. But there were serious logistical obstacles to working offshore, since the Gulf sheikhdoms were undeveloped, lacked basic infrastructure and bore no comparison with the commercial environment of the United States at that time. Great Britain was the predominant foreign power in the region, and sought to restrict the access of non-British firms through a network of treaties and undertakings with the local rulers.

In Saudi Arabia, where British influence was waning, the government decided to work with the onshore concessionaire, the Arabian American Oil Company (Aramco). In 1939, Dick Kerr, an Aramco geophysicist, had drawn a red arrow on a map of north-east Saudi Arabia, writing alongside: "possible high area offshore". The arrow pointed out into the Gulf past a hooked spit of white sand called Safaniya, translated as "the place where navigators meet". In 1949, offshore drilling began there and Kerr's prediction proved to be correct, with the "high area" indicating the presence of an

In that gulf, there was no continental shelf; its waters were not very deep and nowhere exceeded 75 fathoms. The geologists had ascertained that the geological structure of the soil beneath the sea was the same as that of the adjacent territory which contained immense reserves of mineral oil. Consequently fantastic deposits of oil would certainly be discovered.

Judge Manley O. Hudson, 1950

Casting the lead aboard SS Bandra off the Saudi Arabian coast in July 1935. The shallowness of the Arabian Gulf often required soundings to be taken, but also made it highly accessible for oil exploration.



Source: John D. Mountain, Smithsonian Library

oil reservoir thousands of feet beneath the seabed. This turned out to be the first of many discoveries in the Gulf – and the largest offshore oil reservoir in the world.

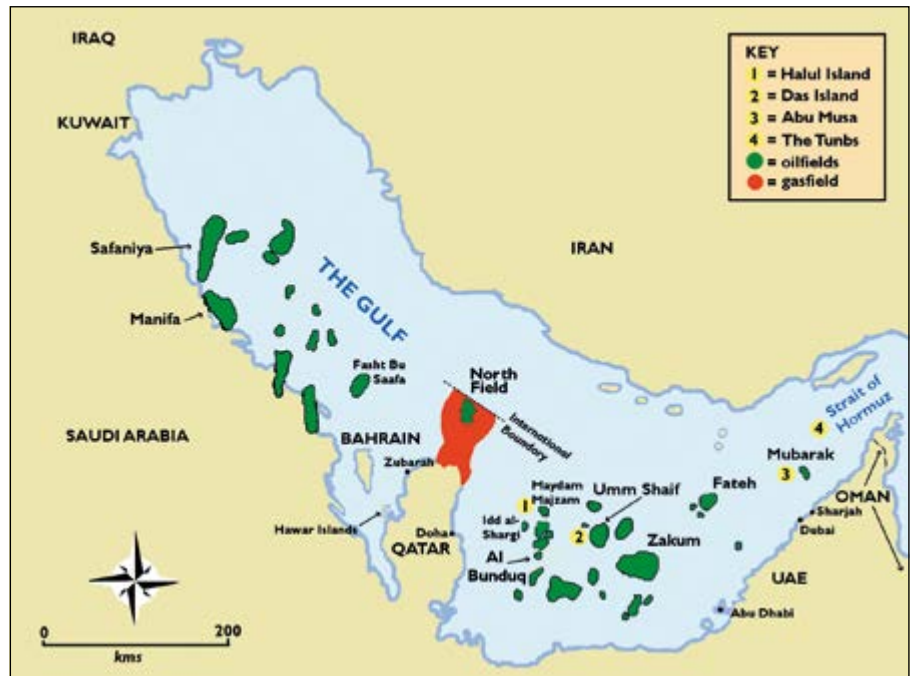
Qatar: Disaster and Discovery

In Qatar, the first offshore concession was granted to Superior Oil of California, a veteran of offshore operations in the Gulf of Mexico, and Central Mining and Investment Ltd, a British company. The company holding the onshore concession, Petroleum Development (Qatar) Ltd, disputed the ruler's right to grant a concession to the Superior group, claiming that they already held the rights; an arbitration decided the issue in the ruler's favour. However, Superior Oil withdrew from the venture in 1952, citing 'financial, political and economic' difficulties, and the concession went to Shell, another company with offshore experience.

The Shell Company of Qatar was formed in October 1953, with its headquarters at Doha. Undersea surveys began with a converted merchant vessel, *Shell Quest*, which was used as a base for marine operations and a floating depot for men and equipment. A drilling rig, described as looking like an 'interstellar radar tower', soon appeared in the incongruous surroundings of Doha Bay.

By December 1956, the rig had drilled one well to a depth of 2,042m and had just completed a second one at 3,657m but without finding any oil. Then disaster struck: the rig was being towed to Doha for modifications when the wind changed direction and a heavy cross-sea developed. Two 2,000-ton pontoons supporting the platform broke loose and all the lights went out. The platform legs were damaged, the helicopter landing stage collapsed and several Qataris tragically lost their lives.

The wreck delayed Shell's operations in Qatar and caused it to review its \$21 million investment. In the event, the company decided to persist and the exploration programme was restarted, with successful wells being drilled at Idd al-Shargi (1960) and Maydam Majzam (1963). Oil started flowing in 1964. After the discovery of the massive North gas field in 1972, with a smaller oilfield above, this country of dwindling oil resources was eventually propelled into the top rank of natural gas producers.



Map of the Gulf showing the places and offshore fields mentioned in the text.

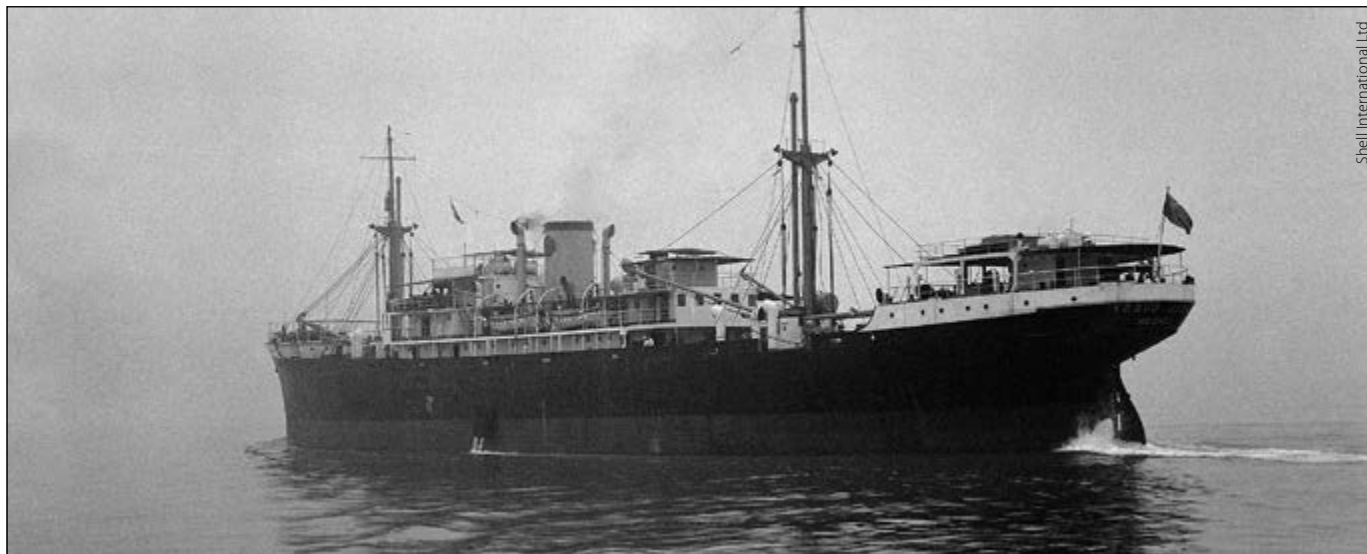
Abu Dhabi: Islands in the Stream

In 1953 Sheikh Shakhbut, the ruler of Abu Dhabi (part of today's United Arab Emirates), granted a 65-year offshore concession covering 30,370 km² to a subsidiary of British Petroleum (BP), D'Arcy Exploration. The starting point was a geological and hydrographic survey of the seabed conducted by the ocean explorer, Jacques Cousteau, on

his research ship, *Calypso*. In 1954, BP – in partnership with Compagnie Française des Pétroles (Total) – created an operating company, Abu Dhabi Marine Areas Ltd (ADMA). The *Sonic*, a marine exploration vessel belonging to Geophysical Service Inc, then carried out a seismic survey of the concession area. In 1956, the *Astrid Sven* arrived on the scene: this was an ageing 1,200-ton

An Aramco offshore drilling rig in 1951.





Shell Quest, used for marine survey work off the coast of Qatar in 1953–5.

freighter once used by the Nazis to refuel their U-boats in the Pacific Ocean. The ship was fitted out with facilities for 30 personnel on board, all the necessary equipment and a drilling platform which was cantilevered over the vessel's side.

Having decided to drill, the challenge was to set up a rig and the infrastructure to support operations. BP drew on technologies from the Gulf of Mexico in the construction of a jack-up drilling platform, the ADMA Enterprise, which was built in Hamburg and then towed to the Gulf. The deserted Das Island became the hub of operations: an airstrip, accommodation and eventually oil storage tanks were built. In 1958, the first oil well was drilled on the old pearling bed of Umm Shaif, striking

good-quality oil at 1,676m, followed by further discoveries, including the supergiant Zakum field. In 1962 the first cargo of oil was loaded onto BP tanker, *British Signal*. In 1972, BP sold a 45% share in ADMA to the Japan Oil Development Company (JODCO).

Zakum is the biggest oilfield in Abu Dhabi and one of the largest offshore fields in the Gulf – and in the world. It covers an area of about 1,500 km² and lies in an average water depth of around 20m and consists of an upper and lower reservoir. The ADMA partners decided to push ahead with developing the lower reservoir layers. These had better quality oil and were more productive, since they were at a higher pressure than those in the upper reservoir, which

they decided not to develop.

As a result of this decision, two new companies were created: ADMA-OPCO to operate the lower field and the Zakum Development Company (ZADCO) to develop and operate the upper field. The latter company now has three major shareholders: the Abu Dhabi government with a 60% share, ExxonMobil with 28%, and JODCO with 12%.

Dubai: Fields of Good Fortune

In Dubai, after D'Arcy had obtained the first offshore concession in 1954, oil development was put on hold for several years. Finally, in 1966, the Continental Oil Company acquired a 50% share in the concession and drilling began, leading to the discovery of the Fateh ('Good Fortune') field. The problem of storing oil in shallow waters was solved by building and transporting large floating tanks, known as khazzans, and towing them to where the oil was produced offshore. As the first khazzan was being towed into position there was a vast bubbling outflow of air along the rear skirt line, with a corresponding amount of noise as air was expelled. In the words of a Continental Oil engineer, it was like a "thunderous belch".

On 22 September 1969, the first tanker of oil was exported from Fateh Field, thus enabling Dubai to finance a number of massive projects new to the Gulf; this was the start of the modern city of Dubai.

For Sharjah, a protocol agreement with Iran over the disputed Abu

Sheikh Shakhbut, ruler of Abu Dhabi (on left), with his brothers aboard the Sonic in February 1955.



NAPE SUMMIT

THE WORLD'S LARGEST UPSTREAM OIL AND GAS EXPO

FEBRUARY 10 – 12, 2016
HOUSTON, TEXAS

One Expo at One Location
Integrates **International** Prospects
into One Powerful and
Opportunity-Packed Exhibit Hall

INTERNATIONAL MARK



LOOK FOR THE DROP TO QUICKLY IDENTIFY
INT'L EXHIBITORS ON THE 14-ACRE SHOW FLOOR

GLOBAL PARTICIPATION



NUMBER OF COUNTRIES REPRESENTED
ON 2015 NAPE SUMMIT SHOW FLOOR

NAPE

Where Deals Happen

REGISTER

- ATTEND
- EXHIBIT
- SPONSOR
- ADVERTISE



Learn more at www.napeexpo.com | [f](#) [t](#) [in](#) [v](#)

History of Oil

Musa Island ensured that, when the Mubarak field was discovered in 1972, its oil would be shared with Iran. This oilfield was found about 35 km east of the island by the Buttes Gas and Oil Company operating through Crescent Petroleum. Initially, the field went on stream at high rates, and other wells tested even higher, but by 1983 production had slumped to 6,400 bopd and to 5,900 bopd two years later.

Drawing Lines on the Sea

Oil exploration gave rise to several disputes between the rulers over their maritime boundaries. Kuwait was in an awkward position: bordered by Saudi Arabia and Iraq, and facing Iran. This led to arguments over maritime boundaries that would fetter oil exploration and development. A dispute between Saudi Arabia and Bahrain over the Fasht Bu Saafa oilfield was settled in 1958 with the former extracting the oil and the latter sharing the proceeds. Qatar and Abu Dhabi argued over Halul Island until two British experts determined that it belonged to the former and the Al Bunduq oilfield was to be shared between them. Dubai and Abu Dhabi were at loggerheads for many years over their maritime boundary, particularly when the Fateh field was discovered, until the matter was settled in 1968.

During the 1930s, an ongoing dispute between Qatar and Bahrain over the Hawar Islands was exacerbated



The Zakum Central Supercomplex in 1979.

by the prospect of finding oil in the area. The British representative ruled against Qatar and, when it came to delimiting the maritime boundaries in 1947, the UK government confirmed his decision. The dispute was eventually

settled by international arbitration in 2001: Bahrain retained the Hawar Islands and Qatar kept Zubarah, part of the mainland to which Bahrain had laid a claim.

More about strategic gain than oil prospects, the dispute between the United Arab Emirates (UAE) and Iran over the Abu Musa and Tunb islands was the most serious territorial issue. In 1971, on the eve of the inauguration of the UAE, Iranian forces occupied the islands and claimed them for the Shah. The two Arabian claimants – Sharjah and Ras al-Khaimah – became part of the UAE, which took up the claim on their behalf; but it is unresolved and remains a contentious issue in the region today.

Quentin Morton's book, *The Petroleum Gulf: The Discovery and Development of Offshore Oil in the United Arab Emirates*, is to be published in 2016 by the UAE National Archives.

Acknowledgement:

Thanks to Dr Alan Heward and Peter Morton for their assistance. ■

Dubai Khazzan No.1 being towed to its site in the Fateh oilfield in August 1969.





Working the Barents Sea?

Experience a field trip to Svalbard with Nautilus

Reservoir Analogues for the Southwestern Barents Sea: Outcrop Examples from Svalbard

Tutors: Erling Siggerud & Andy Thurlow

14TH AUGUST - 19TH AUGUST 2016

A six-day field course to Svalbard that focuses on facies architecture and stratigraphy with application to coeval reservoir rocks and petroleum systems of the southwestern Barents Sea.

For more information please visit:

www.nautilusworld.com



Register interest by 23rd Feb 2016

Email: svalbard2016@nautilusworld.com

Quote Reference: GEN298

Cost: £6,990 + VAT OR 90,500 NOK

Terms and Conditions Apply

RPS[®] Training

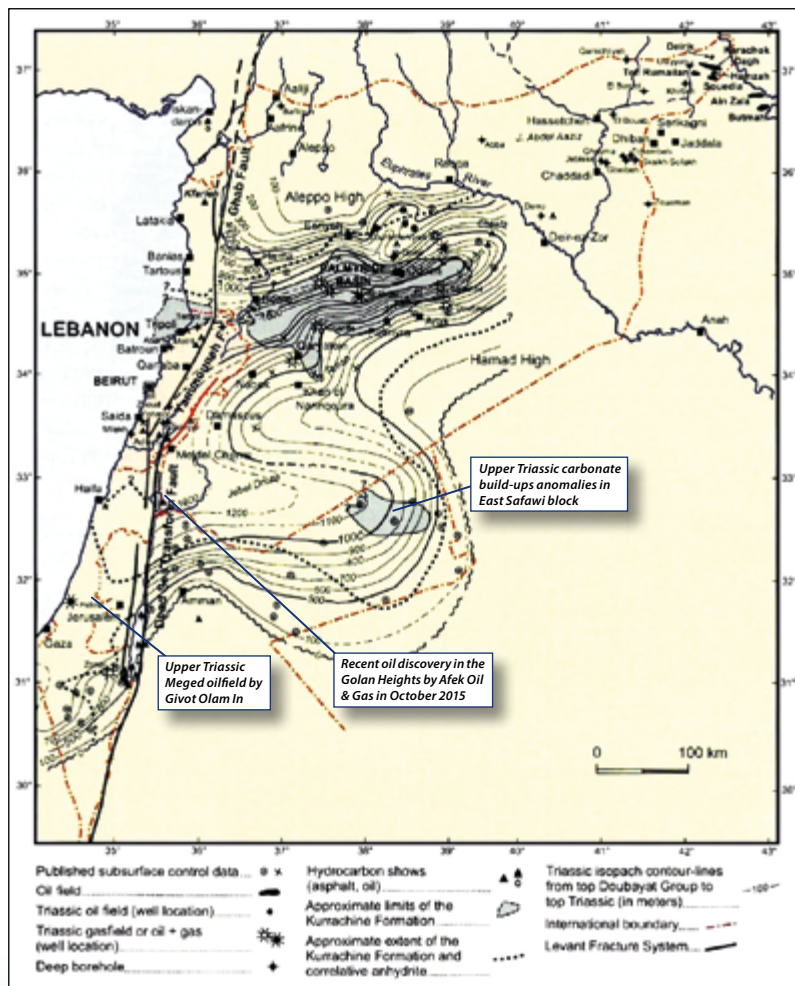
The Triassic Margin Play

MUNIM AL-RAWI, Ph.D., Carta Design

The Triassic margin is a significant but underexplored frontier play in the Levant region, particularly in Jordan.

The Levant covers a large onshore area in the East Mediterranean region including Lebanon, Syria, Jordan, Palestine and Israel. The Triassic carbonate is already a proven reservoir and play in the region, with several oil and gas fields having been discovered in Triassic carbonate reservoirs in the Triassic Basin in Syria. Petroleum exploration in the southern margin of the Triassic Basin has also found important oil discoveries in onshore Israel and the occupied Golan Heights. In this article we look at those discoveries and consider exploration by Petrel Resources in northern Jordan, which revealed a similar possible carbonate build-up anomaly in the Triassic

Looking across the Sea of Galilee to the Golan Heights, location of the most recent significant discovery in the region, which is thought to be reservoired in the Triassic.



Triassic Play Map of the Levant Region. Modified after Nader, F.A., 2014 (map compiled from Wetzel, 1974, and Beydoun and Habib, 1995).

carbonate formations in the East Safawi block, west of the Risha gas field in north-east Jordan.

The potential of the Triassic hydrocarbon exploration in Jordan and the region was highlighted by the late Professor Ziyad Beydoun of the American University, Beirut (AUB), in a geological conference



in October 1994 in Amman, Jordan. His views were published in the *Journal of Petroleum Geology* (Beydoun and Habib, 1995) before the passing away of Prof. Beydoun in 1998.

Triassic Exploration: Syria and Israel

Exploration in the Triassic in Syria began in the early '60s, with the first discovery in 1963 being the Middle Triassic Kurrachine reservoir at the Khirbah field, situated in the North Syria Platform. Although it was only small scale, it paved the way to further Syrian Triassic discoveries, which by 2003 had reached a total of 38 fields, six in the Upper Triassic Mulussa Formation and 32 in the Middle Triassic. All of these are located within the Triassic Basin in Syria, but none are in the southern Triassic margin.

In Israel Triassic exploration began in the early '80s with the drilling of Atlit-1, a deep well in the north which flowed asphalt from the top Triassic and had 100m of strong oil shows in the Upper Triassic before being abandoned due to hole problems. Zuk Tamrur, found in the '90s in southern Israel near the Dead Sea, produced 250,000 barrels of light oil from the Lower Triassic Ra'af carbonates before depletion. In the area from Tel Aviv northward, several wells drilled in the '90s had shows in the Triassic (OGJ, 2002).

