VOL. 7, NO. 3 – 2010

GEO ExPRO

GEOSCIENCE & TECHNOLOGY EXPLAINED

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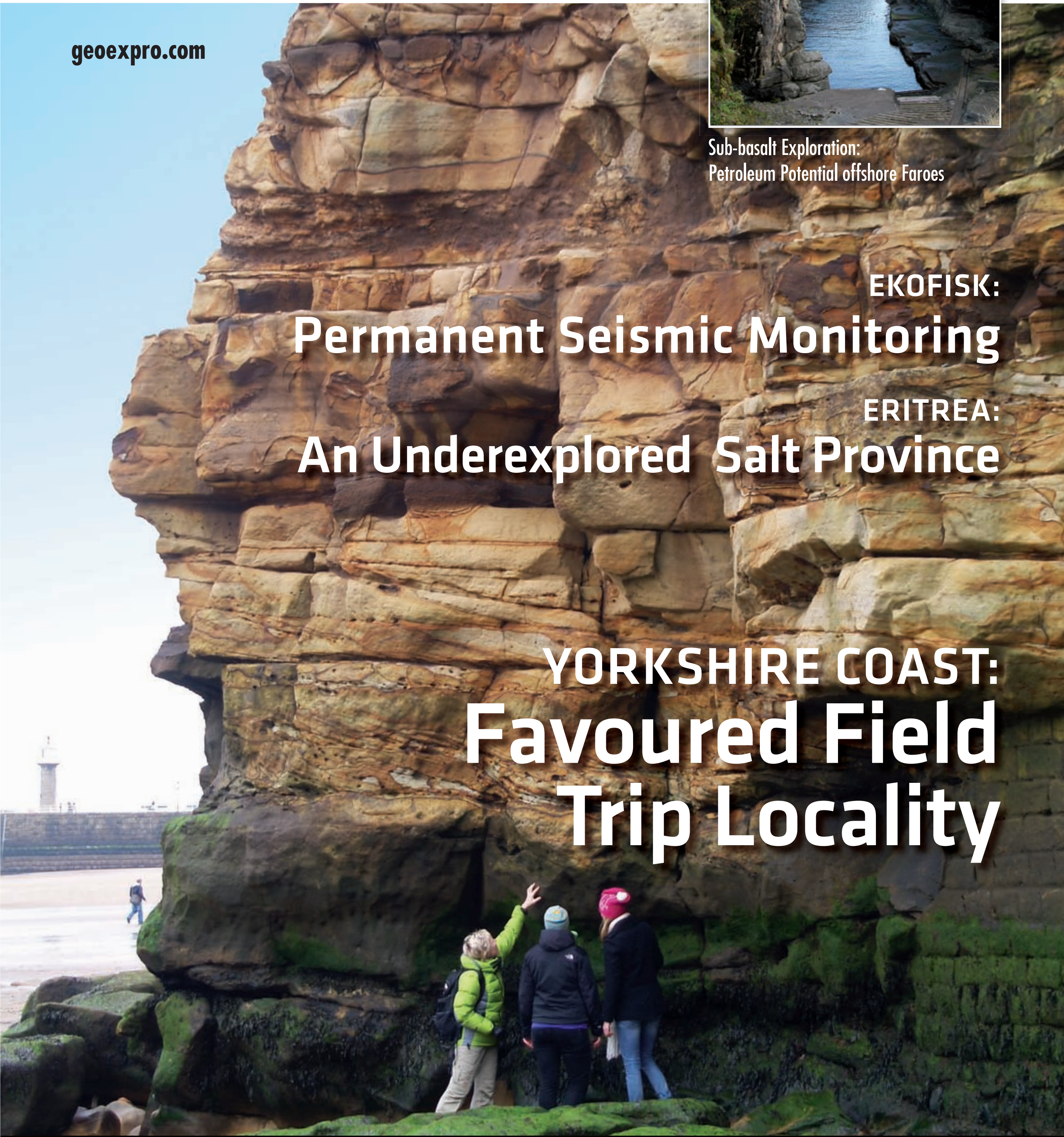
Sub-basalt Exploration:
Petroleum Potential offshore Faroes



EKOFISK:
Permanent Seismic Monitoring

ERITREA:
An Underexplored Salt Province

YORKSHIRE COAST:
Favoured Field Trip Locality

GEOLOGY GEOPHYSICS RESERVOIR MANAGEMENT

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COLUMNS

FEATURES

Faroes
For years the Faroe Islands have had to look on while their larger neighbours in north-west Europe have extracted untold riches in hydrocarbons from off-shore acreage. Has their turn finally come?

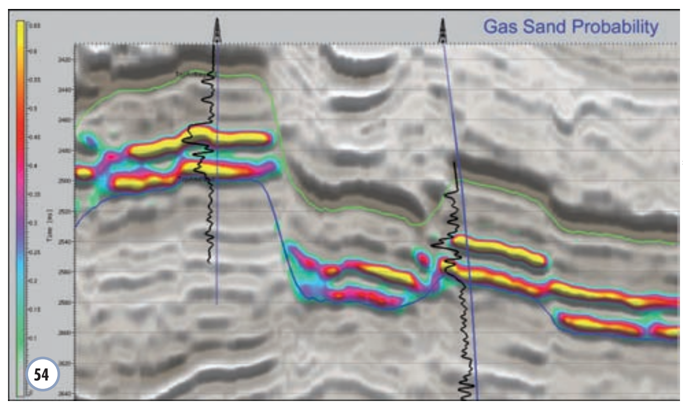


Illustration: Fugro Jason

Sub-salt imaging
One of the major challenges in understanding the nature of the subsurface is to accurately depict geology when data is sparse. By combining well logs and seismic data, seismic inversion can be used to visualize subsurface geostructures in a realistic form.

Photo: Tom Smith

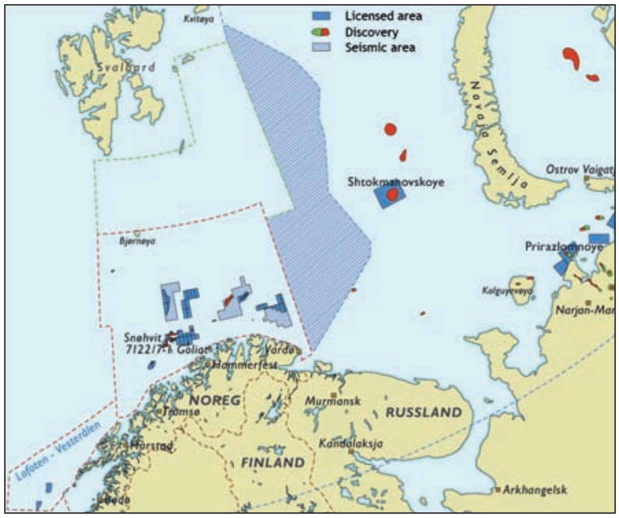
Photo: US Coast Guard

BREAKTHROUGH AGREEMENT IN THE BARENTS SEA

"This is a historic day. We have reached a breakthrough in the most important outstanding issue between Norway and the Russian Federation," said Prime Minister Jens Stoltenberg prior to the signing of an agreement between the Norwegian and the Russian negotiating delegations on the bilateral maritime delimitation in the Barents Sea and the Arctic Ocean.

The agreement was announced April 27 in a joint statement by the Foreign Ministers of Norway and the Russian Federation.

At stake was a prospective area totaling 175,000 sq km, equivalent to 30 North Sea quadrants, or the combined size of the Southern Gas Basin, the Central Graben and the Viking Graben in the North Sea.



Following 40 years of negotiations, a solution of the contested area in the Barents Sea has now been found in which the area is split in two parts of approximately the same size. Many traps have already been mapped based on old data, several of which are huge and may prove to be giant and supergiant fields.

The issue of the maritime delimitation between Norway and Russia in the Barents Sea and the Arctic Ocean has been the object of extensive negotiations over the last 40 years. The negotiations have now been completed, although technical control work remains before the final treaty is ready for signature. After that it will be considered by the two countries' national assemblies.

When it is all finally settled the seismic industry will be queuing up to acquire data, or more likely, will enter into fierce competition to acquire the highest quality 2D as well as 3D geophysical data of all kinds, in an area in which huge resources are expected. Such a large area should therefore provide ample food for hungry entrepreneurs.

The recommended solution involves a maritime delimitation line that divides the overall disputed area in two parts of approximately the same size. In addition to a maritime delimitation line, the two delegations recommend the adoption of treaty provisions regarding cooperation on fisheries and petroleum activities.

In the field of hydrocarbon cooperation, the two delegations recommend the adoption of detailed rules and procedures ensuring efficient and responsible management of their hydrocarbon resources in cases where any single oil or gas deposit should extend across the delimitation line.

A new Hot Spot has arrived.

Halfdan Carstens
Editor in Chief

THE SALTWICK FORMATION

The Saltwick Formation (Alenian) of the Cleveland Basin is interpreted to be delta plain deposits representing the first, of three, progradational phases of a delta complex in the Yorkshire basin. It contains amalgamated distributary channels, swamps, and crevasse splay deposits. This unit is taken as an analogue to the Ness Formation in the North Sea. The picture shows a stack of amalgamated distributary channels just outside Scarborough.

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Halfdan Carstens

Significant Interest in the Norwegian 21st Round

The purpose of the forthcoming 21st round on the Norwegian continental shelf is to provide the industry access to attractive areas with potential for giant discoveries.

Following a January 13 deadline, The Ministry of Petroleum and Energy has received proposals from 43 companies, down from 46 in the previous round, regarding which blocks the companies believe should be included in the 21st licensing round on the Norwegian shelf.

The invitations to nominate were sent to all licensees on the shelf and pre-qualified companies. Numbered licensing rounds (the first one was in 1965) include mainly frontier areas of the Norwegian continental shelf with potential for large and even giant discoveries.

"With the 21st licensing round I seek to give the oil industry access to attractive areas which are less explored. It is important to provide the industry access to frontier areas through predictable licensing rounds. This contributes to maintain the activity level on the Norwegian continental shelf and secure the shelf's attractiveness. The nominated areas will hopefully contribute to long term value creation in the petroleum industry," Terje Riis-Johansen, Norwegian Minister of Petroleum and Energy says.

307 blocks or parts of blocks have been nominated, with 138 blocks being nominated by two or more companies. The average size of a block is roughly 300 sq km in the Barents Sea, 400 sq km in the Norwegian Sea and 550 sq km in the North Sea. In comparison, a block in the US Gulf of Mexico is roughly 23 sq km.

The oil companies have thus had an opportunity to nominate the blocks they find interesting. The Norwegian authorities will now prepare a proposal for which blocks will be announced. This proposal will be subject to a public consultation process, where all stakeholders will be invited to give their opinion. The Government will then decide which blocks should be announced, based on an overall evaluation.

The companies' nominations will be an important part of which the decision is based upon when the Ministry announces the 21st licensing round. This announcement is intended to take place before summer 2010. Awards of new production licenses are planned for spring 2011.

Among the companies that have shown interest in the forthcoming round we find **Shell**, BG, **Chevron**, ConocoPhillips, Eni, **ExxonMobil**, GDF Suez, Petro-Canada, Nexen, Statoil, Talisman, Total and Wintershall. Most noteworthy, **BP** is missing. BP is then the only company of the four remaining "seven sisters" (they shrank to four in the industry consolidation of the 1990s) not being interested.

Amongst the "new seven sisters", the most influential energy companies from countries outside the Organisation for Economic Co-operation and Development (OECD), as identified by the Financial Times (Saudi Aramco, Russia's Gazprom, CNPC of China, NIOC of Iran, Venezuela's PDVSA, Brazil's Petrobras and Petronas of Malaysia), none are paying attention with respect to the Norwegian continental shelf.

The Seven Sisters on the western coast of Norway (Nordland county) remind geoscientists that the small grains that make up the reservoir sandstones offshore Mid-Norway come in part from the Norwegian mainland, in part from Greenland.

ABBREVIATIONS

Numbers
(U.S. 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

Record Number of UK Blocks Available

An unprecedented number of blocks is offered in the 26th UKCS Licence Round to prove up some 20 Bboe.

In late January 2010 the UK Department of Energy and Climate Change (DECC) announced the 26th UKCS Licence Round – the first since the oil price peaked and also since the credit crunch and banking crisis hit the industry.

Believing that there are around 20 Bboe recoverable reserves left on the UK Continental Shelf, DECC is offering an unprecedented number of blocks - over 2,800 - from all portions of the waters around the UK. These include large tranches of almost completely unlicensed seabed, such as the south-west approaches in the Atlantic, right up to the Irish border, and the frontier region of the deep waters west of the Hebrides, off north-west Scotland. To encourage companies to look at this virgin territory, over which little seismic or other data has been gathered, the UK government has introduced a new Frontier Licence with an extended nine year exploration term for the West of Scotland area.

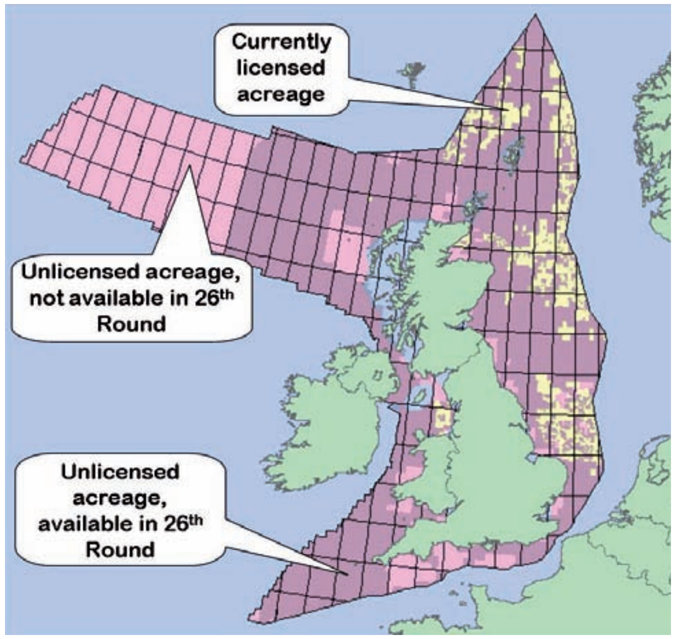


Image: Hannon Westwood

Map showing acreage available in the 26th UKCS Licensing Round

101 undeveloped fields

But how much potential is there really in this mature province, which has already been producing oil for nearly 35 years?

According to industry consultants, Hannon-Westwood, the area available in this round includes 101 fields which have already been discovered but not yet developed, offering an unrisked resource potential of over 1Bboe. Having analysed these discoveries, the company believes that the highest chance of discovering hydrocarbons lies in Lower Tertiary reservoirs, which possibly hold 261 MMboe; in the Upper and Middle Jurassic reservoirs, with over 327 MMboe; and the Permian Rotliegendes, holding potentially more than 134 MMboe of undeveloped reserves. These older horizons, however, tend to contain the reserves in smaller fields, some possibly only 5 MMboe. The majority of the undeveloped discoveries lie in the Central and Southern North Sea, with only eight being in the underexplored West of Britain area.

Hannon-Westwood has also identified 764 undrilled prospects in the 26th Round acreage, with potential unrisked reserves as high as 37Bboe, in comparison to DECC's more conservative estimate. The most promising leads are to be found west of the Shetlands, in an area where a number of large fields, such as Rosebank, have recently been discovered, but the logistics of working in these difficult and deep waters mean that only large fields will be economically feasible. About 80% of the recognised prospects lie in the Central and Southern North Sea.

Prospectivity for oil is most promising in the Central North Sea and the West of Shetlands, while the Southern North Sea, as well as West of Britain, remains the main location for dry gas prospects, although there is potential for gas-condensate in the Northern North Sea.

Photo: Jane Whaley

A highly-experienced geologist and proven oil finder, Chris Bulley has a wide range of experience in oil and gas exploration from a technical, commercial, acquisition and disposal perspective

Impact of the oil price

Chris Bulley of Hannon-Westwood has analysed the effect of the oil price on the most recent UKCS Licensing Rounds, and has concluded that the rising prices experienced through the most recent Rounds has encouraged the larger companies, which have cash flow from production, to put in strong bids with multiple well commitments. By contrast, the small companies, which used the relatively easy terms of the Promote Licence as a good way to gain a foothold in the area, have found the competition hard recently, and in the 25th Round in 2008, when oil was USD120 per barrel, only 40 Promote Licences were awarded, a marked reduction on the 76 awarded in the 23rd Round in 2005, when the oil price was less than USD60 a barrel. It will be interesting to see what happens in this Round with a totally different economic climate.

According to DECC, the UK's oil and gas industry still provides three quarters of the country's energy needs, as well as some 350,000 jobs.

First New Boat in 26 Years

The last time a purpose-built survey vessel was launched was back in 1984, when Racal introduced the 'Lady Harrison' to the North Sea. So the unveiling in March 2010 of Fugro Survey Limited's new high resolution geophysical survey ship, the 'Fugro Searcher' was a significant event in the industry. The vessel, built in Germany by Fassmer, has been designed to carry out a wide range of geophysical, geotechnical and environmental tasks, obtaining data which will be vital for the safe, efficient and cost-effective planning and design of seabed and sub-seabed structures such as pipelines, platforms and drilling rigs.

MV Fugro Searcher, the first purpose built survey vessel to be launched since 1984

The vessel carries a seismic airgun array of up to 970cm^3, a 4,000m streamer, digital sidescan sonar and a hull-mounted Kongsberg SBP300 sub bottom profiler, and it is designed to be fitted with a range of geotechnical equipment such as vibrocorers, grab samplers and cone penetrometers. The ship, which is 65m long, is also capable of deep water surveys utilising Fugro's autonomous underwater vehicles (AUV) spreads.

The 'Fugro Searcher' has been designed to operate efficiently in the harsh environment of the North Sea. Its special hull, resilient engine mounts and state-of-the-art propeller and bow thrusters will ensure that the vessel will remain stable and acoustically quiet during survey operations, while keeping its carbon footprint to a minimum. When not running lines or using the onboard processing and interpretation room, the ship's complement of 42 can relax in one of two lounges, the video room, gym or internet cafe.

The ship is not only designed with the oil and gas industry in mind, but also the offshore renewable energy sector. With over 7,000 wind turbines anticipated to be installed in the North Sea over the next few years, this is a growing market for survey companies.

New Discoveries Make Headlines

One of the most active and rapidly expanding bases for oil and mineral exploration is the focus for a conference in Houston in September.

The 9th session of this unique conference, jointly sponsored by the Petroleum Exploration Society of Great Britain (PESGB) and the Houston Geological Society (HGS), convenes this year in Houston, for a two-day program of talks and exhibits, September 8 and 9 at the Marriott Westchase hotel. Unique in its joint sponsorship, alternating venue between London and Houston and its focus on African Exploration, the annual meeting has brought explorationists and scientists together from around the world, enabling a special connection between the organizations and the attendees.

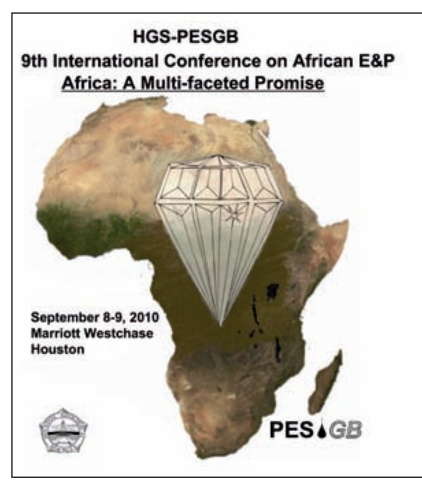
Nearly 3,000 people have attended in the last nine years and the conference continues to be one of the premier events for those exploring in Africa.

From one coast to the next, interest continues to remain high in Africa. Fueled by new discoveries in offshore Ghana and Sierra Leone in West Africa to Uganda and offshore Mozambique in East Africa, this continent continues to make headlines as one of the most active and rapidly expanding bases for oil and mineral exploration.

When we started this joint effort, each society had been putting on an international conference every two years due to the time it took to organize with a purely volunteer organization. After talking with Ray Bate of the PESGB nearly a decade ago on how to collaborate, we decided to join forces for an annual event, helping each other line up good speakers with pertinent topics. It is the quality of the program that continues to attract attendees. Each venue, (London and Houston) draws a different crowd allowing lots of material and ideas to get shared.

This year's meeting promises to have an excellent program with some great talks about recent discoveries as well as regional geology and emerging technologies. Many of the speakers are from the Houston area. As Ray Bate would say, the Houston meeting is an opportunity to draw on these "indigenous companies", several of which are driving successful exploration ahead in Africa.

Another feature of the conference is the "vendor" community. They are able to display their important contributions to the technology of exploration in Africa at the conference. Many of these vendors that provide services in

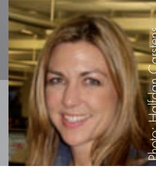


Africa use the conference to reach a "targeted audience" of explorationists and managers who are focused on Africa.

For latest information on this year's conference, go to **www.HGS.org**

Al Danforth
Houston Geological Society
International Explorationists Group

Thina Margrethe Saltvedt (Ph.D.)
Senior macro/oil analyst at Nordea Markets, Oslo, Norway



US Shale Gas Fever – a Potential Pandemic?

Shale gas fever is spreading rapidly from the US to other parts of the world. Spurred by technological breakthroughs and lack of access to the world's oil resources, the oil majors are competing for the rights to shale gas resources. According to Advanced Resource International, the combined US gas reserves are now sufficient to cover consumption for the next 100 years. Considerable resources are being deployed to identify the opportunities for shale gas production also in Europe and in energy-hungry China.

US ambitions to become **self-sufficient** with gas could now become a reality. The US administration wants to reduce America's dependence on gas deliveries from politically unstable countries such as Algeria, Egypt, Nigeria and Qatar. For a long time that has also been a dream in Europe. Russia covers around 25% of total gas consumption in the EU, but supplies have been periodically unstable. Energy independence is high on the European Parliament's agenda. A European gas revolution mirroring that seen in the US could contribute to undermining Russia's role as gas supplier to the European market.

At present, gas accounts for an estimated **20%** of the world's total energy consumption. Economic growth, gas prices as well as global energy policies are key drivers of gas demand. As a result of the global recession, manufacturing activity decelerated and household income growth declined. Taken together, that translated into a sharp drop in gas demand. Moreover, the technological breakthrough in the US meant that it became feasible to exploit gas reserves that were previously regarded as inaccessible. And the US market, which previously clamoured for gas, was now flooded. Since last year's bottom, the upward trend in gas prices has been more moderate than the rises in oil prices.

Coal, heavy oil, nuclear power, renewable energy and electricity are the key **substitute products** for gas. Near term, there is limited scope for switching between various energy sources due to technical constraints. Consequently, the choice of energy source is not made until companies and households have to put new energy-intensive equipment into use. Long-term expectations for gas prices will therefore be critical for the role played by gas in the total energy mix going forward.

A gas revolution on the **transport** side remains a dream. There is considerable potential if gas prices remain at competitive levels and the political will is there. Using gas as a fuel provides an environmental gain compared to petrol and diesel. But some barriers still have to be broken down before gas can conquer the fuel market. Gas as an environmental fuel is trailing in the competition with biofuels and electricity.

Shale gas also involves a **downside**. Worries centre on whether the production process will pollute the groundwater. Now the US authorities consider imposing restrictions on drilling near water reservoirs.

Outside the US, the potential for shale gas production is highly uncertain. It is by no means certain that the technology used to extract shale gas in the US is easily adaptable for use elsewhere. The political commitment to focus on shale gas versus renewable energy is not always there. In Europe, energy efficiency measures and stricter environmental requirements have led to a gradual decline in gas demand. That reduces the economic incentive to invest in shale gas extraction. Lack of equipment, materials, labour, infrastructure as well as distribution channels may also drive up production costs.

The **technology breakthrough** for shale gas production is characterised both as a paradigm shift and a game changer, but the technological, political and economic challenges remain manifold. Nonetheless, we expect the new shale gas discoveries to influence the energy mix. But the extent will depend on whether the US shale gas fever really turns into a pandemic.

Sources: The Economist, Financial Times, Advanced Resource International, EIA and IEA

Production Geoscience 2010

The programme for the Production Geoscience Conference at Norwegian Petroleum Directorate (NPD) in Stavanger, November 2-3, 2010, is currently being put together. This year we have invited both international and national keynote speakers to enlighten us on this year's theme; "Closing the loops – From dynamic to static modelling"

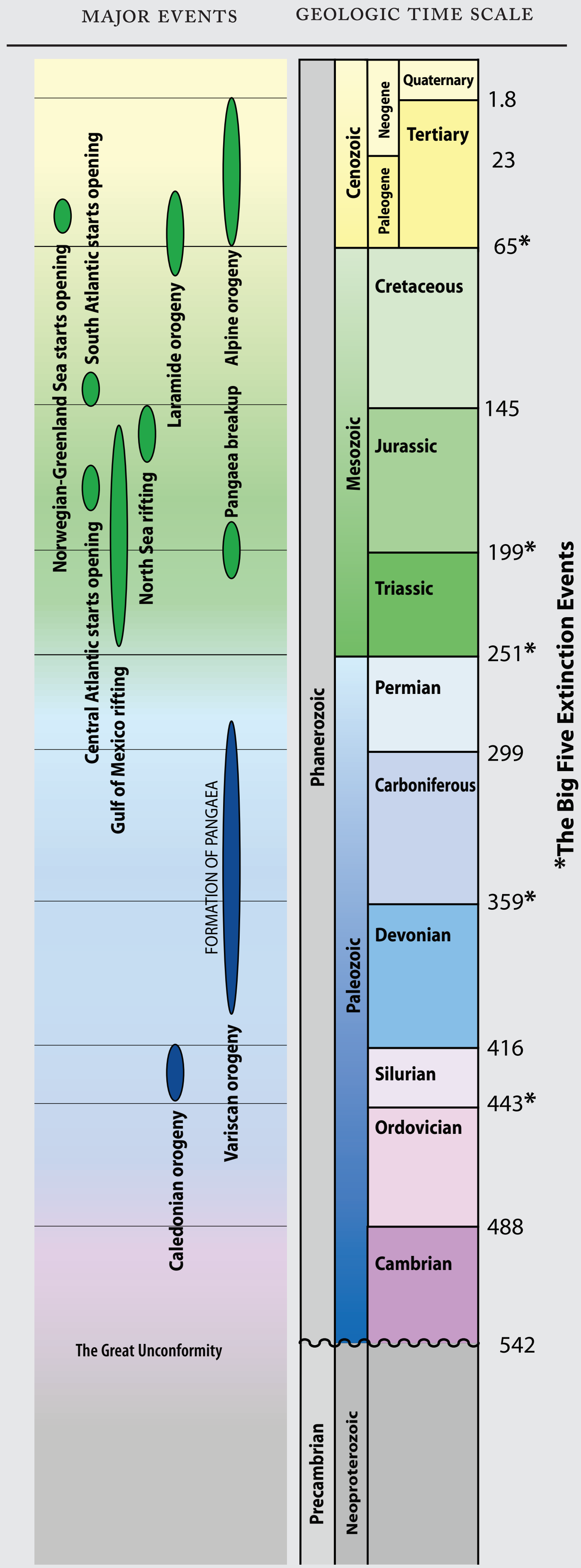
Fridtjof Riis from the NPD will do a keynote on pressure and the importance of understanding pressure development in of producing fields. Jan Dirk Jansen from TU Delft will give a keynote on practical and formal methods for updating reservoir models using dynamic information.

Abstract deadline for this conference is not due until **15th of August**. The organizing committee however appreciates early incoming abstracts. We encourage the authors to present methods and/or field examples showing how production data can be included in simulation models and feed back into the static geomodels. We particularly welcome practical case studies which can be implemented using standard suite of geomodelling and desktop tools. In addition, examples of where other non-standard data types have been included into reservoir modelling workflows are also welcomed.

This year as the last, the organizing committee has decided to invite software vendors to actively participate in a special session to demonstrate their abilities to perform history matching workflows from geomodel to simulation model. New enhancements improving the often time consuming loops between the different models are in focus as well as abilities to include any type of production data improving the models.

For more information about the conference and submission of abstracts see **www.geologi.no/pg2010** or look up our ad in this number of GeoExpro.

The Production Geoscience conference will be held in Stavanger, Norway, not far from the island idyll of Ryfylke.



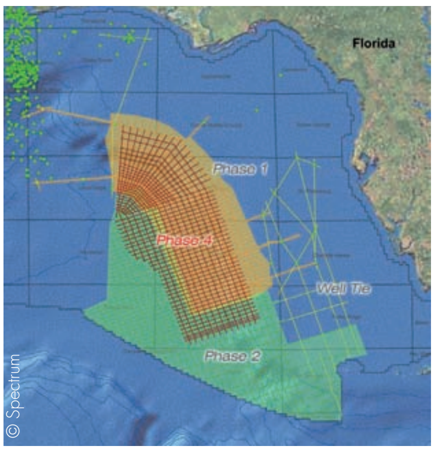
Spectrum's Big Wave in the Eastern Gulf

Spectrum has commenced Phase 4 of the Big Wave Multi-Client seismic programme in the eastern Gulf of Mexico just days after the Obama administration announced its eastern Gulf of Mexico lease proposal. Using the GGS Atlantic 2D seismic vessel, it comprises a key infill survey of over 12,000km and is designed to generate a tighter grid for prospect level mapping. Phase 4 will increase Spectrum's Eastern Gulf of Mexico coverage to 65,000km of long offset seismic data.

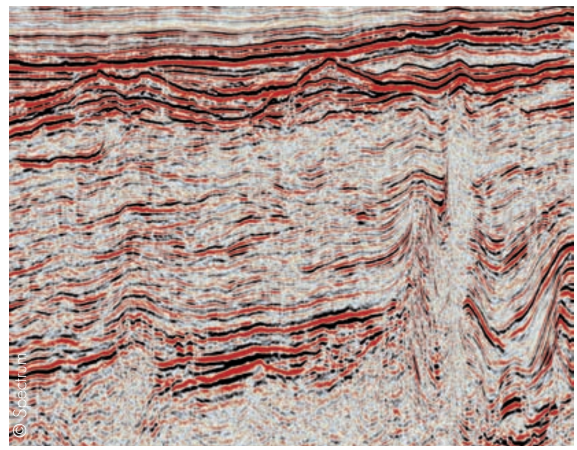
This new infill acquisition coincides with Secretary of the Interior Ken Salazar's announcement on the 31st March 2010 that the Obama administration will expand oil and gas development and exploration on the U.S. Outer Continental Shelf: "The (US Department of the Interior) strategy calls for developing new areas offshore, exploring frontier areas, and protecting places that are too special to drill." said Salazar. "By providing order and certainty to offshore exploration ... we are opening a new chapter for balanced and responsible oil and gas development here at home."

The Obama administration's strategy calls for expanded development and production throughout the Gulf of Mexico, including resource-rich areas of the Eastern Gulf of Mexico which are covered by the Big Wave program but are currently under Congressional Moratorium and closed to development.

"The plan we are proposing calls for 4 more lease sales in the Gulf of Mexico by 2012 and, in the years beyond, would open up two-thirds of the oil and gas resources in the Eastern Gulf while protecting Florida's coast and critical military training areas," said Salazar. "Our efforts to strategically open new areas in the Eastern Gulf would represent the largest expansion of our nation's available offshore oil and gas supplies in three decades."



The Big Wave Multi-Client program is across the richest single tract that would be open to drilling under the latest Obama plan.



This seismic section from the Big Wave programme illustrates a number of prospective play types associated both with the mid-Cretaceous sequence boundary and also with the salt tectonics prevalent in the area.

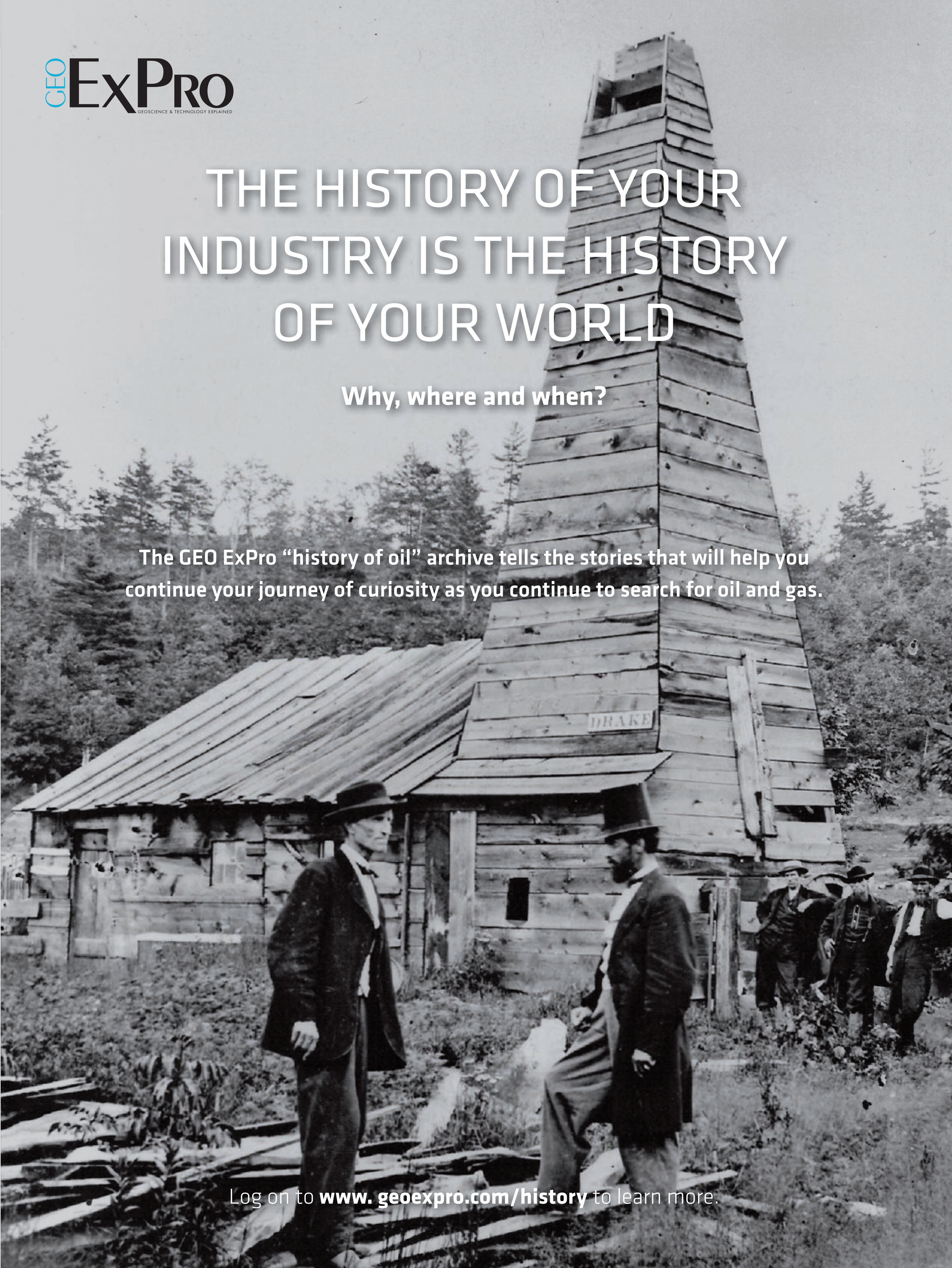
CGGVeritas Vessel Wins Industry HSE Award

The CGGVeritas seismic vessel, the Bergen Surveyor, has won the annual HSE Award given by the TGS-NOPEC geophysical company (TGS) for 2009.

The award is given for the best HSE performance of all the vessels used by TGS during each year. The annual HSE award was launched a number of years ago to raise HSE awareness and encourage and promote the importance of a strong safety culture on board the survey vessels.

The CGGVeritas vessel Bergen Surveyor has received the 2009 Award in recognition of its strong HSE performance while conducting three surveys in the North Sea, Greenland and West Africa. For the North Sea survey, the vessel acquired data from April to July with very little technical or operational downtime despite working in busy waters with the presence of shipping traffic, fishing vessels, oil field operations and other seismic crews.

The award citation stated: "Throughout the year the crew demonstrated strong HSE reporting especially with regard to leading indicators such as toolbox meetings, drills and audits which are believed to reduce the number of actual incidents. This strong HSE performance has also helped lead to a strong operational performance as confirmed by the high production and efficiency statistics. The successful completion of the Baffin Bay survey was due in part to the mitigation measures put in place and the continued diligence of the crew."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PETRONAS Signs up for Low Frequency Seismic Research

PETRONAS is the latest major oil & gas company to join the Low Frequency Seismic Partnership (LFSP) conducted by Spectrum.

PETRONAS has joined existing members - Cairn, Chevron, ExxonMobil, GDF Suez and Pemex - in the research and development of low frequency seismic technologies as part of the three-year JIP.

The news follows a number of recent Low Frequency (LF) seismic milestones, including the completion of an extensive synchronous survey for Shell in Egypt, and the current acquisition of the most comprehensive LF data set to date over a gas storage facility in France, a project sponsored by the LFSP.

Expanding Indonesia Programme

TGS continues its multi-client 2D seismic acquisition program in offshore Indonesia. An additional 7,300 kilometers of 2D seismic data is now being acquired in three areas along the Sundaland Margin; including offshore South Java, West Sumatra and Northwest Sumatra, Indonesia.

These new seismic surveys complement TGS' existing data library. Upon the completion of this latest program, the TGS Indonesia library will exceed 108,000 kilometers of 2D seismic; 400,000 kilometers of multi-beam bathymetric data and 1,200 core samples covering over 1 million square kilometers of Indonesia's deepwater basins. TGS has the largest geoscientific multi-client data library in Indonesia and the only multi-client data across the entire Sundaland Margin.

TGS Halts Wide Azimuth Survey

The recent rig fire and subsequent spill in the Gulf of Mexico on Mississippi Canyon block 252 is located within the boundaries of the TGS Justice Wide Azimuth (WAZ) survey.. The acquisition was temporarily halted on 20 April 2010 when all nearby vessels were called to aid in the rig accident. After being released by the coast guard less than 24 hours later, the vessels re-initiated data acquisition in the Justice WAZ survey and operations continued until the morning of 30 April 2010.

On 30 April 2010 the Coast Guard established a vessel exclusion zone in the area of the resulting oil spill. Due to safety concerns, the WAZ crew was advised to leave the survey area in order to allow complete access for the ongoing spill containment and dispersant efforts.

On 30 April 2010, TGS moved the WAZ crew into an adjacent project area away from the exclusion zone. As of early May, the oil spill continues and further acquisition is prohibited.

The oil slick outside the Mississippi delta on April 28.

Image courtesy: NASA

Schlumberger acquires Nexus

Schlumberger has acquired Nexus Geosciences, Inc., a Houston-based provider of integrated seismic software and services for rapid imaging, modeling and interpretation. The group will become part of the WesternGeco business unit.

The company has developed proprietary technologies for fast imaging and modeling, enabling oil and gas companies to rapidly build, update and validate their velocity models. This information can enable them to reduce uncertainties even in the most complex geological environments.

"Our customers are exploring in areas of increasing geological complexity while under considerable time pressures," said Maurice Nessim, vice president of WesternGeco GeoSolutions. "The combination of Nexus proven imaging and modeling expertise with WesternGeco advanced imaging solutions and global reach will allow us to help our customers meet these challenges more effectively."

The 80m high cliffs at Heygsmúlabarmur, on Suðuroy, the most southerly of the Faroe Islands, show several separate lobes of the Beinisvørð Formation of the Faroe Islands Basalt Group. The top surfaces of these are clearly weathered (red colouration), which is relevant to explorationists, because of the problems this causes to seismic.

Photo: Simon R. Passey – Faroese Earth and Energy Directorate

Faroe Islands:

Increasing Activity Shows Promise

For years the Faroe Islands have had to look on while their larger neighbours in north-west Europe have extracted untold riches in hydrocarbons from offshore acreage. Has their turn finally come?

JANE WHALEY

The 1st Faroese Licensing Round was held in 2000 in a mood of great anticipation, but drilling results did not prove the optimism justified. Over 200 wells have been drilled on the UK side of the median line, yet only a handful in Faroese waters, predominantly due to the negative presence of large volumes of Palaeogene basalt overlying the primary prospective levels.

Now, however, geologists from the remote islands, which lie in the North Atlantic about 300 km north-west of Scotland, are saying that recent investigations suggest that success may be just around the corner. "The Faroese Continental Shelf could be the next big thing," suggests Heri Ziska, Chief Geoscientist with the Faroese Licensing Authority. "In recent years additional wells, combined with advances in seismic technology, have started to reveal the secrets hidden in the deep waters around the islands. There are always challenges in frontier areas and the Faroes is no exception, particularly with sub-basalt imaging and stratigraphic plays in the forefront. However, we have learnt a lot over recent years, and the outcome is looking much more positive."

SIX KILOMETRES OF BASALT

The Faroe Islands are part of the Atlantic margin of North West Europe, the basic tectonic framework of which was formed during the Palaeozoic Caledonian orogeny, as several land masses came together to form the supercontinent of Pangaea, establishing the underlying north-east to south-west trend which is still prevalent today. Later movement, commencing in the Late Palaeozoic as Greenland separated from Europe, resulted in a further major fault system, oriented north-west to south-east.

The oldest post-Caledonian sediments are Devonian redbeds, deposited in an intermontane basin environment, and overlain by Permo-Triassic fluvial and alluvial rocks. A major Middle Jurassic unconformity was followed by marine deposition, including the organic rich Kimmeridge Clay. The area suffered major rifting and subsidence during the Cretaceous, and deep rift basins, presumably Cretaceous or older, have been identified on seismic data from the Faroese Continental Shelf. Most palaeohighs were drowned by the late Cretaceous, preventing an influx of large volumes of coarse clastic sediments, and extensive shale deposition probably occurred during this time interval.

One of most significant geological events was extensive volcanism, which commenced at the end of the Paleocene, prior to the separation of the Faroe Plateau from Greenland. Most of the shelf was covered by substantial flood basalts, with a total stratigraphic thickness in excess of 6 km. They are subdivided into three separate formations, the lower two being separated by a thin sedimentary section.

Post-rift subsidence continued through the Cenozoic, with deep water conditions prevailing by the Eocene and continuing through to the present day.

EVIDENCE OF PETROLEUM SYSTEMS

Sub-seabed mapping of the Faroese Continental Shelf has revealed a number of prom-

ising structures below the basalt which could potentially hold billions of barrels of oil, and there is evidence of the elements required to make a working petroleum system. Despite several attempts, the sub-basalt horizons remain essentially unexplored.

The presence of oil and gas in wells and also as seeps proves hydrocarbon generation in the area. The main source rock is expected to be the Late Jurassic Kimmeridge Clay, which is widespread on the North Atlantic margin. There is also geochemical evidence of the presence of a Middle Jurassic lacustrine source rock, particularly on basin margins, and a Cretaceous source rock has been speculated.

Reservoirs from Cambrian to Eocene have been found on the UK side of the Faroe-Shetland Channel, but as yet only the Upper Paleocene has been investigated in the Faroes. The UK reservoirs are sourced by sediment from the Shetland Platform, but the distance to the Faroese Continental Shelf means that large quantities of potentially reservoir forming sediment are unlikely to have been derived from there. The East Greenland margin, which prior to continental break-up was close to the present day Faroese Platform, could be a major source of sediments, and there is palynological and mineral evidence to support this. In addition, the Faroese Platform itself may also be a sediment source, assuming that the land mass was emergent at various times in its history.

Seal is not expected to be a problem, with deep marine shales thought to be present beneath the basalt over much of the area, as evidenced by the only well to have successfully penetrated the volcanics. In the Judd Basin in the south-east, however, wells found larger volumes of sand than anticipated, and effective seal is a potential issue in this area.

SHORT, HECTIC EXPLORATION HISTORY

Interest in the Faroes has been increasing since the 1980's, after hydrocarbon discoveries were made west of the Shetlands, close to the border. After years of negotiations between the islands and the Danish government, which has sovereignty over them, exploration on the Faroese Continental Shelf started in 1994. By 2000 almost 50,000 km of 2D and 8,000 km^2 of 3D seismic data were acquired, and a long running boundary dispute between the Islands and the UK resolved. "The 1st Round was held in an atmosphere of intense optimism," says Heri,

Imaging under basalt

When the North Atlantic Margin broke up in the Early Tertiary, large volumes of molten rock were extruded onto what is now the Faroese Continental Shelf - possibly as much as one million cubic kilometres within a period of less than three million years. This has proved a hindrance to oil exploration, as it absorbs the higher frequencies, and the ray path is distorted by velocity variations between basalt and surrounding sediment, while the uneven surface of the volcanics results in energy scattering.

Over the years a number of methodologies have been applied to overcome this, including ocean bottom seismometers and cables, dragged arrays, vertical cables and multi-pass shooting, as discussed on page 54-56 (ION seismic). By combining the results of these various methods, a consistent picture of the sub-basalt structure and geology has now been built up.

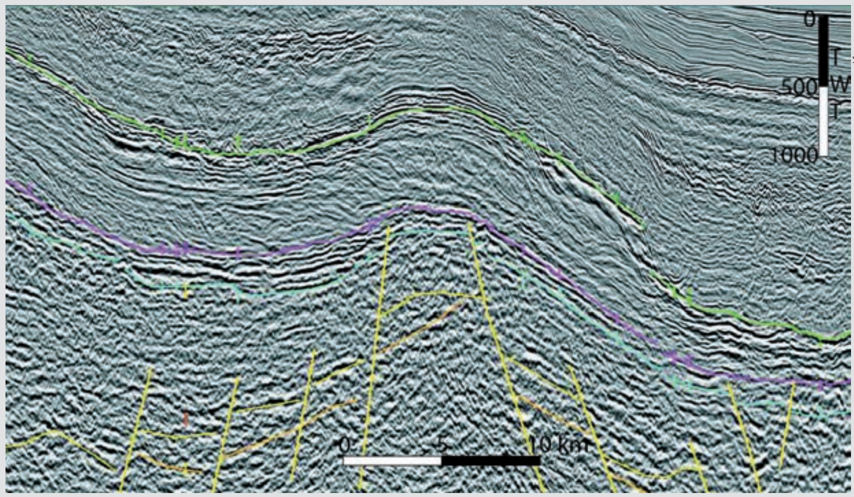


Image: jardfeingi

Seismic line through the Faroe Shetland Channel, across the East Faroe High

View of Tindhólmur, in the western part of the Faroe Islands. The brown sedimentary units towards the base of the island belong to the coal-bearing Prestfjall Formation, sandwiched between two volcanic formations belonging to the Faroe Islands Basalt Group.

"and in terms of applications it was a great success. Seven licenses, all with geophysical commitments, were awarded to 12 companies, with eight commitment wells in the work programme."

The first well in Faroese waters, Longan, in 935m water depth, was drilled in 2001 in the Judd Basin, 125km south-east of the Islands, considered the most promising area as it has little basalt. The well targeted Paleocene sandstones deposited in slope and basin floor environments, analogous to the Foinaven and Schiehallion fields just across the UK border. Unfortunately, it only showed traces of hydrocarbons, but encouraged further drilling. The next well, Svinoy, in December 2001, 40km to the east, was technically the first discovery well in Faroese waters, with good reservoir sands, and some gas, although not in commercial quantities. It was followed by Marjun, near the UK border, which found significant quantities of light oil and gas in the Lower Paleocene reservoir. Unfortunately, the 2002 follow-up well was dry, and the search for a Foinaven analogous trap in the Judd Basin faltered.

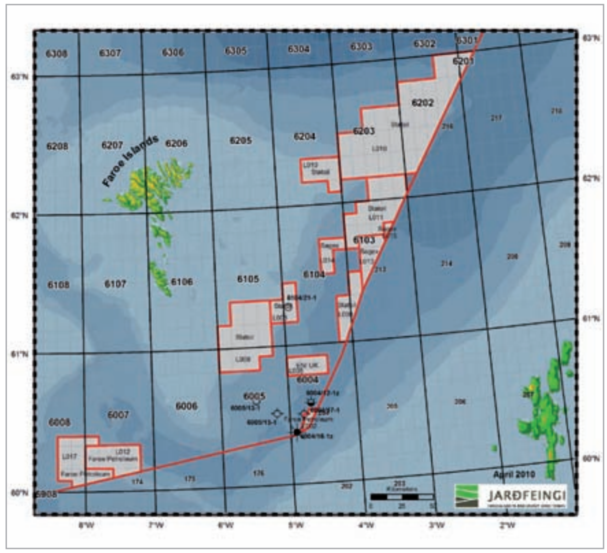


Image: jardfeingi

Wells drilled and the areas under licence on the Faroese Continental Shelf.

FIRST SUB-BASALT TARGET

These poor results meant that the 2005 2nd Faroese Licensing Round was only moderately successful, although the UK Rosebank intra-basalt oil and gas discovery in 2004 aided interest, leading to the drilling of the first sub-basalt well in Faroese waters, in 2006. This well, 6104/21-1, was also the first away from the Judd Basin. It was drilled about 100km east of the southern tip of the Faroe Islands, on the East Faroe High. The target, Brugden, was a 4-way dip closure over a tilted, possibly Mesozoic, fault block with sub-basalt Palaeocene reservoir horizons, and with potential secondary targets within the basalt itself.

One kilometre of basalt had been expected, but the well actually penetrated 2.5 km of volcanics before finding the underlying Paleocene horizons. Unfortunately, drilling problems meant that the target horizon was never tested, but as Heri points out, a number of interesting things were learnt

Photo: Simon R. Passey – Faroese Earth and Energy Directorate

Klaksvík, on Borðoy in the north-western Faroe Islands, is the second largest town in the Faroes.

from this well. "Importantly, we discovered that drilling through basalt was much easier and quicker than we had expected. The well TD'd at 4,201m in Paleocene shale, probably a regional seal for underlying Paleocene reservoirs. Although no significant hydrocarbons were found, there were traces of gas and indications of a working petroleum system, and as the stratigraphic target was not reached, the prospect remains undrilled and promising."

The most recent well, 6005/13-1A, drilled in April 2008 on the northern edge of the Judd Basin, again found large thicknesses of basalt, terminating before reaching the stratigraphic sub-basalt target. However, oil companies and the licensing authorities in the Faroes feel that they gained major insights and are not discouraged. As evidence of this, three further wells are planned in the near future in Faroese waters. The first of these, to be drilled this year near the edge of the basalt, is on the Anne-Marie prospect, which appears on seismic similar to Rosebank, 45km to the north-east.

The 3rd Faroese Licensing Round in July 2008 saw three licences awarded to various companies, including Faroe Petroleum, whose acreage covers the Wyville-Thomson Ridge, described as 'the largest undrilled anticline in Europe'. The geologists in the company have identified the potentially billion barrel Rannva prospect, and hope to drill next year.

THE NEXT BIG THING?

So will the Faroe Islands be the next big thing, as Heri Ziska suggests? "Compare exploration on the Faroese Continental Shelf with that on the UKCS," he says. "There has been exploration the UK side for over 30 years, and hundreds of wells have been drilled, while the Faroese area has only been open for exploration for less then ten years. On the UK side the whole stratigraphic column has been targeted, and all basins explored, while in the Faroese only the Paleocene has been effectively investigated, while five of the six wells drilled to date have been in a single sub-basin."

"We understand so much more now than we did even five years ago," Heri continues. "We know that there are a number of large structures present, which we can now visualise, even through great thicknesses of basalt – and we also know that we can drill quickly and efficiently through the basalt. These structures include potential traps in large-scale Cenozoic folds like the Wyville-Thompson ridge, and Mesozoic rotated fault blocks, which are located in relatively shallow waters at drillable depths. We have a much greater understanding of the evolution of the North Atlantic margin. There is evidence that at least one hydrocarbon is system active over large parts of the shelf, reservoir rocks are likely to be present, and there are many different plays to chase."

The Faroese Continental Shelf remains a high risk area, but the potential rewards appear to outweigh the risks involved.

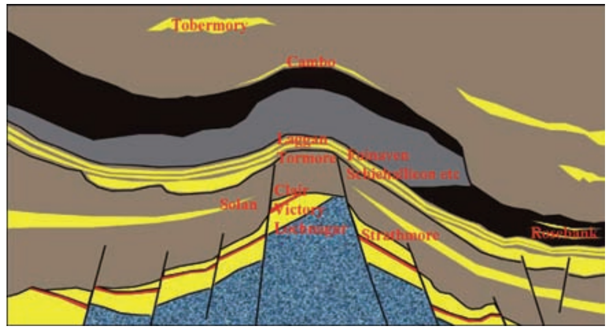


Image: jardfeingi

A schematic interpretation of the Faroese Continental Shelf, with potential west of Shetland style plays identified.

Sheep, fish and seabirds

The Faroe Islands lie halfway between Iceland and Norway, 300 km north-west of Scotland. They cover an area 113km long and 75 km wide and consist of 18 islands, almost all of which are inhabited, with a total population of around 50,000. Although lying only about 400 km south of the Arctic circle, the islands are warmed by the Gulf Stream, so the harbours never freeze and snowfalls are occasional and short-lived. There are very few trees, and only 6% of the land is cultivated, the rest being pastureland for approximately 70,000 sheep.

The first settlers on these remote islands were probably monks, arriving in the seventh century, swiftly followed by Vikings, who set up trading posts all around Northern Europe. In the 12th century the Faroes became part of the Norwegian empire, later taken over by Denmark. Since 1948 the Islands have been a self-governing region of Denmark, with their own parliament and flag.

The Faroese are renowned sailors and fishermen and fishing is the most important source of income for the islands, accounting for 97% of exports by volume and about 20% of GDP. Tourism is also important, as the remoteness, the fresh, clean air, the wildlife, particularly seabirds, and the unique culture attract 40,000 visitors annually, with an additional 35,000 arriving with cruise ships. In fact, a National Geographic Traveller Survey recently voted the Faroe Islands the best island destination in the world.

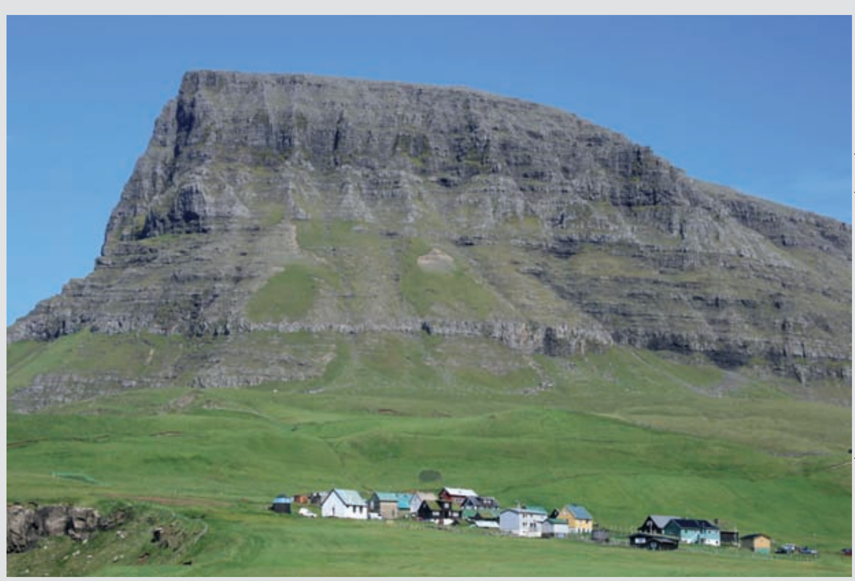


Photo: Simon R. Passey – Faroese Earth and Energy Directorate

The village of Gásadalur on the western island of Vágar has just 16 inhabitants and is overlooked by the 612m Heinanøva mountain

An Underexplored Salt Province

A thirty year independence struggle with Ethiopia means that the natural resources of Eritrea remain largely untapped, but there is ample evidence that this now peaceful country is highly prospective for oil and gas

Photo: Boris Kessler

The Dahlak Islands in the Red Sea, where oil seeps encouraged exploration in the 1920's . They have been famous for pearl fishing since Roman times

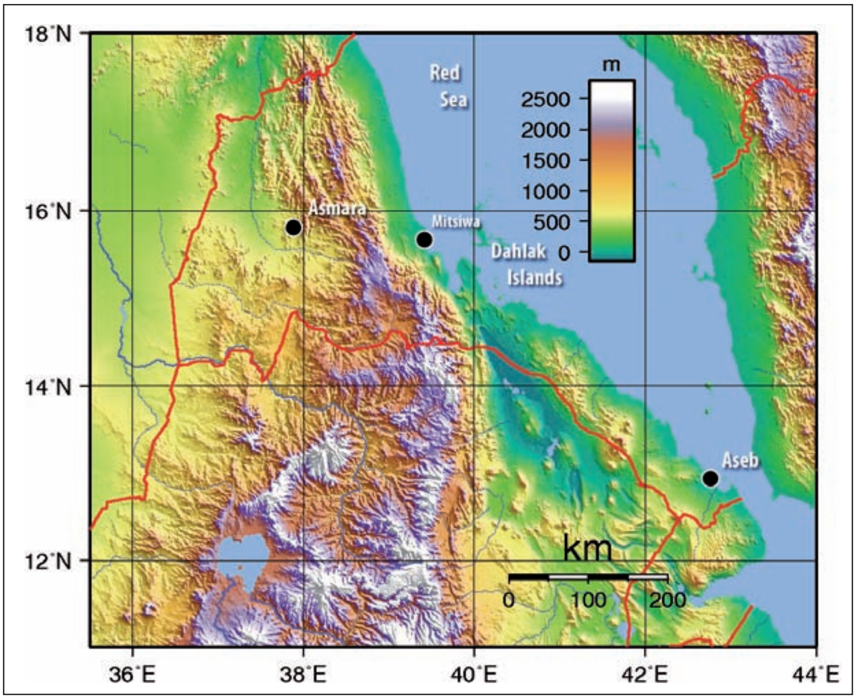


Image: NASA

Most of the hydrocarbon potential of Eritrea lies in its 16,600 km^2 Red Sea acreage.