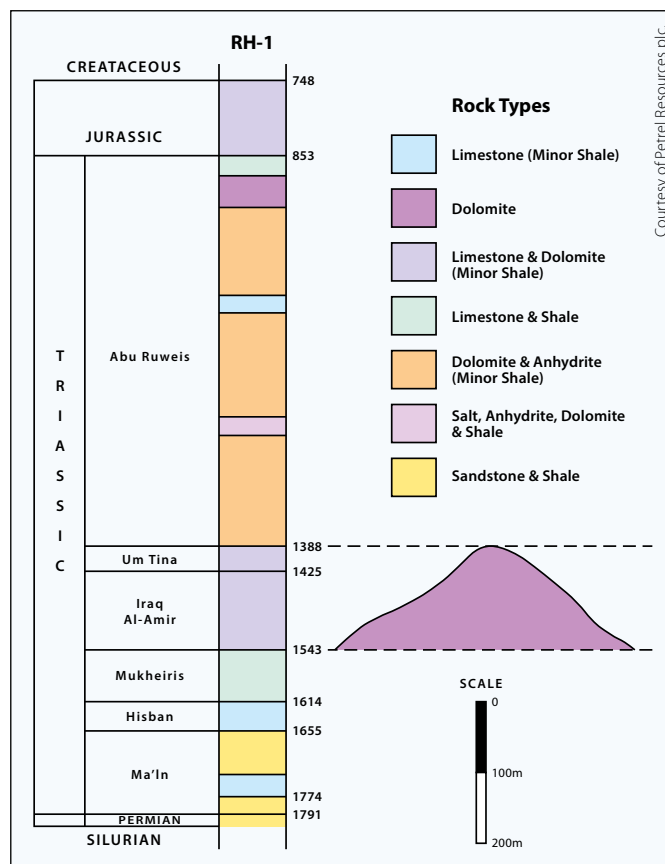
In 2002 Zion Oil & Gas Inc. began developing the Triassic reef play in the Ma'anit Licence area in northern Israel, bordering the north-west of the Palestinian West Bank Territory. It was targeting a buried platform or barrier reef potentially sealed by Upper Triassic and Lower Jurassic shales and anhydrites. With this in mind, in 2005 the company drilled Ma'anit-1 on the Ma'anit structure and drilling breaks and shows of hydrocarbons were recorded from 3,650m to the total depth of 4,570m, but it was determined that the well was not commercially viable. In 2009, Zion drilled the Ma'anit-Rehoboth-2 well in the same area and small quantities of crude oil were produced, but the company determined that commercial quantities of hydrocarbons were not present, and later the same year some evidence of oil was seen in a well in a neighbouring licence, targeting the same play.

Recent Israeli Discoveries

In 2004 a commercial oilfield, Meged, was discovered in Israel, east of Tel Aviv, lying west of the border with the West Bank in Palestine. The reservoirs are Triassic carbonate equivalents of the carbonate formations in southern Syria and northern Jordan and the oil is sourced from the Lower Silurian shales.

Seven other deep (Triassic and deeper) wells have been drilled in Israel. Of these, Deborah-2a had live oil shows, fluorescence and chloroform cuts in the samples, but the reservoir was tight.

Three drillings have so far taken place in the southern Golan Heights, which have found large reserves of oil. The most recent, on 7 October 2015, was when Genie Energy's subsidiary Afek Oil & Gas announced a significant oil discovery there, reportedly from well Ness-6. According to press reports, the reservoir here is 350m, so there could be potential for significant quantities of hydrocarbons. It is assumed that the reservoir is Triassic, as that is the only reasonable play objective in this area.



Triassic stratigraphy in the Safawi Block, Jordan. After Naylor, et al., 2015.

Triassic Exploration: Palestine and Jordan

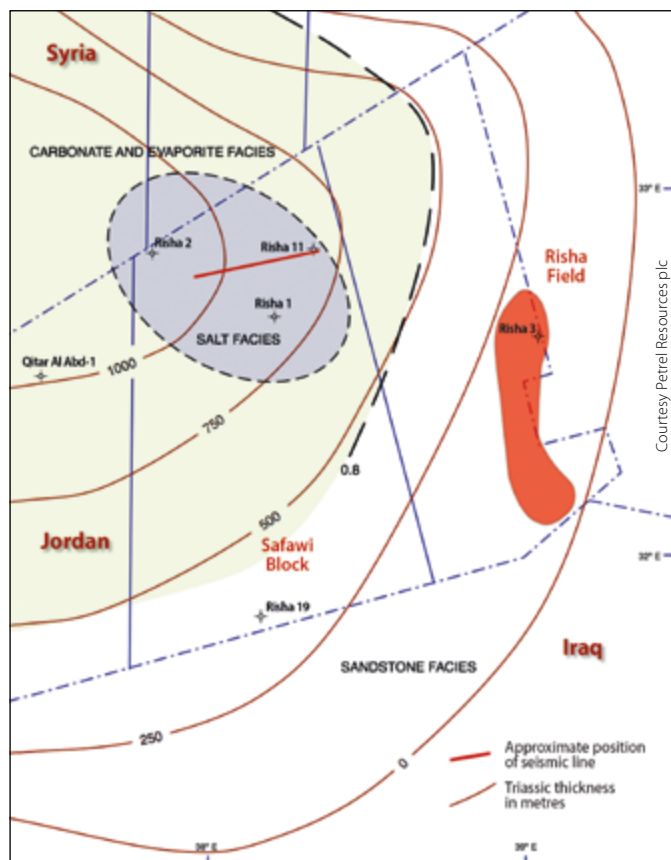
Oil exploration in Jordan, including the West Bank of Jordan in pre-1948 Palestine, began in 1956. The Ramallah-1 well was drilled in 1958 in the West Bank and had oil shows in the Jurassic and Triassic formations. The other three wells subsequently drilled in the West bank, Halhul-1, Mar Saba and Jericho-1, also reached the Jurassic formations.

In Jordan Suweileh-1, drilled in 1960 west of Amman, was the first well to penetrate the Triassic at shallow depths overlying the Cambrian formations. It had oil and gas shows, presumably in the Cambrian. Several other wells in Jordan penetrated the Triassic formations with no significant record of hydrocarbons, but three wells drilled near the northern border with Syria had oil and gas shows in the overlying Jurassic formations, and the hydrocarbons may have migrated from Triassic source rocks in Syria. These wells were North Highland-1 (1987), which reached the Cambrian formations and North Highland-2, also drilled in 1987, and which extended to the Precambrian basement. The third well was Ramtha, drilled in 1970, which reached the Triassic formations.

Triassic Stratigraphy and Shows in Jordan

In northern Jordan, the basal Triassic section – the Ma'in Formation – comprises an interbedded sandstone and shale sequence, with some carbonate interbeds. The thickest sand intervals occur in well RH-1, drilled in north-east Jordan close to the Syrian border. The average porosity is in the order of 17% to 19%. Although the interval has reservoir potential, no hydrocarbons were indicated in a petrophysical analysis of the

Exploration



Salt facies anomaly within the Triassic carbonate and evaporite facies in north-east Jordan. After Naylor, et al., 2015.

four wells drilled to date in the East Safawi block (RH-1, RH-2, RH-11 and RH19).

The middle section of the Triassic (top Um Tina to top Ma'in) comprises a varied limestone sequence with interbeds of shale

Countryside in north-west Jordan, where the North Highland wells are located – very different to the flat desert scenery further east in the Safawi block.

and dolomite. Porosity and reservoir potential are low, with the exception of parts of the Mukheiris Formation seen in wells RH-1 and RH-19. The logs show the porosity to be very variable, ranging from zero to as high as 30% for some intervals in RH-19. Wells RH-1 and RH-2 show only limited higher porosity streaks that give an average porosity of around 14% over a net section of 4–10m. RH-11 has more potential but this is restricted mainly to the Mukheiris interval where the average porosity is around 20% over 15m; the other intervals on this well are similar to RH-1 and RH-2. RH-19 has higher porosity within the Um Tina, Iraq Al-Amir and Hisban than the other wells, but the sequence also appears to be more interbedded with shale.

Again, although there is reservoir potential, little evidence of hydrocarbons was reported from this section. The well report for RH-1 records some 'uneven bitumen distribution' within this part of the section. No shows are reported for RH-19 but the logs appear to suggest some definite potentially movable hydrocarbon-bearing intervals within the Mukheiris.

The upper part of the Triassic section in northern Jordan (Abu Ruweis Formation) consists mainly of dolomites with interbeds of anhydrite and salt. The log responses do not indicate the presence of hydrocarbons within this interval in any of the wells.

Bitumen has been recorded at several levels in the Triassic. In the RH-1 and RH-2 it occurs patchily in the upper Abu Ruweis and more consistently through the lower Abu Ruweis, Um Tina and Iraq Al-Amir Formations, and into the top of the Mukheiris Formation. There are records of bitumen throughout the Hisban Formation, but little in the Ma'in Formation.

These Jordanian formations can be compared to the Megeed oil field in Israel, where the main reservoir is the Upper Triassic Mohilla Formation, which is divided into three different members. From oldest to youngest these are known as Mohilla 'A', 'B' and 'C'. The Mohilla Formation is correlative



So you've run your inversion.

Have you detuned it?

Tuning Effects Mask True Geological Trends.
Earthworks Reservoir DT-AMP™ 3D Seismic
Detuning

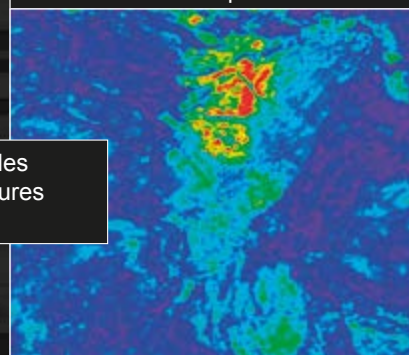
- Removes tuning from 3D Seismic
- Accelerates amplitude interpretation
- De-risks amplitude anomalies



EARTHWORKS
reservoir

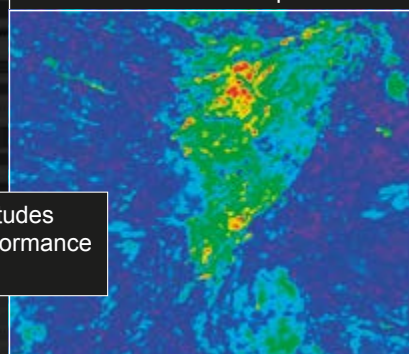
www.earthworks-reservoir.com +44 (0) 1722 343990 sales@earthworks-reservoir.com

Relative Impedance



- Bright Amplitudes
- Localised Features
- Tuning!

Detuned Relative Impedance



- Detuned Amplitudes
- Structural Conformance
- Geology!

with the Abu Ruweis Formation in northern Jordan.

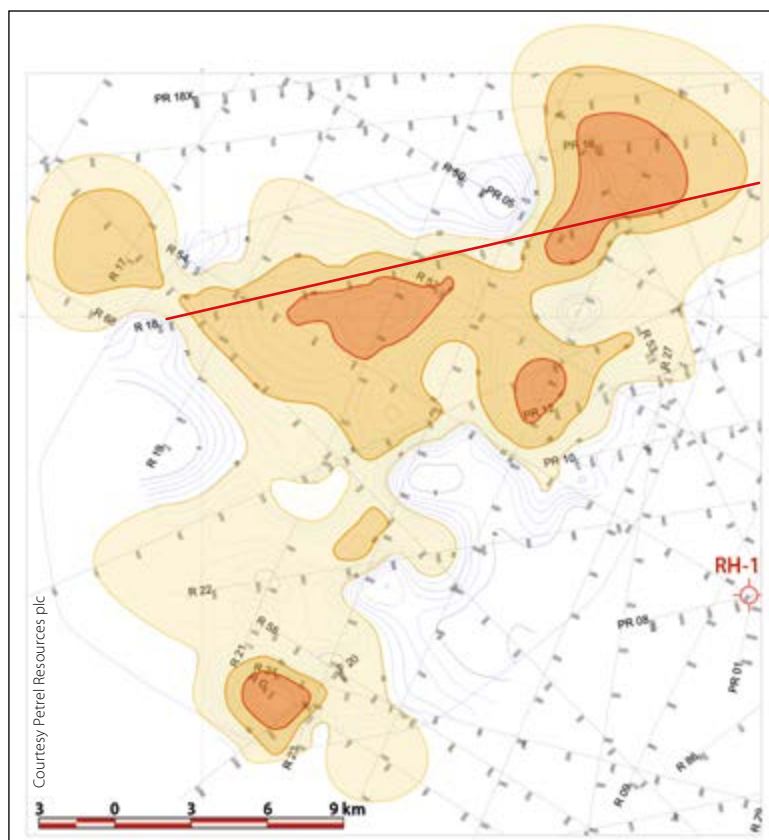
The main reservoir in Meged is the Mohilla 'A' member, which consists of a porous carbonate grainstone facies with porosities ranging between 3% to 12% and permeabilities ranging between 0.5 to 5mD. This is encountered below 4,000m in the Meged closure and covers an area of around 180 km². The overlying anhydritic mudstones of the Mohilla 'B' and 'C' members provide the top seal over the structure. Hydrocarbons in the Meged oil field are sourced from the regionally present Silurian shales, as typed by oil recovered from the Meged-2 and 4 wells.

Carbonate Build-Up Anomaly

Could there be carbonate reef play in the Triassic of Jordan similar to that in Ma'anit in Israel? A number of anomalous seismic features were noted within the Triassic interval on several seismic lines during a study undertaken for Petrel Resources in 2005. Although there appeared to be some type of build-up within the section against which beds at the same level abut, it was also possible that they were merely seismic artifacts. However, re-processing of all the seismic lines has shown that the features are actually real.

When all examples of these features were plotted (both 'possible' and 'relatively certain'), they were seen to fall within the central part of the Triassic Basin, where salt is developed within the Abu

Upper Triassic carbonate build-ups map in the Safawi Block, Jordan. Red line indicates position of seismic line shown on page 58. After Naylor, et al., 2015.



Exploration

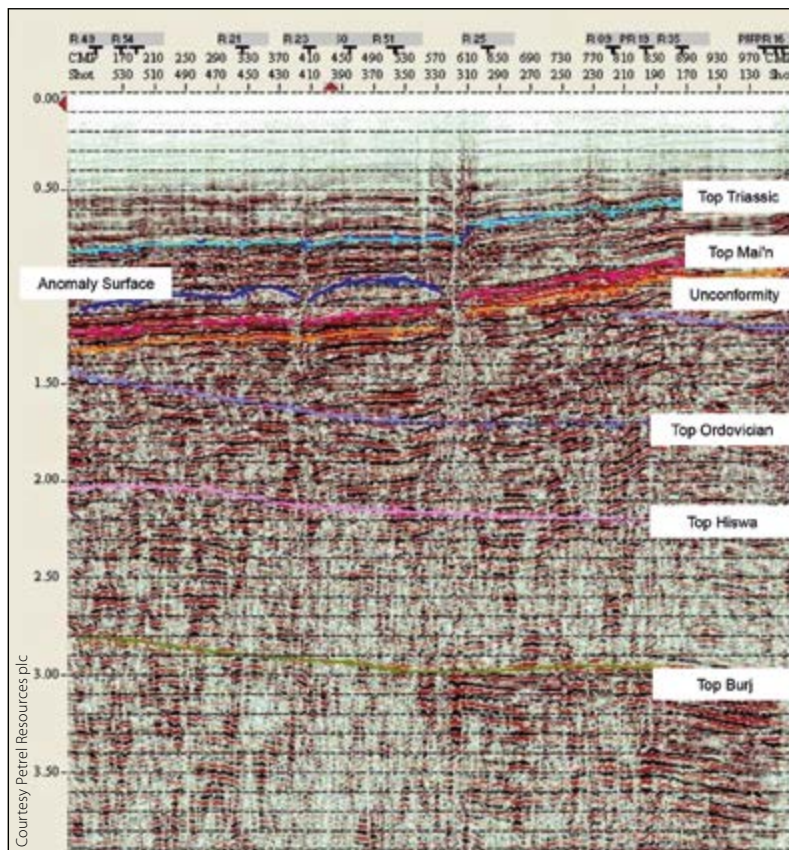
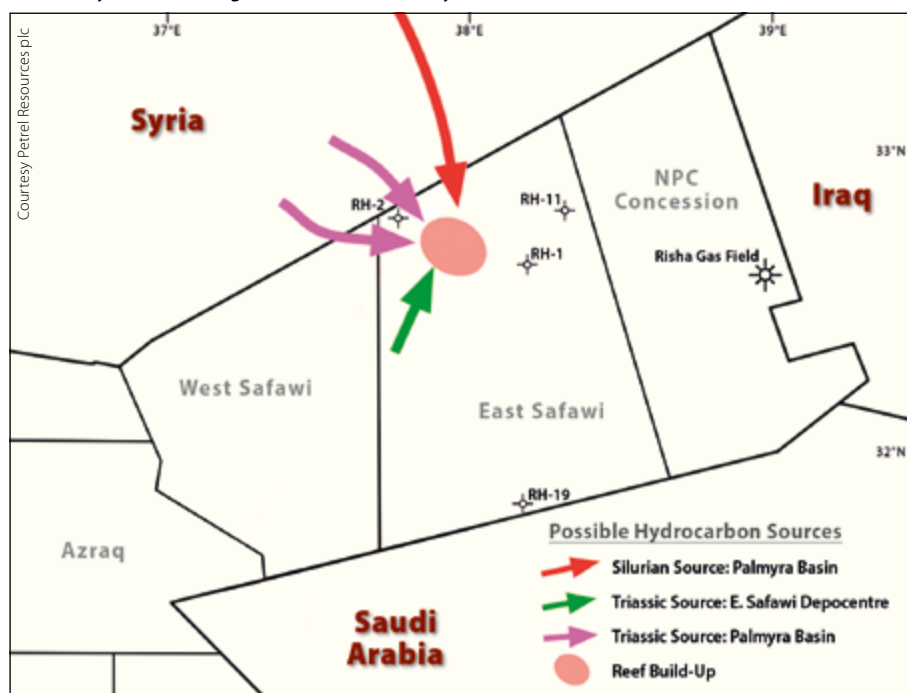
Ruweis Formation. Onlap of younger strata can be observed on the flanks of the features. Given the facies setting and lithologies, together with the form of the features, a carbonate build-up (reef or bank) is the most feasible explanation. Based on the well-ties and horizon picks, these carbonate build-ups appear to have been established on the Mukheiris Formation platform or on the basal unit of the over-lying Iraq Al-Amir, and at their thickest (135–150m) extend up to a level equivalent to the top of the Um Tina Formation or into the basal beds of the Abu Ruweis Formation. It is interesting to note that this is the stratigraphic level at which oil was observed during drilling up-dip at the RH-11 well, which is about 15 km to the east. The build-ups were presumably upstanding during their growth, although the surrounding areas were probably incrementally filled, but at slower rates. The upstanding feature appears to have been contiguous throughout its extent, rather than forming a series of independent pinnacles.

Further Work Needed

The recent Upper Triassic oil discoveries in central Israel and the Golan Heights and the Triassic section in northern Jordan all contain intervals of reservoir quality beneath the evaporite-salt horizons of the Abu Ruweis Formation and its equivalents in Israel, the latter providing a regional seal and some protection against reservoir breaching. Unfortunately, the current seismic interpretation maps in northern Jordan do not show well-defined undrilled structural closure at Triassic levels and further work is needed in this area.

Exploration stratigraphic leads such as the carbonate build-up anomalies should be seriously considered as exploration targets as they are expected to occur in carbonate basin margins such as that of the Triassic Margin in the Levant. ■

Possible hydrocarbon migration routes. After Naylor, et al., 2015.



West-east seismic line showing the Triassic anomaly. After Naylor, et al., 2015.