JANE WHALEY

Like many of us, when Eritrea was first mentioned to Alec Robinson, he reached for the atlas. "It's not the first place that springs to mind when thinking of African hydrocarbon exploration," the CEO of Centric Energy admits. "But that's the point. It's one of the few relatively unexplored places left in the world – and it has great potential. The Eritrean Red Sea has all the classic features of pre- and post-rift sedimentation, including syn-rift evaporites, as well as a known oil-rich source, and sediment feeder channels leading to prospects in less than 50m of water. There are also oil seeps on the islands of the Dahlak archipelago, and along the coast."

"In addition to all the positive geological indicators," Alec adds, "it is now one of the safest and most peaceful places to work in Africa. The government has made great efforts to encourage oil companies to the country, and there is no evidence of corruption."

The geology of Eritrea is dominated by metamorphosed Precambrian rocks, which were deformed by the pan-African orogeny, and then further altered by the intrusion of Lower Palaeozoic granites. As a result, the country abounds in minerals such as gold, copper, and zinc, but most of the areas prospective for hydrocarbons are found offshore.

"... one of the safest and most peaceful places in Africa"

MASSIVE GAS BLOW-OUT

Eritrea lies at the southern end of the Red Sea, which was formed in Oligo-Miocene times (36 – 20 million years ago) as the African land mass broke away from the Arabian shield. Pre-rift arching and break-up of the continental crust led to the formation of the Red Sea, with block faulting on the flanks and strong subsidence in the central part, both very important for the formation of hydrocarbon traps. As rifting continued, fluviatile and lacustrine sedimentation was followed by shallow marine clastics and, with circulation in the Red Sea diminishing, the deposition of evaporites. Rifting through the late Miocene was accompanied by horst-graben faulting and fault block rotation, until by the Early Pliocene, about 5 Ma ago, small pull-apart basins along the axis of the Red Sea and Gulf of Aden were developing oceanic crust. These eventually coalesced to form the passive margins found today lying on the edge of the deep water trough of the central Red Sea, which drops rapidly to over 2,000m.

Alec Robinson is a petroleum geologist who has spent nearly 40 years in the oil industry, many of them with Amoco. He has lived and worked in many parts of the world, including Colombia, Peru, Oman, Norway and Argentina. Now based in the UK, he has been President and CEO of Centric Energy since 2006.

Alec and his colleagues at Centric believe that these sediments could hold large quantities of hydrocarbons. "Although exploration started back in 1921, only eleven wells have ever been drilled in Eritrean waters, with a further 12 shallow holes back in the 1940's on offshore islands. Eight of the offshore wells had good oil or gas shows, and the widespread occurrence of seeps is further evidence of a working petroleum system."

"In fact one well, C1, drilled in 1969 by Exxon and Mobil, suffered a massive gas blowout, and continued flowing for 55 days before finally stopping naturally. From the limited and varying quality data available, a number of prospects and leads have been identified in both the pre- and sub-salt formations of the Eritrean Red Sea," Alec says.

PRE-AND POST-SALT PLAYS

As with other classic rifts, there are two distinct play types, separated by the syn-rift evaporites. "A number of promising source horizons have been identified, both above and below the salt," Alec explains. "There are Late Jurassic organic-rich shales and marls, as well as several promising source horizons in the syn-rift, with TOCs ranging from 3% – 8%. The most recent wells, drilled by Anadarko in 1998, also found potential source shales in the post-rift Desset Formation.

Most of the exploration to date has centred on the post-salt plays, and initially Centric Energy will be concentrating on these, although Alec believes that the syn- and pre-rift plays are also very prospective. "To date, all the seismic shot has been 2D, which has not effectively imaged the pre-salt. Modern 3D seismic is required in order to clearly delineate the sub-salt horizons," Alec says.

Post-rift reservoirs include Neogene lenticular sandstones and reefal limestones, with hydrocarbons trapped in structures formed by salt tectonics, including turtle backs, rollover anticlines, fault detachments and drapes over salt diapirs. "We believe there are also interesting stratigraphic traps, like deepwater ponded turbidites and channel sands, which have not been investigated yet by the drill bit."

"The syn-rift sediments, just below the salt, are also promising – in fact, the major blow-out in well C1 occurred just as the drilling reached this point," Alec continues. "While the Late Miocene formation is predominantly evaporitic in the areas drilled so far, it includes marginal fluvial, aeolian and beach sandstones, which may form thicker horizons as they extend into the basin. And, of course, with all that salt, along with proven shale intervals, seal is not expected to be a problem."

Further potential is offered by the pre-rift, pre-salt horizons, which are completely unexplored, although they can be visually checked at outcrop along the coast. Plays are expected to include rotated fault blocks and horsts, particularly in the less eroded downdip areas, with potential reservoirs including Mesozoic fluvio-deltaic to shallow marine clastic sequences and dolomitised limestones, and Paleozoic fluvio-glacial sandstones.

"A number of promising source horizons have been identified"

WHY SO LITTLE EXPLORATION?

Centric Energy is finalizing the terms of a Production Sharing Contract for an offshore block and has been given exclusivity while finding a partner. At the moment, it is the only oil company active in Eritrea, although an Eritrean-Chinese company, Defba Oil, holds two large areas near the Sudan border. ▶

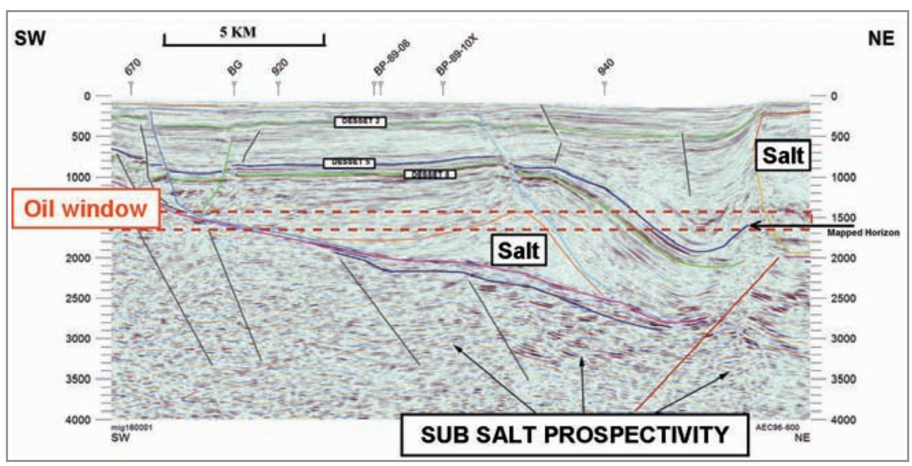


Image: Centric Energy

The Eritrean Red Sea offers potential both above and below the salt.

Parts of Eritrea are surprisingly green and fertile

Which begs the question: why have previous companies exploring in Eritrea either not done more exploration or not followed up the minor discoveries?

"Obviously, after 30 years of war, the security situation was off-putting and left companies with concerns about operating in the country," Alec replies. "But there were a number of other factors. Several of the wells, particularly those drilled in the 70's, found gas, which at a time was not a sought-after commodity. That is no longer an issue, as Eritrea has a clear need for additional energy to support development - at the moment there is only one 85 MW power station for the whole country - and there would be a definite local market for any gas we find. In places, the presence of volcanics has resulted in abnormally high geothermal temperatures, which deterred some explorers who did not realise that the high geothermal gradients are localised."

"Of course, seismic technology has only recently reached a point where we can properly image the salt and see the horizons beneath it, opening up the potential of the pre-rift. And it takes a little nerve to explore in a frontier area like this, which may be easier for a smaller organisation like us."

Centric Energy is still a very small company, having started out in 2006 as West African Energy, focussing on West Africa with blocks in a similar rift basin in Mali (see *GEO ExPro* 2008, no 4, pp26 – 30). Wanting to move further afield, it changed its name to Centric Energy and has recently signed a production sharing contract in Kenya.

OIL, GOLD – AND PIZZA!

Eritrea is trying hard to overcome the violent historical perspective most people hold of the country. The infrastructure is being rebuilt and efforts have been made to develop the economy, including putting in place attractive oil and gas licensing terms.

Sixteen foreign minerals exploration companies are now working there, reflecting the confidence of foreign investors, and the country's first gold mine, Bisha, is due to start producing later this year, bringing much-needed revenue to the country.

"It's a great place to visit," says Alec Robinson. "Asmara, the capital, is in the hills, so it has a very pleasant, temperate climate, and is very safe to walk around. The people are delightful, and don't give you any hassle. Since it was once part of an Italian colony, the architecture in the town is often in an interesting sort of Italian-colonial art deco style. And they make great coffee and pizza!"

Fascinating Cultural Fusion

Eritrea is a mostly mountainous country, bordered by Sudan, Ethiopia, Djibouti and the Red Sea. Its Red Sea coast, 1,200 km long, is one of the hottest and driest areas in Africa, and the Dahlak Islands,in the Red Sea, are one of the least known or explored reefs in the Red Sea. The mountainous Central Highlands, where the capital Asmara is located, are cooler and more fertile.

Eritrea has a rich, diverse culture, home to nine different ethnic groups. A number of archaeological sites represent its vast and interesting history, including the powerful Aksumite kingdom which ruled from 400 BC to 9 AD, presiding over both sides of today's Eritrea – Ethiopia border. It was influenced by both Christianity, possibly through Syrian merchants, and Islam. Later, from the 16th to the 19th century, the Ottoman Turks and the Egyptians fought for control of the Eritrean coast and its ports, until ultimately, in the second half of the 19th century, it became an Italian colony. By the end of the 1930's, Eritrea was one of the most highly industrialised countries in Africa. The British took over Eritrea after the Italian army were defeated by the Allied forces in 1941, until 1950, when it was granted self-government within a federal union with Ethiopia.

In 1961, Eritrea sought independence from Ethiopia, beginning Africa's longest conflict of the 20th century. Self-government was declared in 1993, after 32 years of struggle, only to be broken by the 'border dispute' in 1998, which resulted in the death of 19,000 Eritreans. Prior to the war, most of Eritrea's trade was with Ethiopia, and so the country has suffered economically, with food and energy shortages, while the large number of conflict-related deaths means there is a shortage of manpower to re-build the economy. Two thirds of the predominantly rural population of five and a half million receive food aid.

Despite all its troubles, Eritrea's vast and struggling history has led to a fascinating fusion of cultures. Asmara is full of wonderful vintage Italian cafes and pizza parlours, and art deco Italian architecture, while Massawa on the coast represents Eritrea's Islamic influence and contains several works of early Islamic architecture, although many of the historical buildings are derelict and in need of repair.


Photo: Alec Robinson/Centric Energy

St. Joseph's Cathedral in Asmara was built during the Italian occupation of Eritrea in the 1920's. Its 57m tall Gothic bell tower is visible from everywhere in the city.

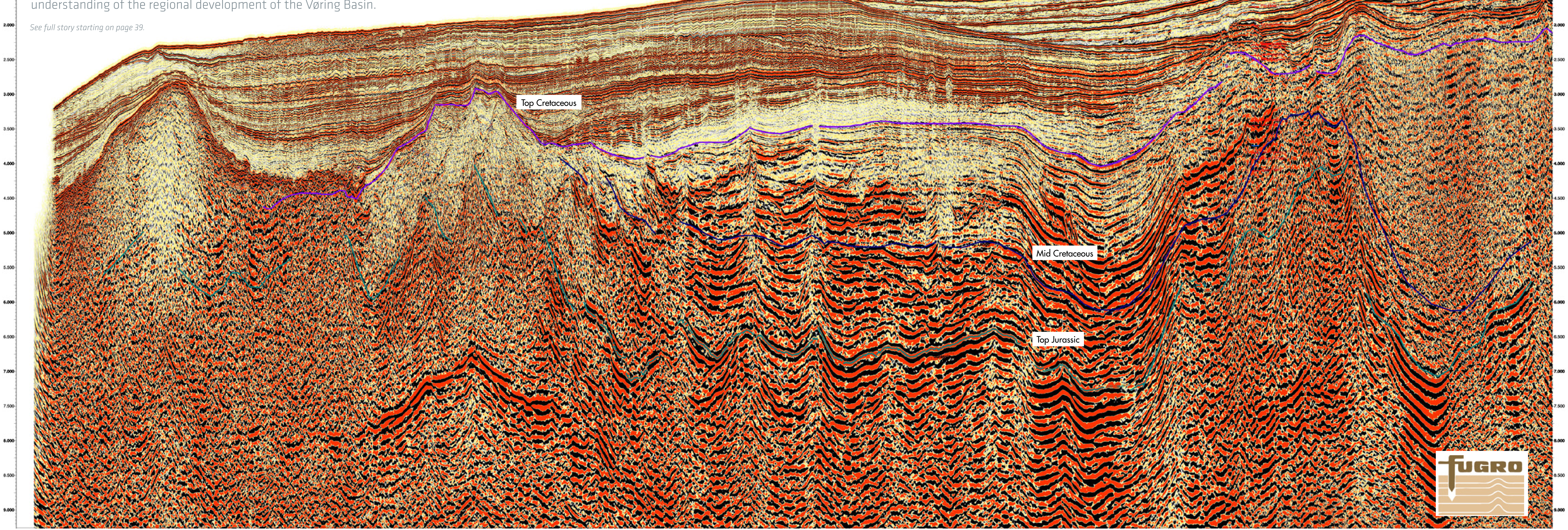
THE NORWEGIAN SEA:

Improved Imaging with Long Offset Data

A 4x4 km grid with long offset data in the Norwegian Sea helps getting a better understanding of the regional development of the Vøring Basin.

See full story starting on page 39.

The small island Lovund lies almost on the Arctic circle off Norway's north western coast and is notable for the large puffin breeding colony located on the rocky North slope of the island.



JURASSIC TARGETS: Improved Imaging Define Local Highs

While the first deep water wells in the Norwegian Sea failed to reach the Jurassic, significant data improvements may now make it possible to delineate Jurassic targets in deep grabens and structural highs.

LARS S. EIKUM , GEOLOGICAL ADVISOR

MNR AND EXPLORATION IN THE VØRING BASIN

The first two deep water wells in the Vøring basin were drilled by Exxon on the Utgard High (former Bodø High) in 1987 and 1991. The primary targets for both wells were the Middle Jurassic reservoirs. To the industry's surprise, both wells failed to reach Jurassic sediments. The first well was terminated half way into the third igneous intrusion and the second well was terminated in the Late Cretaceous.

Although no hydrocarbons were encountered in any of the wells, the geological information from the first well had a significant impact on later exploration in the Vøring Basin.

The Campanian sandstone penetrated was very important to the understanding of the Nise sand deposition and distribution in the basin. This formed the basis for the Nyk-discovery made by BP 6 years later. The thermal effect of igneous intrusions could not have been modelled without the information from this well and this continues to be one of the major challenges explorationists face on the Atlantic margin.

Seismic imaging at the time of drilling these wells was poor, and the complexity of the Utgard High was better imaged by gravity data than seismic. During the last 20 years a significant effort has been made to improve the quality of seismic data in the region and with new long offset data there is a much better understanding of the regional development in the Vøring Basin.

Fugro commenced the acquisition of the Mid Norway Regional survey (MNR) in 2004. To date, more than 67,000 km of seismic has been acquired and processed in co-operation with our partner TGS, and further phases are planned. The goal is to provide a consistent 4x4 km grid over the entire shelf to highlight areas for further 3D acquisition, with reduced exploration cost and risk.

Another challenge in the exploration of the Vøring Basin has been the lack documentation of other effective source rocks than in the Late Jurassic. Unfortunately, the deep and early burial of this sequence makes it a questionable source for oil in most of the region. In addition, regional seismic data have not had good enough imaging to allow a proper tie of the Jurassic section into the western part of the basin.

With the new long offset MNR data the deep structures in the basin can be mapped with confidence and a Top Jurassic map produced. This surface has significant relief. Deep grabens and local highs emerge, providing a series of exploration targets.

After 30 years of data gathering and more than 20 years after the drilling of the Utgard High, new data has again made Jurassic rocks a viable target in the Vøring Basin. Although the Jurassic is buried too deep for conventional drilling today, many local highs are present along the western margin. Dalsnuten is one of these structures and will be tested later this year. Whether this well will give the long sought after oil discovery in the Vøring Basin or not remains to be seen. However, as with the wells on the Utgard High, this well will provide valuable geological information for future exploration of this area.

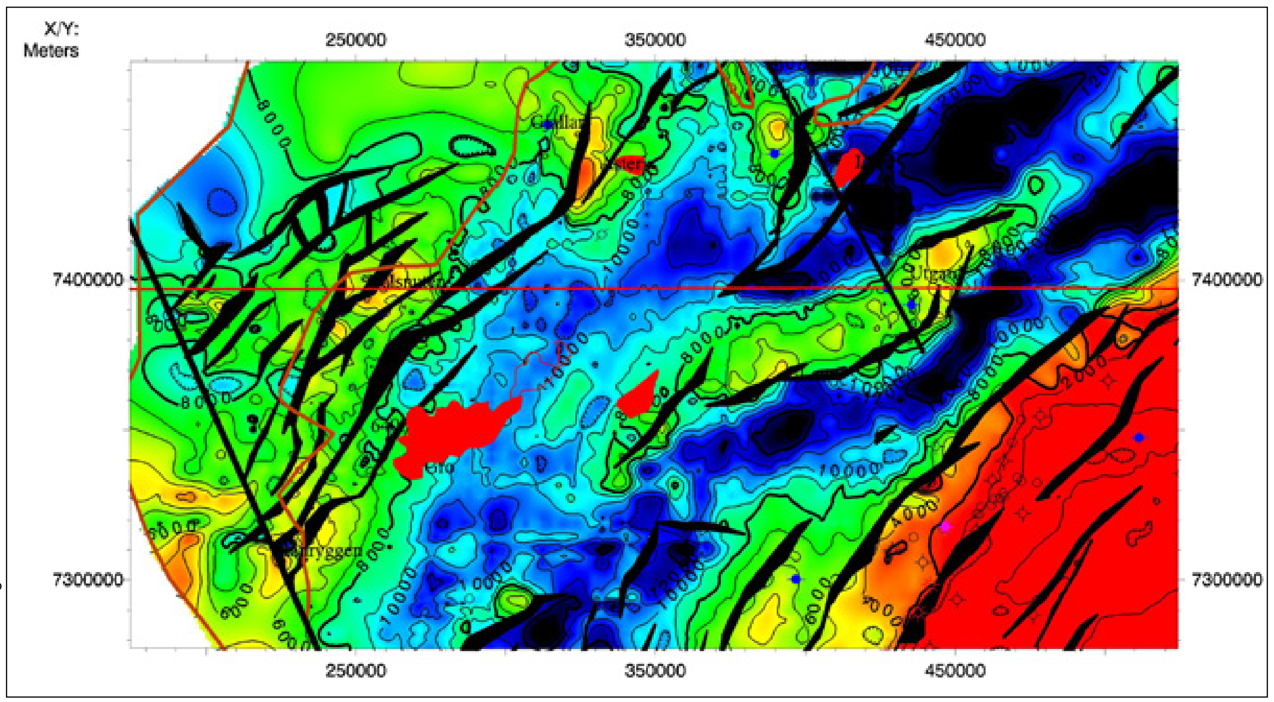


Illustration: Fugro

Overburden of top Jurassic time depth converted with stacking velocities.

Mid Norwegian shelf with main structural elements and Mid Norwegian Regional (MNR) seismic coverage. The line coloured in red shows the line displayed on previous pages.

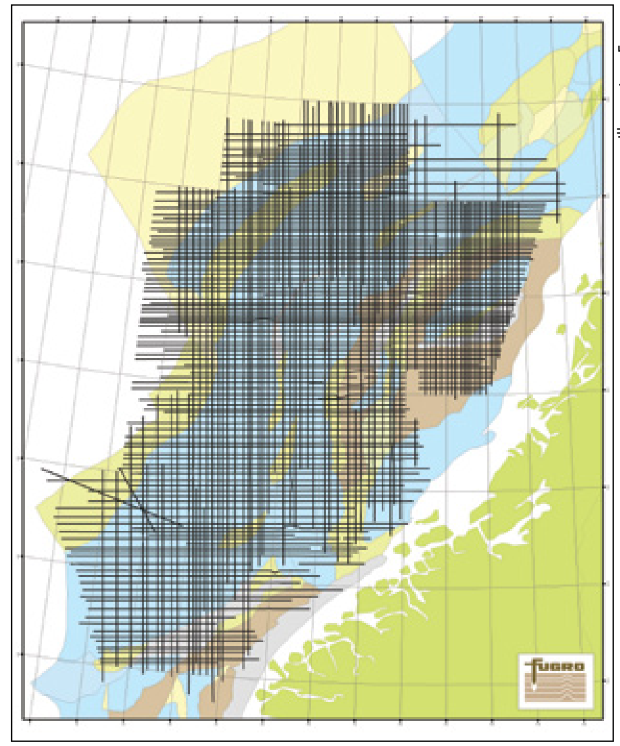
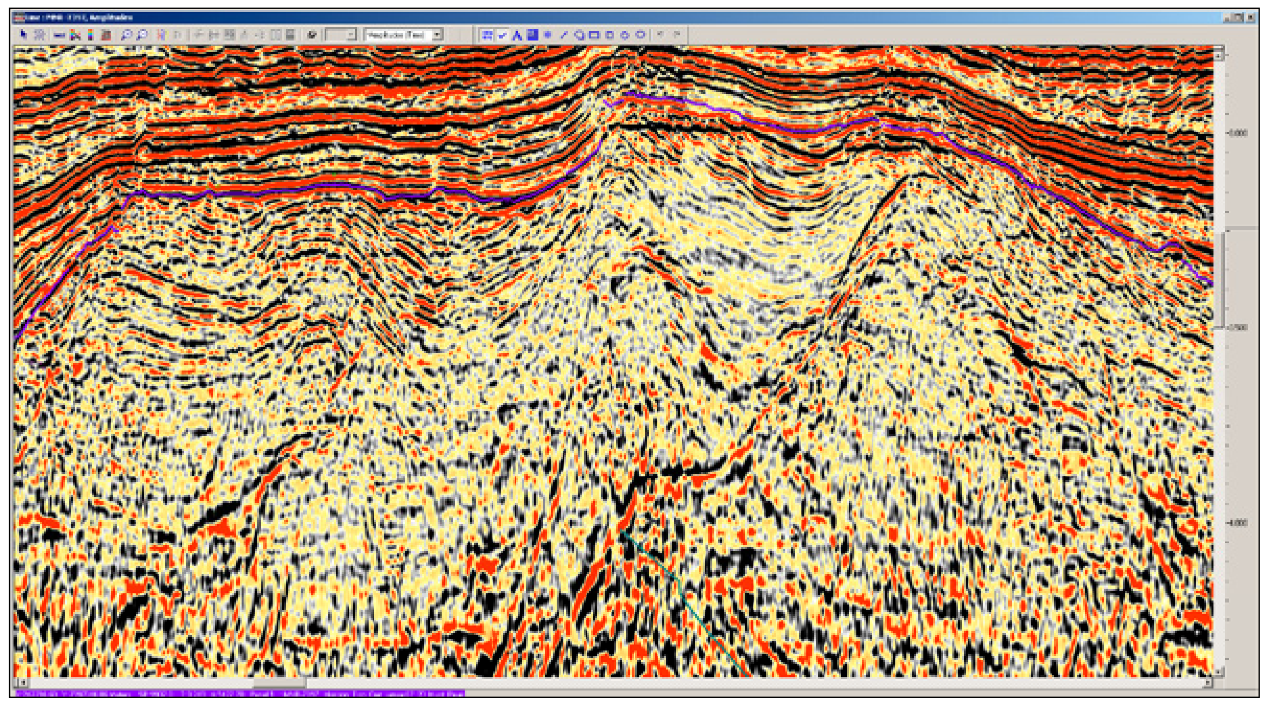


Illustration: Fugro



The prospect Dalsnuten is a result of Late Cretaceous rifting and rotation of fault blocks within the Gjallar ridge. Late Cretaceous sands are expected to contain hydrocarbons indicated by the "flatspots" in this example. Hopefully the well will reach the Jurassic and verify the presence of an Upper Jurassic source rock.

A new spin-off from HRT Petroleum, South America's largest service company, HRT Oil & Gas, is staking their fortunes deep in Brazil's Amazon Jungle.

Bright Future for Brazil's Newest Independent?

Starting a new company in the upper Amazon region of Brazil will have its opportunities and as well as considerable challenges.

THOMAS SMITH

"With Brazil's prolific offshore fields and the huge sub-salt discoveries receiving all the headlines, onshore exploration has been very quiet," says Marcio Rocha Mello, President of the newly formed exploration company, HRT Oil & Gas. "However, onshore opportunities loom large. The Solimões Paleozoic basin has hardly been scratched by the drill bit. This is the place we have chosen to start our campaign to become Brazil's leading independent. Not restricting ourselves to one basin, we also see other attractive plays in Brazil and West Africa and have already acquired eight offshore exploration blocks in Namibia."

WHY A NEW COMPANY?

In 2004, Marcio Mello formed High Resolution Technology and Petroleum (HRT) with the goal "to create the best petroleum system consulting and oil services company within the South Atlantic realm". (See GEO ExPro v. 5, no. 4, pp. 72-74). Marcio and the company Vice-President, Dr. Nilo Azambuja, built the new company using their extensive experience at Petrobras that set them apart from other working geoscientists.

In forming the company, Marcio recognized that "Oil companies are facing difficult challenges in finding new oil and gas deposits. Most frontier areas pose considerable risks with very high costs. Thus, we built a company that is knowledge-based and by fully integrating the skills necessary to do detailed basin modeling, exploration risks can be reduced."

> *"We live by our motto 'NO MORE DRY WELLS'."*

Thus their optimistic approach, and having essentially had all the ingredients of an exploration company in place, they just needed to

Photo: Frontpage

add leases. The opportunity came swiftly and, as Marcio did in forming HRT Petroleum in just a few days, HRT Oil & Gas took shape virtually overnight.

"Near the end of 2008, we were hired by the Argentinean/Brazilian Company, MS Oil and Gas, to perform a 3D petroleum system and risk assessment on part of their 21 blocks in the Solimões Basin," says Marcio. "Once the project was completed, we were asked to help raise funds for MS Oil and Gas through BMO Capital Markets in New York but was informed that be very difficult."

"I was then asked by BMO if I believed in the asset," Marcio continues. "I was quick to tell them that I would bet my career and company on it. Our credibility and knowledge base convinced them to offer to raise capital if we would explore the Solimões Basin assets. I hesitated two seconds, told them to come to Rio; a new company is being formed."

Photo: Tom Smith

Dr. Marcio Rocha Mello is President and founder of HRT Petroleum and HRT Oil & Gas. He had 24 years experience with Petrobras before starting his own companies. Dr. Mello has developed specialized studies regarding petroleum systems in sedimentary basins across Latin America and West Africa and has published over 200 papers on the geology and geochemistry of these areas.

WHY THE SOLIMÕES BASIN?

From June 2009 to November 2009, HRT Oil and Gas bought a controlling interest in MS Oil and Gas's 21 blocks. It was like a dream coming true for Marcio since he started his career here over 30 years ago participating in the discovery of the basin's largest gas and condensate field. He has also published several papers about the area's petroleum systems.

Covering an area about half the size of Europe, Brazil's onshore intracratonic basins represent huge exploration challenges but possible large rewards for the adventurous (See GEO ExPro v. 5 no. 5, pp. 44-50). Most of the basins remain largely unexplored because, at first, many areas were set aside for Petrobras when they had the exploration monopoly in Brazil. They were further ignored and put to a low priority due to the great exploration success in the offshore Campos, Santos and Espírito Santo basins.