References:

- Beydoun, Z.R. and Habib, J.G., 1995. *Lebanon revisited: new insights into Triassic hydrocarbon prospects. Journal of Petroleum Geology*, v. 18, no. 1, p. 75-90.
- Energypedia Exploration, 2015. *Israel: Afek Oil & Gas announces significant oil discovery on the Golan Heights. 07 Oct 2015. www.energypedia.com/israel/new-165230*
- Nader, F. H., 2014. *The Geology of Lebanon. Scientific Press, UK. Use for Figure 1.*
- Natural Resources Authority (NRA), 2001 and 2004. *Petroleum Exploration Opportunities in Jordan. Amman, Jordan.*
- Naylor, D., Al-Rawi, M., and Sha'th, T., (MS, 2015). *Possible Carbonate Build-ups within the Triassic section of north-east Jordan.*
- Oil and Gas Journal*, 2002. *Search for Gas in Triassic Reefs progresses in northern Israel. February 2002. PennWell Corporation.*
- Ziegler, M. A., 2001. *Late Permian to Holocene Paleofacies Evolution of the Arabian Plate and its Hydrocarbon Occurrences. GeoArabia, Vol. 6, No. 3, 2001, p445-504.*

Organised By:



Global Pacific & Partners



Advance Notice

-14th - AFRICA — INDEPENDENTS — FORUM —

24th - 26th May 2016

The Waldorf Hilton, London

www.globalpacificpartners.com

MANAGEMENT

Duncan Clarke: duncan@glopac.com

Babette van Gessel: babette@glopac.com

Dan Read: daniel.read@ite-exhibitions.com

SPONSOR/EXHIBITION

Amanda Wellbeloved
amanda@glopac-partners.com

Sonika Greyvenstein:
sonika@glopac-partners.com

REGISTRATION: Judith Moore

Tel: +27 11 880 7052
judith@glopac-partners.com

MEDIA: Jodee Lourensz

Tel: +31 70 324 6154
jodee@glopac-partners.com

Avoiding Reservoir Souring

Determining the source of H₂S on an offshore oil production platform is an important part of preventing or controlling this unwanted gas.

JOHN J. KILBANE II, Intertek

A platform in the Gulf of Mexico. As oilfields mature, the reservoirs become increasingly subject to reservoir souring due to H₂S.

Hydrogen sulphide (H₂S) is a corrosive and toxic gas that can be present in oil and gas reservoirs as a result of thermochemical reactions in the subsurface, or because of biochemical reactions caused by sulphate-reducing bacteria. The presence of H₂S in reservoir fluids (reservoir souring) is highly undesirable, and knowing the source of the gas can guide efforts to prevent or control this unwanted gas.

A Useful Case Study

As oilfields mature they are at increased risk of reservoir souring from microorganisms and this risk increases when water flooding, often practised to help maintain reservoir pressure and to enhance oil recovery, is used. Water flooding and hydraulic fracturing can introduce microorganisms and nutrients into the subsurface, and over time microbial growth can increase and create significant amounts of H₂S.

Periodic monitoring by an oil company of H₂S concentrations in gas samples collected at various locations on an offshore oil production platform indicated that H₂S was becoming a pervasive problem that was getting worse in wells that had previously not contained detectable concentrations of the gas. The greatest concern was that reservoir souring had occurred and that elevated/increasing concentrations of H₂S would continue causing safety and corrosion issues, thus increasing the cost of oil production. The reservoir temperature was about 160°F (70°C), drilling had not employed hydraulic fracturing, and water injection/flooding was not being practised. For these reasons, and because limited microbiological testing indicated no detectable microorganisms, it was initially thought that reservoir souring was not the source of the H₂S.

Subsequent analysis of sulphur isotopic ratios in H₂S samples





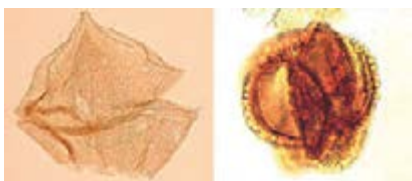
Our scientific staff cover a wide range of expertise gained from many parts of the globe, dealing with many and varied projects. The unique combination of in-house geological services and a staff boasting extensive offshore and oil company experience provides a competitive edge to our services. We offer complete services within the disciplines of Petroleum Geochemistry, Biostratigraphy and Petroleum Systems Analysis, and our customers expect high standards of quality in both analysis and reporting.

High quality analyses and consulting services to the oil industry



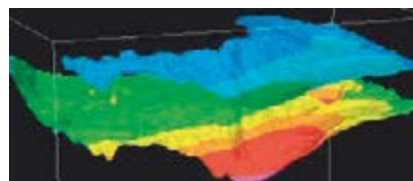
Geochemistry services

In addition to providing a full range of geochemical analyses of unsurpassed quality analysis, APT also offers insightful and tailor-made interpretation, integrated data reporting, and basin modelling and consulting services. We pride ourselves on quality and flexibility, and perform analyses and report results to our clients' specifications.



Biostratigraphic analysis and services

APT delivers a full range of biostratigraphic services, ranging from single well reports and reviews of existing data to full-scale field or basin-wide evaluations. We take no established truths for granted, and we turn every stone in the attempt to bring the stratigraphic knowledge a few steps forward.



Petroleum systems analysis

APT has gained extensive experience in Petroleum Systems Analysis using the "PetroMod" suite of programs. Projects range from simple 1d modeling of a set of wells to complicated 3D models with maturation, kinetics, generation, expulsion, and migration and accumulation issues to be resolved or predicted.

Geochemistry services

- Analytical services
- Reporting
- Interpretation
- Exploration Solutions
- Petroleum consulting services

Biostratigraphy

- 24 hours Hot Shot analysis
- Routine biostratigraphy
- Well-site biostratigraphy

Petroleum System Analysis

- Analysis
- Interpretation
- Data Reporting
- PetroMod or other tools

APT- Applied Petroleum Technology Group
www.aptec.no

APT Group- Head Office Norway
nm@aptec.no

APT (UK) Ltd
patrick.barnard@aptuk.co.uk

APT (Canada) Ltd
mf@aptec.ca

collected from gas samples from the platform seemed to indicate that the source was microbiological. Preliminary data then seemed contradictory, and it was not clear what the source actually was. A more thorough investigation was authorised that involved the collection and analysis of gas, water, and oil samples from multiple locations. This more comprehensive data set revealed that H₂S of non-biological origin was present in some production fluids obtained directly from wellhead and primary separator samples, but H₂S of biological origin was also present in many samples obtained from the topside water handling system.

This case study demonstrated that only by obtaining comprehensive data from multiple samples that included H₂S quantification, sulphur isotopic ratios in gas and water samples, microbiological data from growth and genetic testing, and water chemistry testing to quantify organic acids was it possible to conclude that there were two sources of H₂S in samples from this offshore platform. The oil company now knows that thermogenic H₂S is migrating into the oil production reservoir and that the topside water-handling system is vulnerable to microbial contamination, and it can plan accordingly.

Chemical or Biological?

The confusion regarding the source of the H₂S resulted from sample collection by field production personnel who were not experienced in reservoir souring, geochemistry, or microbiology. After routine monitoring of gas stream samples

revealed detectable concentrations of H₂S at a location on the oil platform, the result was confirmed with additional field measurements. Management subsequently requested that the oil production personnel should collect H₂S samples using an Isotrap and they should perform additional field measurements of H₂S at various locations on the platform. The source of H₂S (from chemical or from biological processes) can often be determined by quantifying the amounts of the stable isotopes of sulphur, chiefly ³²S and ³⁴S. Chemical processes generally do not discriminate between isotopes, whereas biochemical and microbiological processes have a preference for ³²S. Therefore, if a reaction product is depleted in ³⁴S as compared with the starting material, then the reaction can be determined to be biochemical.

The analyses to quantify the various stable isotopes of sulphur require a sufficient mass of H₂S, and the Isotrap device is designed to collect the necessary amount. When the Isotrap was placed on the gas outlet of the separator serving the well where H₂S had been observed, it failed to completely fill the device over a period of a few hours. However, during that time it was determined that higher H₂S concentrations were detected at a nearby location in the water treatment system, which received water from this separator. When the Isotrap was moved to this location it filled quickly and was then sent to the laboratory. The amount of ³⁴S present in this sample was 8.3‰, a value that is relatively low and was interpreted to be possibly consistent with microbiologically produced H₂S, fostering concern within the

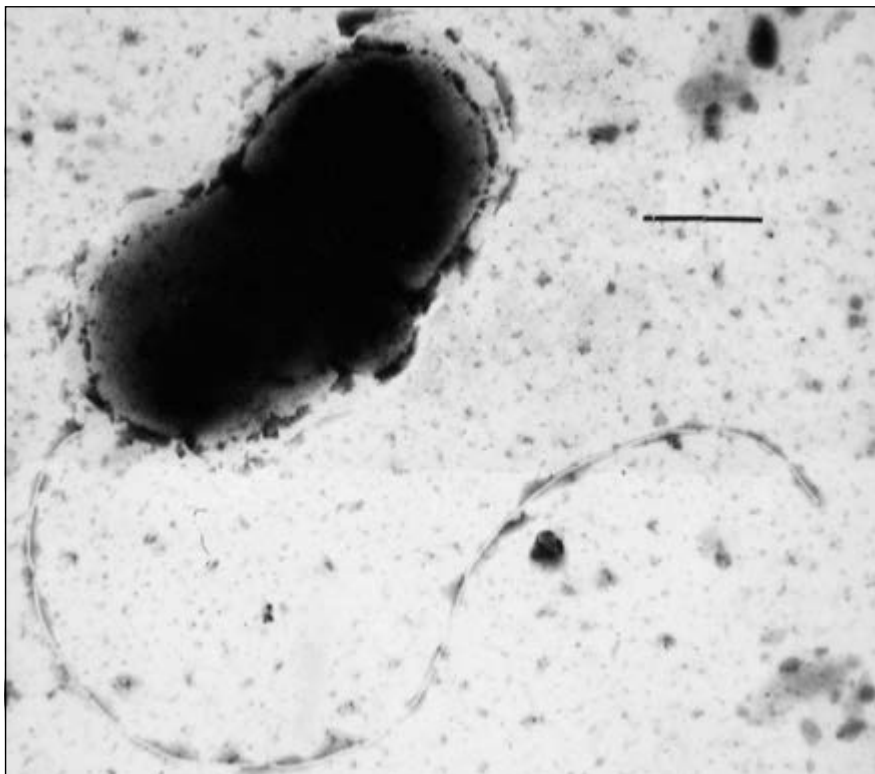
Reservoir Management

oil company that reservoir souring due to microbial metabolism was occurring. This worrying conclusion, however, was based on two mistakes.

When the data was received it was attributed to separator gas from a specific well, but the individual who collected the sample did not appreciate that knowing the precise location that the sample was collected from was important to the interpretation of results.

The second mistake was not realising that sulphur isotope abundance in various materials in nature can vary considerably, so that merely obtaining data for the sulphur isotopic ratio in a given sample will generally not allow conclusions to be made as to whether a given material originated from chemical or from biochemical reactions. For the microbiological conversion of sulphate to hydrogen sulphide, depletion of ^{34}S in the sulphide has been reported to typically range from -15‰ to -25‰ and this can only be determined by obtaining sulphur isotopic data from the sulphate in the produced water and in the H_2S in the gas: both samples should be from the same well.

Moreover, the precise location of any samples collected is important, as was shown in subsequent testing. The data in the table below illustrate that subsequent, more thorough testing documented that there was essentially no change in the sulphur isotopic ratio when H_2S samples obtained from primary separator gas samples were compared with values from sulphate in the produced water from these same wells. However, when H_2S samples were obtained from topside water-handling system locations downstream from the primary separators, then significant depletion of ^{34}S in the sulphide was observed, which is consistent with microbiological sulphate reduction. Additional testing (data not shown) also demonstrated that organic acids such as acetic acid and propionic acid were present in topside water samples but not in separator water samples. Organic acids are a byproduct of microbial metabolism. Furthermore, microbial growth tests and genetic tests (qPCR or quantitative



Biological cause: *desulfovibrio vulgaris* is the best-studied sulphate-reducing bacteria species; the bar in the upper right is 0.5 micrometre long.

polymerase chain reaction) documented the presence of acid-producing bacteria, sulphate-reducing bacteria, and other microorganisms in topside water samples but not in separator water samples.

Biological Processes Not Responsible

When all of these data are considered, there is no evidence for microbiological activity in the subsurface creating reservoir souring; however, once the produced water is brought topside it is vulnerable to microbial contamination and the subsequent production of H_2S . The source of the thermogenic (chemically created) H_2S recently observed in the gas from some wells is unknown, but is presumably due to the presence of a H_2S -containing gas/oil/water source that is in communication with the oil-producing zones tapped by these oil wells. Knowing that biological processes are not responsible for the observed H_2S in reservoir gases will

allow the oil company to take appropriate steps in producing oil from existing wells, and it will influence the future exploration and production activities at this oil field.

As a result of this study biocide has been added to the topside water-handling system at this oil platform, and a programme for the routine monitoring of corrosion-associated microorganisms has been implemented. ■

Sulphur isotopic data from offshore gas and sulphate samples

Well	Sample Location	$\delta^{34}\text{S}$ ‰		‰ Differential
		Gas	Sulphate	
#1, sample set A	separator	33.9	32.9	1.0
#1, sample set B	topside water system	8.4	32.9	-24.5
#2, sample set A	separator	30.8	32.7	-1.9
#2, sample set B	topside water system	8.6	32.4	-23.8

KNOWLEDGE FOR DECISIONS.

DAKS™ is a knowledge platform that enables you to apply lessons learned and best practices from over 1,400 rigorously documented reservoirs. Benchmarking and analytical tools, along with the ability to capture knowledge about your own assets for comparison against proven analogs, empowers you to make better E&P decisions.

- **Validate your project assumptions against facts from proven reservoirs to help reduce subsurface uncertainty**
- **Capture your asset knowledge and benchmark against global analogs to identify potential areas for improvement**
- **Identify reserve growth potential and candidates for acquisition or divestiture to help optimize recovery**
- **Generate and test new ideas for exploration and production**

CCRESERVOIRS.COM

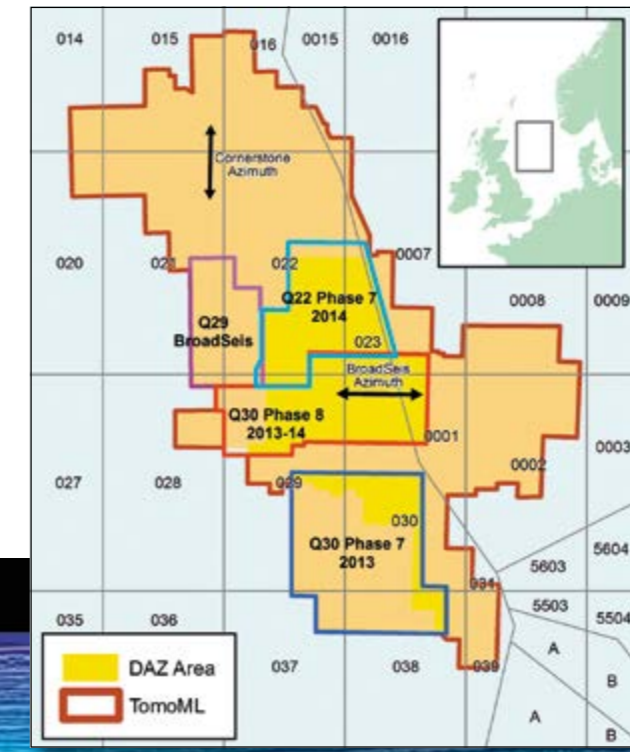
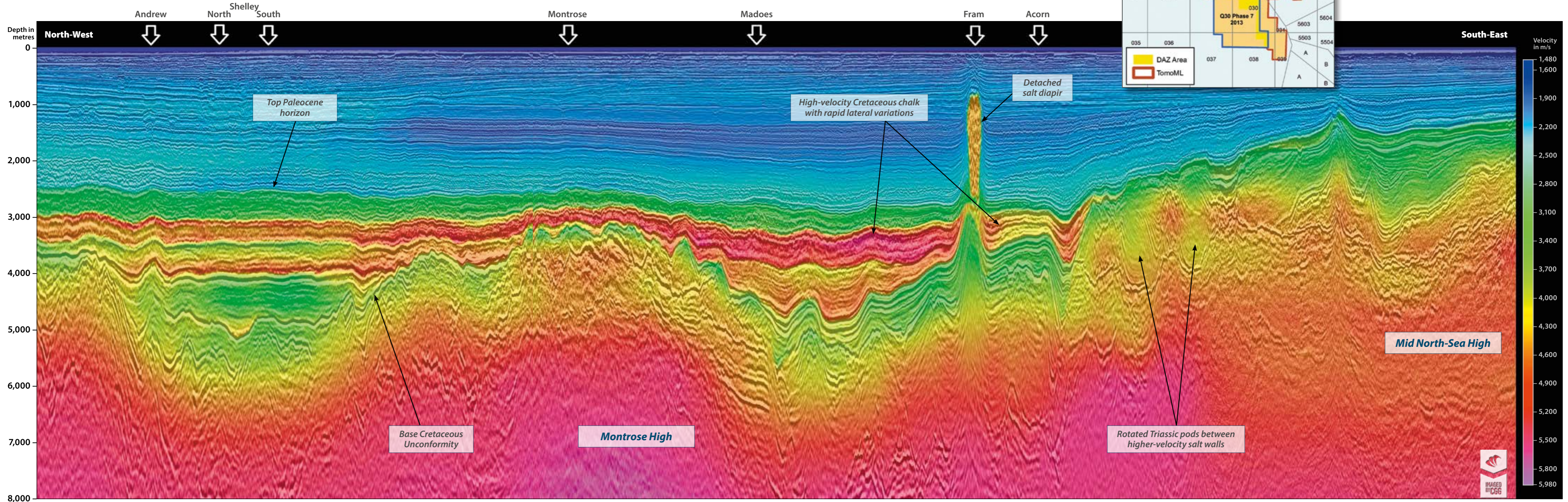
For more information, contact info@ccreservoirs.com

C&C Reservoirs
ANALYZE. EVALUATE. OPTIMIZE.

UK Continental Shelf: Raising the Bar for Regional 3D Seismic in the Central North Sea

Random line oriented north-west to south-east across the data, intersecting several fields (modified from Hollingworth et al., 2015). The final velocity model is co-rendered with the PSDM full-stack amplitude data highlighting both geologically consistent regional trends along with local facies variations.

High-quality and well-positioned seismic data are key requirements of the decision-making process to recover the remaining and bypassed hydrocarbons in mature areas. A great deal of seismic exploration has taken place within the Central North Sea, using a variety of acquisition configurations including the latest broadband solutions. Through decades of exploration, most surveys in this mature basin have been reprocessed multiple times as techniques have evolved and, every so often, significant advances in technology warrant the application of these new approaches in a wholesale way. This is what CGG has recently achieved with new seismic acquisition and reprocessing of key multi-client surveys covering the entire Central Graben in the North Sea.



Exploring the Remaining Potential of the Central North Sea

GREGOR DUVAL, STEVE HOLLINGWORTH and LUKE TWIGGER, CGG

Well known for its challenging seismic imaging, the Central North Sea (CNS) still harbours a wide range of exploration opportunities.

The imaging challenges arise from several aspects of the CNS's unique geology: relatively shallow waters (less than 100m), near-surface Pleistocene channels and iceberg scours, the presence of a thick layer of Cretaceous chalk, Permian salt diapirs and associated complex deformations, highly faulted and rotated fault blocks capped by a major regional unconformity, i.e. the Base Cretaceous Unconformity (BCU), and an overall thick overburden which pushes many reservoir targets very deep into the high-pressure high-temperature (HPHT) domain. The need for greater accuracy of deep imaging and structural interpretation has seen a steady rise in the number of pre-stack depth migration (PSDM) projects. Recent developments in multi-layer tomography (TomoML) now allow complex PSDM projects to be completed within a significantly reduced timescale while at the same time improving image quality.