The Solimões basin is one of the less explored of the onshore basins containing proven reserves of 200 MMbo and 3.1 TCF gas and has already produced over 200 MMbo. The first discovery was by Petrobras in 1978 when the Juruá field unveiled a large gas and condensate province along the basin axis. In 1988, Petrobras encountered light oil and gas in the Urucu and Urucu East fields.

In spite of Petrobras's success in the basin, only 226 wells have been drilled in a prospective area covering over 480,000 km2 or an area nearly the size of Spain. Of those 226 wells, there have only been 78 wildcat exploration wells drilled to date.

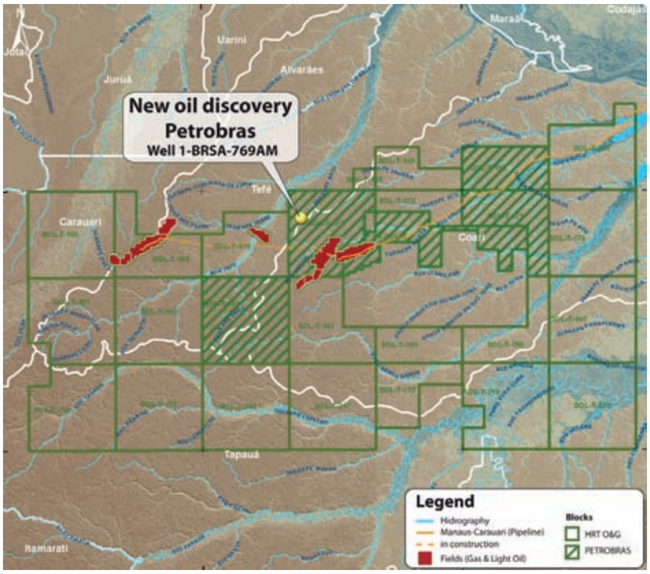
The basin is currently producing the largest amount of natural gas and the third largest amount of boe of any Brazilian sedimentary basin. Light oil production peaked at 70,000 bopd in 1998 and has dropped to 34,000 bopd and 13,000 boe of natural gas at present day. Petrobras has recently completed a $2-billion pipeline project that brings production to Manaus, a major trading hub located where the Rio Negro and Amazon rivers join.

©HRT

Located in the western portion of the Amazon region, the Solimões Basin has an established Paleozoic petroleum system including discoveries of light crude oil, gas, and condensate.

WHY NOW?

"In January 2010, Petrobras discovered light oil only 12 km from our leases," says Marcio.



©HRT

Map showing existing fields, 2010 Petrobras light oil discovery, and HRT's 21 lease blocks covering 46,000 km².

©HRT

The South Atlantic joined showing the close ties between the sedimentary basins in Brazil and those of West Africa.

"Based on correlation with important producing basins such as those in the north of Africa (Murzuq, Kufra, Illizi, Sirte, and Ghadames), as well as our recent analysis of the area, shows this to be the 'tail of the elephants', just the first discovery of a sequence. The majority of exploration wells drilled in the Solimões basin is positioned over structural highs and rarely reaches the depocenters with the Silurian/Devonian organic rich shales and associated reservoirs. This recent discovery reinforces our interpretations for the high potential in the deep horizons in the basin depocenters."

The sedimentary record is comprised of five sequences separated by unconformities related to orogenic events, attaining thickness of more than 4,800 m in which at least 3,400 m are Paleozoic. The basal sequence corresponds to continental to shallow marine siliciclastic rocks of Ordovician age.

"Organic rich, marine Silurian and Devonian shales are the primary source rocks for the basin," says Marcio. "The Devonian black shales attain a thickness of 80 m and have TOC values up to 12%. Due to lack of sampling, the Silurian source rocks are poorly understood. Very good reservoir characteristics are found in the Juruá Formation, Pennsylvanian age eolian sandstones that average 18% porosity and reach 100 m in thickness."

"The potential is enormous. The basin contains large, undrilled anticlines, with reverse faults sealed by halite and anhydrite," contends Marcio. "The whole depocenter is at the end of the oil window stage generating light oil and humid gas."

"This basin has all the elements that make for an unbelievable petroleum system."

WHAT IS NEXT?

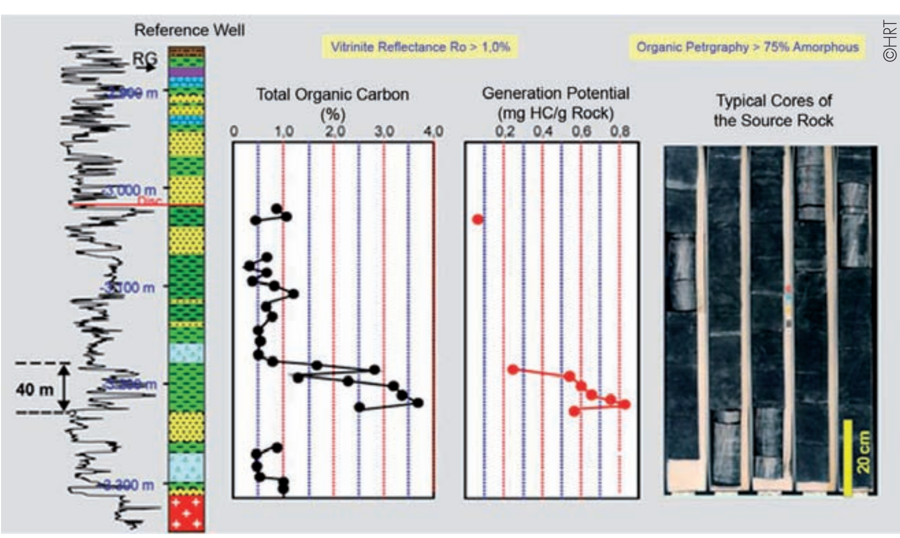
"Our current holdings in the Solimões basin have existing wells that have already proven larger amounts of gas, light oil, and condensate," says Marcio. "We have plans to start drilling by October, 2010 and to drill over 100 wells in the next four years. Brazil currently imports 60% of their gas needs from Bolivia. This basin has the largest potential for gas and light oil of any onshore province in Brazil and provides us with a huge exploration and production opportunity."

Not content with the huge potential opportunities the Solimões basin provides the new company, Marcio is seeking exploration opportunities throughout Brazil and is already looking at international projects in areas such as Namibia, Colombia and Angola. It seems he likes the "forgotten basins" like the Solimões and has obtained eight offshore exploration blocks in Namibia together with Universal, Inc., a Canadian public company.

"The basins off Namibia have been forgotten for decades being overshadowed by the success offshore Angola. Our recent petroleum system modeling and prospect resource analyses have identified large prospects in three of the studied blocks," says Marcio. "We think there could be more than 5 Boe in these unrisked prospects with objectives in the Upper Cretaceous turbidite sandstones as well as the syn-rift carbonates and sandstones that are analogous to the Tupi and Jupiter fields in southern Brazil."

HRT Oil & Gas plans to spend a lot of money in both areas, not only to prove that their analyses are correct, but more importantly to certify billions of boe and start production before June 2011.

Finally, Marcio Rocha Mello admits, "People believe in destiny. This is my destiny. I worked in the Solimões basin as a young geologist. I was there for the first discovery. Now, this has come back into my hands."



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High TOC values and generation potential for the basins source rocks are a key element when evaluating the petroleum system.

From Gold Coast to

With as much as three billion barrels of recoverable oil found since 2007, offshore Ghana is one of the most talked about new frontier areas of recent years.

JANE WHALEY

Although oil and gas were first found offshore Ghana in 1970, petroleum companies showed very little interest in the West African country until exploration moved into deeper water. Since 2007, however, major discoveries in the deepwater Tano basin in West Ghana have changed the opinion of many companies, and look set to revolutionise the country as well. The Jubilee, Odum and Tweneboa fields have combined estimated recoverable reserves of possibly three billion barrels. This is a significant volume and of great value to a country where the majority of people live on an average income of US $1,500.

LONG HISTORY – LITTLE SUCCESS

The existence of seeps had been known for many years in western Ghana, and they were first investigated with shallow drilling as early as 1896. A number of wells found oil, and drilling continued intermittently over the next 70 years, but commercial quantities of hydrocarbons were not discovered.

In 1968 the Government of Ghana announced the first licensing round, offering 22 blocks offshore. By 1980, a further 31 wells were drilled, but resulted in merely three discoveries: Cape Three Points and Tano in the Tano Basin, straddling the Ghanaian/Cote d'Ivoire border, and Saltpond in the central Saltpond Basin. Only this last was put into production, in 1978, producing 3.5 MMbo before it was shut-in seven years later.

With little further interest from the industry, the country decided to make itself more attractive, establishing the Ghana National Petroleum Corporation in 1983 and introducing new laws and incentives for exploration. This resulted in the acquisition of large quantities of seismic and the drilling of a number of wells, but still little of significance was found. Not until drilling technology advanced into deep waters was the true potential of Ghana discovered.

SUCCESS IN DEEP WATER

Companies began to move further offshore, led by Hunt's 1999 Cape West Three Points minor discovery in 1,000m water. They started looking at the western part of the Tano Basin, where 3D seismic identified interesting prospects in the deeper water. In all, four deep water wells drilled between 1999 and 2004 found hydrocarbons, proving the existence of an active petroleum system. Finally, the oil industry in Ghana had began to take off – but still nothing in commercial quantities.

Not, that is, until June 2007, when a consortium of Tullow, Kosmos, Anadarko and E.O Group announced a 'significant' discovery with their Mahogany 1 well in Block West Cape Three Points. This was the **Jubilee** field, now estimated to contain between 600 and 1,800 MMbo recoverable, confirmed a few months later by Hyedua-1, 5km to the south-west. The two wells intersected a large continuous accumulation of light sweet 37° API oil in excellent quality stacked reservoir sandstones. Further appraisal wells confirmed the size of the discovery, and also identified extensive underlying sands which could hold further reserves. Well tests showed that production may be as high as 20,000 bopd.

The Jubilee field was followed in 2008 by **Odum**, about 20 km to the east, also in block West Cape Three Points, in water depth of 955m. This found heavier oil, with 22m of net pay. The following year Tullow and partners moved further west, and near the border with Cote d'Ivoire found the **Tweneboa** Field, thought to hold 1.4 Bboe. The second well on this field also found a deeper oil and gas condensate section.

The most recent discovery was **Dzata**, a Cenomanian/Albian faulted anticlinal trap found in March this year, which lies about 100km south-east of Jubilee and opens a new trend in the eastern part of the Tano Basin.

THICK CENOMANIAN SOURCE HORIZON

Much of Ghana comprises metamorphosed sedimentary and volcanic rocks over 2,000 million years old, the source of the gold which originally attracted European colonisers. The offshore, however, is dominated by Cretaceous and younger sediments deposited during and after Africa and South America rifted apart. As the continents separated, a major fracture zone system formed, trending roughly south-west to north-east, along with associated faults and folds, and these fractures and structures play a significant part in the hydrocarbon geology of the region.

Offshore Ghana comprises three main basins. The western Tano Basin and the eastern Keta Basin are primarily Mesozoic, with the Palaeozoic Saltpond Basin sandwiched between them. For many years, exploration efforts were centred on Tertiary plays in shallow water. Despite this, the only producing field, Saltpond, has a Palaeozoic reservoir, the Middle Devonian – Carboniferous Takoradi Formation, which was deposited in a fluvial-marginal marine environment when Africa and South America were still one land mass.

Pre-rift continental rocks were overlain by Lower Cretaceous (Aptian-Albian; 125–100 MA) syn-rift fluviatile to shallow marine sediments. A number of lakes formed in the rift, and the resultant lacustrine sediments provide a good source rock. The South Tano High, a major structural feature influencing the prospectivity of the area, developed at this time.

During the Cenomanian (Late Cretaceous), the whole West African margin was rapidly inundated, and thick organic-rich shales were deposited over a wide area, forming another important source horizon for hydrocarbons. Their maturity was a matter of debate, until the recent discoveries were shown to be sourced from this level.

Photo: Paul Archer

As a modernised deepwater port and other infrastructure is built in nearby Takoradi to accommodate the oil industry, the small coastal town of Sekondi is anticipating major changes.

Black Gold

MAJOR FAN SYSTEMS

By the Late Cretaceous a deltaic complex had developed in the west of Ghana, depositing thick layers of basin floor fans and turbidity flows into the deepening Tano Basin. These are the large fan systems which form the main reservoirs in the Jubilee, Tano and Odum fields. Continued extension and subsidence resulted in deposition of thick shales, which seal Jubilee and the other prospects in the area.

Deposition was slower in the late Cretaceous in the Saltpond Basin, with marked erosion surfaces and a thinner sedimentary package. The Keta Basin also appears to have suffered more erosion that Tano, although the main potential of the basin is still perceived to be in the Upper Cretaceous. African specialist Afren, which holds a large block in this basin, believes that this section has thick fan sandstones similar to the Jubilee play, and has identified a number of prospects. Its first well, Cuda-1, spudded in 2008, targeted a Campanian fan complex, but encountered high pressure and had to be abandoned.

A thick transitional marine sedimentary package was deposited during Cenozoic times as the whole area of offshore Ghana underwent thermal subsidence. The Tertiary has not proved productive, probably because the traps are not of sufficient size to warrant exploitation.

LEGISLATION TO AVOID PROBLEMS

There is much discussion in Ghana over the best way to exploit this oil bonanza, with a determination not to copy the errors of its neighbour, Nigeria. Ghanaians are keen that oil riches will be used to benefit the whole country, and they have been trying to develop an oil and gas policy that is acceptable to the general public, yet sophisticated enough to ensure oil revenues are spent responsibly. The Norwegian government has been assisting them to construct the appropriate legislation, and they have held open consultation forums around the country.

There have already been problems, as Ghana blocked the sale of Kosmos Energy's stake in the Jubilee field to Exxon, preferring the state-run Ghana National Petroleum Corp to acquire it. Ghana does not have production-sharing contracts, and the carried GNPC participation is 10%, so the main return to the government will be in taxes and royalties. Ghana's neighbour, Cote d'Ivoire, has threatened action, claiming that some of the fields may actually lie over the border in their territory.

Ghana has begun to build a deep water port and improve infrastructure in the area, ready for the first oil, due ashore late in 2010. Meanwhile, it is needs to ensure transparent institutions and regulations in order to avoid the violence and corruption brought by oil booms elsewhere in Africa.

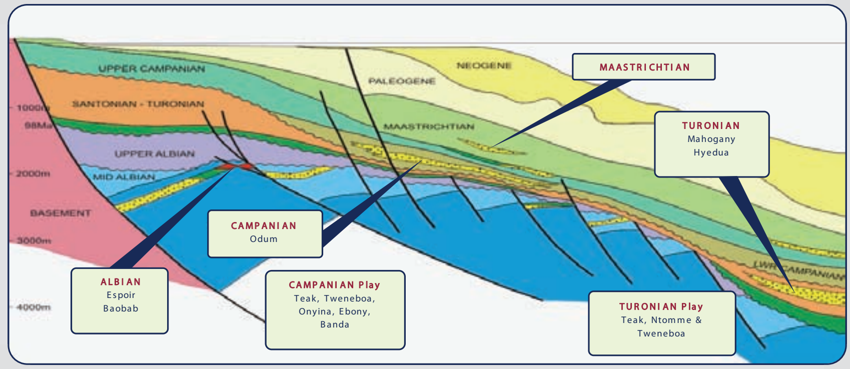
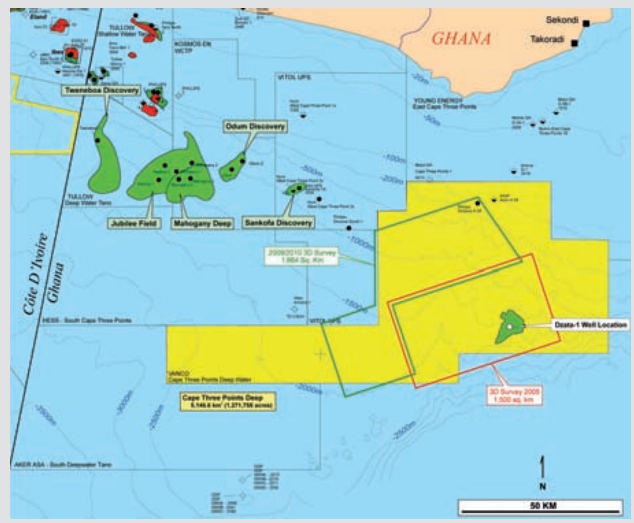


Image: Tullow

A variety of plays have been found in the West African margin off Cote d'Ivoire and Ghana, including sub-thrust traps, Senonian anticlines and stratigraphic pinchouts and structural closures within the syn-rift clastic sequence.



Cartography: © Vanco

Ghana's recent discoveries have all been in the deep waters off Western Ghana

The Gold Coast and the Slave Trade

Ancient Ghana originally lay 800 km north of the present country, occupying the area between the Senegal and Niger Rivers. It was a wealthy and prosperous kingdom, the old capital city Kumbi Saleh being an important southern terminus in the Saharan trade routes, but a drought in the 12th century, coupled with changes in trade routes, led to its decline.

In 1471, the Portuguese arrived on what was known as the Gold Coast, because it was the source of gold in the Muslim North Africa trade routes. It supplied over 10% of the world's gold at this time and is still Africa's second largest producer of gold.

In the 16th century demand for slaves to work on plantations in the new world resulted in the west coast of Africa becoming the main source of slaves. European goods were transported to Africa, where they were traded for captives, who were then brought to the new world to work on plantations. It is estimated that roughly 6.3 million slaves were shipped from West Africa to America, with approximately 5,000 a year from the Gold Coast alone. The slaves were marched to the coast, where they were held large forts before being crammed onto ships in for a voyage that could take as long as two and a half months. It is estimated that a mere 20% of them survived to reach America.

Photo: Jane Whaley

The fort at Axim, in the west of Ghana, was built by the Portuguese about 1515 and was a trading point for gold as well as slaves, who were crowded into damp underground dungeons before being shipped to America.

In the 17th and 18th centuries, the Dutch, English, Danish and Swedish competed for gold and slaves with the Portuguese. These European powers struggled and fought for dominance until the last quarter of the nineteenth century, when the British gained full possession of all the coastal forts, making them the major European power on the Gold Coast. In 1960, the country gained independence from Britain, becoming the Republic of Ghana.

3D Contrast Property to Enhance Subsurface

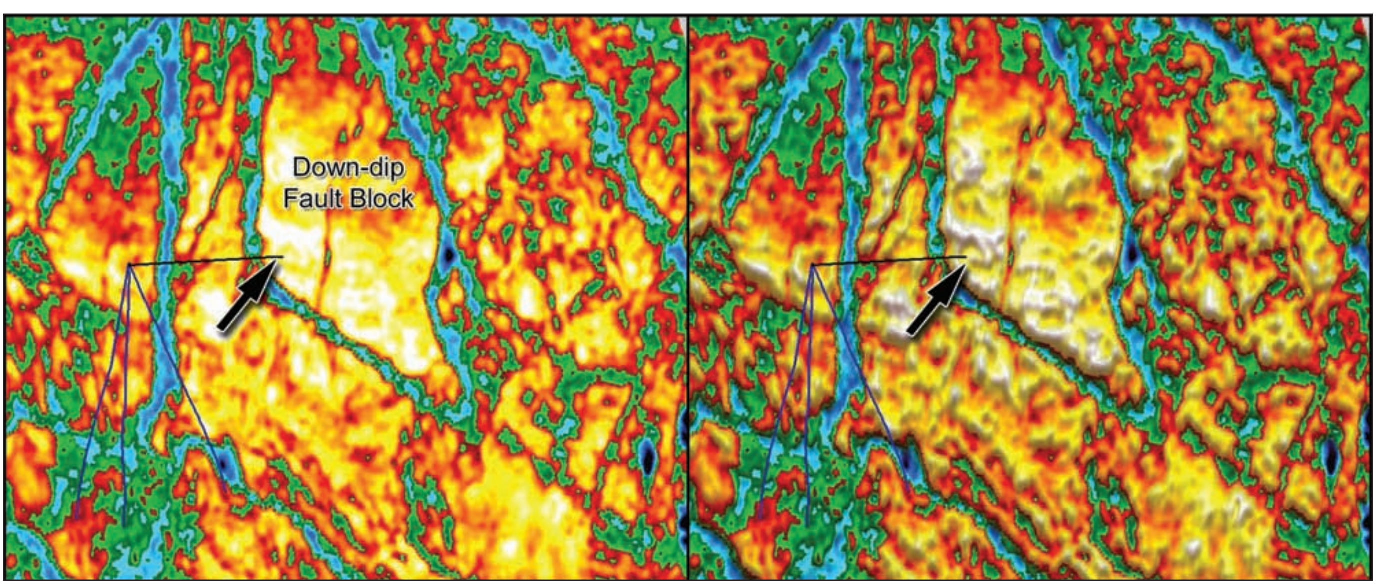
One of the major challenges in understanding the nature of the subsurface is to accurately depict geology when data is sparse. By combining well logs and seismic data, seismic inversion can be used to visualize subsurface geostructures in a realistic form.

ROBERT VAN EYKENHOF AND ETIENNE WILDEBOER SCHUT, FUGRO-JASON, AND VINCENT AUBIN, GDF SUEZ

Volume rendering tools for visualizing the subsurface have seen significant advancement over the past 15 years, with the introduction of 3D texture for interpretation of large data sets. Although very useful for global reservoir characterization, these tools are often less suitable for highly detailed geological interpretation because available rendering methods lack the required resolution and require substantial computing resources. In addition, they generally do not include the required specialist interpretation tools for fine scale analysis. As a result, interpretation is still mostly done using classical 2D software that offers more flexible tools and workflows.

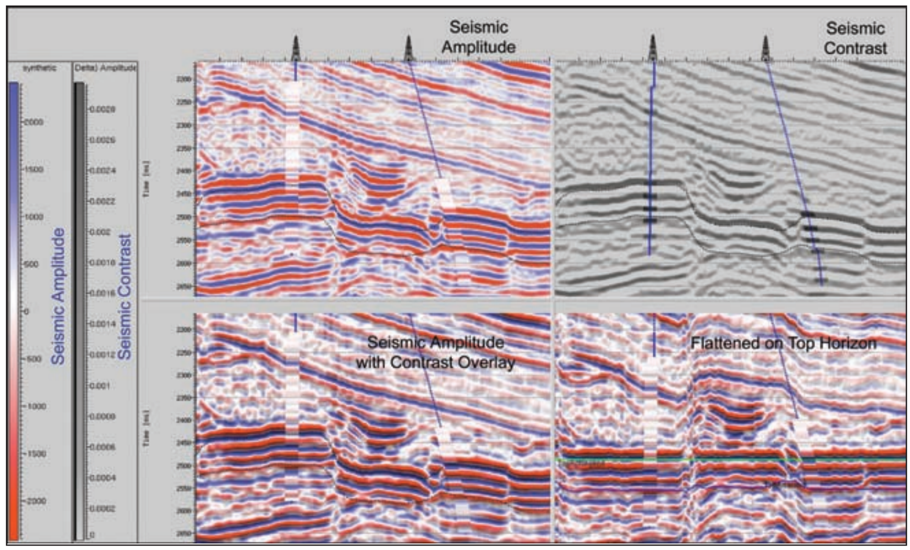
An alternative technique for fine scale analysis has been developed recently which is not subject to these limitations. Incorporating 'bump mapping', this technique adds textures and patterns to an object's surface without heavily taxing computing resources. Detailed grayscale bump maps and volumes are created to bring out the underlying 3D texture in contrast map, panel and section displays to visually emphasize structural information to the displayed properties.

A recent study of a prospective field in the Dutch North Sea illustrates the technique's effectiveness in the interpretation of seismic inversion results. GdF SUEZ commissioned the study to determine the probability of gas sands in a new area of their license, where multiple wells were already producing gas. Seismic surveys in the new area showed a promising bright spot, but its location below the gas-water contact in the producing area added unacceptable risk. In addition, the company was concerned that the thick salt overlay was affecting the seismic amplitude.



Minimum P-impedance map at Rotliegendes reservoir level. Low P-impedance at reservoir level indicates high probability of gas bearing sands for a newly drilled well in the adjacent fault block (arrow). 3D texture from shading (right panel) provides additional detail by adding gray zones just around the minimum P-impedance extremes, emphasising reservoir quality variations and faults. GdF SUEZ successfully drilled the new well in the down-dip structure as indicated by the black arrow.

Mapping Visualisation



Seismic panel through two wells, with a seismic property panel overlain by the grayscale map calculated from seismic contrast to create the illusion of lighting and shadowing, enhancing lateral variations. Warmer and bright colors appear nearer in depth to viewers than cooler colors, shading is added to reds, orange or yellows so that these amplitudes appear to protrude. The technique enhances structural features and layer connectivity, to aid the interpreter.

The contrast property mapping technique was used to generate contrast maps, panels and sections with which to closely inspect and differentiate gas sands from tight sands, shales and high reflectivity artifacts caused by the overburden Zechstein formation.

ROCK PROPERTIES FROM SEISMIC

GdF SUEZ has been producing gas for a number of years from the Permian Upper Slochteren fluvial/aeolian sandstones in the Dutch North Sea where the regional top seal is a Zechstein evaporitic sequence. Several deformation phases from Triassic to recent have resulted in the present day complex structural setting.

The objective of the reservoir characterization study was to combine sonic and density well logs with seismic data in a common domain and use that information to determine the rock properties in the Rotliegend sands. The study began by combining general geologic insight with specific petrophysical data recorded in nine nearby wells, five of which had encountered gas in the Upper Slochteren of the Rotliegend Group.

Two zones were chosen for well log quality control, one in the evaporitic Zechstein formation, which gives a very distinct sonic log response, and the second in the reservoir. Rock physics modeling was applied to make up for the lack of acoustic logs, for elastic log correction and simulation of different reservoir fluid conditions.

The petrophysically corrected well logs were then used to determine the seismic wavelets at the various offset ranges. Analysis of the seismic gathers showed the seismic response was severely disturbed below the thickest portion of the Zechstein salt. A simultaneous inversion was run using a set of laterally varying wavelets to compensate for the apparent energy absorption below the Zechstein.

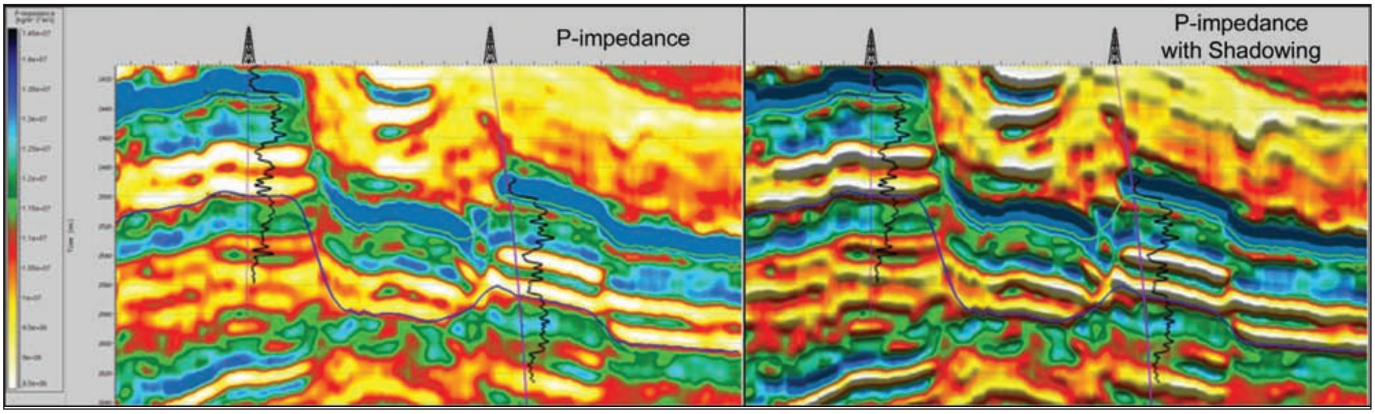
GAMING SHOWED THE WAY

Over the past decade, the advent of PC gaming and entertainment has added greater realism in 3D rendering, as gaming companies introduced a fresh approach to texture through light and shadow. The human brain relies on colour, shading and lighting to provide clues into the nature of the object under review. For example, colour helps differentiate an apple from an orange, lighting and shading distinguishes a circle from a sphere, even in a 2D space. Similarly, lighting and shading can also indicate texture, showing the distinction between a smooth sphere, a fuzzy tennis ball and a bumpy orange. The angle of the light and its nature - ambient, diffuse, specular or emissive - also affect how the object is perceived.

Initial implementations of this new approach relied on a technique called bump mapping, which uses shading and lighting to give the impression of a 3D surface without the high computational overhead of full 3D rendering. This was used to improve fault mapping, and structural interpretation of seismic, and the method was later expanded by adding 3D texture to maps to identify faults and discontinuities with lighting effects used to enhance the display of seismic data in 3D.

3D CONTRAST MAPPING

Building on this foundation, 3D contrast property mapping is now used to add texture to map and section displays without the



P-impedance from seismic inversion through the newly drilled well location, demonstrating increased contrast and fine detail of the inversion results. The reservoir sands appear as low P-impedance layers, showing continuation of down-dip sands in the down-dip block (right). Added shadow aids delineation of geological features.

need for computer-intensive 3D volume-rendering tools or sophisticated calculations. Shadow and lighting effects are applied to properties using semi-transparent grayscale property overlays, which improve realism and add visual depth to the image, very useful in as map or section display. Contrast property mapping can be performed on any type of laptop or desktop computer without the need for specialized hardware or software.

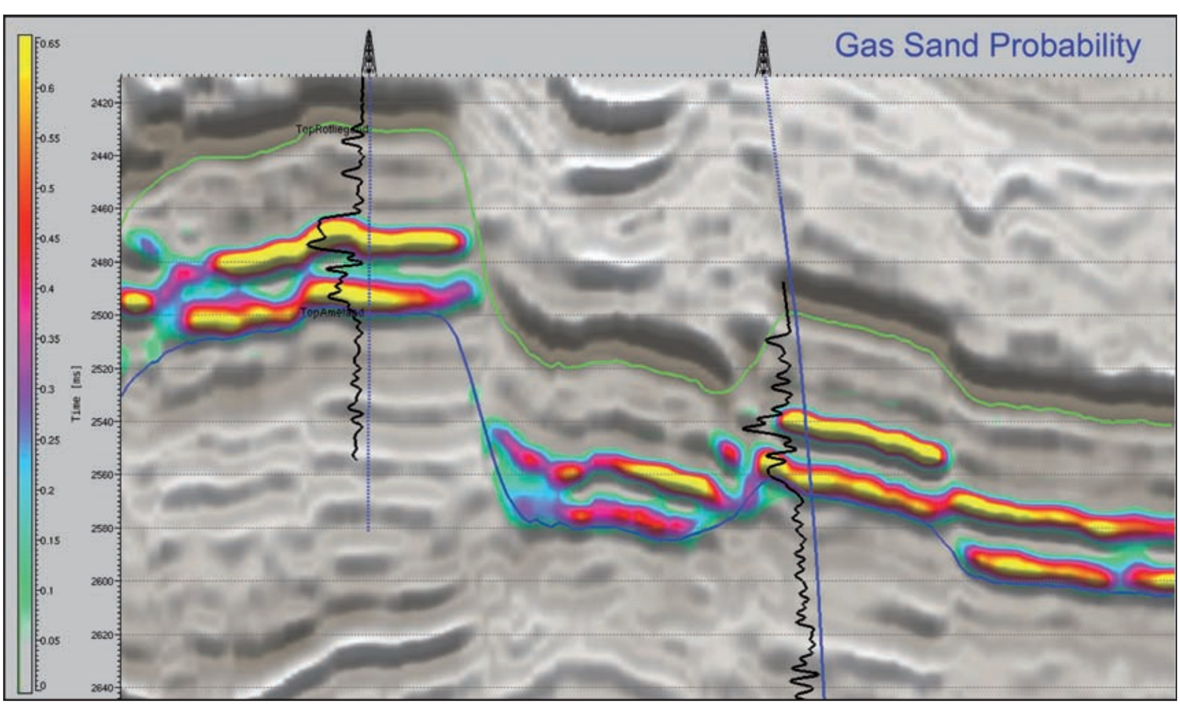
With light and shadow, artifacts are far clearer and the details are more apparent. Any property can be displayed in this manner, including seismic, elastic properties from inversion, derived porosity and pay probability data. The technique can easily be combined with traditional interpretation tools to better understand subtle geometric relationships between layers.

The data is drawn on a plane but made to appear as if it is drawn in 3D. Although the grayscale maps and impedance are somewhat affected by seismic attenuation caused by the salts and anhydrites deposited just above the reservoirs, it is clear that the technique adds significant contrast and structural information to the property map. It is much easier to see potential boundaries between reservoir sections and identify subtle variations in reservoir quality.

SUCCESSFUL WELL

Using these modern 3D visualization techniques, it is possible to highlight the consistently high probability of gas sands and distinguished them from non reservoirs and seismic artifacts caused by the Zechstein formation. The technique proved fast and efficient, running without specialized 3D software or expensive hardware, and can be combined with all the benefits of 2D interpretation tools. This technique has the potential to aid geological understanding related to stratigraphy, structural connectivity and faults, and to improve communication among asset team members and with management.

And, as always, the proof was in the final result. Following this study, GdF SUEZ decided to drill, chose a location based on the study results – and found good quality gas bearing sands as predicted.



Gas sands probability derived from inversion result shows the derived pay probability. The well to the right, drilled in the down-dip block, showed good quality gas bearing sands as predicted

Northeast Atlantic Continental Margin: Improved Sub-basalt Imaging

New seismic survey techniques promise to improve the regional understanding of sub-basalt geology along the highly prospective Northeast Atlantic margin.

MENNO G. DINKELMAN, CHIEF GEOLOGIST AND PAUL KEANE – BASINSPAN PROGRAMS, ION GEOPHYSICAL

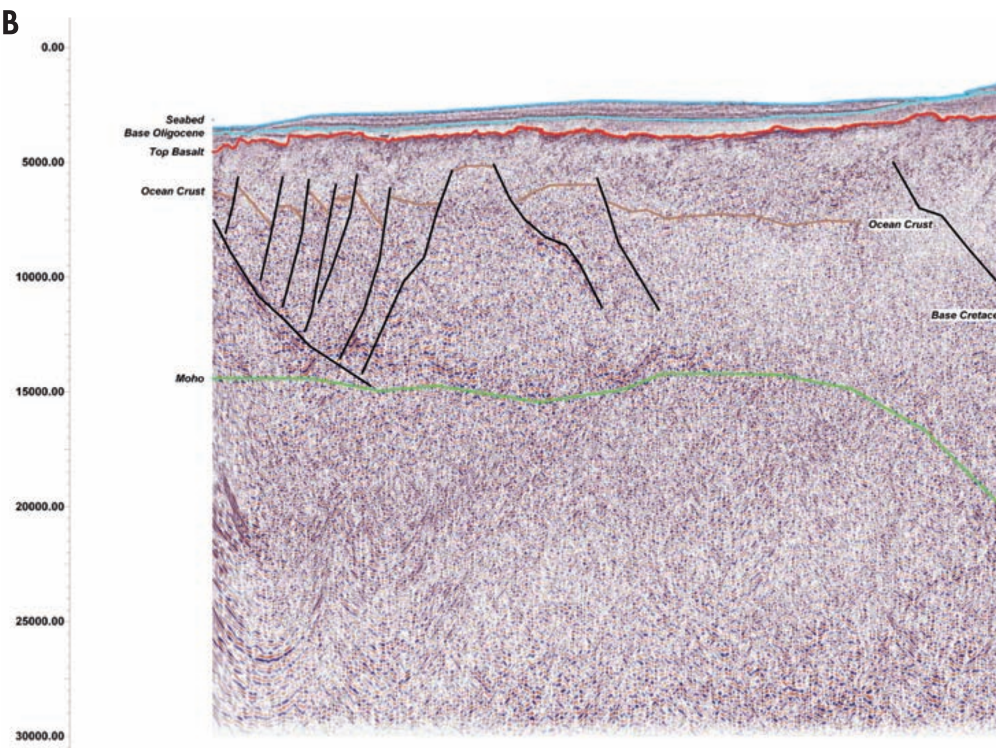
The Faeroes-Shetlands and Møre-Vøring Basins along the North East Atlantic Margin are covered by a large flood volcanic province that has thus far significantly hampered exploration. Imaging through the basalt has proved difficult and the base layer appears to be a transitional zone without strong reflectors. Employing recent improvements in seismic acquisition and processing, ION Geophysical's Northeast AtlanticSPAN™ 2D regional reconnaissance seismic survey is believed to be the only contiguous and consistent seismic program along this margin. The survey has enabled long range basin analogies to be made in areas where there is very little quality seismic and even less well control, resulting in the identification of potential new plays in what is still a largely very underexplored margin.

Seismic Section (A)

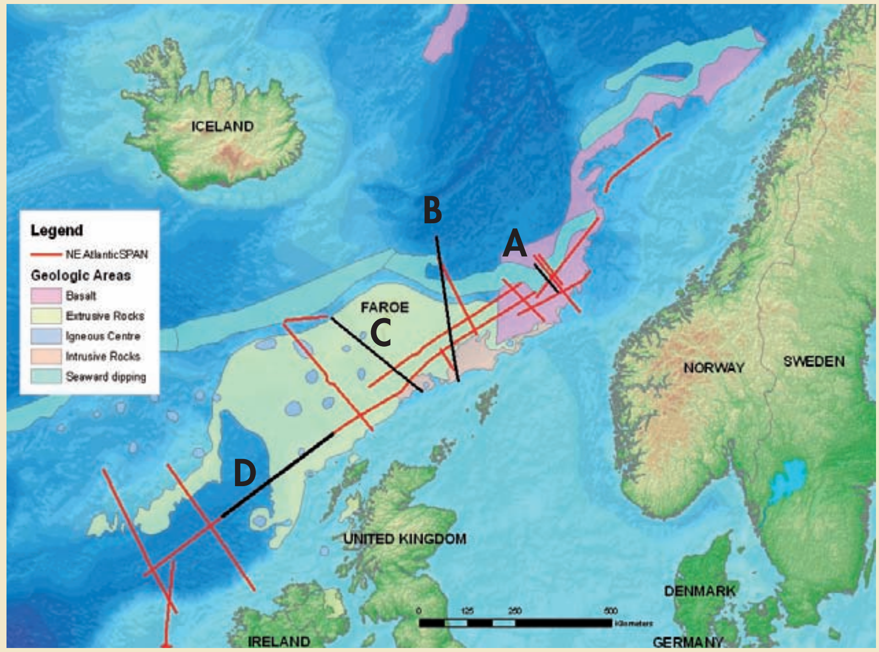
This is a dip line across the Møre Margin off southern Norway, showing internal basalt stratigraphy. The seismic shows that many igneous sills were injected into this supracrustal section during the Palaeogene, ranging in thickness from 2 to 150m. The sills are mainly injected around 1-3 km below the level of the Palaeocene basalts, where the depth of sill injection was determined by the point at which the magmatic pressure exceeded the prevailing lithostatic pressure. Below this depth, the magmatic pressure was insufficient to overcome the lithostatic pressure and only dyke injection would have occurred. Hence, the deeper Jurassic source rocks may have escaped pervasive heating from sill injection as they are situated at greater depths.

The left hand side of the section shows examples of seaward dipping reflectors (SDRs) that in some areas reach up to approximately 7 km maximum thickness. This is interpreted to be new oceanic crust erupted above sea-level at this thickness. The basalts flowed landward from the spreading centre to produce lava deltas, with eastward prograding foresets. These can reach up to 1 km in vertical relief, indicating the probable palaeo-water depths. Below the landward (eastern) edge of the basalts, rifted sedimentary strata between 5-7 km in thickness are clearly imaged and can be traced for a short distance below the basalts. Stratal reflections are imaged, even under the thickest sequence of SDRs, however these are apparently injected by a large number of magmatic sills.

B

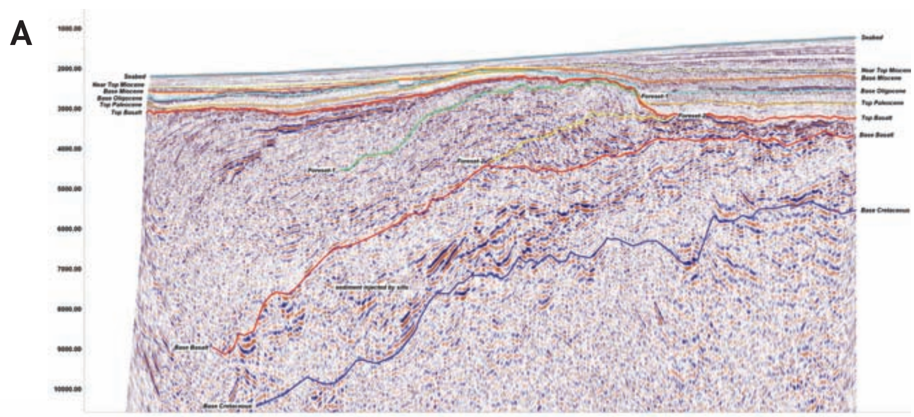


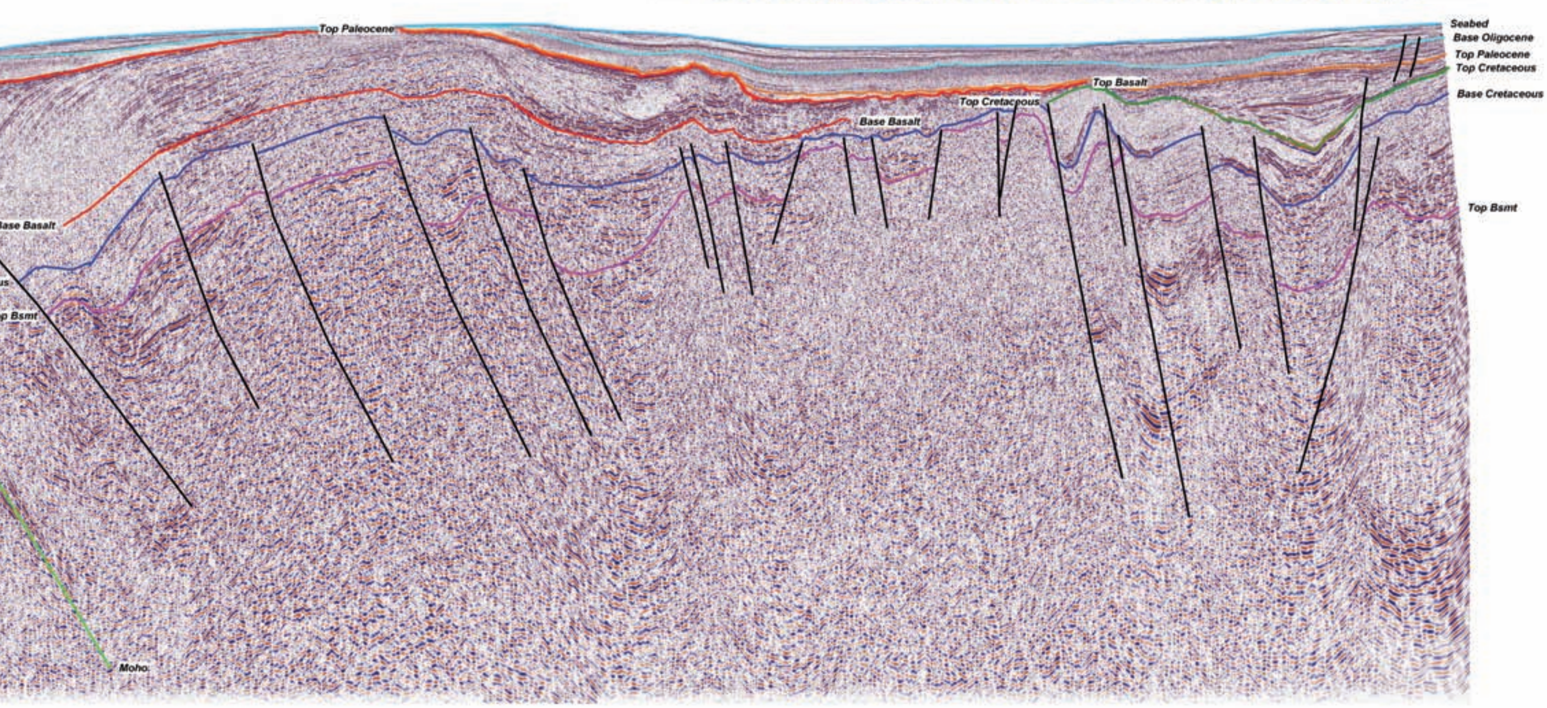
The North East Atlantic margin extends more than one thousand kilometres north east of Ireland to the southern coast of Norway. The area covered by early Tertiary extrusive and intrusive volcanics and igneous rocks is illustrated as shown. The four seismic lines shown are highlighted in black. ION Geophysical's NE AtlanticSPAN grid is shown in red.



SEISMIC SECTION (B)

This line runs north over the Fugløy Ridge, which is a large anticlinal structure situated approximately 100 km to the north east of the Faroe Islands, separating the Norwegian Ocean basin from the Faroe-Shetland Trough. It has been proposed that the ridge, as a possible compressional fold structure, was formed by a mantle plume uplift at the end of the Paleocene, approximately 55 million years ago.





As one traverses the line, the crustal makeup goes from oceanic, through the continental ocean boundary, onto continental crust, so the southernmost part of the line is identified as stretched continental crust. On the left hand side of the section we see possible evidence of the Moho and the SDRs are again quite visible. Of note are a number of identified Mesozoic tilted fault blocks beneath the basalt, lying at shallow, drillable depths below less than 3km of basalt with the potential for major hydrocarbon accumulation. To our knowledge many of these structures have never been recognised before, making them high risk yet viable plays which have yet to be tested. Similar features are also identified in the areas beneath the Wyville-Thompson and Ymir ridges.

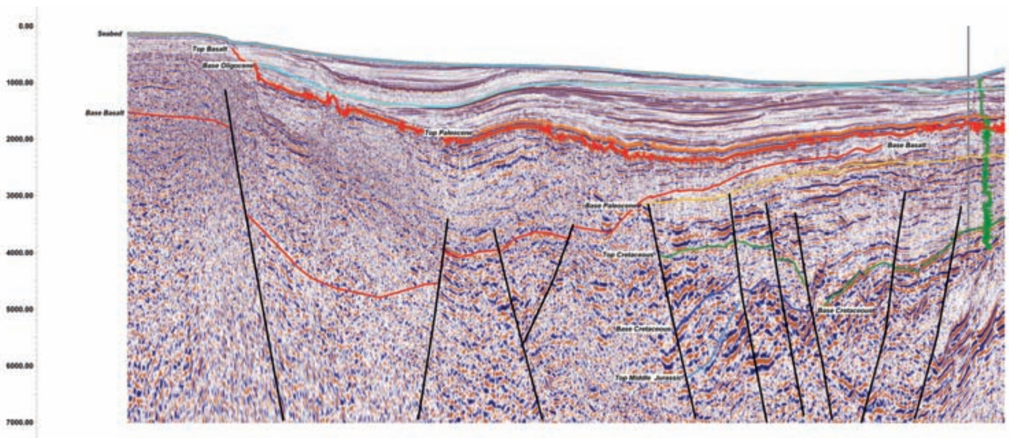
SEISMIC SECTION (C)

This line lies south of the Faeroe Islands and trends NW-SE. The south-eastern part of the line ties the William Well (6005/13-1) drilled in 2007. The top basalt in the well is associated with is a very strong reflector but there is no clear reflector at the base basalt, possibly due to a low frequency event and character changes. However, note the well defined deeper stratified reflections suggestive of the presence of Mesozoic strata. One challenge in exploration across the regions has been trying to image the base basalt reflector which has been notoriously difficult. New data shown here suggest a reason for this may be because it is often a transitional zone of thinly bedded tuffs, lavas and sediments, thus there is no clear seismic event that can be associated with it. Large-scale Cenozoic age folds such as the aforementioned Fugløy Ridge are underlain by Mesozoic rotated fault blocks which constitute major potential traps with Mesozoic reservoirs and Jurassic source rocks present. The Cenozoic folds are cored by Late Cretaceous strata and are laterally extensive.

SEISMIC SECTION (D)

The final example is extracted from a very long regional SW-NE strike line (see map) running from the northern part of the Rockall Trough to offshore central Norway. The Rockall Trough is a very large NE-SW trending basin bounded to the west by the Hatton Bank and to the east by the Irish and UK continental shelf. The northern boundary is formed by the Wyville-Thompson and Ymir ridges and the south is bounded by the Charlie Gibbs Fracture Zone. The seismic data show rotated and tilted fault blocks of Mesozoic strata below the basalts. They also show that the Paleogene volcanics are present in the northern part of Rockall but not in its southern sector. Shown clearly is the top basalt while the base basalt reflectors are less continuous and less clearly distinguished from the underlying sediments. In the Rockall Trough sediment thickness can reach up to 7 km and in places 2-3 km of Pre-Cretaceous strata is interpreted. The data does indicate that the Rockall Trough has good potential hydrocarbon prospectivity, but deep wells will be needed to test whether an Early Paleocene or Cretaceous sandstone reservoir and Jurassic source rocks are present.

C



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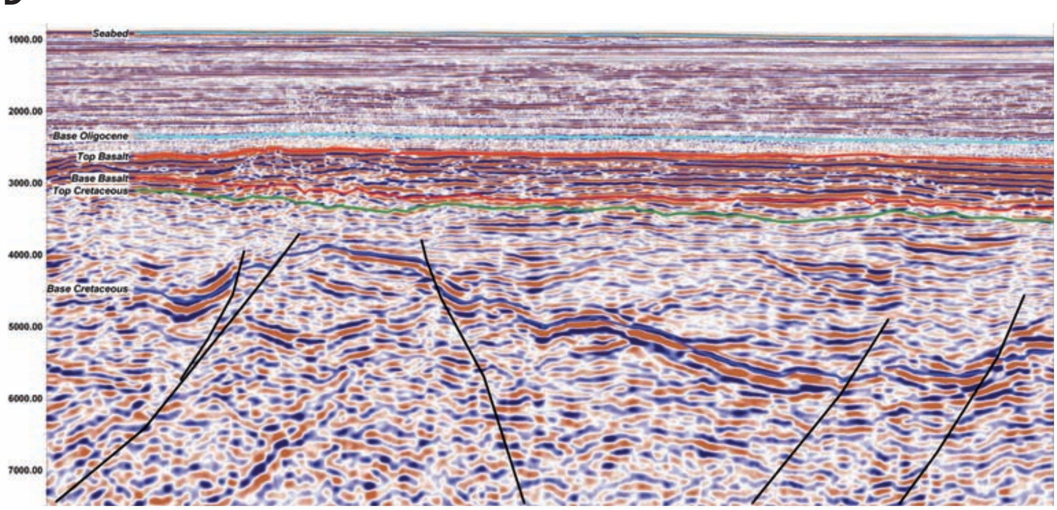


The Data

All data were acquired with long offsets (10km) and long record lengths (18 secs). Working with Pre-Stack Depth Migration (PSDM) data is a new approach to advance the understanding of hydrocarbon potential, deep stratigraphy and structure. Data were consistently processed through both PreSTM and PreSDM sequences. Four lines are taken from the regional survey, which stretches from south west Ireland, through Rockall and the Faeroes-Shetland Basin and on to the Møre and Vøring Basins off mid-Norway. The examples shown here are all Pre-Stack-Depth-Migrated sections from areas within the volcanic belt, including offshore southern Norway, the Faeroes-Shetland Basins and the Irish waters of the northern Rockall Basin.

CSEM Reduces Exploration Risk

A recent scientific study shows that the average discovery rate for exploration wells drilled on prospects with a significant CSEM anomaly is as high as 70%, twice as high as the discovery rate for wells drilled on prospects without a significant CSEM anomaly.

The past years have seen an increased focus on the use of CSEM technology for hydrocarbon exploration in the marine environment. However, although the technology has been demonstrated to aid both detection and delineation of hydrocarbon-filled reservoirs, there has been significant scepticism in the industry with respect to whether or how much the technology can actually help de-risk prospects.

Most oil companies have for this reason been reluctant to fully implement CSEM data into their exploration process. An exception is the independent Norwegian oil company Rocksource which has used CSEM data and internal integrated expertise as key risk reduction tools for their marine exploration activities since their start-up in 2004.

"There is now increasing evidence that this approach may very well be a beneficial one," says Chief Technology Officer of Rocksource Geotech AS, a subsidiary of Rocksource ASA, Dr. Jonny Hesthammer.

STATISTICS BASED ON 86 WILDCATS

In a recent article published in The Leading Edge (CSEM performance in ligth of well results, Vol. 29, No. 1, 2010), the Rocksource team, suplemented with key EMGS personnel, has evaluated the largest empirical database related to CSEM success rates available to date.

"By mid-2009, EMGS had collected more than 400 marine CSEM surveys. By the same time, Rocksource had analysed marine CSEM data over more than 70 prospects related to their own business activities as well as tested the technology in 6 calibration areas. From this combined data set we were able to compile results from 86 wells for statistical analyses. In order to keep the study at an objective level, we focussed on providing information on basic observed statistical results, rather than more subjective interpretations."

"In short, we recorded if a well was announced by the operator as a discovery or not. Next, we observed from basic CSEM data (normalised plots for the fundamental frequency) if the location of a well corresponded to an anomalous response in the CSEM data. If a normalised anomalous response of more than 15% was observed, we termed this significant," says Hesthammer.

Of the 86 wells available for analyses, **36 were drilled prior to the acquisition of CSEM data** and, thus, serve as calibration studies. The remaining **50 exploration wells were drilled after having acquired and analysed CSEM data**. For the exploration community, the results from the 50 exploration wells should allow for an investigation of the potential of the technology to enhance exploration success rates in CSEM suitable settings.

> *"The technology serves as an important risk reduction tool in a portfolio setting using an integrated approach*

The database span numerous basins from (in alphabetical order) the Barents Sea, Brazil, Ghana, Gulf of Mexico, India, Malaysia, Mediterranean, North Sea, Norwegian Sea, Offshore Sarawak, South-China Sea, Sulu Sea and West-Africa. The distribution of surveys around the world within different basins and geological settings strengthens the validity of the statistical analysis on a global scale.

EXCEPTIONAL DISCOVERY RATE

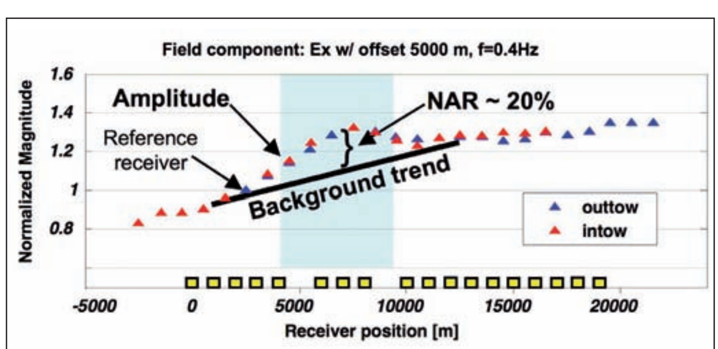
The results of the analyses are exciting indeed.

The study shows that the average technical discovery rate for the 50 exploration wells – those with EM data – is 56%. But more importantly, the database shows that the discovery rate improves to 70% when only prospects with a **significant CSEM anomaly** are included in the analysis.

The average technical discovery rate for the 20 exploration wells drilled on prospects without a significant CSEM anomaly is consequently reduced to 35%. Thus, wells drilled on prospects with a significant CSEM anomaly has twice as high discovery rate as those drilled on prospects without a significant CSEM anomaly.

For comparison, 95% (19 out of 20) of calibration surveys displaying a significant CSEM anomaly represent discoveries, whereas only 19% (3 out of 16) of calibration surveys without a significant CSEM anomaly represent discoveries.