The Right Seismic in the Right Place

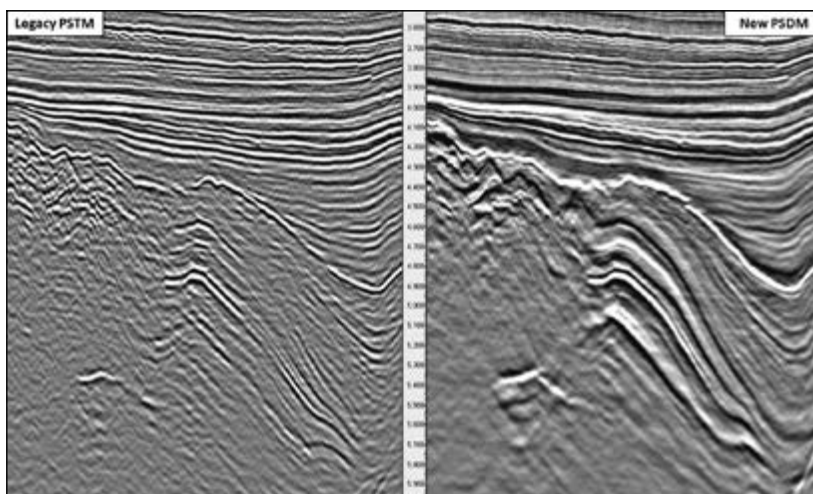
The project incorporated 35,000 km² of seismic data acquired across ten quadrants of the UK and Norwegian Central North Sea, from UKCS Quadrant 38 in the south to UKCS Quadrant 15 in the north (see map on foldout page), making it one of the largest single-model PSDM projects ever undertaken. Most of the surveys were conventional flat towed-streamer acquisition. However, three of the more recent surveys were acquired using the BroadSeis™ variable-depth streamer broadband solution (Soubaras, 2010) with 8 km maximum offset. In addition, a 9,000km² area benefits from dual-azimuth (DAZ) coverage where broadband seismic data have been acquired orthogonally to the underlying legacy survey. This provides enhanced illumination of the complex structures beneath the BCU where it is deeply buried in the Central Graben.

The main objective of the project was to obtain a high-quality, fully processed depth image through PSDM. In order to draw the best out of the depth imaging, three key technologies were added to the processing workflow: the latest shallow water and short period multiple suppression algorithms, frequency bandwidth extension provided by advanced ghost wavefield elimination (GWE) techniques in the τ -p domain (Wang et al., 2013; Poole et al., 2013), and high-reliability tomography using a multi-layer non-linear approach to build an accurate regional velocity

model. The initial velocity model and subsequent iterations of tomography along with anisotropy parameters were calibrated to ten horizons and 225 wells in total. Anisotropy was accounted for through tilted transverse isotropy in the velocity model with the main axis set perpendicular to the horizon framework. The key horizons used were: Top Sele Formation, Top Cretaceous Chalk, Top Plenus Marl Formation (Near Base Chalk), Base Cretaceous Unconformity, Top Salt, where diapirs pierced through shallower layers, and Base Zechstein.

The final model reveals geologically consistent regional trends in the velocities. This is demonstrated in the foldout image cutting through some of the main structures and fields of the Central Graben such as Andrew, Montrose, Madoes and Fram. Much of the exploration potential remains in the deeply buried Mesozoic structures below a thick Upper Cretaceous chalk interval, which presents many challenges for achieving stable velocities with reflection tomography. Thin layers, complex facies transitions, large vertical velocity contrasts and the reduced offset range of reflection events within high-velocity layers all make inversion difficult. Despite these challenges, multi-layer tomography was successful in producing a reliable velocity field, which is clearly seen in the foldout image. With the addition of GWE, a broad bandwidth was achieved, which further enhanced imaging at depth due to a strengthening of the low frequencies without compromising the higher ones. Combined with a powerful demultiple, the final results show significant improvements over existing narrow-bandwidth PSTM data, hence offering a new look at deep Mesozoic and Palaeozoic structures of the Central Graben.

Comparison made in Two-Way-Time domain between the legacy PSTM and the new PSDM benefitting from dual-azimuth coverage, new broadband acquisition and new depth imaging workflow. This shows how imaging is greatly improved throughout the section and most importantly below the BCU.

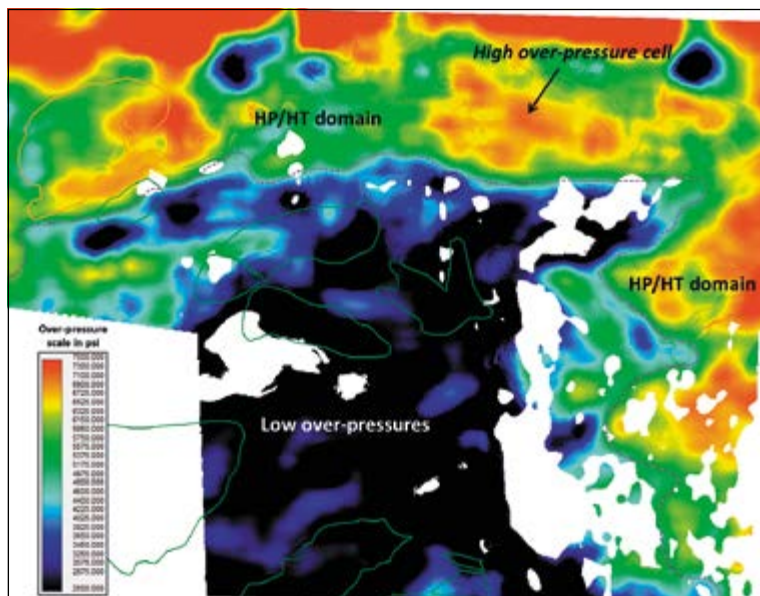


Beyond the Seismic Reflection Image

Complementing the seismic image, a range of seismically derived attributes is currently being processed to help extract the maximum information from the data. Targeting the HPHT plays and with the help of strong low frequencies and a stable velocity field, a quantitative 3D pore pressure prediction can be generated from seismic data. The methodology requires calibration of well data, close to 100 wells in this case, with formation pressure measurements, P-wave velocity and density logs. Eaton's empirical law (Eaton, 1975) is used to characterise the relationship between formation pressure measurements and P-wave velocities.

For this study, the Central North Sea stratigraphy is divided into four main rock units defined by key horizons used in the velocity model building: the Tertiary-Quaternary silici-clastic deposits, the Upper Cretaceous chalk, the Lower Cretaceous silici-clastic unit and the pre-Cretaceous rocks. Eaton's parameters are then calibrated independently for each unit and normal compaction trends are adjusted accordingly. In other words, this has the effect of removing the dominant rock type and matrix component from the seismic velocity field so that we only look at its pore component. Another reason for dividing the stratigraphy into four units is that each of them is subject to different over-pressure mechanisms that need to be addressed by independent calibration of Eaton's parameters. For example, the Tertiary section is dominated by disequilibrium compaction processes, whereas the pre-Cretaceous carries a significant component of unloading and fluid expansion due to past erosion, uplift and ongoing hydrocarbon expulsion from the mature Kimmeridge Clay source rock. Using this methodology, an estimation of pore pressure trends can be extracted from seismic velocities. This is being processed over a target zone of 16,100km² over the HPHT domain of the Central Graben.

Moreover, the extraction of Amplitude Versus Offset (AVO) attributes was helped by the stable velocities obtained from the multi-layer tomography, calibrated anisotropy parameters and properly depth-imaged seismic offset gathers. Relying on the quality of data conditioning and amplitude preservation through the various steps of seismic processing, a relative pre-stack elastic inversion is processed to generate AVO attributes. This process requires no well control so the inversion results are not biased and purely data-driven. The attributes can be used for qualitative AVO screening, looking in particular at the remaining Tertiary plays and prospects in the Central Graben. The figure right shows an example section sliced through the Marconi field (also known as Vorlich) characterised by a prominent low V_p/V_s anomaly. This field was re-discovered



Example map of average over-pressure through the Jurassic section around the Appleton and Fulmar fields.

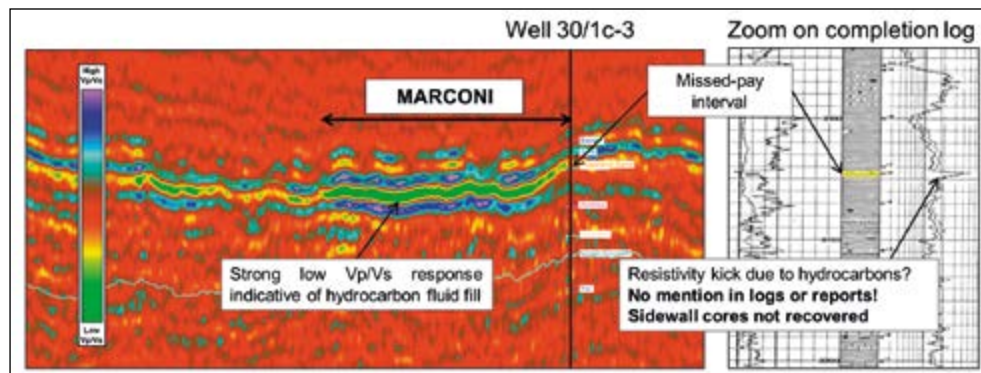
in 2014 after well 30/1c-3, drilled in 1985, missed the main pay in the Paleocene-Eocene Cromarty sands. Although the first well penetrated a thin 3m sand interval associated with a high resistivity kick on the wireline logs, no further tests were carried out and hydrocarbons were missed, thus demonstrating the need for reliable AVO screening.

An Integrated Approach

The case study presented here demonstrates how the latest technologies in seismic processing and regional reservoir characterisation can be combined to provide a full suite of data and help explore the remaining potential of the Central North Sea. We fully answer the needs of a mature basin with over 35,000km² of contiguous 3D seismic data, including a seamless PSDM volume with stable velocities for accurate imaging, broad bandwidth for resolution at all depths and dual-azimuth coverage in geologically complex areas for better illumination. These data are complemented with a seismic velocity-derived pore pressure prediction volume over 16,100km² targeting the HPHT domain of the Central North Sea, along with un-biased AVO attributes generated over the entire Central Graben for qualitative screening of potential hydrocarbon anomalies and prospects.

References available online. ■

V_p/V_s ratio section through the Marconi/Vorlich discovery with well 30/1c-3 tie and completion log.



Revitalising UKCS Exploration



Azinor Catalyst is a leading edge tech-driven exploration company.

We have built an operated portfolio of twelve UK licences, capturing 250 million bbls of net risked resources by leveraging our state of the art seismic database. This data includes over 90,000 km² of conventional seismic and over 16,000 km² of latest generation Broadband seismic.

With long-term financial backing from Seacrest Capital, we are assembling an exciting portfolio of opportunities. This position gives Azinor Catalyst the breadth to explore the North Sea 'the right way'.

We are looking forward to being part of the next exciting chapter in the North Sea's E&P story.

Lebanon

The New Levantine Exploration Opportunity

M. SOLEDAD VELASCO, Ph.D.

The Eastern Mediterranean region has recently become noticeable for its oil and gas exploration success, particularly in the Nile Delta Cone and southern Levantine Basin, offshore Cyprus and Israel. However, some countries in this region have been producing hydrocarbons for a very long time. Just a few years ago, for example, Syria was producing 400,000 bopd, and at 2.5 Bbo it possessed the largest hydrocarbon reserves of any producer in the greater Levant region, excepting Iraq. Lebanon resides squarely in the centre of these known regional hydrocarbon systems, but their existence and association have yet to be assessed.

Lebanon extends along the eastern coast of the Mediterranean Sea and lies within the same Mesozoic basal area in which major oil and gas fields have been found in the offshore and onshore Levant Basin and the northern part of the Arabian shield (Figure 1). Hydrocarbon exploration in Lebanon started in 1930; since then, only seven wells have been drilled, all of them onshore and none having reached rocks older than the exposed (Jurassic) strata nor encountering oil or gas in commercial quantities.

Most Mesozoic rocks in Lebanon were deposited in the intraplate Palmyride Basin, which extends from north-east Egypt northwards through Israel, Lebanon and Syria to north-west Iraq (Figure 1). Subsidence of the Palmyride Basin began in the Late Permian and was probably associated with the opening of Neo-Tethys. It has been suggested that the Palmyride trough continued to be a depocentre in Syria until the Late Cretaceous.

Need for New Exploration Era

Due to the recent oil and gas discoveries, the Eastern Mediterranean region has become a desired place for further exploration. As a consequence, new interest began to build in Lebanon's hydrocarbon potential, in particular around the country's offshore prospects just north-east of the major gas discoveries at Leviathan and Aphrodite. Multiple sets of 2D and 3D seismic data were acquired over the entire offshore region of Lebanon.

Having enriched the country's offshore geophysical database, the Lebanon Petroleum Administration (LPA) turned its attention to gathering geophysical measurements and re-assessing the hydrocarbon potential of the country's onshore basins. Initially, the plan was to acquire several hundred line-km of 2D seismic, but those plans were scaled back and ultimately never implemented because of the challenges to terrestrial geophysical acquisition posed by Lebanon's topography. Consequently, NEOS and its local Lebanese partner, Petroserv, proposed a plan that involved acquiring a suite of airborne geophysical measurements – including gravity, magnetic, radiometric and hyperspectral – complemented by sub-surface regional resistivity

Lebanon lies at the centre of known regional hydrocarbon systems, but it is poorly explored and understood, possibly due to topographic challenges to terrestrial geophysical acquisition. A recently acquired suite of airborne geophysical measurements complemented by sub-surface regional resistivity data aims to remedy this situation.

data acquired using ground-based magnetotelluric (MT) receivers. The two-month acquisition operation over a 6,000 km² area of investigation in the northern onshore portion of the country and its near-shore coastal waters concluded earlier this year. Once processed, the acquired measurements were integrated and simultaneously interpreted with other legacy G&G datasets, including the limited well data, along with some of the offshore seismic data.

The key questions addressed by the project included:

- Whether there was evidence of an active and extensive hydrocarbon generating system underneath the project area.
- Whether and how Lebanon's onshore and near-shore hydrocarbon system(s) related to others in the area, in particular, the mega-discoveries in the Eastern Mediterranean.
- Whether evidence for potential commercially viable reservoirs existed, especially in the Triassic interval, and given the modelled burial depths, thickness, trapping mechanisms and areal extent.

New Data Brings Hope

During October 2014, NEOS acquired hyperspectral data over the northernmost portions of the Lebanon Project area (Figure 2). These data were collected in order to better understand and characterise the geology, petroleum systems, and hydrocarbon prospectivity of the northern study area.

Due to the physics of acquisition, as well as security prohibitions and flight restrictions in the area, the small southern onshore portion of the Lebanon Project was not covered by the hyperspectral acquisition outline.

The hyperspectral measurements, which are used to search for indirect and direct hydrocarbon indicators on the surface, identified mineral alteration zones often associated with hydrocarbon micro-seepage in large parts of the survey area. These data also indicated a large expanse of oil seeps throughout much of the area of investigation. The sheer number of these seeps and their locations along newly mapped fault networks and along the boundaries of key stratigraphic intervals suggest an active (and potentially liquids-prone) hydrocarbon-generating system beneath Lebanon.

During November and December 2014, NEOS acquired over 6,900 line kilometres of airborne gravity and magnetic data in northern Lebanon (Figure 3).

A sedimentary basin architecture study was conducted to identify major contacts between the sediments and the basement. Depth parameters were computed using the spectral signature of the gravity and magnetic data, 2D forward modelling and

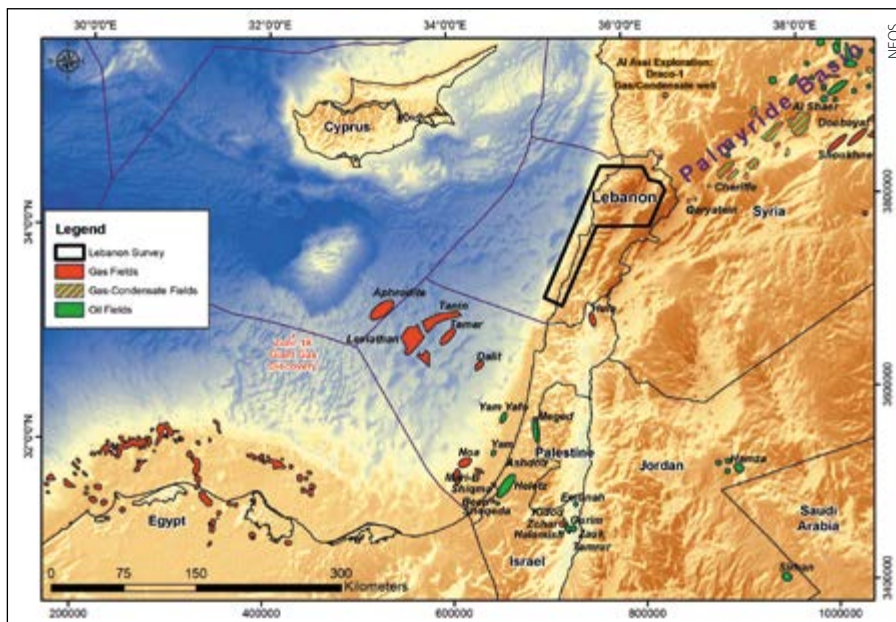


Figure 1: Map showing the location of the study area outlined in black, with oil and gas fields around the country of Lebanon.

inversion methods.

Four 2D profiles were created in the study area to gain better knowledge of the structure and relationship between the sedimentary basin and the Precambrian basement (Figure 4). Based on known geology and results from the 2D modelling, this area is characterised by irregular basement topography with Palaeozoic to recent sedimentary cover. The strata is faulted and folded by Tertiary to present tectonic activity that occurs in the region. The geometry and thickness of the sedimentary basin are constrained by well data and were modelled to fit the gravity and magnetic data.

The top of basement surface is predominantly irregular, and becomes deeper towards the

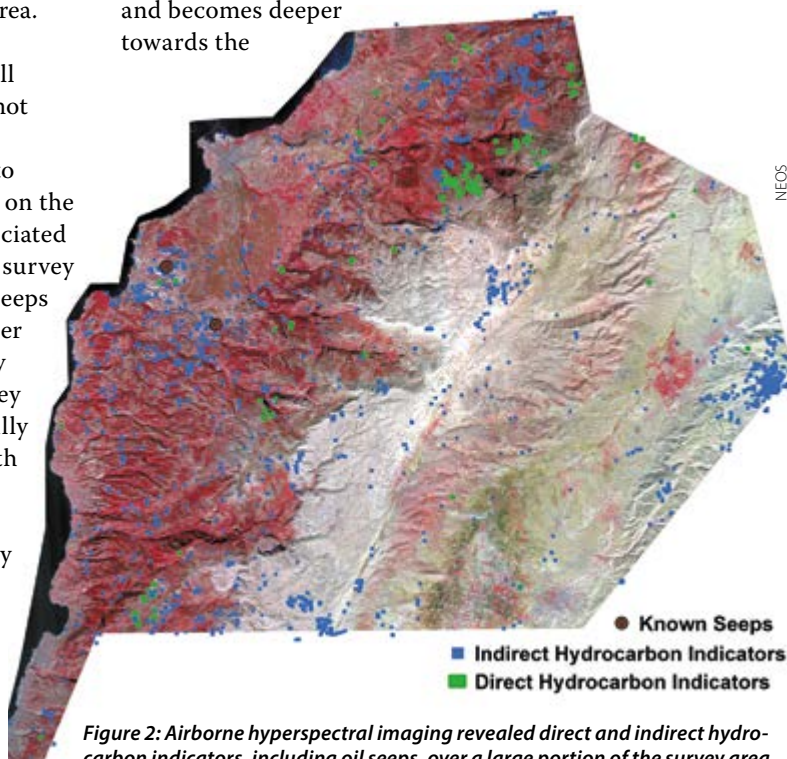


Figure 2: Airborne hyperspectral imaging revealed direct and indirect hydrocarbon indicators, including oil seeps, over a large portion of the survey area.

Exploration

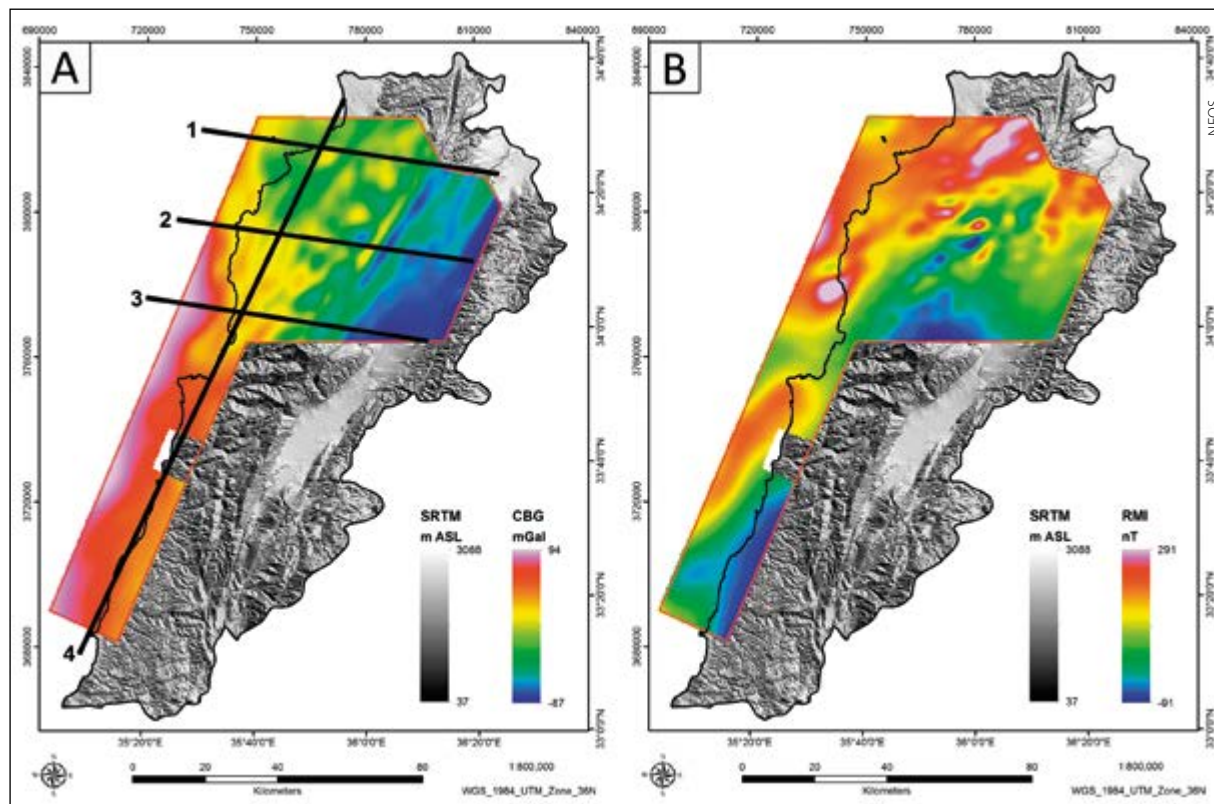


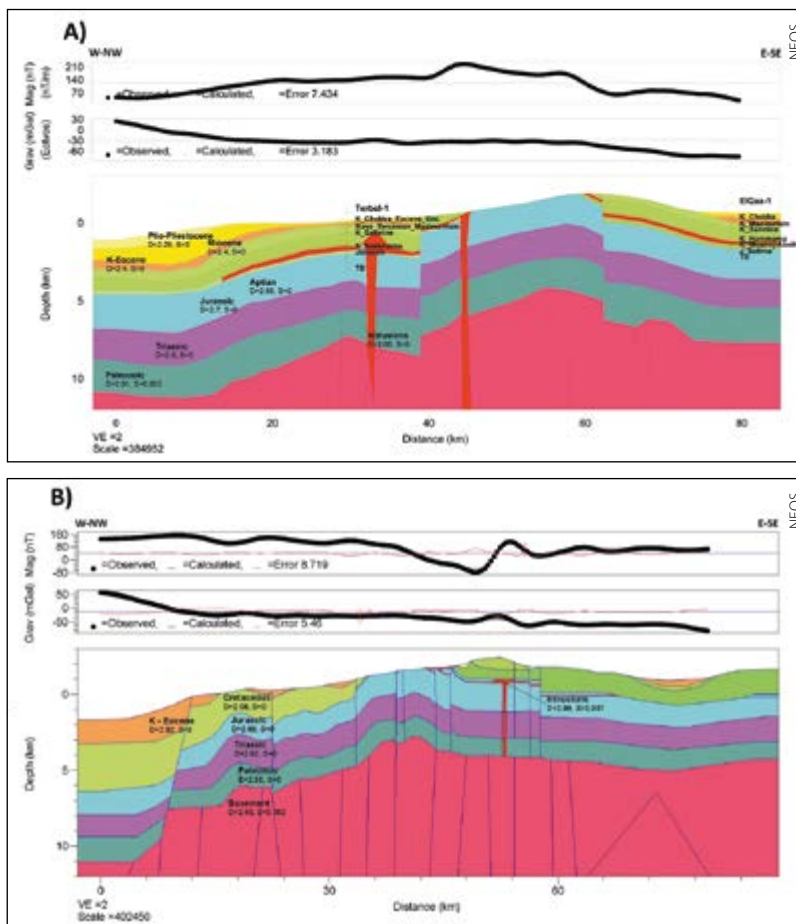
Figure 3:
A) Bouguer gravity data with solid black lines showing the locations of 2D modelling profiles.
B) Reduced Magnetic Intensity (RMI) data.

offshore transition zone. The structural layers derived from the 2D models, as well as interpreted formation tops from well data, were gridded to create starting horizons for the 3D model. Structural model inversions over the gravity and magnetic data (Figure 5) indicate general agreement with an average basement depth at ~7,000m below the surface, with depths ranging from 4,000m to 11,000m subsea. Since the deepest well drilled penetrated just over 3,000m of sedimentary sequence above the Jurassic, the remaining 4,000m of basin have to be accommodated by additional and older sedimentary layers to reach this basement depth. Therefore, the model had to include Triassic and Palaeozoic layers, each up to 2,000m thick. This was a key finding from the project, as it affirmed the existence of several intervals that have proven to be prolific source rock and reservoir intervals in the region.

The Triassic and Palaeozoic petroleum systems in the Eastern Mediterranean region have been tapped in Jordan, Israel and in the Palmyride Basin in Syria. Stratigraphic correlation based on wells shows that the Jurassic and Cretaceous (probably also Triassic) sequences thicken towards the present Mediterranean coastline.

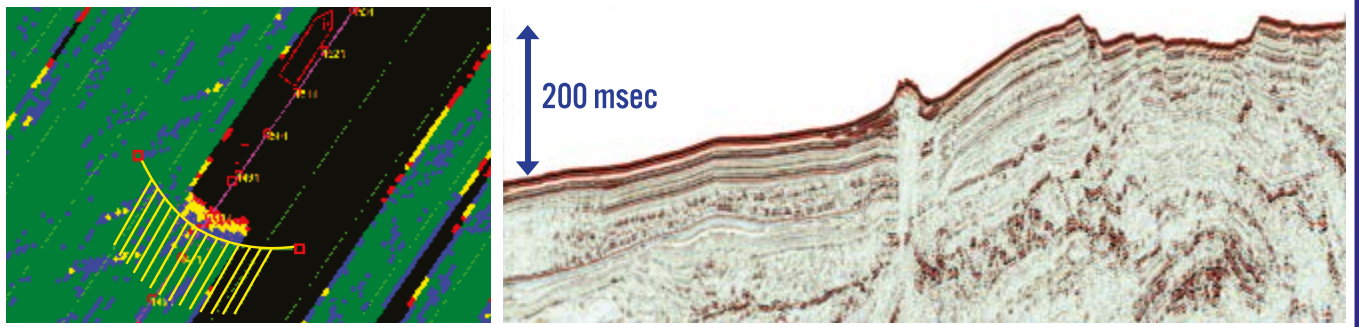
Figure 4: A) Line 1. B) Line 3. The black lines in the top two panels represent the measured magnetic and gravity data, respectively, with values calculated from the models; the red line represents the error between the two. See Figure 3A for profile location.

This suggests that the position of Lebanon coincided with a regional depocentre within the Palmyride Basin (Nader, 2011) and that, perhaps, rocks similar to the reservoirs in Syria can



Reduce Risk, Reveal Opportunities UHR3D Seismic

- Ultrahigh - resolution 3D (UHR3D) for detailed geohazard imaging, shallow reservoir monitoring, and shallow exploration
- Least - squares adjusted network solution and real-time binning ensures complete subsurface coverage



To reveal the opportunities you may be missing, contact: **NCS SubSea**
ncs-subsea.com +1 281-491-3123



also be found in Lebanon.

The existence of a Triassic sequence onshore Lebanon has been a matter of debate for a long time and only a few studies have focused on its hydrocarbon potential. The lack of Triassic outcrops and well penetration forces one to rely on indirect measurements to define this sequence, but the modelling efforts of this project strongly indicate that thick Triassic (and Palaeozoic) intervals exist in the survey area (see page 54 for further discussion on the Triassic in the region). The fact that hyperspectral imaging indicates numerous and areally extensive oil seeps and indirect hydrocarbon indicators in the area further de-risks Lebanon's exploration potential.

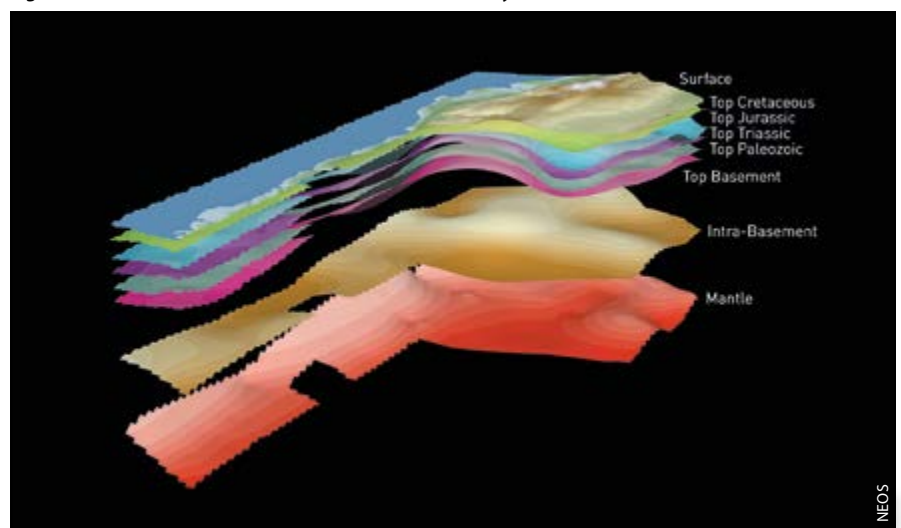
Exploration Opportunity

Additional interpretive products generated during the project identified the presence of multiple source rock intervals, the existence of sedimentary depocentres, and typical structural trapping mechanisms such as anticlinal closures and prospective reservoir intervals abutting faults.

The features noted above were observed at different intervals within the geological column and in different parts of the area of investigation, including

along the near-shore coastal waters of Lebanon, suggesting a variety of potential exploration play types (both gas and oil plays) might exist in the country. The onshore hydrocarbon potential is found in deeper and older sediments in the stratigraphic column with a gas and liquids upside, whereas the offshore and near-shore potential appears to be more gas prone and trapped in younger and shallower sediments. The multitude of plays and the stacked nature of several of them – all now high-graded following this project – serve to de-risk the overall exploration opportunity. ■

Figure 5: 3D model inversion results for the entire survey area.



Teamwork at Rangely

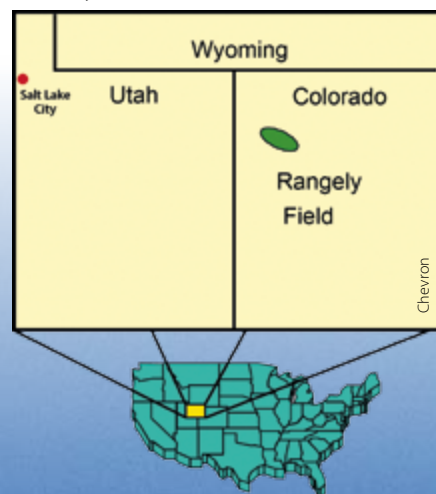
THOMAS SMITH

Colorado's Rangely oil field, with over 900 MMb of oil produced, has been viable and economic for more than seven decades thanks to an innovative and flexible approach.

One of the oldest and largest conventional oil fields in the US Rocky Mountain region, Rangely is in a remote north-west corner of Colorado along the White River. This area was originally referred to as Raven Park in the early 1870s by C. A. White, a geologist with the Hayden Survey. The upper portion of the White River valley was formed by erosion of the relatively soft Upper Cretaceous Mancos Shale on the crest

of a large anticlinal structure. The discovery of an oil seep in a spring along the north bank of the White River brought attention to the area as a potential oil field and a number of companies were organised among the local residents to prospect and develop it. Drilling started in 1901 with oil discovered in the Mancos Shale at depths of 150 to 520m. By 1903, 13 different companies had drilled the

The Rangely oil field is located along the eastern edge of the Uinta Basin in north-eastern Colorado, about 270 km east of Salt Lake City, Utah.



A display, at its original well head site of the Raven A-1 replica pumping unit that discovered the deep Weber Sand Unit in 1933. The photo, taken in the spring of 2013, shows a workover rig in the background. The discovery well display was moved to the Rangely Museum in the spring of 2015 to make room for field operations.

Thomas Smith



Rangely field, yielding just 10 barrels per day.

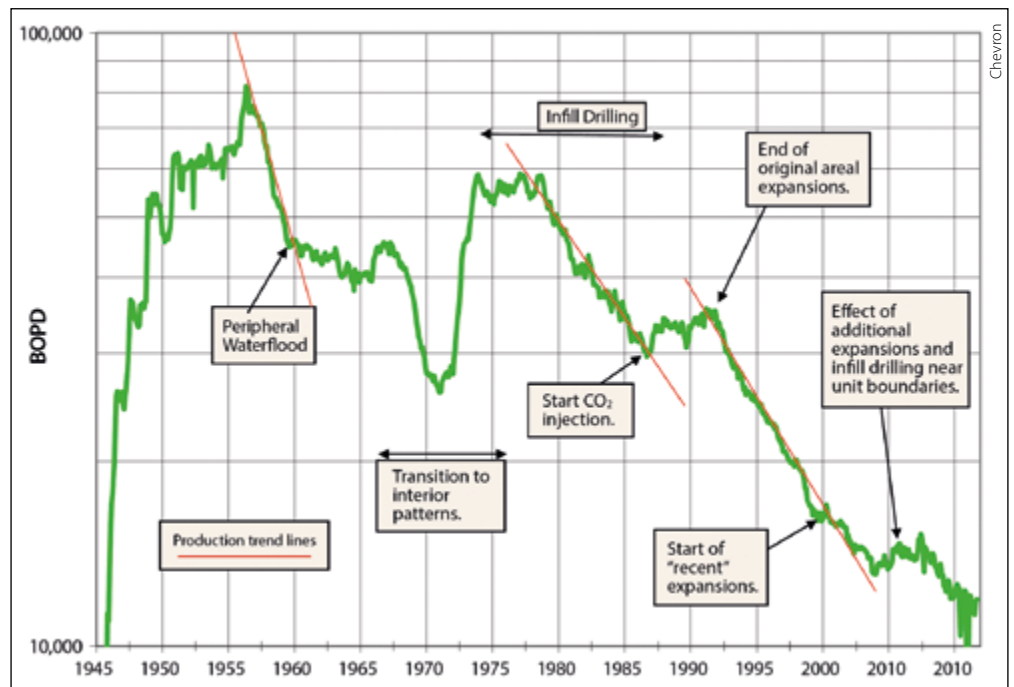
Almost 30 years after those first disappointing wells were drilled, Raven A-1 was spudded by the California Company (now Chevron) in 1931. It took more than a year to drill down to an oil saturated sandstone at a depth of 1,931m. In 1933, the well tested at 230 bopd from the Weber sandstone and remained shut in for 10 years after producing 8,000 bo. The well had discovered a huge field with more than 1.9 billion barrels oil-in-place, but it would take World War II to increase the demand for oil before the remote field would be developed. Since then, the field has undergone a multitude of projects that have slowed production decline and greatly increased the overall oil recovery. Chevron learned early on that to effectively produce this complex reservoir, they had to rely on the operations personnel to closely monitor each well in order to make timely adjustments to their production programme.

Production History

Development drilling began in April 1944 and after just a year and a half, 182 wells had penetrated the productive Weber sandstone. At one point in 1946, 54 rigs were operating simultaneously, and by 1949, 478 wells on 40-acre spacing (~0.16 km²) had been drilled. Produced gas injection began in 1950 to help maintain reservoir pressure.

Further declines in reservoir pressure led to a full scale water flood operation in 1958, with peak production reaching 82,000 bopd. Infill drilling started in the early 1970s. The water flood continued until a tertiary recovery programme using carbon dioxide (CO₂) injection was initiated in 1986. Additional expansions and infill drilling, including a pilot project testing 10-acre (~0.04 km²) spacing, have continued, with the most recent new well drilled in 2013.

All of the secondary and tertiary production programmes, as well as



A number of projects designed to bring more oil to the surface have kept the Rangely field economic for 70 years.

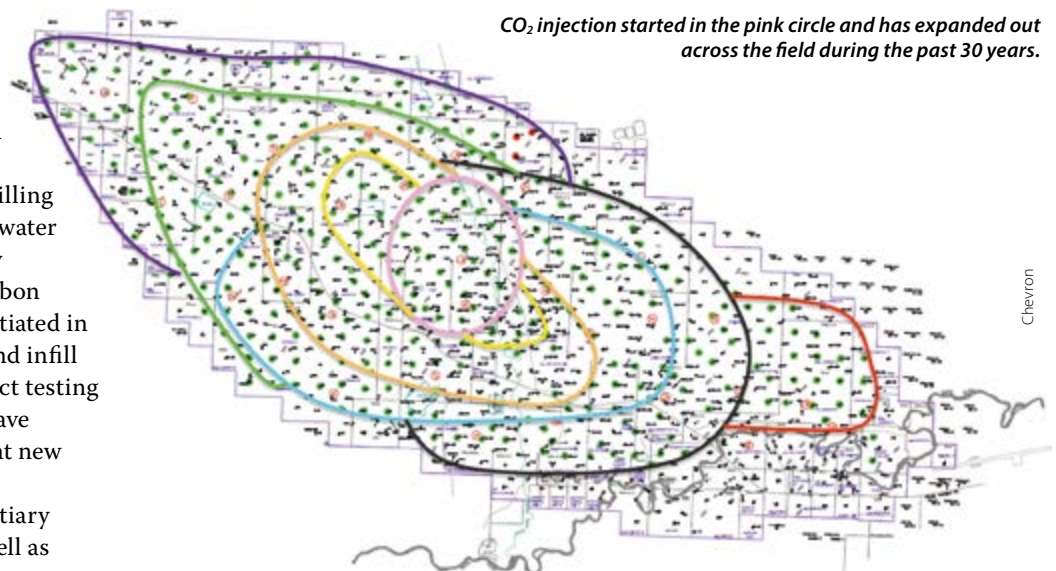
infill drilling, are designed to recover additional oil-in-place and extend the life of the field. The water flood programme was carried out by drilling additional wells where water is injected into the reservoir, maintaining reservoir pressure and pushing oil toward production wells. The CO₂ injection tertiary recovery programme resulted in some surprises and a change in the original design plans.

The Rangely CO₂ Project

Before starting tertiary recovery at Rangely, Chevron expected to recover 821 MMbo with the water flood – about

43% of the 1.9 Bbo originally in place. They also expected to gain another 118 MMbo by adding CO₂ injection. (Note: The field is still going strong, producing 11,000 bopd and 1,200 bpd NGLs.) Chevron had a large net gain in production but also one that required the investment of millions of dollars. Operating costs increased as CO₂ reacted with water to form carbonic acid, necessitating all the equipment used in producing this field to be corrosion resistant.