"If these data are representative, then there



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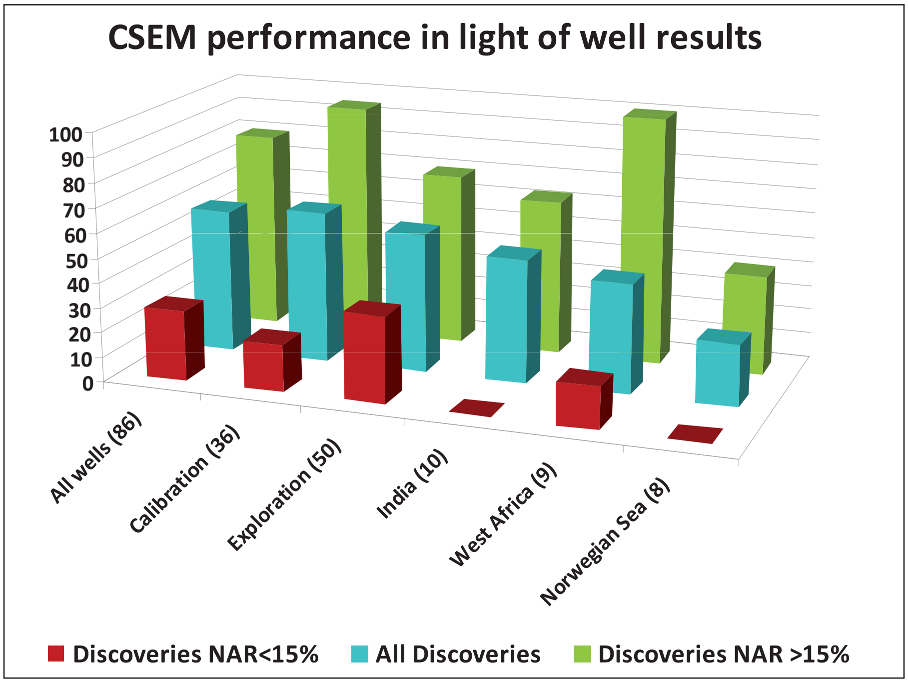
An example of a normalised amplitude response plot from the Barents Sea. This example shows a maximum normalised anomalous response (NAR) of 20% with respect to the background trend.

is increasing evidence that the appropriate application of CSEM data in a portfolio setting will significantly improve exploration drilling success rates in CSEM suitable areas," Hesthammer claims.

The stunning results from the calibration surveys support this statement. As much as 19 (86%) of the 22 existing discoveries are associated with a clear EM anomaly as observed from the CSEM data, whereas 13 (93%) of the 14 calibration surveys acquired over prospects that are proven dry display no or only a weak CSEM anomaly. It seems clear that the CSEM technology will likely display a significant anomaly if enough hydrocarbons are present at depths and under conditions suitable for the technology.

In a follow up study published in First Break (CSEM technology and hydrocarbon exploration efficiency, Vol. 28, May 2010), the authors have evaluated the CSEM response with respect to amounts of hydrocarbons present.

"There appears to be a clear correlation between the lack of hydrocarbons and lack of a significant CSEM anomaly. None of the 8 technical discoveries made on prospects associated with no or only a weak CSEM anomaly are major discoveries. In fact 5 of the 8 discov-

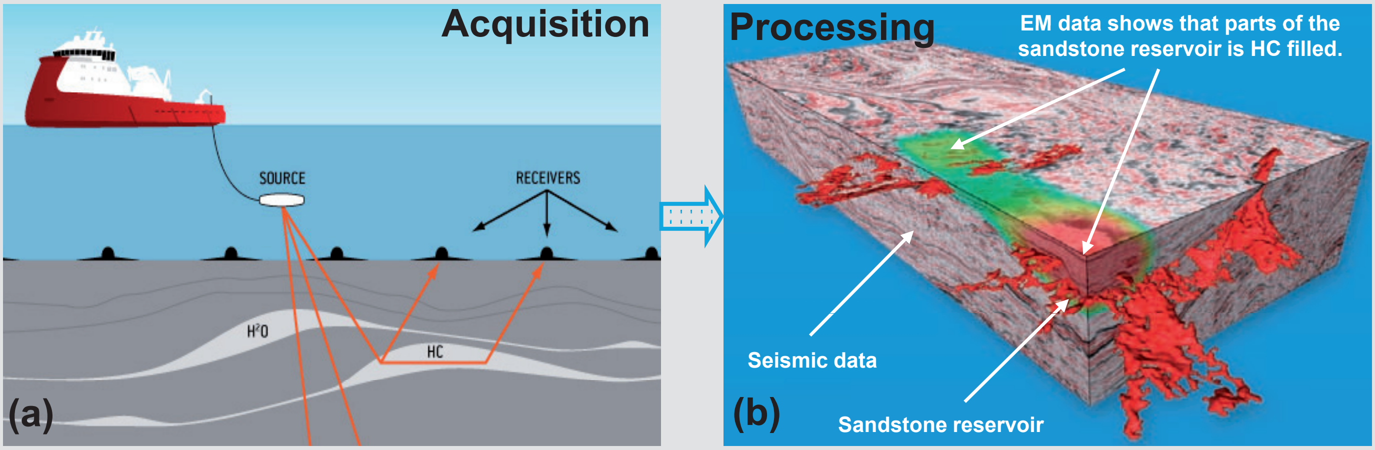


Discovery rate for exploration wells drilled on prospects with CSEM data acquired prior to drilling the wells. For all wells included as well as for areas with at least 8 wells available for analyses, exploration wells drilled on prospects with a significant CSEM anomaly show a higher discovery rate than for wells drilled on prospects without a significant CSEM anomaly. The difference is 35 percentage points for all wells (excluding calibration surveys), 63 percentage points offshore India, 83 percentage points offshore West-Africa, and 40 percentage points for the Norwegian Sea.

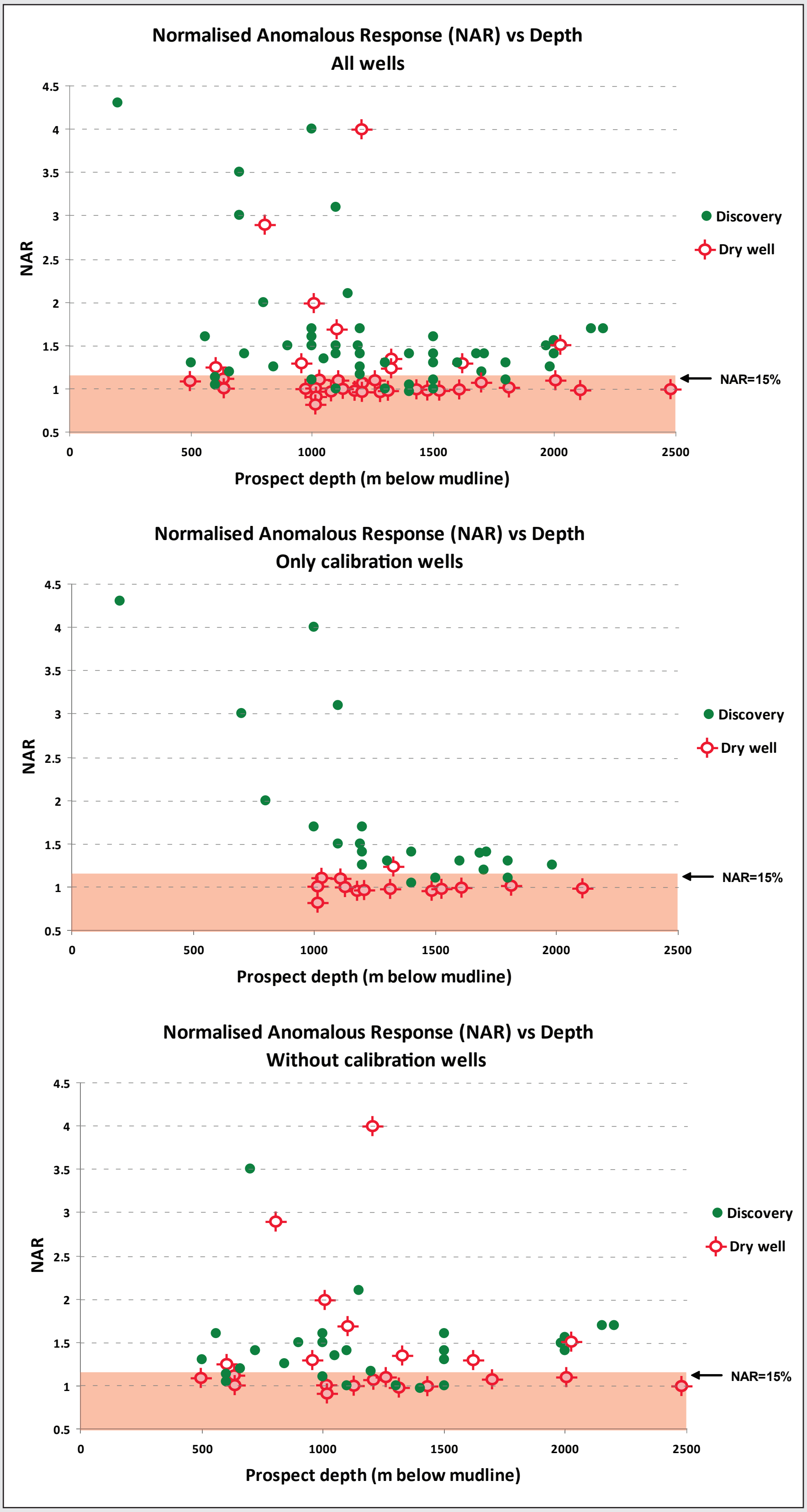
The marine CSEM technology

The concept of remote resistivity surveys is based on the knowledge that the propagation of an electromagnetic (EM) field in a conductive subsurface is mainly affected by spatial distribution of resistivity (assuming non-magnetic and non-polarisable materials).

In marine environments, saltwater-filled sediments represent good conductors, whereas hydrocarbon-filled sediments represent examples of resistive inclusions that scatter the EM field. The EM field emitted by a controlled source is scattered by subsurface inhomogeneities and recorded by receivers placed on the seafloor (Figure a). The information obtained can be used to estimate the true subsurface resistivity distribution by applying inversion and migration techniques as well as numerous other analysis types (Figure b).



(a) During a typical CSEM survey, a dipole source is towed above EM receivers placed on the seafloor. The source emits an electromagnetic field that propagates in the subsurface (for simplicity, the energy propagation is shown as ray paths in the figure, although the energy at the low frequencies used mainly propagates through diffusion). The presence of hydrocarbon-filled sediments in the subsurface will scatter the EM field, and part of the scattered field propagates back to the seafloor where the signal is recorded by receivers equipped with electric and magnetic sensors.
(b) To find out if oil or gas is present in the subsurface, acquired EM data must be processed and interpreted. This is an extensive and iterative process that requires access to advanced processing and analysis tools.



The empirical data used in the current study. The observed normalised anomalous amplitude response (NAR) is plotted against the depth to prospect (below mud line). (a) Plot of all 86 wells including the 36 calibration wells. (b) Plot of all 36 calibration wells. (c) Plot of all 50 wells excluding the calibration wells.

eries are announced as non-commercial, and only 1 is declared commercial. This reduces the commercial success rate for wells drilled on prospects with weak or no CSEM anomaly to 5-14%. This is in sharp contrast to the discoveries from prospects with clear CSEM anomalies, where numerous major discoveries have been made. As such, there is a clear indication that the CSEM technology can not only address the detection of hydrocarbons, but also the commerciality. Although it is interesting to make a discovery, it is a lot more interesting to make a commercial discovery," Hesthammer says.

"Prospects with a significant CSEM anomaly has twice as high discovery rate as those drilled on prospects without a significant CSEM anomaly

REDUCING – NOT ELIMINATING RISK

"Our study relates discovery rates to the most basic observations from CSEM data and should therefore be relatively objective. It is also the most extensive documentation of factual well results (close to 90 wells) related to the CSEM technology documented to date. The results clearly suggest that there is a correlation between observed normalised anomalous response and rate of exploration success for the wells in the database, also with respect to commerciality. This is strong positive evidence of the potential of the technology," claims Hesthammer, main author of The Leading Edge article.

"It is also clear from this study that the CSEM technology does not eliminate risk, but has the potential to significantly reduce risk if applied correctly. As such, CSEM data should not be used on a single well basis. The technology serves as an important risk reduction tool in a portfolio setting where each prospect is analysed as extensively as possible using an integrated approach where all available data are utilized," says Hesthammer.

"This study of the most extensive CSEM database so far should serve to remove much of the uncertainty related to the potential of the CSEM technology," concludes Jonny Hesthammer.

Fur further details and constraints, the reader is referred to the articles in The Leading Edge (Vol. 29, No. 1, 2010) and First Break (Volume 28, May 2010).

West Loppa:

A Hot Spot in the Barents Sea

3D seismic in the Barents Sea reveal promising traps and convincing flat spots.

RUPERT HOARE, WESTERNGECO AND PAUL BATHURST, EXPLORATION GEOSCIENCES

As the twenty-first Norwegian licensing round approaches, the Barents Sea remains an area of high exploration interest for the oil and gas industry. A large number of nominations have been put forward for the licensing round and interest is particularly strong to the west of the Loppa High. 3D multiclient data were acquired in 2008. Results indicate some obvious flat-spots within the Triassic and frequent high-amplitude shallow reflections believed to be gas or gas hydrates. This article discusses the geological features of West Loppa and the potential implications.

REGIONAL GEOLOGY

The West Loppa area forms part of the western margin of the Barents Sea. The main structural elements developed in association with the opening of the North Atlantic in the Late Jurassic and Early Cretaceous. The two main structural features are the Loppa and Veslemøy highs.

The **Loppa High** is an old, Devonian feature. It is flanked by the Hammerfest, Tromsø and Bjørnoya basins. Sediment cover on this high is thin.

The **Veslemøy High** sits between the Tromsø and Bjørnoya basins and is a Mesozoic aged feature with a structural trend of WSW-ENE.

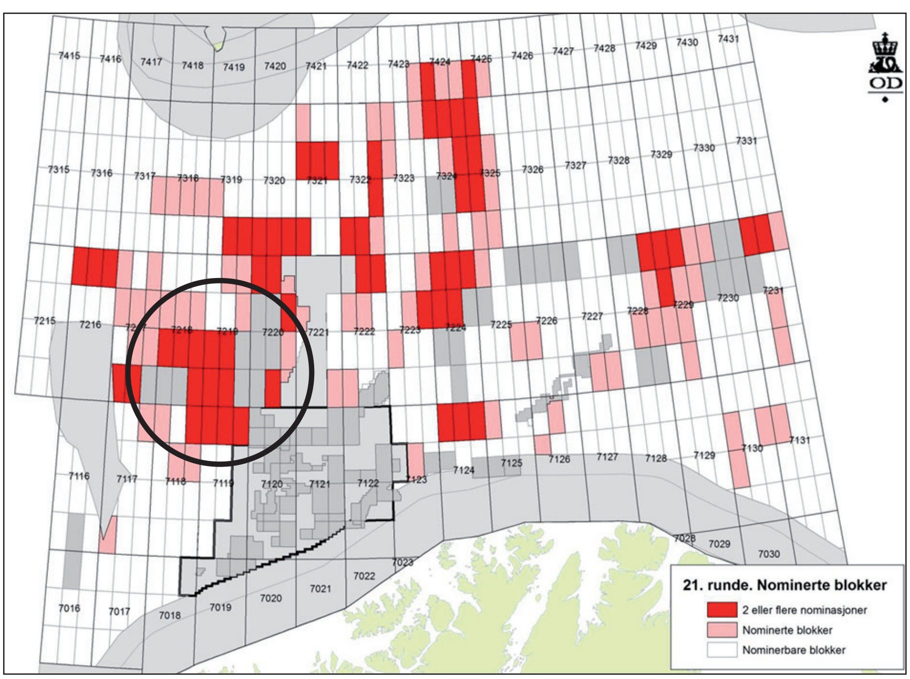
The early history (Late Carboniferous-Permian) is one of warm water platform carbonate and reef development on structural high areas with carbonate muds and evaporates in basinal lows. During the Permian, a significant climatic change took place with a cooler more temperate climate leading to the development of cool water carbonates. In the late Permian and into the Triassic, the Uralian fold-belt developed to the east and this came to dominate the sedimentary succession. Erosion of the mountain chain gave rise to significant clastic input, as fluvial and delta deposits, through the Triassic. These sandstones are inter-bedded with marine shales.

A major hydrocarbon **source rock** of Middle Triassic age is recognized throughout the Barents Sea area. The Steinkobbe has total organic carbon (TOC's) of 2-5%. Locally other Triassic source rocks are seen. For example, the 7219/9-1 well contains black shale within the Upper Triassic Fruholmen Formation with TOC's of 1.3-3.6%.

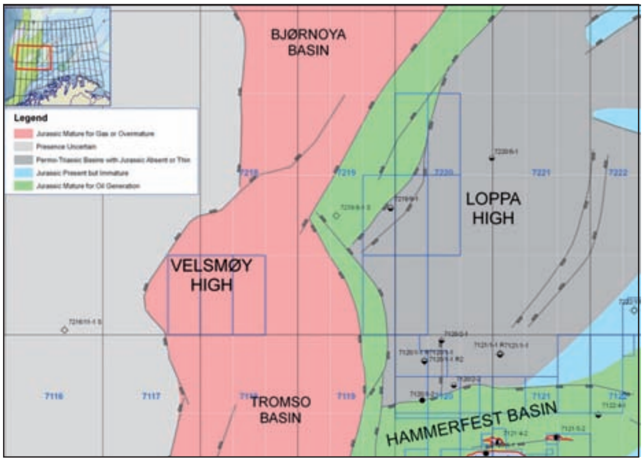
The coarse clastics derived from the east form good quality reservoirs (Klappmyss, Kobbe, Fruholmen and Snadd formations). However, in general these sands become thinner and finer grained to the west, away from their provenance. The location of the West Loppa area means that the understanding of the distribution of these potential reservoirs is crucial. This is demonstrated by the 7321/7-1 well, which contains just two sands in the Snadd Formation of 6 and 11m each, while the 7219/9-1 well has several sands within the Snadd of 5-20 m thickness but with porosity of only 10-15%.

Fluvial and deltaic conditions extended though the Lower Jurassic with the deposition of the Nordmela and Tubåen sandstones. During the Middle Jurassic a transgression gave rise to the development of the Stø Formation, a wave dominated shoreline facies. The 7219/9-1 illustrates these reservoirs, the Tubåen having 64 m of net sand (17% porosity), the Nordmela has 59 m net sand (porosity 16%) and the Stø has 99 m net sand with an average porosity of 18%.

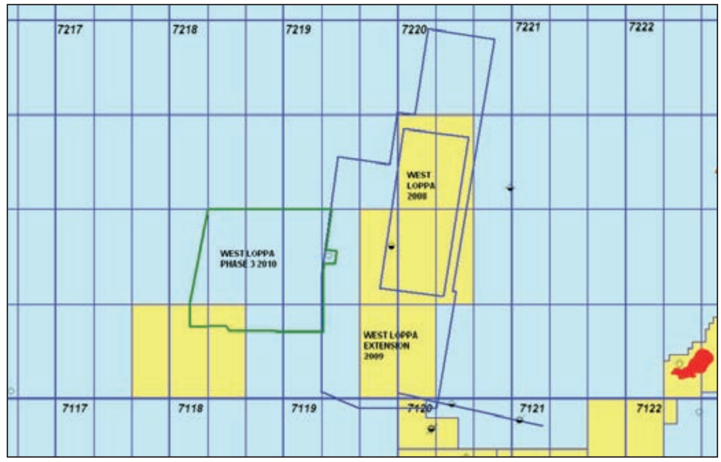
Extension in the Late Jurassic led to the development of deep water conditions in which the Hekkingen Shale was deposited. This forms both a high quality hydrocarbon source rock with TOC's of up to 10% and a major regional seal when combined with the overlying Cretaceous shales.



Nominations in the Norwegian 21st Round in the Barents Sea are shown in red colours. Blocks nominated by a minimum of two companies are shown in bright red. Note the cluster of nominations in quadrants 7218, 7219 and 7220 in between licensed blocks. Not all the nominated blocks will be included in the round when announced before summer.



Regional geological features of the western part of the Barents Sea.



West Loppa: Recent 3D surveys conducted by WesternGeco.

The Barents Sea generally underwent steady subsidence, albeit with local uplift, during the Cretaceous and into the Tertiary, but in the west Barents Sea a major period of tectonic activity and rifting affected the Veslemøy High.

Late Tertiary and/or post glacial uplift of the Barents Sea has affected both the present day maturity of source rocks and also allowed for the remigration of oil and gas.

SEISMIC ACTIVITY

Western Geco has conducted several 3D surveys in the West Loppa area. A 915 km^2 survey was shot in 2008. The blocks covered by the survey were later awarded in the 20th round. Drilling is expected to commence in the autumn of 2010.

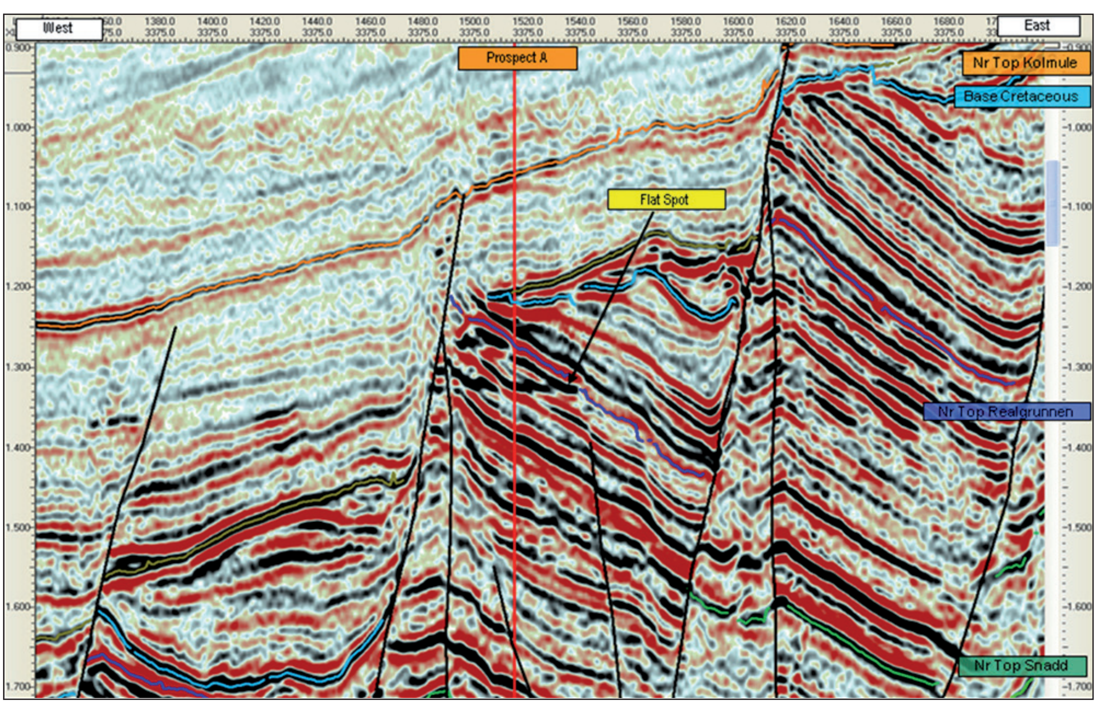
The 2008 survey covers two fault terraces on the west flank of the Loppa High. Stacked reservoirs are probable in several Triassic and Jurassic (Realgrunnen) formations.

The survey area was extended to the north and to the west in 2009, covering both blocks awarded in the twentieth round and also unlicensed acreage. The 2009 survey covers an additional area of 2,640 km2. Processing was completed in March 2010. Initial interpretation shows multiple prospects at Tertiary, Cretaceous, Jurassic and Triassic levels. Both Triassic structural plays and Cretaceous stacked submarine fan systems are supported by direct hydrocarbon indicators.

In 2010, further acquisition has continued in this exciting area. The survey will extend 3D coverage to the west and southwest of Well 7219/8-1 over an area of 1370 km^2, where mapping of existing 2D data shows potential Tertiary, Cretaceous and Jurassic plays. ■

Acquisition parameters for the
WEST LOPPA EXTENSION SURVEY 2009

Vessel	Geco Triton
Line orientation	NNE-SSW
Streamers	10 x 5000 m x 100 m
Streamer depth	8 m
Source	Dual 3147 cu in
Source spacing	50 m
Source depth	7 m
Shot point interval	18.75 m
Record length	6 sec



The seismic example is an east-west line from the 2008 fast-track processing. The data indicates an obvious flat spot on one of the fault terraces with a strong change in amplitude of the reflector above. There is also a possible, less obvious, flat spot in the higher terrace.

Drilling Uphill

In Brunei, Shell has an ongoing programme drilling into the reservoir from below. Drilling, completing and producing an upside-down well, however, poses a number of interesting questions.

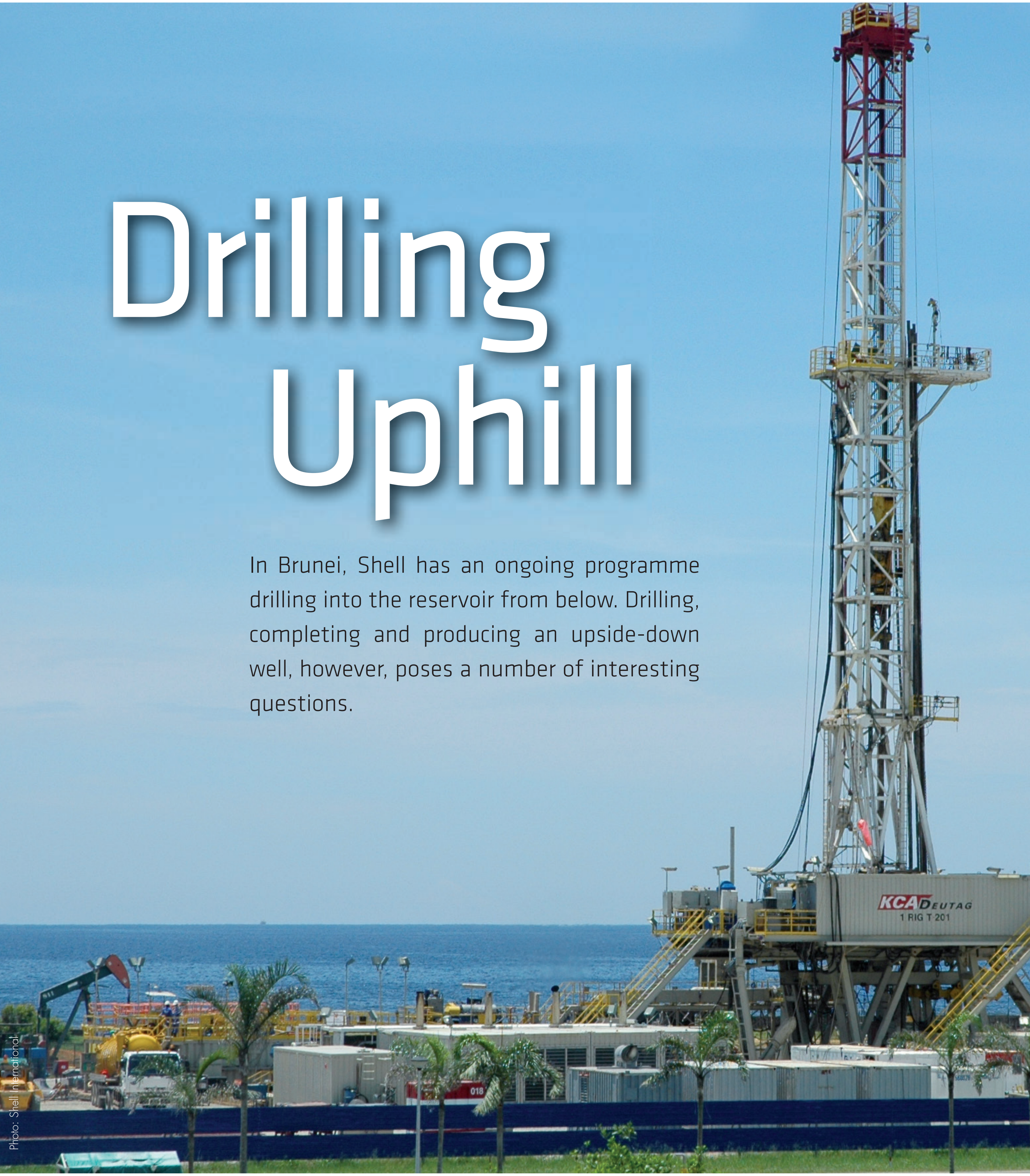
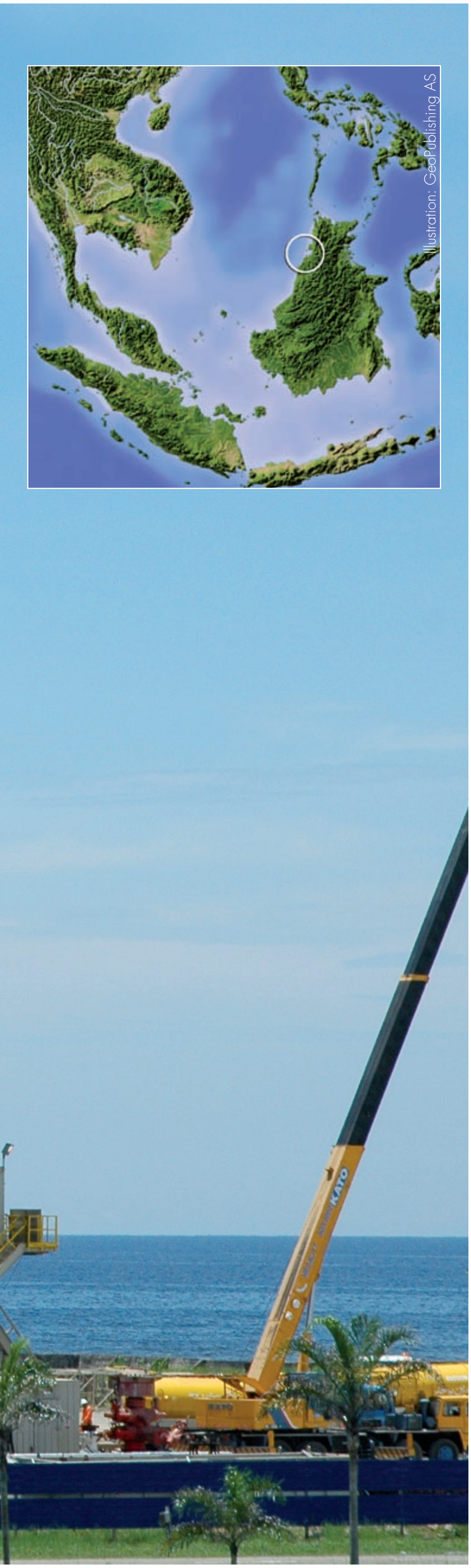


Photo: Shell International

In 2004, the first discovery well was drilled under the shallow marine surf zone of the northern flank of the giant Seria field



PAUL WOOD

The independent Sultanate of Brunei Darussalam in North-West Borneo has been a leader in oilfield technology almost since the start of the oil business. Geology surveys were difficult to conduct in the flat coastal swamp area near Seria in the mid 1920s, so the early explorers used the relatively new-fangled method of gravity surveying. After a core-drilling campaign in the late 1920s, the Seria Field discovery well was drilled in 1929, flowing oil and gas from a depth of 288 metres (945 feet).

THE SERIA FIELD

The Seria Field is located on an anticline that straddles the present-day coastline. Although the most predominant trapping style in this region is controlled by load-induced deltaic tectonics, basement-controlled tectonics and uplift have played a major role in Seria. The internal structure of the anticline is very complex, with a collapsed crest and many thin reservoirs and complex faults, especially in the northern (offshore) flank.

Seria, operated by Brunei Shell Petroleum Sdn. Bhd., is defined as a giant oilfield and achieved one billion barrels of production in 1991, which was marked by the distinctive one billion barrel monument, opened by His Majesty Sultan Haji Hassanal Bolkiah. Although the field is still producing, by the 1990s production was considerably less than the peak of the 1950s of over 100,000 barrels a day. But most of the production was from the onshore part, the complexity and shallow water (2 to 10m) of the Northern Flank having deterred exploration and development until then.

3D to improve imaging

In 1989, a 3D seismic survey had been acquired over the Seria anticline and the surrounding area, but could not fully resolve the complex shallow crestal and North Flank areas in spite of the best reprocessing available during the 1990s. Towards the end of that decade, technology once again came into play on both the geoscience and drilling sides, to give the Seria Field a new lease of life.

In 1998, a high resolution 3D survey was acquired over part of the previous 3D, to cover the central part of the Seria Field and much of the North Flank. The survey used the latest seismic technology of the late 1990s, with close shot and receiver line spacing and intervals and over 2,000 channels per shot. Close attention was paid to the continuity of multi-azimuth sampling, with, if possible, no omitted or offset shots.

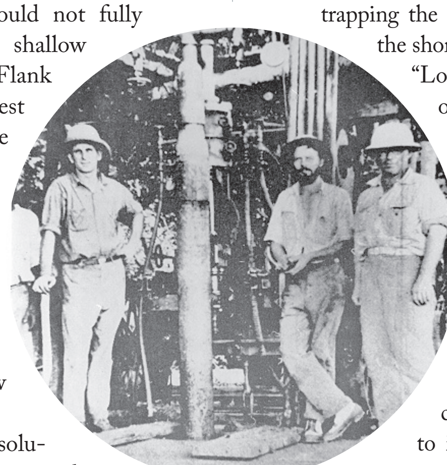
Whereas the 1989 survey had mixed Vibroseis with explosives and airgun sources, all shots in 1998 were impulse sources, buried charges onshore and airguns offshore. Micro-charges and special Magnaseis™ detonators were even used by a specially trained crew in the town and other sensitive areas to maintain coverage whilst observing the highest safety standards.

The new data proved to be of high quality and much improved vertical and spatial resolution. With both the old and new 3D surveys processed using pre-stack depth migration, a multi-disciplinary evaluation team made new maps showing the as yet unexplored prospects in the near-offshore areas. To further accelerate the programme, the prospects were split into clusters so exploration could continue while development was taking place at the first discoveries.

A DIFFERENT CONCEPT OF DRILLING

Having defined the sub-surface sufficiently to be able to launch a development programme, the next challenge was the drilling campaign. The very shallow water meant it would not be cost-effective to drill into the complex fault traps from offshore. John Church, a geologist and geophysicist by training, and now the development leader for Brunei Shell's North Flank Field, explains that the main problem is that the fault blocks trapping the hydrocarbons dip toward the shore:

"Logically, given the geometry of these formations, you would traditionally drill and develop them using offshore infrastructure. But that's much more expensive than using an onshore rig, and quite ridiculous given that it's so close to the shore that you could literally swim out to it. So we looked at how we could access the formations



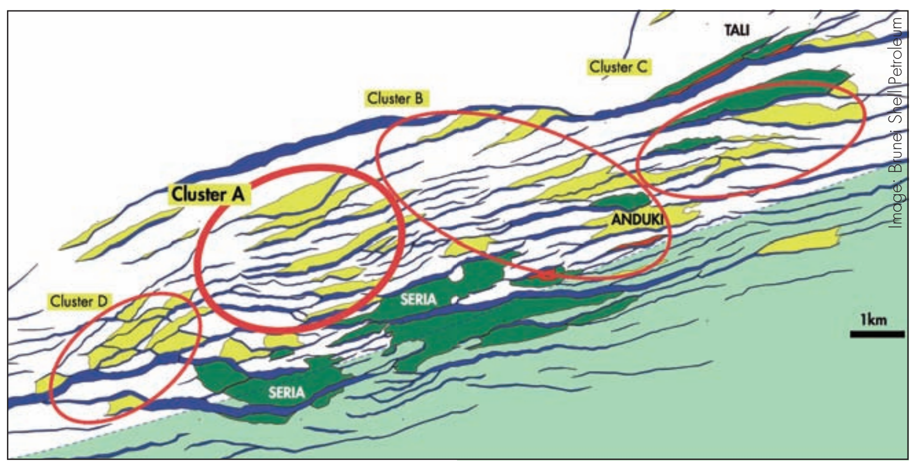
Core drilling in Seria in 1927

The Seria Field 2 billion barrel monument.

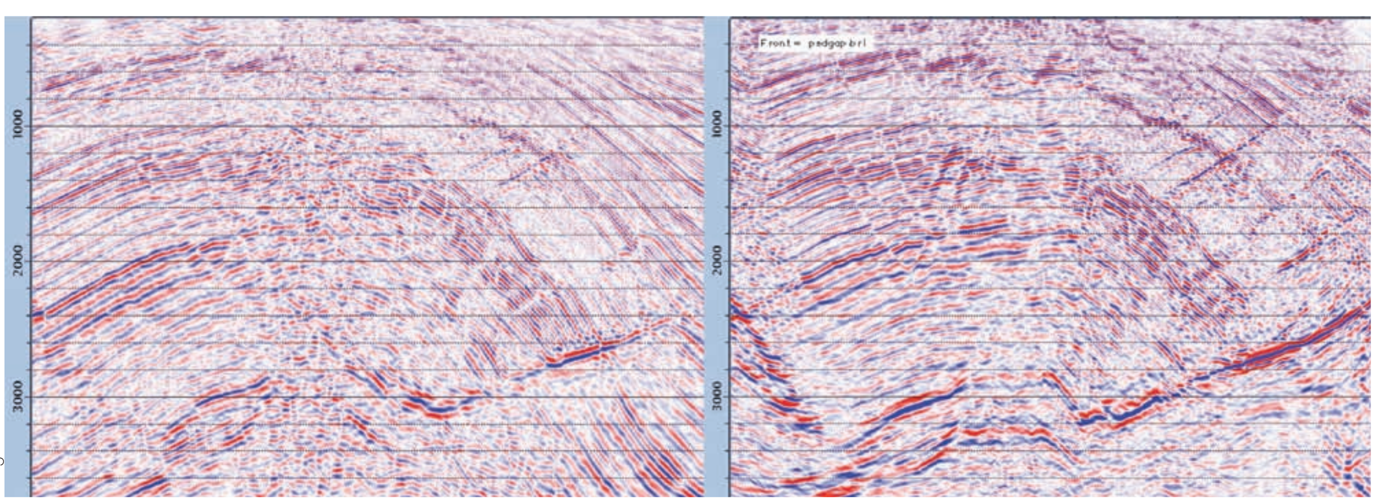
from the shore. It was possible, but it meant first drilling under the fault plane and then upwards so that we accessed the oil bearing strata from underneath."

This technique, which involves drilling the formations 'uphill', from top to bottom, was given the name 'fish-hook' drilling, after the shape of the well profile.

"Drilling, completing and producing an upside-down well poses a number of interesting questions. Like, 'how do we get the drill to actually go uphill? Can we install a gravel pack over the reservoir and what would happen if we needed to do a cement abandonment of an uphill section? And given that pressure normally increases with depth, how do you get the oil to flow downhill?' In short, there were



Map showing clusters of exploration and development prospects in the offshore part of Seria (onshore shown in light green).



Seria 1989 (left) and 1998 (right) 3D seismic lines with pre-stack depth migration. Note improved definition of faulting in the 1998 survey in the offshore part (right hand side of sections).

no guidelines for drilling, completing and producing uphill wells, so almost everything was a step into the unknown," John explains.

The development team was able to benefit from the experience gained in another leading suite of Shell technologies developed in Brunei, Smart Field. Rotary steerable drilling has been taken to near technical limits when drilling 'snake wells' in the Champion West Field, and software modifications allowed these techniques to be used in Seria when drilling more than 20 degrees above the horizontal. The drill collars, applying weight to the bit, had to be moved further back along the pipe, to keep them in the vertical section.

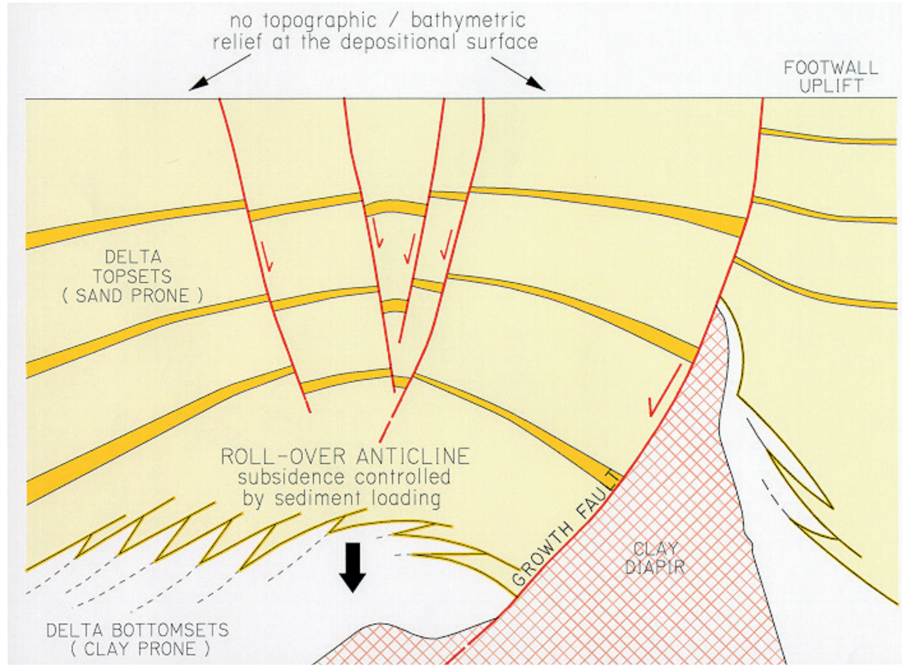
"Actually, compared with the other issues, this was relatively straightforward," says John. "The completion challenges such as the wire screen and gravel pack were trickier. The fine mesh screen stops fines from getting into and eventually blocking the wellbore. It is protected by a uniform gravel layer between the wire screens and the formation rock face. Initially we couldn't work out how to gravel-pack an inverted wellbore."

WORTHWHILE INVESTMENT

With oilfield services company Halliburton, a solution called the reverse port technique was developed. This involved pumping gravel to the toe of the well and then, working backwards (i.e. downhill), packing it along the outside of the screens. The team then had to work out how to manage production in the upside-down hole. Because the production at the toe of the hole was from a shallower level than further back along the production string, they had to get the oil to flow down into increasing pressure. The experience from Champion West again came into play. They applied Smart Field technologies to split the production interval into four separate zones that could be controlled independently.

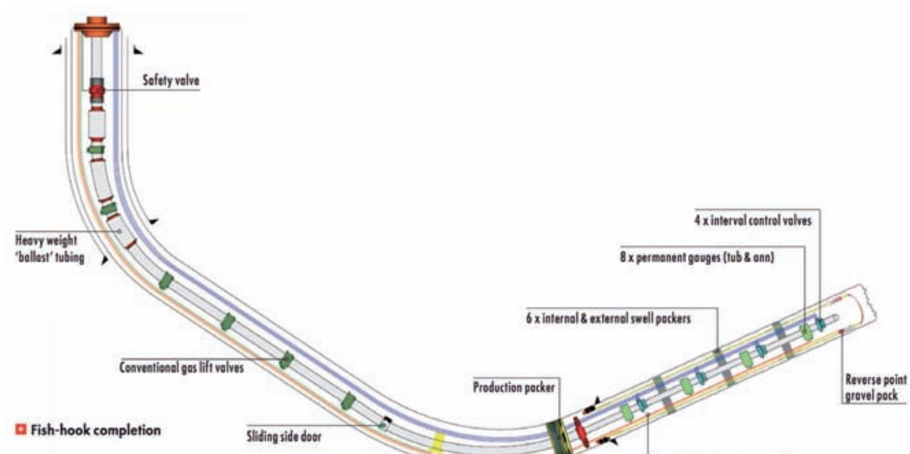
15 of the 'fish-hook' wells have been drilled so far, ranging from 1,500 to 4,000 metres in length. The techniques have been refined and optimised to give cost-reductions as experience is gained. Two of the early wells were connected to existing facilities less than a year after drilling. John Church points out that the combination of seismic and drilling technologies will allow many small fault blocks to be developed up and down the Brunei coast. The investment in these technologies has certainly been worthwhile.

Acknowledgements:
We should like to thank Brunei Shell Petroleum Sdn Bhd. and Shell International for kindly granting permission to publish this article.



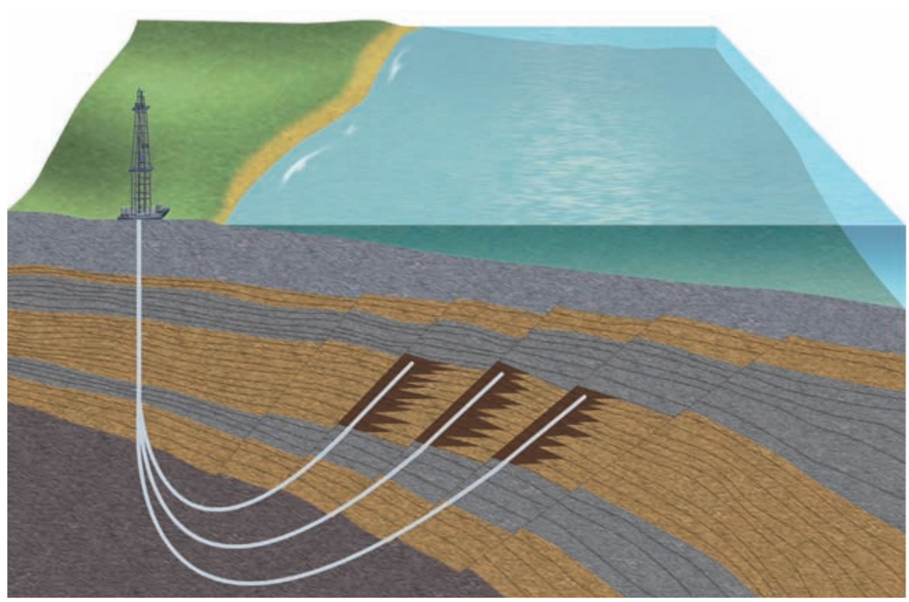
Characteristics of deltaic deformation style

Image: Brunei Shell Petroleum.



Details of fish-hook completion

Image: Shell International



Fish-hook wells drill upside down into the deepest reservoirs first

Image: Shell International.

The End is Nigh?

The third and final Geocontroversy debate at the 7th Petroleum Geology Conference last year centred on the future of one of the most mature hydrocarbon areas in the world, as delegates discussed the motion: 'Is exploration in the North Sea finished?'

"In a time of dire economic downturn, is it better to be unrealistic, or to tell the sober truth?" This was the question Richard Hardman, former North Sea Exploration Manager for Amerada Hess and now a Director of FX Energy, put to the assembled delegates at the conference, many of whom had themselves spent most of their working life exploring in the area.

Putting the alternative argument and showing that there is still a purpose to North Sea exploration, was Jim Hannon, Managing Director at consulting company HannonWestwood. It should be noted that there was a certain amount of disparity between the protagonists as to the understanding of the phrase 'North Sea' in the title of the debate. Richard Hardman defined it geographically as the area of the North Sea Basin, including the seabed belonging to Norway, Germany, Denmark, the Netherlands and the UK, while Jim Hannon tended to use data citing the UKCS, including the area west of the Shetlands, which is not technically the North Sea. However, although this difference has some bearing on the facts and figures discussed, the main thrusts for and against the argument were unaffected by it.

RESERVES AND RESULTS

In Jim's opinion there are four interrelated components to the debate: resource potential, drilling results, commercial issues and the nature of the participants in the North Sea. Without looking at other North Sea countries, the potential of the United Kingdom Continental Shelf (UKCS) was originally estimated at 60 Bboe, of which about 35 Bboe have already been produced, leaving potentially 20 Bboe still in the ground to be recovered. But, he asks, "can it be recovered? Is there the technical, political and business resolve to pursue the remaining opportunity?" According to the HannonWestwood database, 8 Bboe of these reserves have already been found, in 430 undeveloped discoveries. But that gives an average discovery size of just 21 MMboe, emphasising Richard Hardman's point that in the UK, new plays are either of moderate risk and small, or large and very risky, involving new and untested ideas. The Netherlands sector of the North Sea, he points out, may still have potential, but it is a very complex area and investment in the most modern technology will be needed to identify these subtle traps.

Jim Hannon pointed out that between 2004 and 2009 more than 250 exploration wells were drilled in the UK North Sea and West of Shetland area. "This has lead to success rates of 86% for appraisal wells and 42% for exploration wells. By 2011 a further 190 wells will have been drilled, suggesting that enthusiasm for the basin remains undiminished, despite the suggestion in the title of the debate that the North Sea is 'finished'. The database also details of over 1,500 prospects, with total unrisked potential of 65 Bboe, the average prospect size being around 40 MMboe.

OIL PRICE OR INVESTMENT?

Ultimately, as with so many things, does the final answer to this discussion lie in economics? Both speakers would agree that it does, while arriving at very different conclusions. Taking conservative parameters in his economic models, Jim analysed the UK undeveloped discoveries and undrilled prospects and concluded that "at USD40/bbl only 18 of the undeveloped discoveries, 4% of the total, are commercial, but at USD60/bbl around 200 discoveries become viable. Similarly, at USD 40/bbl only 6% of the identified prospects are commercial, rising to 45% if the oil price is USD 60/bbl. This

Photo: Jane Whaley

Julian Rush (left) acted as moderator for the debate, in which Jim Hannon (centre) opposed and Richard Hannon (right) proposed the motion "This house believes that exploration in the North Sea finished."

means that with an oil price of USD 60/bbl, the UKCS has some 900 commercial, undeveloped structures containing a total of 9 Bboe, with a net present value (NPV) of USD100 billion – a very substantial business opportunity, by any measure." He adds, however, that "present investment in the North Sea is not sufficient to realise this potential. Is there the technical, political and business resolve to pursue the remaining opportunity?"

Richard, by comparison, believes that costs in the North Sea are now too high and the rewards too uncertain to allow it to be viable for much longer. "Compare the red tape and cumbersome procedures in Norway, the lack of unexplored acreage in Denmark, and the small prospect sizes in the UK, with somewhere like Poland," he says. "Unless you have infrastructure, it is just too expensive, particularly for a newcomer, to exploit these minor reserves. Most discoveries will be activated by a company already established in area."

TOO SOON FOR THE WAKE!

Which leads on to Jim's final factor in this discussion: the number and nature of the participants in the North Sea. In March 2009 there were 176 licensees on the UKCS alone, in an area which he believes would be best served by only 40 to 50 companies. A good range is needed, and Jim noted that the larger organisations are still buying into the North Sea, for both exploration and production. "The majors will continue to target high value prospects, while for others, the key for success will be some consolidation and the innovative alignment of funding to talent," he concludes. "The North Sea may be on hold for a while, but it's too soon to hold the wake!"

However, Richard Hardman says, "the North Sea used to be a company maker. The Piper field made Occidental back in the 1970's, while in the 1990's Buzzard was a company maker for Encana. Now, however, it is in danger of becoming a company breaker".

So, did the delegates listening to the debate think that we are we refusing to face reality in the North Sea? They sided with Jim Hannon, declaring there is yet life in the North Sea – but then, as Richard Hardman so aptly put it, a pessimistic explorer is a contradiction in terms. "To explore satisfactorily you have to think creatively, and then take a risk that you may be wrong, so exploration geologists are inclined by trade, training and inclination to be optimists." Perhaps this result was actually a reflection of what they wanted to think, rather than what they actually believed. Only time will give us the true answer.

What do you think? Send your comments to jane.whaley@geoexpro.com

Permanent Seismic Monitoring of the Ekofisk field

Installing a Life of Field Seismic system on Ekofisk will help understand reservoir depletion and ensure future production wells are drilled where there is still oil left.

Per Gunnar Folstad is Team Lead for the Ekofisk Subsurface Life of Field Seismic Group with ConocoPhillips in Stavanger, Norway.

This section is edited by:

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ConocoPhillips, operator of the Norwegian PL018 license, will install a recording system for permanent seismic monitoring at the Ekofisk Field in 2010. The scheme will allow for cost-efficient, high-quality and highly repeatable 3D 4C (4-component) seismic acquisition twice a year.

The main objective of the system is to undertake comparative "time-lapse", or 4D seismic, analysis for improved understanding of reservoir depletion zones and injected water expansion fronts within the reservoir interval, thereby reducing the drilling and production risks for future production wells.

A second objective is to improve structural imaging of the "gas-obscured" crestal area which covers approximately one-third of the field.

Unlike receivers in a seismic streamer, which only record compressional waves, 4C receivers located on the seafloor also record shear waves reflected from the subsurface. Reflected shear waves are important for imaging through the "gas-obscured" area at the crest of Ekofisk. By combining compression and shear waves it is possible to derive more accurate elastic properties of the overburden and the reservoir.

A third objective is the utilization of 3D 4C seismic data to reduce drilling risk in the overburden.

4D SEISMIC OBSERVATIONS

Changes in seismic signals over time (4D), as observed by repeat 3D surveys over producing fields, are a result of alterations in reservoir fluid composition and pore pressure caused by production and injection programs. Normally, the dominant 4D effects are time and amplitude changes in the reservoir, as porosity remains unchanged. However, in highly porous chalk fields such as Ekofisk, 4D changes are also transmitted into the overburden due to reservoir compaction during depletion and water injection.

The compaction-induced geomechanical changes in the overburden results in large 4D effects, measured as changes in two-way travel-time between surface and top reservoir. Joint interpretation of the five Ekofisk 3D seismic streamer surveys (1989, 1999, 2003, 2006 and 2008) has revealed overburden travel-time differences as large as 20 ms.

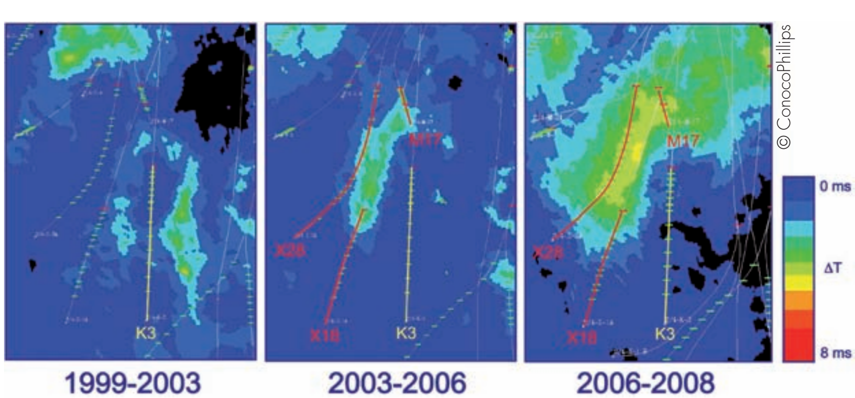
Production and injection data from wells prove the overburden travel-time differences to be strongly correlated to the underlying reservoir compaction. In fact, detectable travel-time differences are observed at wells which have been active for less than a year.

A second and subtler component of the 4D signal is an amplitude difference caused by impedance changes occurring as the reservoir responds to water injection and pressure depletion. Although noisy on streamer seismic data, this 4D signal is important in planning new wells that are targeting specific intra-reservoir zones.

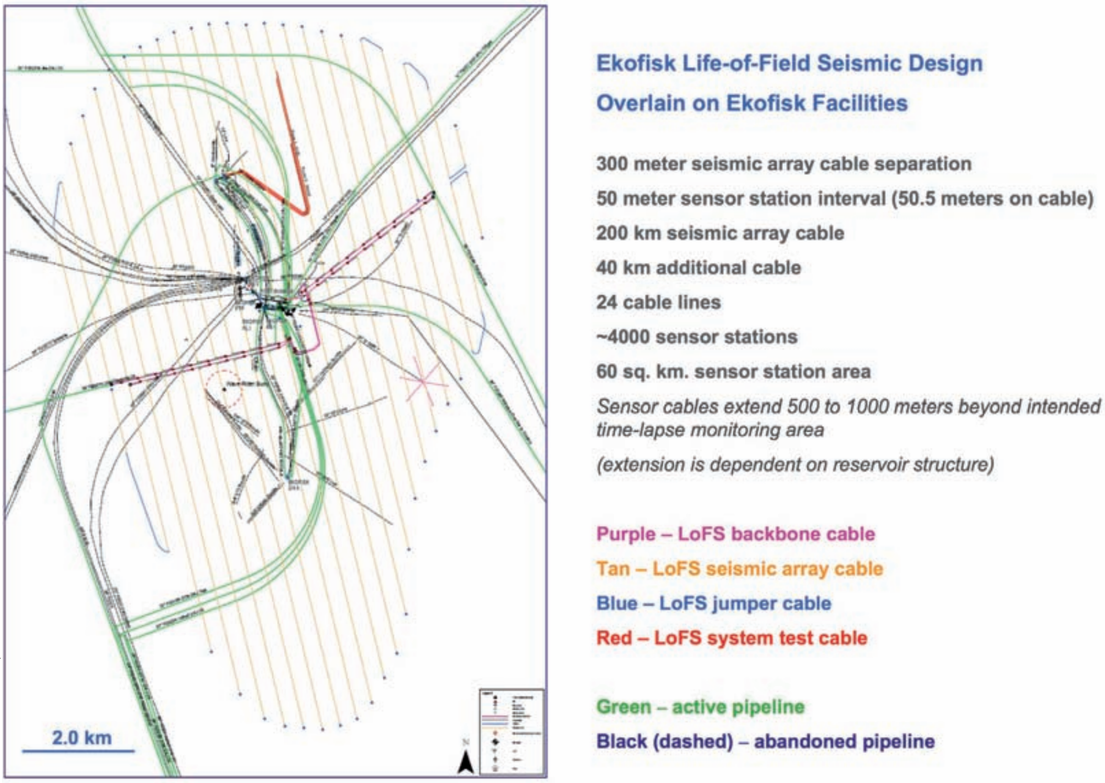
4D seismic is being used extensively in reservoir monitoring and in the planning of new Ekofisk wells. The combination of overburden travel-time and reservoir amplitude differences is used in a predictive sense to help place new producers in areas of considerable waterflooding risk. However, the subtle amplitude changes are noisy, and challenging to interpret reliably from streamer 4D seismic data.