The CO₂ is purchased from a gas sweetening plant near La Barge in southwest Wyoming and is transported 77 km

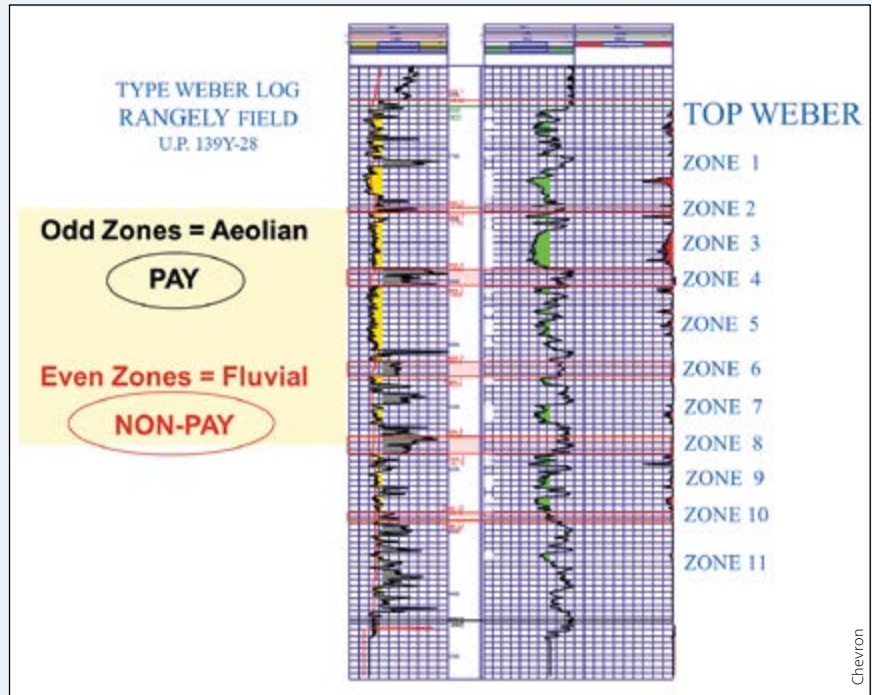


CO₂ injection started in the pink circle and has expanded out across the field during the past 30 years.

Rangely Field Geology

Today, the Permian to Pennsylvanian Weber Formation at Rangely has been folded into a faulted, elliptical dome about 18 km in length. The fault has a north-west to south-east orientation and runs along the south-west side of the anticline. Oil occurs at depths of 1,700m to 2,070m. Average gross thickness is 160m while the average effective reservoir thickness is 58m.

The Weber lithology is primarily aeolian sandstone separated by fluvial stringers. The aeolian sediments were deposited in dune and interdune environments. The dune sediments are cross laminated and the major productive lithofacies have an average porosity of 12%. Permeability is highly variable, averaging 8 md. The fluvial deposits are dominantly arkosic sandstones, siltstones and shales and form intraformational permeability barriers between the aeolian pay zones.



The Weber Formation shown on the type log. The interval is divided into 11 zones alternating between fluvial (non-pay) and aeolian (pay) environments. Not all zones are present across the field, making the development programme challenging.

via pipeline to Rock Springs, Wyoming. Chevron’s pipeline then moves the gas another 208 km to the Rangely field. Pipeline and facility construction started in 1984. The company originally purchased 75 MMcfpd of CO₂, peaking in 1990 at 150 MMcfpd before dropping to the current 30–36 MMcfpd.

CO₂ injection into an oil pool

increases oil recovery because of the modifications it creates in the crude. Some of the more important changes include: reducing the oil viscosity, which makes the oil less resistant to flow; swelling the crude to push more oil out of the rock; and increasing gas pressure which also pushes more oil out of the rock and to the well bore.

CO₂ and water are pumped into the Weber sandstone in alternating cycles (water alternating gas or WAG), sweeping more oil to the producing wells. Production consists of a variety of petroleum components, water, and gases. The production stream is separated into the various parts to recover the petroleum while the CO₂

One of the many wells on the Rangely field.



Thomas Smith

and water are treated and reinjected. The field now has ~400 active producing wells and ~275 injector wells.

Teamwork

Chevron's Erik Woodward, the Rangely Technical Team Lead, and James Cooper, a petroleum engineer at Rangely, explain: "A typical WAG injection programme consists of alternating slugs of water and gas injected into the reservoir. Injected gas acts as the solvent or mobilising agent but it does a poor job of displacing oil. Injected water helps to displace the oil and improve sweep efficiency. In most fields, parameters that are critical in affecting the enhanced oil recovery included the WAG ratio, injection rates, cycle, well spacing, gas breakthrough, reservoir pressure, and sweep efficiency. These factors are constantly monitored by the technical team and operations personnel at the field. Typical programmes in other CO₂ floods call for a 'WAG' ranging from once a month to every six months. The complex heterogeneity of the Weber reservoir at Rangely requires a significantly higher WAG tempo in order to keep optimised facilities and maximise production. We are currently doing between 25 and 60 WAGs per week and over 3,000 in

a year for the entire field. This takes a good operations team monitoring daily changes in pressures and production rates so that the technical team can make adjustments to the WAG programme."

To keep this field operating efficiently, Chevron employs about 50 operations personnel, with four 'WAGgers' just to keep track of and to make the 3,000+ WAGs each year. On a daily basis, the WAGgers monitor pressures and injection rates and relay that information to the Rangely Technical Team, which consists of a team leader, an injection engineer, geologist, reservoir engineer, and up to five production engineers.

"The WAG with CO₂ injection is a complicated process. Results can vary from expectations and the team has to make changes to the programme. We communicate closely with the operations personnel to identify trends quickly, in order to make the best reservoir production plans," says Erik Woodward. "The interaction with Operations is one of the most critical components of efficiently executing the WAGs and changes must be clearly communicated to Operations, who make it all happen."

Now and Beyond

Necessary changes to the WAG programme included tapering. The original programme called for a 1:1 ratio of water to gas. The revised WAG programme uses more water in ratios of 2:1 and 3:1 and reduced half-cycle slug sizes to control gas production. Initial design called for half-cycle slug size of 1.5% hydrocarbon pore volume (HCPV) and now varies between 0.25 and 1.5. Close monitoring and infield drilling have increased the sweep and made the CO₂ flood an economically successful project. Technical innovation and the flexibility to make quick and sometimes dramatic changes to the flood have been critical in field development.

Chevron is always looking for opportunities to increase production in the field. Some of the more obvious projects include continuing to tweak the WAG, more infield drilling in under-developed areas of the field which may include 10-acre spacing, switching injectors to producers, and improving and increasing fracturing operations.

One thing is certain: Erik and the entire Rangely team will keep all options open to employ new technology and innovations to maintain the Rangely field production. ■

The Rangely field at night.



Brian Payne

The Ross Sea Antarctica

NICK CAMERON and
'MO' TURNBULL

Remoteness and extreme weather, coupled with increasing environmental concerns, mean that only about 200 visitors reach the Ross Sea each year – but once there they are rewarded with spectacular views and Neogene to present-day volcanoes.

Tourism, and consequently geo-tourism, can never become mainstream activities in Antarctica due to the continent's remoteness, extreme weather and the darkness during the winter months (March to September). There are also increasing concerns about human-induced damage to fragile ecosystems and the accidental introduction of alien life.

Because of the relatively short – albeit often notoriously rough – crossing from South America, the Antarctic Peninsula is the most visited region. In contrast, the Ross Sea has far fewer visitors as it is a long week's sailing through the inevitably even more stormy seas of the Southern Ocean, from Bluff at the far southern point of New Zealand or from Hobart in Tasmania. Furthermore, since ice is inescapable in the Ross Sea, ice-strengthened ships are mandatory.

These vessels are much smaller than the cruise ships that visit the Antarctic Peninsula and as they have shallow, non-stabilised hulls, they roll in cross winds. This results in an often all too lively ship, as the wind almost always blows from the west: we 'enjoyed' 70 knot-plus gusts. No wonder the latitudes south of the 60th parallel are often referred to as the 'Screaming Sixties'.

In all, about 200 visitors reach the Ross Sea each year, although some never actually achieve their landing destinations on Ross Island and mainland Antarctica due to sea ice and/or poor weather. Our trip was organised by Heritage Expeditions and led by the company's founder, Rodney Russ. It began at Bluff with landings on the way south at the Auckland Islands and Macquarie Island and on the return trip at Campbell Island (see the online extended version of this article

on geoexpro.com for a description of the geology of these islands) with disembarkation at Lyttleton, near Christchurch in New Zealand.

As the first draft of this paper is begun (25 February 2015), the air temperature off Cape Evans (Ross Island) is -18°C , which with the wind chill equates to about -40°C – and yet this was still summer. The wind is lifting wreaths of freezing mist from the sea and thick rime coats the ship. No landings are possible. With a water temperature approaching -2°C new ice is rapidly forming, but for now it is being broken up by the wind, but the sea will quickly freeze over for the season once the winds drop. Mount Erebus is enshrouded in cloud, but the bases of the glaciers descending from its sides are periodically visible, as are statuesque clumps of Adélie penguins and dozing Weddell seals.

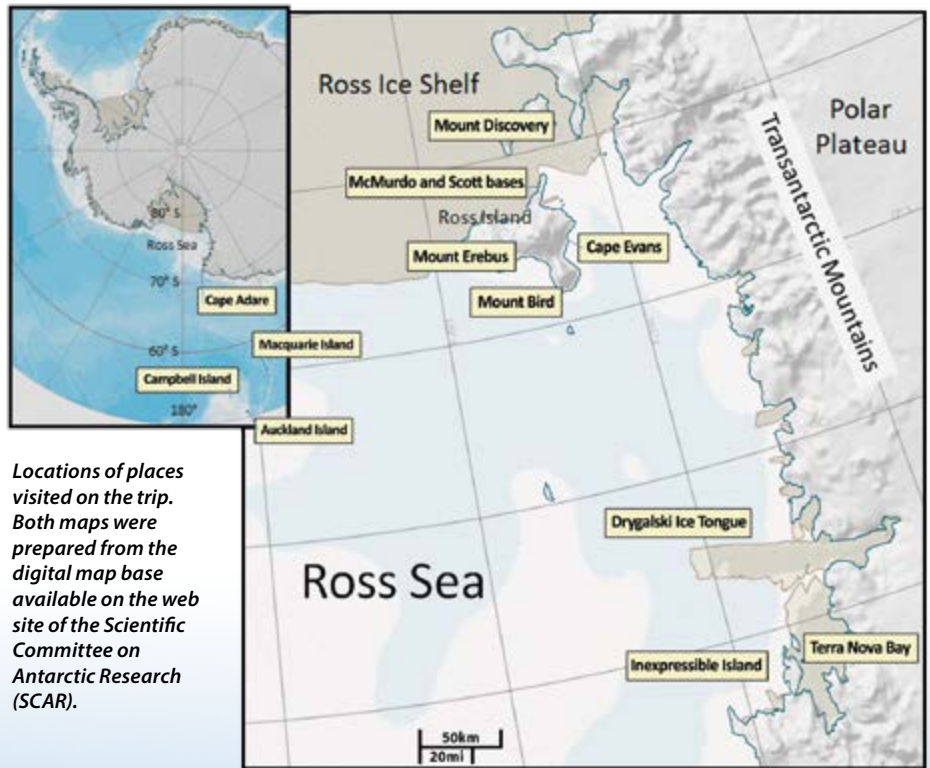


The Geology of the Ross Sea

The Ross Sea occupies a rift zone below which crustal extension has advanced to approximately that of the better known East African Rift System. Its origins remain to be unravelled, but it is positioned along the Mesozoic suture between East Antarctica and West Antarctica. Technically it is part of the West Antarctic Rift System. The western margin is the fault zone which bounds the uplifted 2,000–4,000m high Transantarctic Mountains. The eastern limit is more tenuous, but tracks the eastern boundary of the montage of platelets that make up West Antarctica.

The pre-rift succession of the Transantarctic Mountain begins with metamorphics (Skelton Group) and granites. Above are some 2,500m of terrestrial to shallow marine clastics, which together form the Beacon Supergroup. These sediments are of Devonian to Triassic origin and match those of the Karroo succession of this age elsewhere in Gondwana. Permian glacials, plus *Glossopteris*-associated coals, are present. Thick dolerite sills of the Ferrar Group intrude the sediments.

The current phase of rifting commenced with the uplift of the Transantarctic Mountains in the early Eocene and the coeval formation of the



Locations of places visited on the trip. Both maps were prepared from the digital map base available on the web site of the Scientific Committee on Antarctic Research (SCAR).

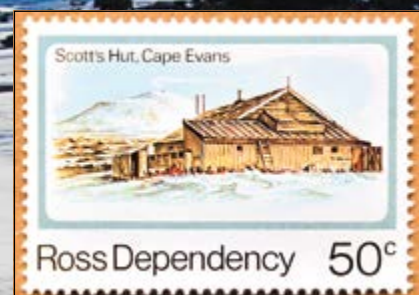
Ross Sea Basin, where more than 4,000m of glaciomarine beds subsequently accumulated above block faulted basement. Volcanism commenced in the early Miocene, becoming increasingly voluminous through time.

The onset of continental scale glaciation in Antarctica was triggered by the opening of the now 800 km-wide

Drake Passage between South America and Antarctica during the late Eocene. This event allowed the completion of a globally unbroken pathway for the circulation of westerly winds and sea currents around Antarctica. Rapid cooling followed in Antarctica, with ice caps developing almost immediately afterwards. To this day, depressions



Ross Island. Captain Scott's Hut at Cape Evans, with Mount Erebus in the background. Uncemented, Plio-Pleistocene pyroclastics from Erebus form the bedrock. The stamp, right, was issued by the Ross Dependency of New Zealand in 1982 as part of a Scott anniversary set. Included in the design is the white summit plume usually characteristic of Erebus.



continue to move endlessly around Antarctica; as this text is further drafted (28 February), we are experiencing a full-blown gale with driving snow off Cape Adare created by the latest of these lows. Once again, no landings are possible.

More detail on the geology of the Ross Sea may be found in the memoir and 1:250,000 map that covers the Southern Ross Sea, for which 'Mo' Turnbull is a senior author. It is available online at <http://www.gns.cri.nz/Home/Products/Maps> with the title *Geology of Southern Victoria Land, Antarctica*.

Neogene Volcanoes

On our trip most planned landings and near-shore transits were possible, though sometimes only after several attempts, with the cloud generally high enough to savour the 'winter wonderland' scenery. Especially eye-catching was the scale of the Neogene volcanoes in and around Ross Island. The most significant was Mount Erebus (3,794m), the world's most southerly active volcano. It is distinguished by its permanent, often boiling lava lake and visually, from afar, by a white plume associated with near continuous Strombolian eruptions. Major eruptions, however, are currently rare, with perhaps the last one observed by Sir James Clark Ross in 1841 during his first expedition to Antarctica.

Equally spectacular were Mount Terror and Mount Bird, the latter being a shield volcano smothered with ground-hugging, Christmas-cake-like layers of ice. All three volcanoes carry



An unusually vigorous eruption from Mount Erebus viewed while at anchor off McMurdo Station at close to midnight.

satellite ash cones and lava domes.

Landings on Ross Island were made at the USA's McMurdo Station and Captain Scott's Discovery Expedition hut on Cape Evans. McMurdo provides the most southerly possible rock landing in the Ross Sea. Geologically it is located at the southern end of a narrow line of young cones known as the Hut Point Peninsula. New Zealand's Scott Base is nearby, but its position on the other side of the peninsula means that it is normally ice bound.

Observation Hill, just south of McMurdo Station, is a prominent cone built of flow banded, phonolite lavas, obsidian and loose scoria. Its 226m-high summit would have been the perfect vantage point for early polar explorers to have scouted out routes up the glaciers running from the Polar Plateau into the Ross Sea.

Important Geological Vista

Even from ship level and with the naked eye, the westward rising glaciers were clearly visible from Ross Island, more than 50 km away across McMurdo Sound. Equally visible were the horizontal beds of the Beacon Supergroup rising steeply above the more subdued coastal topography of the Skelton Group metamorphics. Also surprisingly conspicuous within the Beacon Supergroup were the hundreds of metres of thick, black dolerite sills of the Ferrar Dolerite. This has to be one of the greatest geological vistas possible on this planet, particularly given the importance of this mountain range in understanding the assembly of Gondwana, and its role in providing access to the south for South Pole expeditions.

Often visible in the mountains are



The Transantarctic Mountains viewed from McMurdo Station. The stamp shown above was issued by New Zealand in 1984 as part of a set depicting Antarctic research. These are black Ferrar Dolerite outcrops in the stamp's background mountain, and the geologist is holding an artist's rendition of a *Glossopteris* frond.

harmless-looking, diffuse, ground-hugging mists. In reality, these are blown snow blizzards whisked up by fierce katabatic winds – the bane and sometimes the nemesis of the early explorers.

Dominating the entire view to the south is the Ross Ice Shelf. This ice sheet has an area the size of France and landwards reaches a thickness of 700m. Most spectacular of the ice-embedded volcanoes was the perfect dome of Mount Discovery. Close to the edge of the permanent ice near McMurdo Station a pod of orca or killer whales were spotted as were, at a hopefully safe distance, frolicking Emperor penguins.

At McMurdo's Albert P. Crary Science and Engineering Centre we were shown lightweight, 'wire wool' textured phonolite bombs from Mount Erebus, containing several centimetre-long anorthoclase (an alkali-rich feldspar) crystals known locally as 'Erebus crystals'. These rapidly weather out from their host bombs to collect as loose whole crystals on the ground. Their origin remains unknown, but they are commonly present. For example, long laths of anorthoclase in phonolite were seen in pyroclastic boulders scattered around Captain Scott's hut at Cape Evans. Informally these rocks are known as Kenyte as they were first described from Mounts Kenya and Kilimanjaro volcanoes in East Africa.

The contents of Captain Scott's Hut are perfectly preserved by the 'cold store' weather and tucked away in it we

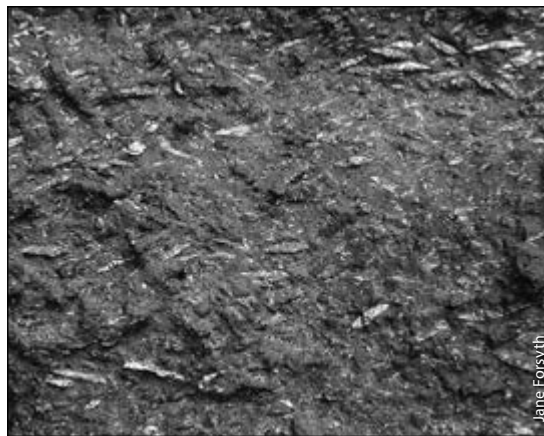
found a geological laboratory complete with a wet analysis kit and rock samples. These include a granite which must have been collected from the Transantarctic Mountains during a sledge expedition.

Inexpressible Island

On the way to Ross Island we entered Terra Nova Bay in East Antarctica. The first landing there, made in perfect weather, was on Inexpressible Island. This island, much of which is a giant *roche moutonnée*, is formed of wind-sculptured granites, partly buried by glacial moraine, also essentially of granitic origin. This landform, together with others in the area, indicates a once far thicker ice cover. The views were completed by a scattering of Adélie penguins and Weddell seals.

Of greater interest to any visiting sedimentologist was a storm beach boulder bed cemented by sea salt. This lithology could only form in the stormy, but desert climate that characterises the inner Ross Sea region. Here there is no rain and rarely more than windblown snow. As such this rock could be unique to the Ross Sea. Another unique feature is that its components include boulders of dumped sea ice.

The sole mainland visit was to the nearby German research base of Gondwana. The landing was achieved in rough, albeit safe conditions, but a



A boulder of anorthoclase-bearing phonolite erupted from Mt Erebus. The anorthoclase (alkali-rich feldspar) 'Erebus crystals' are several centimetres in length.

rapidly strengthening katabatic wind required a hasty retreat. Time did allow an inspection of boulders and outcrops of biotite gneisses. Granite pods are perfectly exposed in nearby cliffs.

Deteriorating weather that day prevented anything more than a mist-shrouded view of the Drygalski Ice Tongue. However, even that was sufficient to reveal the scale and power of this huge ice extrusion into the Ross Sea. It is massive and strong enough to trap Ross Ice Shelf icebergs against its southern wall.

Epilogue

As the draft for this article nears completion, the ship is again approaching yet another volcano. In total contrast to recent weeks, it is warm with bright blue skies, with just a residual swell from the last of those endless depressions, but still replete with so many gracefully skimming albatrosses. And this time the land is green; we are back in New Zealand and the volcano is Lyttelton, near Christchurch. In a professional life often requiring field work for both of us, this gentle scene provided the perfect finale for cementing into our memories a unique geological experience.

Acknowledgements

We would like to thank Heritage Expeditions (www.heritage-expeditions.com) for assistance with this article.

A longer version of this article, including a look at Macquarie Island and the Subantarctic islands, is available online at www.geoexpro.com. ■

An emperor penguin sledging at full speed across the ice. at full speed across the ice.



Back to Source Rocks: Part I

RASOUL SORKHABI, Ph.D

The science and analytical techniques to investigate petroleum source rocks have been developed over the past four decades. Understanding the geology and geochemistry of source rocks is crucial to petroleum geoscience and engineering. In Part I of this article, we review the protracted (with hindrances) formation of organic matter in source rocks, involving processes from solar radiation to sea-floor sedimentation.

The petroleum system consists of source rock, migration pathways, reservoir, seal, and trap. Source rocks represent the hydrocarbon kitchen (generation) in a sedimentary basin. The source rock is also the first logical step to assess a petroleum system, for no matter how excellent a reservoir or a trap may be, without an effective source rock there would be no petroleum charge into the basin.

Searching for Good Source Rocks

Although there is evidence for non-organic methane (notably, gas emissions from volcanic eruptions), the majority of petroleum geochemists and geologists rightly regard the hydrocarbons we produce from sedimentary basins to be of organic origin. One line of evidence is oil shale, which contains plenty of

organic matter (kerogen) but since the rocks were never deeply buried, the kerogen is thermally immature, and upon heating ('cracking'), it transforms to simpler hydrocarbon molecules, similar to those found in petroleum reservoirs. Source rock is the mother of all oil and natural gas reserves.

Fine-grained, clay-rich sedimentary rocks including mudstone, shale (platy mudstone), marl (calcareous mudstone), limestone, and coaly rocks (especially for natural gas) are usually considered to be possible source rocks because coarse-grained sediments are too porous and permeable to retain organic matter. Moreover, organic matter tends to adsorb onto mineral surfaces of clay-rich sediments which, being fine-grained, have a larger mineral surface

area per unit of rock volume. Marine environments in which fine-grained mudstone and clay-rich limestone are deposited coincide with the habitat and burial site of plankton biomass (which contribute 90% of organic matter to petroleum source rocks). Indeed, ocean waters, biota and rocks are the largest sink of carbon on Earth.

A 'good' source rock that yields commercial volumes of petroleum must have a high organic content and have compounds of both carbon and hydrogen molecules (otherwise, we end up with coal). It must be thermally mature through burial, have considerable thickness and lateral extent, and should be able to expel the generated oil.

A given shale formation will have different source-rock characteristics

Upper Cretaceous Mancos Shale, Capitol Reef National Park, Utah.



and ranking in various locations in a basin, and needs to be studied in detail.

Source Rocks in E&P

Despite its fundamental importance, the source was the last component of the petroleum system to be investigated scientifically, and petroleum geology textbooks of the 1920s–50s dealt mostly with reservoirs and traps. The first petroleum geochemistry books appeared in the late 1970s, including *Petroleum Formation and Occurrence* by B.P. Tissot and D.H. Welte and *Petroleum Geochemistry and Geology* by John Hunt.

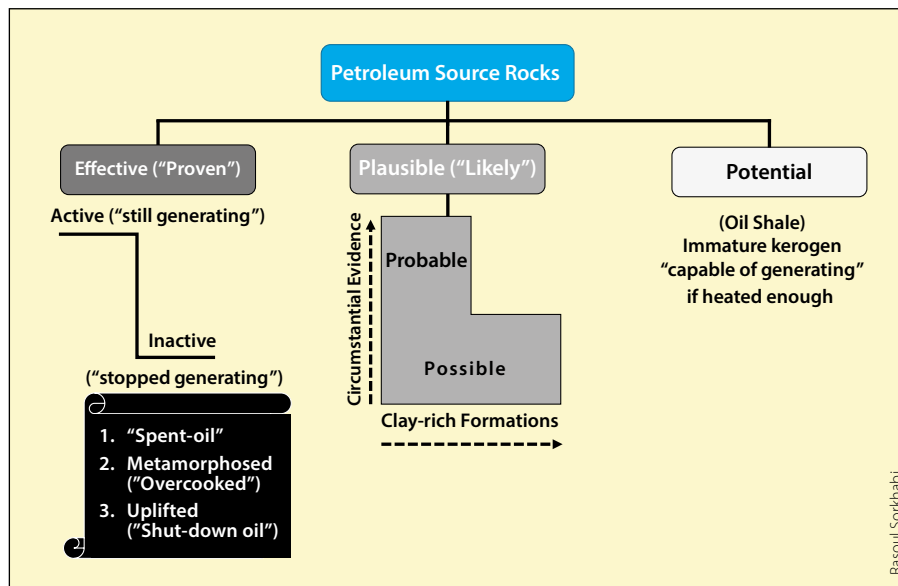
Because source rocks lie in the deeper parts of the basin they are not easily accessible for sampling and analysis. Analytical techniques for source rock geochemistry are also relatively recent: RockEval (pyrolysis) and vitrinite reflectance techniques were developed in the 1970s, and basin modelling software for source rock maturity and petroleum generation appeared in the 1980s.

The history of the petroleum industry since the mid-19th century may be viewed as the rise of four waves in exploration and production: onshore; nearshore and shelf; deepwater; and shale. For most of this history, exploration onshore and nearshore was primarily based on locating seeps and trap structures (so-called ‘wildcatting’). In deepwater basins the source rock is the last layer to be drilled, so we still have little data for deepwater source rocks.

The significance of source rock knowledge in exploiting shale plays should not be underestimated. Even though producing from these low-permeability rocks requires direct drilling, hydraulic fracturing and mapping of fracture sweet spots, at the resource level, the efficiency of shale plays is controlled by their geochemical, mineralogical, depositional and thermal maturity properties.

From Sunlight to Kerogen

Carbon (from Latin *carbo*, charcoal), with atomic number six, is the fourth-most abundant element (0.46% by mass) in the Milky Way galaxy, after hydrogen, 74%, helium, 24% and oxygen, 1.04%. Carbon, like many other elements, was created inside previous



A classification of source rocks based on their probability of performance.

stars in the universe by nucleosynthesis. It constitutes no more than 0.18% of Earth’s crust.

Before oil and gas are generated in the source rock, there is a long pathway for organic matter to be produced, accumulated and preserved in the basin. Organic matter dispersed in sediments is called kerogen (Greek: *keros*, wax, and *gen*, birth), a mixture of complex carbon-based chemical compounds that are insoluble in normal organic solvents because of their high molecular weights. The term kerogen was introduced by the Scottish chemist Alexander Crum Brown in 1906. Note that fresh organic matter in unconsolidated sediments up to 100m deep is not regarded as kerogen.

We often think of solar power as radiation from the sun that directly reaches Earth, but fossil fuels are also solar energy stored in rocks because the sun’s radiation (electromagnetic force) is involved in the production of organic carbon. Fossil fuels are an important component of the carbon cycle on Earth, which describes the interlocking circuits of carbon reservoirs (pools) and exchanges (fluxes) in the atmosphere, biosphere, hydrosphere and lithosphere.

Solar radiation that reaches the top of Earth’s atmosphere has been measured by satellites to be 1,361 W/m². This average annual ‘solar constant’ amounts to a flux of 173,000 TW (173 x 10¹²) of solar radiation for the whole Earth. It includes infrared

(50%), visible (40%) and ultraviolet light (10%). About 30% of solar radiation is reflected back by the atmosphere, clouds and land as shortwave radiation; the remaining 70% is absorbed by land, oceans and atmosphere for various processes, but is eventually radiated back to space. Only 40 TW (0.023%) of solar radiation is involved in photosynthesis, the source of organic matter.

The Carbon Cycle

Photosynthesis and respiration are probably the most familiar processes of the carbon cycle to us. Plants utilise sunlight, carbon dioxide and water to

Carbon budget on Earth.

Carbon Pools (Reservoirs)	Quantity (Gigaton, 10 ¹² ton)
Atmosphere	720
Oceans:	38,400
Total inorganic	37,400
Total organic	1,000
Surface layer	670
Deep layer	36,730
Lithosphere:	
Carbonate sediments	>60,000,000
Kerogens	15,000,000
Terrestrial Biosphere (Total):	2,000
Living biomass	600-1,000
Dead biomass	1,200
Aquatic Biosphere:	1-2
Fossil Fuels (Total):	4,130
Coal	3,510
Oil	230
Natural gas	140
Other (peat, etc.)	250

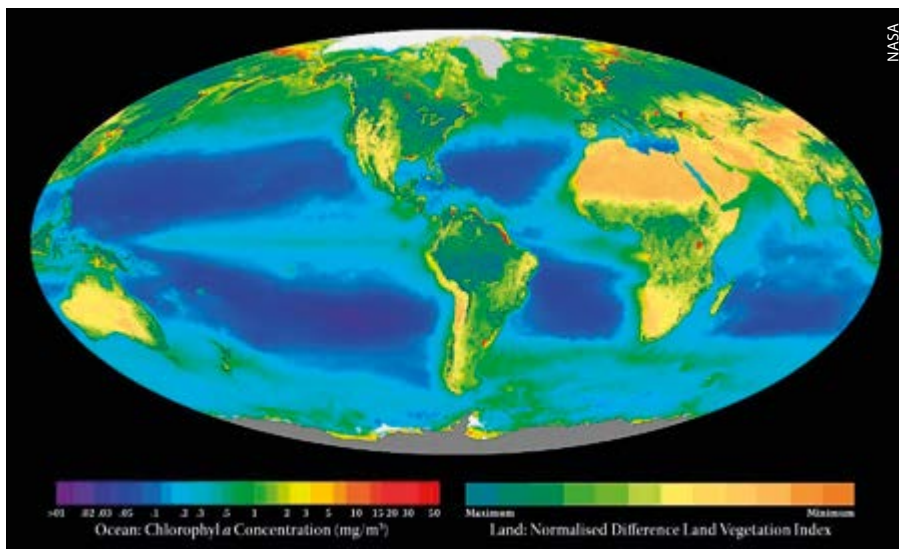
Rasoul Sorkhabadi

Source: The Global Carbon Cycle, Falkowski et al., Science 13 Oct. 2000

produce food (carbohydrate molecules such as sugars) and oxygen. Animals, in turn, depend on plants (or other animals) for food, and their respiration involves inhalation of oxygen and exhalation of carbon dioxide. Photosynthesis and respiration occur in both terrestrial and aquatic ecosystems, the difference being that land plants and animals utilise the atmospheric carbon dioxide and oxygen while marine organisms (phytoplankton and zooplankton) get these substances from sea water. Note that sunlight also penetrates the upper 200m of oceans – the photic zone, where about 90% of marine organisms live.

Photosynthesis and respiration are parts of the ‘fast carbon cycle’. The ‘slow carbon cycle’, which operates on longer time periods, includes the chemical weathering (thus absorbing atmospheric carbon dioxide) and erosion of rocks, and the transport of organic matter by rivers to oceans, as well as the plate tectonic subduction of carbonate rocks and release of carbon dioxide from volcanoes. The slow carbon cycle carries terrestrial carbon to oceans where it is incorporated in marine organisms or deposited as carbonate rocks on the sea floor.

Since high levels of biological activity increase the production of organic matter, the supply of nutrients – phosphates and nitrates – for organisms is another condition favourable for deposition of rich source rocks. Continental margins with sediment-laden rivers naturally have abundant



Distribution of phytoplankton (primary producers of organic matter in oceans) depicted as concentration of chlorophyll.

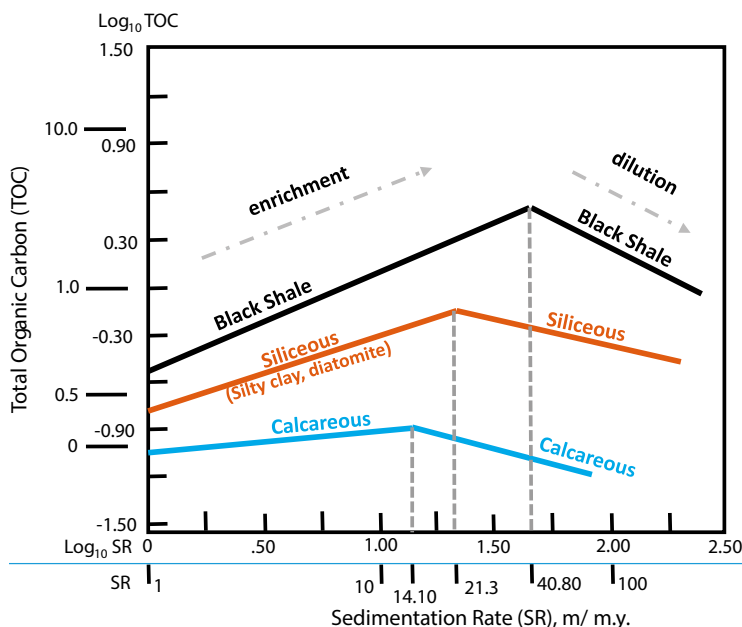
nutrients. Marine ‘upwelling zones’ are also important providers of nutrients to stimulate the growth of phytoplankton populations (primary producers of organic matter). Upwelling is the rise of colder, nutrient-rich water from the ocean bottom to the sea surface, the nutrient content being derived from decomposition of dead plankton. Marine upwelling is caused by various mechanisms. In coastal areas, for example, where winds move parallel to the shore and surface waters move offshore perpendicular to the wind direction, deeper and colder water upwells to the surface. In equatorial coasts, the eastward trade winds drive away surface waters from the western

coastline of the continents, thus inviting deeper colder water to rise and replace the surface waters.

Anoxic Environments and Sedimentation

At present, total production of organic matter in the world’s oceans amounts to 50 billion tons a year, but over 99% of this is broken down by oxidation, microbial activity or physicochemical changes in water column. Therefore, only 0.01–0.001% of organic matter is preserved in sedimentary rocks as kerogen or fossil fuels as part of the ‘slow carbon cycle’. This indicates the preciousness of petroleum resources formed over millions of years, hence their categorisation as non-renewable resources on the human timescale, although petroleum generation is a continuous, renewable process on the geological timescale.

When organic matter combines with oxygen, the reaction produces carbon dioxide and oxygen molecules – the reverse of photosynthesis, and also what happens when we burn fossil fuels. Oxygen thus acts as a double-edged sword: it helps to produce organic matter, yet also destroys it. Therefore, for organic matter to be preserved in sedimentary rocks, an anoxic environment ($O_2 < 0.2$ mL/L) is required. Anoxic conditions are found in lakes with thermally stratified waters (warm water over cold water), in barred near-shore basins with salinity stratification



Relationships between sedimentation rate and total organic carbon for various marine rocks. Data for Jurassic – Recent sediments recovered by the Deep Sea Drilling Project (Johnson Ibach, 1992, AAPG Bulletin, 66: 170-188).

(light water atop dense water), and continental margins at low latitudes (and close to upwelling zones) where water depths of 200–1,500m (below the photic zone) are deficient in oxygen.

Obviously, oceanic anoxic events, during which vast parts of the world's oceans were depleted in oxygen, favour the deposition of organic-rich source rocks. Such events require high levels of atmospheric carbon dioxide (from volcanic eruptions), warm climates (mainly due to atmospheric greenhouse effect), sluggish ocean currents, and euxinic (sulphidic) water chemistry (from volcanic outgassing). Extreme volcanic activity also supplies nutrients that stimulate planktonic productivity in the oceans. Global anoxia have been recorded in the Jurassic and Cretaceous periods – these rocks account for 70% of the world's petroleum reserves. Several intervals of anoxia have also been found throughout the Palaeozoic era. Intense global anoxia have also been linked to marine mass extinctions because of climatic change and toxic (H₂S-rich) waters.

Organic matter in ocean waters exists in three different forms: particulate matter; in solution; and in colloidal form. Particulate organic matter may directly drop to ocean bottom, while dissolved organic matter may be adsorbed onto clay grains, which then sink slowly through the water. Colloidal organic matter flocculates to particulates before sinking.

Organic matter that reaches the

Devonian Marcellus Shale, West Virginia.



sea floor is buried in sediments. It is intuitive to consider that more sedimentation favours the deposition of rich source rocks not only because of the greater volume of sediments, but also because rapid sedimentation and burial impedes oxidation processes, thus preserving organic matter. This is true only to some degree, because high sedimentation rates actually lead to dilution of organic matter in sedimentary rock formations.

A Summing-up

Basins with restricted water circulation and stratified water column will preserve more organic carbon in sediments and produce good source rocks. To sum up our discussion in this article, the following relationship is quoted from a seminal paper by Kevin Bohacs et al. (2005, *SEPM Special Publication 82*, pp. 61-101):

Organic-matter enrichment = Production – (Destruction + Dilution)

Production of organic matter is a function of photosynthesis (sunlight, water, carbon dioxide and nutrient supply) and plankton population. Destruction is related to exposure time to oxidants. Dilution is a function of clastic sedimentation rate and production of biogenic material (silica or carbonate). In short, 'significant enrichment of organic matter occurs where organic-matter production is maximised, destruction is minimised, and dilution by clastic or biogenic material is optimised.' ■



ENVOI

delivering energy opportunities

ENVOI specialises in upstream acquisition and divestment (A&D), project marketing and portfolio advice for the international oil and gas industry.



ACTIVE PROJECTS

GHANA

(Offshore exploration)

TUNISIA

(Onshore exploration)

KENYA

(Onshore exploration)

AGC (SENEGAL / GUINEA BISSAU)

(Offshore exploration/appraisal)

UK: EAST MIDLANDS

(Onshore appraisal/development)

VISIT WWW.ENVOI.CO.UK
FOR MORE INFORMATION



Australia: Encouraging Unconventional Test

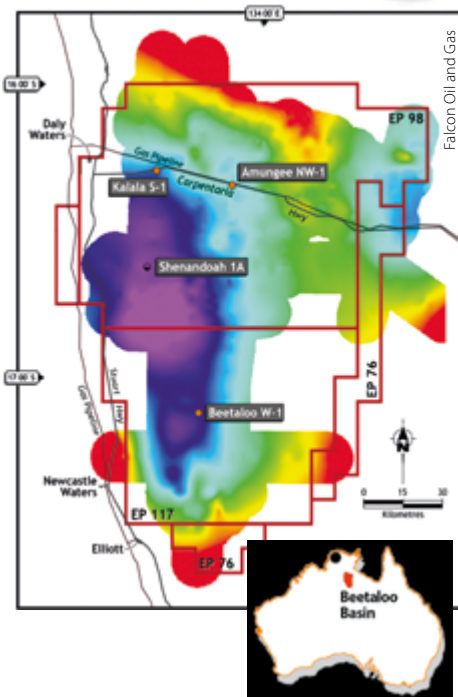
The first of a five-well A\$ 64 million exploration drive in the Beetaloo Basin in Northern Territory has produced some very encouraging results that suggest that the geological characteristics of the basin are indeed viable for unconventional drilling.

Targeting the highly prospective Middle Velkerri source rock sequence, the Kalala South-1 well in EP 98, operated by Origin Energy, intercepted more than 500m of gross pay with net pay of 150m. Significantly, Origin believes the well also identified a number of 'good quality' sand and/or silty reservoirs that suggest there could be a column of 80m of just shale rock which would make it a very suitable candidate for horizontal drilling. A second well, Amungee NW-1, is now underway with a planned total depth of 2,700m; early indications suggest a similar result. This

will be followed by Beetaloo W-1.

The Beetaloo Basin is one of the few remaining virtually unexplored, onshore sedimentary basins. It is a Precambrian Basin that has more than 3,000m of sediment column in which the identification of source rocks has been confirmed as the two unconventional oil and gas generating geological formations of the Kyalla and Velkerri Shale. Each source rock is widespread, with thickness of up to 800m. There are also indications that high quality conventional reservoirs exist. A study by RPS Energy in 2013 estimated the gross recoverable resource potential (P50) of the Beetaloo Basin to be 162 Tcf and 21,345 MMbo.

Kalala South is located 600 km south of Darwin's two major LNG plants, and existing pipeline infrastructure runs through the acreage. ■

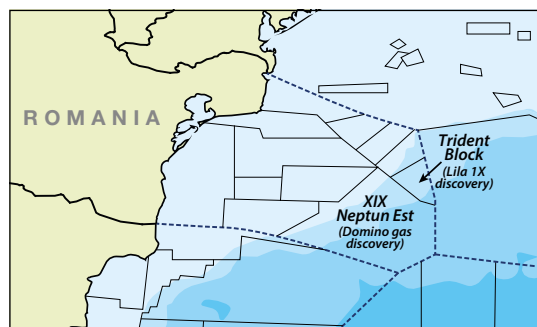


Romania: Lukoil Strikes Deepwater Gas

A Lukoil-operated group, which includes Pan Atlantic Petroleum and Romgaz, have made a deepwater gas discovery in the Trident block (EX 30). The Lira 1X discovery lies in 700m of water in the Black Sea some 170 km from the coast, with preliminary data suggesting it encountered a productive interval with an effective gas saturated thickness of 46m. According to seismic data, the area of the gas field could reach up to 39 km², while reserves may exceed 1.02 Tcf (30 Bcm) of gas, which is to be confirmed during evaluation drilling. Play types in the block are

expected to be roll-over and toe-thrust anticlines and turbidite stratigraphic traps with Miocene deep sea fan and slope clastic reservoirs.

The success of the Lira 1X well will reduce the risk for further exploration on a series of prospective sites with significant potential reserves, located both close to the Lira structure and in other parts of the block. The programme of future works planned for 2016 includes drilling a further exploration well at Lira and the reprocessing of seismic data to confirm



the size of the discovery.

While reserves may not prove to be world class, this is a significant result for Romgaz, which has only recently ventured offshore, after 100 years developing onshore expertise. ■

Pakistan: OMV Boosts Gas Reserves

OMV has revealed that its Latif South-1 exploration well, located in the Sindh Province of Pakistan, around 25 km south of the company's Latif gas field, is a production-boosting gas discovery that has opened up new exploration opportunities in the area. During testing, Latif South-1 flowed at a rate of 2,500 boepd (15 MMcf/gpd) from the Lower Goru Intra C Sands. OMV plans further appraisal work to confirm the size of the discovery, currently estimated by IHS at a modest 50 Bcf.

OMV is amongst the largest international natural gas producers in Pakistan, delivering more than 10% of the country's total gas supply. Two major obstacles in Pakistan which keep further foreign investment at bay are security and political instability. Meanwhile the country's energy requirements continue to mount while natural gas production from indigenous resources falls. ■



Register before 18th December and save up to £264!

PROSPECT AND PROPERTY EXPO

APPEX

GLOBAL 2016

1-3 March 2016
Business Design Centre, London UK

Hosted By



Featuring



The International A&D forum to buy, sell and promote worldwide E&P deals

For 14 years – APPEX, the Prospect and Property Expo – has brought together principals, senior managers, business developers and new venture managers for an unmatched opportunity to network and do business with NOCs, governments, financiers and global E&P deal-makers and decision-makers.

Over 2 and a half days, delegates will explore current and future trends in international business, new oil and gas hot spots and have the opportunity to discover and debate dozens of upcoming prospects from around the globe. All this takes place in a relaxed environment which has carefully been designed for maximum networking, allowing attendees to buy, sell and trade prospects and properties, find new partners and stay one step ahead of the competition.

>> Sponsor

APPEX provides the chance to meet hundreds of new potential clients and partners. Ensure your company has maximum visibility by becoming a sponsor of the event.

>> Exhibit

Exhibiting at APPEX is the most cost effective way to showcase your opportunities, meet face to face with existing clients and find new customers. Exhibiting companies with a prospect to promote have the opportunity to book a speaking slot in the conference programme!

Booth packages start from £1900 + VAT for prospect companies, including walls, furniture and complimentary registration. For more information and further package options, please visit the event website or contact Fionn Devine at fdevine@aapg.org.

>> Register

APPEX registration includes all programme sessions in both the main auditorium and the mini theatre, exhibition admission, lunches, all day refreshments and evening receptions.

Registration Fees	Until 18th Dec	Until 29th Jan	From 30th Jan
Standard 3 days	£630 + VAT	£775 + VAT	£894 + VAT
AAPG Member 3 days	£560 + VAT	£622 + VAT	£686 + VAT

Please visit the event website for the full list of registration prices.

APPEX Global 2015 Sponsors



europe@aapg.org
+44 (0) 207 836 3201
europeevents.aapg.org/appexglobal2016

An Education in Oil

How can the media best engage the public on fossil fuels? Documentary or drama? The BBC has been attempting both.

NIKKI JONES

It seems the BBC has been on a bit of a mission. As the UK grapples with declining North Sea production, the rise of Scottish nationalism and the possibility of becoming a Frack Nation, the corporation has broadcast a three-part radio documentary series on the impact of North Sea oil and a series of seven stand-alone radio dramas, set in oil hot-spots around the world, past, present and future. The aim, it seems, has been to raise the public's consciousness of this industry as it faces unprecedented challenges. It is an attempt that should be applauded, although the results were mixed.

Documentary or Drama?

A Crude History of Britain, presented by James Naughtie, sets out to remind us of the extraordinary technical challenges faced by North Sea engineers in the '60s and '70s. However, it is the cultural, political and economic impacts of oil that are likely to register more deeply with listeners. It is fascinating for those of us who were not there to hear of the gold rush atmosphere, and the impact of Americans with their Stetsons and pints of Dom Perignon arriving in an isolated, traditional Scottish town. It is probably a shock to most British listeners to hear how very dependent the country was on American expertise at the time.

The series is packed with small surprises as it rolls through recent British economic history. Who remembers that in the 1970s there was no taxation structure for oil exploitation and the country was, apparently, 'taken to the cleaners' by the Americans? Who remembers that the industry was pleading with government to keep the oil in the ground as the exchange rate shot up and exports fell? Now that the UK looks enviously at Norway's sovereign wealth

fund, it is interesting to be reminded how successive embattled governments, both left and right, were saved by oil revenues. Did we know that the UK was invited to join OPEC? Or that it chose to see off Nigerian competition by staying outside the cartel and operating through its Saudi allies? I didn't.

In contrast to the documentary series, each episode seemed to be bursting out of its 40-minute slot, each play ambitiously attempting to both educate and entertain. However, the pace and scope of each drama, the dropping in of informative 'asides' and the inevitable inclusion of some casual, light-entertainment sex made many of them hard to follow.

Engaging the Public

What will listeners have learnt? Perhaps that oil is at the top of the tree when

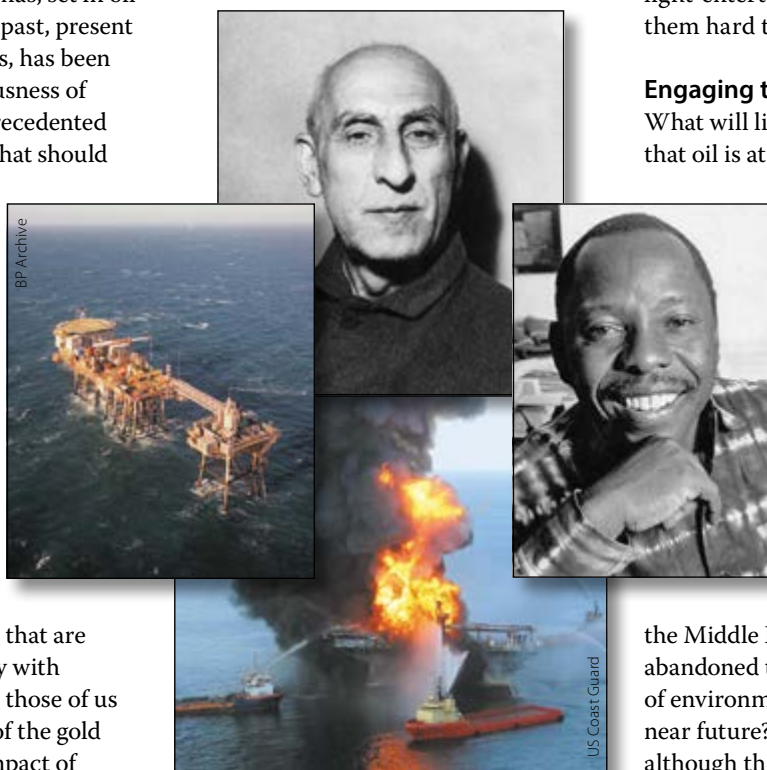
it comes to politically messy, dangerous, don't-look-down industries.

That's not news. Is it useful to remind the public, through fiction, that the British and Americans manufactured witnesses to get the public behind the first Gulf war, that blow-out preventers only ever work 50% of the time, that the world, including

the Middle Eastern oil states, has abandoned the Palestinians, that a range of environmental disasters is likely in the near future? The answer can only be 'yes', although this series succeeded through the most brutish hammering home of basic truths. The finer points were lost in the ambitious, fast-paced plots.

So the question remains: how do you get the public to engage with this most critical of industries? The BBC should be applauded for its attempts, although on this occasion the calm narrative of documentary stayed too safely in the uncontroversial, domestic arena, while the dramas probably lost most of their listeners somewhere in their vaulting ambitions. But more please: worldwide, the public needs to understand where its energy comes from and the implications of its consumption.

Clearly, both drama and documentary have a role to play. ■



All about oil – clockwise from top: Mohammad Mosaddegh, Ken Saro-Wiwa, Deepwater Horizon explosion, North Sea platform 1990.

The seven dramas were perhaps less successful in their mission to inform. Salient episodes of recent 'oil history' were fictionalised with moderate success – the deposing of Mosaddegh, the execution of Ken Saro-Wiwa, the start of the 1990 Gulf war, and the 1975 kidnapping of Sheikh Yamani. Added to this were the purely imaginative attempts of a young journalist to discover 'the truth' behind the Deepwater Horizon disaster, the disappearance of an environmentalist in Alaska and a futuristic look at the UK's fracking industry.

What is missing from this picture...

Energistics Standards

Adopting standards...

- Provides seamless data integration
- Increases efficiency that reduces risks
- Resolves real-time data configuration issues
- Allows multiple vendor project participation

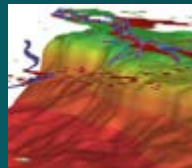
For more information, visit energistics.org/missingpiece



Upstream Standards. Bottom Line Results.®

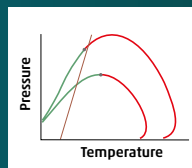
SUB · SURFACE · SYSTEM · SPECIALISTS

GEOS 4



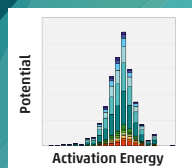
CONVENTIONALS

Pre-drill petroleum properties prediction (GOR, P_{sat}, B_o, etc.) and basin modelling.



UNCONVENTIONALS

Heterogeneity profiling, in-situ PVT prediction and production allocation.



KINETICS DATABASE

220 samples worldwide, bulk and compositional kinetics, geo-files provided for PetroMod®.

GEOS4 - The PhaseFinder People

www.geos4.com | info@geos4.com

Finding Petroleum **digital energy journal**

Events 2015/16



Transforming subsurface operations with data
Stavanger, 03 Dec 2015, Aberdeen, 27 Jan 2016 (TBC)

Transforming Offshore Operations
London, 10 Dec 2015

Finding African Oil
London, 25 Jan 2016

Doing more with E+P Data
Mumbai, 02 Feb 2016

European Shales for Shale oil or gas
London, 10 Mar 20156

Transforming subsurface insights!
Aberdeen, 17 Mar 2016

Transforming subsurface insights!
London, 18 Apr 2016

www.findingpetroleum.com
www.digitalenergyjournal.com

Oil Production Surges in Texas

THOMAS SMITH

Crude oil production in America's No. 1 oil-producing state is projected to reach an all-time high in 2015. The old record of 1.263 Bbo in 1972 will be surpassed this year with an estimated 1.284 Bb. Oil production growth has increased and continues to rise at rates never recorded in the US over such a short period. The September daily average oil production has more than doubled over the past three years. This is all in spite of the recent decline in oil price, rig count, drilling permits and well completions.

According to the Texas Railroad Commission, Texas recorded a record monthly average daily oil production of 3.4 MMB in 1972. Production then went into a slow decline, and a more accelerated decline in 1981. The production slide continued until 2008 when hydraulic fracturing and horizontal drilling into shales and other tight formations started the steady turnaround.

Permian Basin Production

From what started out as just 10 bpd at the Westbrook Field in 1920, followed by the discovery of the supergiant Yates Field in 1926, the Permian Basin had become one of the world's great petroleum basins. Daily production peaked in 1973 at 2.085 MMBpd just a year after the state's peak in daily production. The decline was slowed by enhanced recovery and infield drilling.

The recent meteoric rise in production started in 2011 when companies began targeting the unconventional oil plays in the older strata. The Wolfcamp, Cline shale, Strawn and Atoka became targets below the traditional producing horizons and represent a thick section underlying much of this 400 km-wide by 480 km-long basin.

According to the US Energy Information Administration (EIA), average daily production for October 2015 was 2,012 Mbpd and is projected for November to be up to 2,033 Mbpd, keeping the 21% monthly change that has been going on for almost four years now.

Also from the EIA, since 2011 the rig count was between 450 to over 550 in 2014, and has dropped to just over 200 in less than a year, yet production continues to climb. New well production has risen almost as fast. In 2011, production from new wells was approximately 100 bopd and has risen steadily to 230 bopd in late 2014, then continued with a rapid rise to the current 550 bopd. Simply put, the companies have started targeting the higher productive trends and have learned better completion techniques.

Eagle Ford Production

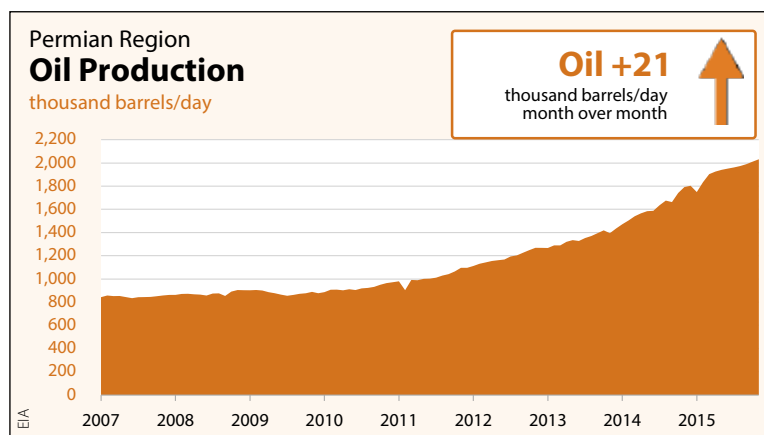
Looking at the rise in the other giant shale oil play, the south-west Texas Eagle Ford, oil production started in earnest in the middle of 2010, after three years of drilling with little improvement in production, which stayed under 100 Mbpd. After 2011, production from the formation nearly doubled every year, reaching 1,059 Mbpd in 2014, according to the Railroad Commission of Texas. Through July 2015 the production increase has slowed, averaging 1,073 Mbpd, and an EIA report has production slowing in the second half of 2015.

As in the Permian Basin, the rig count has dropped off precipitously from approximately 250 in late 2014 to 100 in mid-2015. In addition, new well oil production per rig has increased from under 100 bopd to close at the current 800 bopd, indicating a long and laborious learning curve to these types of plays.

New trends in Texas could include the Pearsall and Buda plays located below the Eagle Ford. Activity started in these plays before the oil price drop and showed promise in depths varying from 2,130m to 3,800m. Other Eagle Ford equivalent plays being targeted in south-east Texas include the Lower Woodbine and the Eaglebine, located on the eastern edge of the Eagle Ford. Close to the Barnett shale play in North Texas, operators are looking at the Marble Falls play that overlies the Barnett. This 122m-thick play has had over 300 successfully completed wells by companies such as EOG and Pioneer Natural Resources Corporation. Further north in the Texas Panhandle is the Granite Wash play and other shale plays overlying the Granite Wash, extending further west. These are oil prone and shallower than the Granite Wash play.

Finally, companies have only scratched a small portion of the Permian Basin. This area is actually divided into the Midland Basin and the Delaware Basin, separated by the Central Basin platform. The equivalent formation names change across the two basins but they seem all to be oil charged. There are also multiple intervals within these shales that are separate plays, which companies are just beginning to explore.

Once oil prices start up again, and with all the shale potential remaining in the state, Texas oil production could increase to even higher levels than seen before. ■



Permian Basin shale plays have led to an average gain of 21 Mbpd month to month over the past four years.

Freedom to imagine.

Geometric Freedom™ lets you focus strictly on your ultimate goals, obtaining the highest quality data despite any geological or operational challenge.

Nodal technology illuminates subsurface mysteries like never before. No one knows that better than we do. We pioneered the technology and have more experience with it, by far, than anyone else around. Our nodal systems, acquisition, proprietary nodal processing techniques and licensing expertise come together to solve the world's most daunting seismic challenges. What can we do for you?

Devastating Results

With few discoveries of note this year, we continue to use more hydrocarbons than we find.

This year has been a big disappointment for explorationists. Only two decent discoveries have been made – so far. Even worse, the exploration success is so dismal that we are finding less than we produce.

The only real good news this year is from Egypt. In September, it became known that Total had made a supergiant gas discovery in the deep waters of the Nile delta. The find has a gas column of 630m in Miocene carbonates and a potential of 30 Tcf (850 Bm³) in place. It may turn out to be the world's 20th largest gas discovery (*GEO ExPro*, Vol.12, No.5). By comparison, the Troll field offshore Norway had original gas reserves exceeding 49 Tcfg (1,400 Bm³).

There are also rumours that Afek Oil and Gas, an Israeli subsidiary of the U.S. company Genie Energy, has made a giant oil discovery on the Golan Heights, operating on an Israeli licence in an area that previously was governed by Syria. Reserves of several hundred million barrels, and all the way up to one billion barrels, have been mentioned.

Apart from this, however, there is not much to report and, according to **Rystad Energy**, only some 12 Bboe have been found this year. It now also seems that 2015 may be the worst year in 15 years. Moreover, since 2011 there has been a steady decline in conventional oil and gas discovered worldwide. The best year since 2000 was 2006 with almost 50 Bboe discovered, although most of that was gas.

Lack of success in the last few years has the immediate consequence that conventional reserves are not being replaced as we produce ever more hydrocarbons.

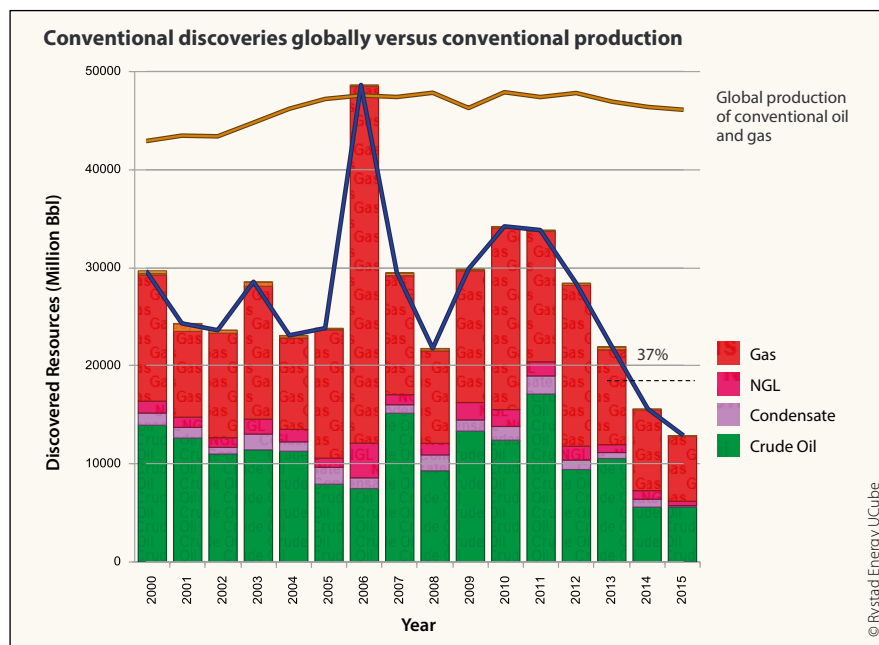
The big surprise to the oil community in the last few years – and the reason for the oil price collapse – has been the growth in shale oil production. This success story has also brought about a significant increase in shale oil reserves.

However, it turns out that the substantial reserve growth caused by shale oil cannot replace the increase in production. It is true that more unconventional oil has been found than is being produced, but by combining conventional and unconventional it turns out that for the last 10 years we have produced more than we have found.

In the long run this will certainly result in a higher oil price. ■

Halfdan Carstens

Conventional oil and gas discovered since 2000.



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 10⁶
- Billion = 1 x 10⁹
- Trillion = 1 x 10¹²

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