MONITORING WITH A PERMANENT SYSTEM

By 2008, 4D seismic streamer surveys had become an established technique to help identify remaining oil



4D travel-time changes at Top Ekofisk from 1999-2003, 2003-2006 and 2006-2008. The images show a propagating waterfront from injector well K3 towards producers X16, X28 and M17 which were put on production in the period 2003-2005. Positive time shifts are a result of reservoir compaction and decreased seismic velocity in the sediments above top reservoir.



Map showing the final design of the Ekofisk Life of Field Seismic (LoFS) system.

zones for new production wells. The risk of encountering water-swept zones had been reduced and the net result was accelerated production and fewer redrills.

Despite the complexity of installing 200km of permanent ocean bottom seismic cables around existing infrastructure and numerous pipeline crossings, the conclusion from a "Value of Information" (VOI) study was still that this would be the best solution for future seismic monitoring at Ekofisk. Key parameters in the VOI analysis were cost estimates of permanent systems versus streamer surveys, track record of 4D seismic for well planning at Ekofisk, expected improvements in repeatability from fixed receivers and the forecasted well program and production profiles within the license period. A permanent array of ocean bottom receivers would enable efficient data acquisition with a source vessel once or twice a year. Included as an upside in the economical evaluation was an expected improvement in imaging of the crestal part of the field with converted (PS) waves.

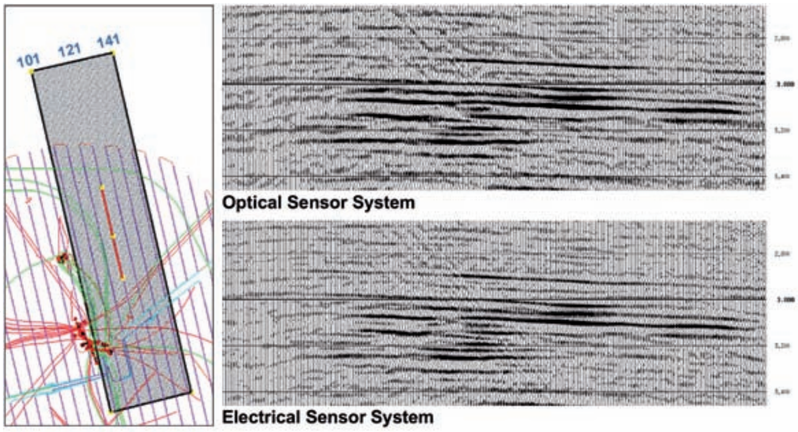
Choice of Cable System

In 2008, ConocoPhillips invited six suppliers to bid on the provision of the Ekofisk Life of Field Seismic (LoFS) system to be installed in 2010. Three of the providers offered "conventional" systems incorporating either traditional geophones or MEMS (micro-electro-mechanical-systems) accelerometers, with subsea analog to digital conversion and data transmission of electrical signals by copper data cable. The other three providers offered "passive" systems incorporating either Bragg grating based optical sensing elements or Michelson style optical interferometers. Digital data transmission in the "passive" systems is by optical fiber and all data processing is done in topside electronics.

A key advantage of optical sensor technology is that the subsea components are completely passive, providing greater durability and reliability when compared with systems that use electronic or moving-coil sensors. The fact that only a small number of optical fibers are used to collect data from many thousands of channels distributed over the reservoir is not unlike a modern telecommunications system. All active signal processing is contained in the topside instrumentation package which can be upgraded with minimum effort as new generations of optoelectronics and optical processing hardware are introduced. However, optical systems for 4D seismic are a new technology with relative limited testing. Optical systems also have tolerance limitations on high frequency output from seismic source arrays, which result in lost track of phase or "overscaling" if limitations are exceeded. For more information on fibre optic systems, see GeoExpro April and May 2009.

As part of the bid evaluation process, a system test was conducted in 2008, in which three cables, one electrical and two optical, were trenched 1m into the seafloor and tied back to a recording system located at the Ekofisk K-platform. Apart from some problems related to "overscaling" of the optical receivers (typically occurring when the seismic source is close to the receiver), the conclusion was that all systems performed well and within the specifications set out in the bid.

In the end, ConocoPhillips decided to proceed with a system based on Bragg-grating optical sensing elements; the Optowave system from Optoplan/CGGVeritas. The Optowave system is made up of fiber optic seismic array



Seismic P-wave stacks from optical and electrical recording systems used for the Ekofisk System Test.

Acknowledgements
We thank ConocoPhillips Skandinavia AS and the Ekofisk partners, Total E&P Norge AS, Eni Norge AS, Statoil Petroleum AS and Petoro AS for permission to publish this paper.

cables, lead-in cables and a laser interrogation instrumentation that will be placed on the Ekofisk M-platform.

To overcome the “overscaling” problem, a source test involving two vessels with airguns from two manufacturers was performed in 2009 over the Optowave cable that had been installed as part of the system test one year earlier. The source test demonstrated that the amount of energy output at very high frequencies (1kHz +) depends on the type of airgun. For the Ekofisk LoFS, the chosen solution is a containerized seismic source from CGGVeritas, to be mobilized and operated from a supply vessel under long term charter for ConocoPhillips. With the chosen seismic source system, “overscaling” is not expected to be a problem.

WAY FORWARD

Installation of the LoFS started in March 2010, with acquisition of the first dataset scheduled for September 2010. The topside recording system on the M-platform will be connected via the NorthSeaCom fiber to a processing center located at ConocoPhillips offices, ensuring fast turnaround of final 4D seismic volumes for well planning, and allowing best possible interaction between processing and interpretation staff. The processing center will also be the location for seismic data acquisition QC.

Compressional (PP) waves from the first survey will be processed to match the last 4D streamer survey, as well as forming the basis for future 4D monitoring surveys. In addition, the first survey will be processed using a prestack depth imaging sequence which will also include the converted (PS) waves. Repeatability of PS-waves for 4D seismic analysis will be tested on the second survey to be acquired in April 2011. A development program is ongoing to establish the processing sequences before the first survey has been acquired. A data system for proper archiving of LoFS data and key interpretation products is also being developed and scheduled to be ready by the time the first survey is completed.

Experience with LoFS at Ekofisk may in the future lead to installation of similar systems at other fields in the area, such as Eldfisk.

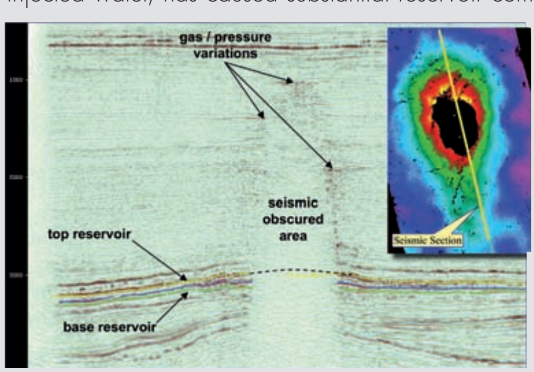
Ekofisk

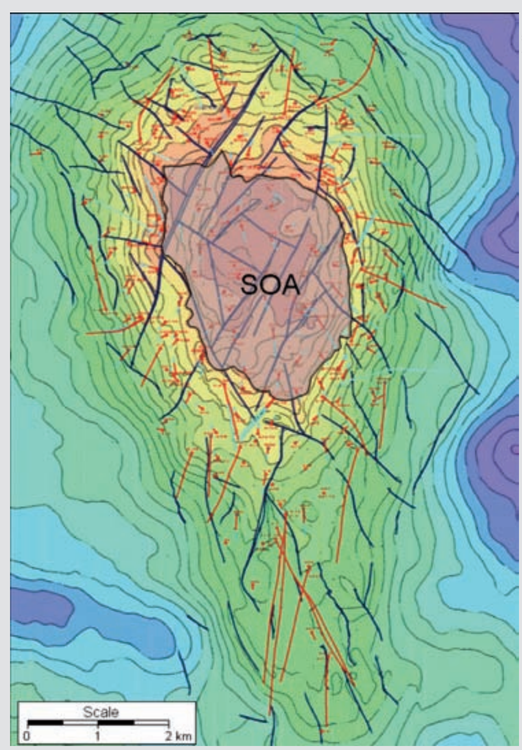
The Ekofisk field, located in block 2/4 in the Norwegian sector of the North Sea, is formed from fractured chalk of the Ekofisk and Tor formations of Early Paleocene and Late Cretaceous ages, most of which had high initial porosity in the range of 30-50%, but low permeability in the range 1-5 mD.

The reservoir is an elliptical anticline, 11.2 km long and 5.4 km wide at 2900-3300m depth. At the crest of the field is the seismic obscured area (SOA) where gas charged zones in the overburden complicate imaging with conventional seismic data.

Ekofisk was discovered in 1969, and has been on production since 1971. The field was originally developed by pressure depletion with an expected recovery factor of 17%. However, a large scale water injection program which started in 1987 has proved successful and has contributed to a substantial increase in oil recovery. The initial pressure depletion, plus water weakening of the chalk due to the injected water, has caused substantial reservoir compaction, causing the seabed to subside by up to 9m.

ConocoPhillips expects to recover about 50% of the oil originally in place, with roughly 800 MMbo (125 MMm^3) recoverable resources remaining at the end of 2008.





Top of Ekofisk formation structure map and seismic cross-section through the seismic obscured area (SOA).

The First UK Giant

The semi-submersible rig Sea Quest which found the Forties Field in 1970, and had also made the first UK oil discovery at the Montrose Field. It was one of the first rigs purpose built for UK waters, constructed in 1967 by Harland and Wolff in Belfast. It was finally scuttled off Nigeria after a major blow out.

Jane Whaley

Oil Field

The giant Forties Field was discovered in 1970, only the second oil field to be found in the UK North Sea. Originally predicted to run dry by the early 1990, it has now produced 2.64 billion barrels – and is expected to continue for another 20 years.

As is so often the case, the discovery of the Forties Field, the first major oil field in the UK North Sea, was serendipitous. In late 1969, while BP geologists were still trying to understand the – to our eyes now, very primitive - seismic shot over their Central Graben acreage, the Sea Quest drilling rig became available. Since the Forties structure was the only one over which a site survey had been shot, it seemed better to drill there than leave the rig idle. In October 1970 well 21/10-1 hit a 119m high column of good quality oil - the Forties Field, with recoverable reserves estimated at the time to be 1.8 Bbo, had been found.

POOR EXPECTATIONS

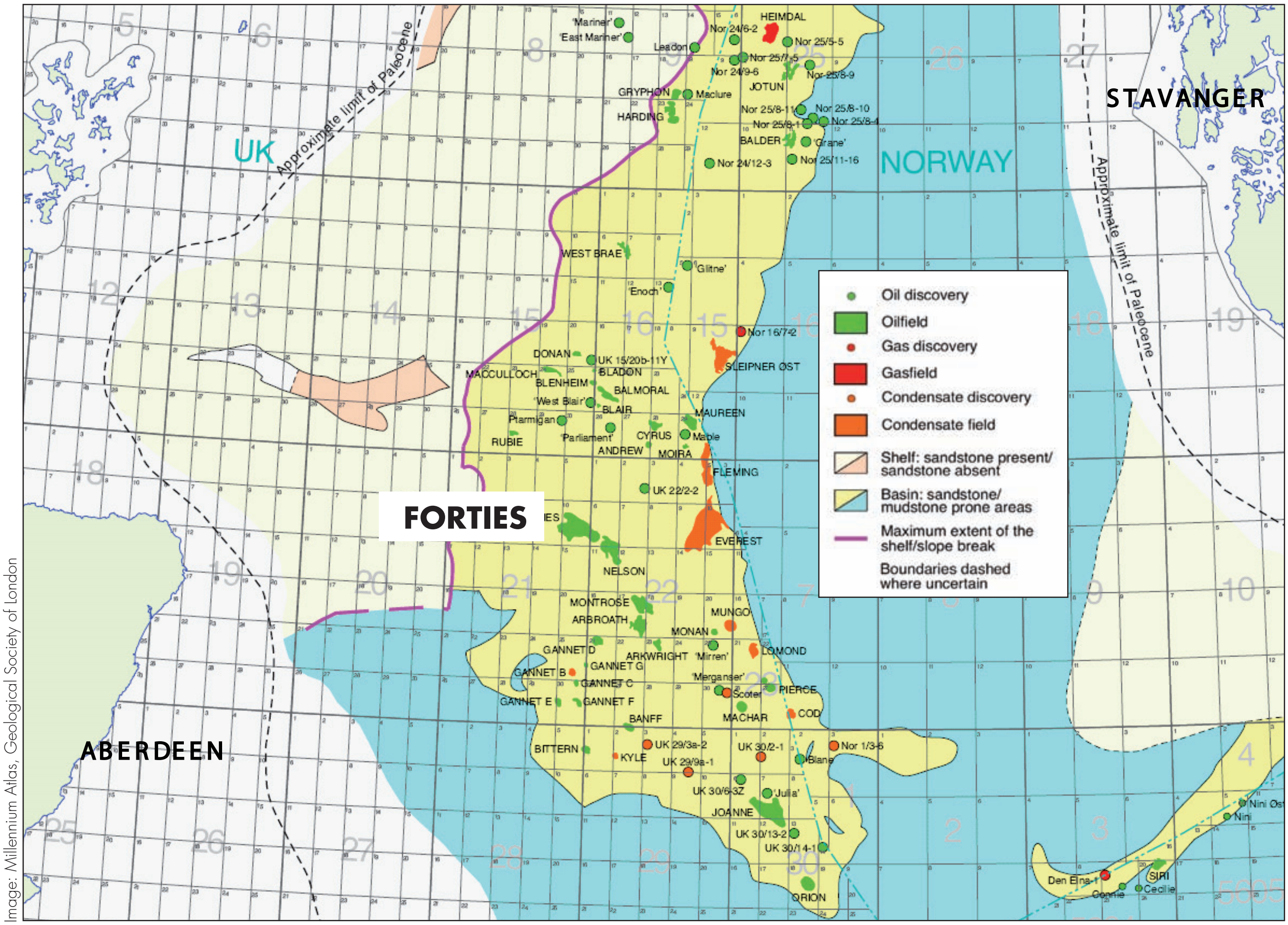
In early 1969, oil companies were becoming disillusioned with the prospects of finding oil in the North Sea. Nine wells had been drilled in the UK sector of the Central North Sea, but with little success. The early explorers had been surprised and excited when the first seismic lines across the Viking Graben, in the centre of the area, had shown significant Tertiary basins, over 3,000m deep, rather than the extension of the Palaeozoic fold belts of Scotland and Norway which they had expected. But they were disappointed as good Lower Tertiary reservoir sands proved illusive, while poor results from the Cretaceous meant a British Ekofisk – the first giant Norwegian field, which is reservoired in the chalk – seemed unlikely to be found.

In fact, as Myles Bowen from Shell is quoted as saying (Moreton, 1995) “in May 1969 the view was that all the worthwhile gas fields in the Southern North Sea had been found, while the search for oil in the north was doomed to failure.”

Then a small field, called Montrose at the time, but now known as Arbroath, was discovered in the middle of the Central North Sea, and although deemed only just commercial, prospects for North Sea oil looked up.

1ST UK GIANT FIELD

BP had obtained its acreage in Blocks 21/9 and 21/10, at the northern end of the Central



Paleocene fields and discoveries in relation to sandstone distribution.

Graben and about 180km east of Aberdeen, in the 2nd UK Licensing Round in 1965. As the BP interpreters continued reviewing the seismic, they realised that they could map a large Palaeocene four way dip closure. When this was tied to a nearby well with minor oil shows on Block 22/6, drilled a few months earlier by a Gulf/Shell consortium, they saw what looked like a large thickness of potentially oil bearing sands in the anticline.

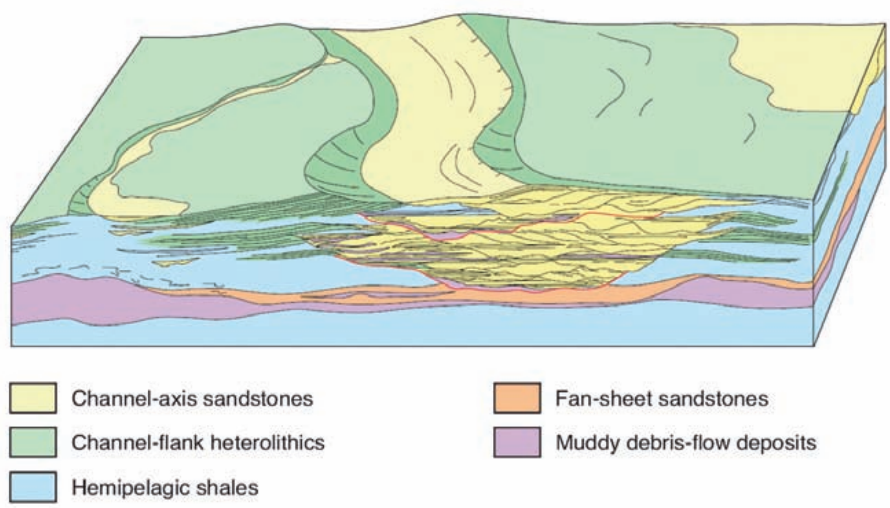
And, in October 1970, that is exactly what they found. After a five well appraisal programme over 1970 and 1971, BP was able to announce that the Forties field, at a depth of 2,130m sub seabed, covered an area of 93 km^2, much larger than initially estimated, and contained in-place reserves of 4.6 billion barrels of good quality, 37° API oil.

Interestingly, the major prize of the Forties field nearly belonged to another company, as Richard Hardman explains in the UK Oil and Gas fields Millennium Geological Society Memoir, in an article entitled 'lessons from oil and gas exploration in and around Britain'. He points out that BP were not the only company to have identified an interesting structure on Blocks 21/9 and 21/10. "The BP geologists concerned with the prospect did not try to run economic cases as they felt their knowledge was too sketchy to be meaningful. There is no doubt that if economics had been the determinant, BP would never have drilled the Forties discovery. In contrast, it transpires that Shell geologists had correctly analysed the Forties anomaly as containing over one billion barrels, but they were so afraid that their management would think them ridiculous that when they were considering farming-in to the block with BP, they arbitrarily reduced the reserve calculation to 'over 200 million barrels', (not likely to be economic at the very low oil prices at the time), and management decided not to participate."

Having found this giant field, BP then set about planning the first major oil field development in the UK sector of the North Sea, a task which took several years. Four fixed steel platforms were installed on Block

Forties Echo is one of five platforms working in the field

21/10 in 1974 and 1975, with a total capacity for over 100 wells, and a system capable of handling 600 Mbpd. Development drilling began in June 1975 and production started on 12th September 1975, with the field, named Forties after the sea area in which it lies, officially inaugurated by Queen Elizabeth II in November 1975. A fifth platform was added on the south-eastern extension of the field in 1985, where production started in 1987. The oil is produced using peripheral water injection, enhanced by pressure from the underlying natural aquifer.



Forties depositional model, showing the different flows which formed the reservoirs.

Image: Millennium Atlas, Geological Society of London

SANDS DRAPED OVER BASEMENT HIGH

The main reservoir in the Forties field, and in a number of other major North Sea discoveries, is the Upper Paleocene, Late Thanetian Forties formation. Prior to the deposition of these sediments, the North Sea Basin was largely cut off from major oceanic currents, before the opening of the North Atlantic resulted in a rise in sea level. The Forties formation was deposited over a wide area at this time, 55 million years ago. It is a mixed sand and mud turbidite fan complex, which flowed south-eastwards, bringing sediments eroded from the uplifted Scottish Highlands to the north-west, forming a submarine delta trapped in what is now the Moray Firth.

The Forties Formation is usually split into two lithologically distinct sequences; an upper, predominantly sandy sequence, deposited as a submarine fan, which contains most of the oil found in the formation and a lower interbedded sandstone and shale sequence, deposited as feeder channels on the sea floor.

The actual reservoir at the Forties field consists of several stacked sandstone bodies, where the primary targets are the channel sandstones, which are separated by poorer quality thin interchannel facies. The average porosity of these reservoir sands, which have a gross thickness at the Forties field of 350m, is 27%, permeability is 400 mD and water saturation 23%.

As the turbidites flowed down into deeper water, they were deposited on top of the underlying structures, which in the Forties field formed a Jurassic-aged basement high, over which the sands were draped, thinning slightly at the apex of the feature. This formed the simple dome in which hydrocarbons, migrating upwards from the Jurassic Kimmeridge Clay buried deep within the underlying sediments, could be trapped. This rich mature source rock originated from kitchens to the south and north-east, where the main phase of expulsion started in the Middle Eocene, 50 million years ago, and continued to the present day. The field is structurally simple, with only limited faulting, post-dating major episodes of faulting in the North Sea.

The reservoir is sealed by the overlying conformable mudstones of the Sele Formation, deposited after a regional rise in sea level at the end of the Palaeocene.

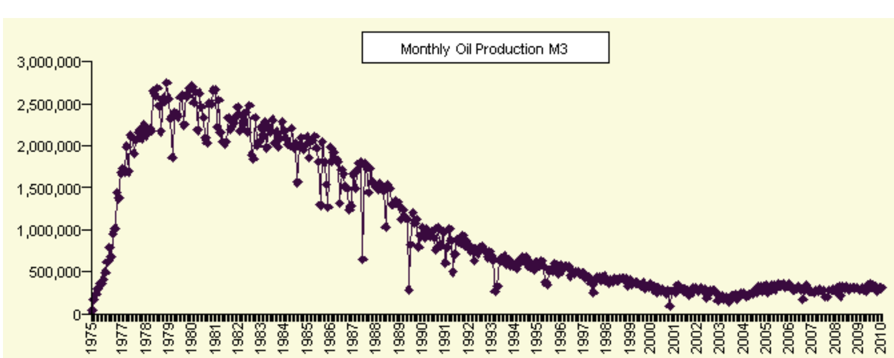


Image: DECC

Production from the Forties Field has exceeded expectation, reserves having increased by 35% since the start of production.

STILL GOING STRONG

When production from Forties commenced in 1975, it was predicted that the field would stop producing by the early 1990's. In 1990, it was expected to be shut down by the year 2000. Yet now, forty years since it was first discovered, the Forties Field is still producing and the recoverable reserves have increased by 35% since the start of production, even though the area of the field as defined by the oil-water contact has remained approximately the same.

Plateau production of 500 Mbopd was reached in 1978, which lasted until 1981, declining to 77 Mbopd in 1999. At this point the field had already produced 2.5 Bbo and still had nearly 60 producing wells. With production down to 35 Mbopd, BP controversially sold the Forties field in 2003. It is such an iconic field for UK North Sea exploration that some commentators likened this to 'selling off the family silver'.

The purchaser, Apache, initiated an intensive re-evaluation of the field and found a further 800 million barrels. By undertaking various efficiency measures (see GEO ExPro Vol 7, no 1, p. 8), and installing new equipment, it has brought new life to the field. Forties is now producing 70 Mbopd and is expected to be still pumping oil for the next twenty years.

Acknowledgement: *Thanks to Ken Glennie and Richard Hardman for assistance with this article.*

Ref: Moreton (1975) (ed.) 1995. Tales from Early UK Oil Exploration 1960–1979. PESGB.

Photo: Halfdan Carstens

North Sea Reservoir Analo
Make Popular Student Des

Scarborough, with a population of around 50,000, is the biggest seaside resort on the North Yorkshire coast. The most striking features of the town's geography are the long stretches of beaches and the high rocky peninsula pointing eastward into the North Sea, separating the North Bay from the South Bay. The South Bay is the focus for tourism, with cafes, amusements, arcades, theatres and various entertainment facilities, some of which certainly ruin what could have been a pleasant atmosphere. Geologists have to take comfort in several exposures of colourful sandstones with excellent sedimentary structures, all at a distance from the urban noise.

gues tination

The steep, towering cliffs along the Yorkshire Coast of northern England have become a favoured field excursion destiny for petroleum geology students. Excellent analogues to the Middle Jurassic Brent reservoirs in the North Sea make a perfect excuse for students who need practical exercises in sedimentology.

More than 1200 years ago, from 793 onwards, Vikings from Norway and Denmark started attacking northern Britain, and in 866 York was captured by a Viking army. Eric Bloodaxe, the last Viking King of York, was not thrown out until 954.

York – or Jorvik – prospered under Viking rule, taking advantage of the Vikings' abilities as seamen and traders with connections from Newfoundland in the west to Uzbekistan in the east, and from Greenland in the north to the Mediterranean in the south. The population increased from a couple of thousand when the Vikings arrived to possibly fifteen thousand inhabitants 200 years later.

In 1066, when Jorvik had developed into the richest and second largest and city in England, King Harald Hardraade of Norway invaded England and recaptured York, but was subsequently defeated and killed in the Battle of Stamford Bridge just outside York. This failed invasion marked the end of the Viking Age.

START IN THE MUSEUM

Nowadays, geologists from Norway are again invading Yorkshire, not to fight and conquer, but to learn about North Sea sedimentary rocks, because along this stretch of coast we find time and facies equivalents to several North Sea reservoir formations, particularly those of Middle Jurassic age.

The Yorkshire coast is also visited by other geologists from many countries, as some of the exposures are world-class. Moreover, amateur geologists run to the cliffs and the beaches below to look for another specimen of a treasured fossil (possibly a dinosaur footprint, if in the right place). With the help of a field-guide easily accessible online from several universities, or one of the guide books that can be purchased in local shops, you can go there by yourself and enjoy the culture, the scenery and the sedimentary rocks.

If so, the starting place is the Rotunda Museum in the Middle of Scarborough (GEO ExPro 08/2009, pp. 58-62).

The Yorkshire coast is easily accessible from London or any major city in the UK if you come from abroad. An efficient train service brings you from London to York in a matter of a couple of hours, while you need one more hour in addition to get to Scarborough, which is the natural place to stay during your visit. A geological tour of the area needs to last for a few days to be properly rewarded. In York, you will find the fascinating Jorvik Viking Centre, as well as many historicbu ildings.

The Shell exhibit on the first floor is a sure winner. Here you can test your geological knowledge and at the same time build your own dinosaur park along the banks of a river in Jurassic time. Good for all ages.

William Smith, who published the first ever geological map in 1815, became the designer and then foreman of works of the Scarborough Museum, which was opened in 1829. The museum later became known as 'The Rotunda', because of its distinctive cylindrical shape.

THE HEATHER MOORLAND

The Yorkshire Coast, best exposed between *Staithes* (Lower Jurassic shales) in the north and *Flamborough Head* (Upper Cretaceous chalk) in the south, is said to be one of the most beautiful landscapes in England. Cliffs, coves, headlands and bays are enjoyed by tourists all year long.

Inland from the coast, we find the high moors and forested hills, while in between the landscape is enriched by dales (valleys), gorges and escarpments.

The *North Yorkshire Moors*, one of the largest expanses of heather moorland in the UK, is a national park that is clearly defined to the east by the coastal cliffs. The northern and western boundaries are delineated by the steep scarp slopes caused by rivers eroding into the soft Lower Jurassic shales, while the moors themselves rest on Middle Jurassic sandstones, which erode slowly and form soils deficient in nutrients. They are also less permeable to water, impeding drainage and encouraging the formation of bogs.

Altogether, this makes a splendid framework for researching the rocks that make up this coastal stretch. From north to south we find an almost complete sequence of Jurassic and Cretaceous rocks along the cliffs. Access may be difficult in places (watch for avalanches and loose stones) and it is necessary to keep an eye on the tide table.

THE DINOSAUR COAST

The Cleveland Basin is so named because the Vikings called the land they raided Cleveland, meaning the land of cliffs, a name that is still very appropriate today, as the cliffs are an important resource for studying North Sea rocks.

"Along the Yorkshire coastline, there is an almost continuous exposure of sedimentary rocks ranging in age from Lower Jurassic to Upper Cretaceous. They have long lateral continuity, but accessibility is in some places restricted due to the almost vertical cliffs," says Sverre Ola Johnsen, professor at the Norwegian University of Science and Technology, who has been bringing students here for more than 30 years.

"The reason we go here are the similarities with the age-equivalent succession in the North Sea. The Middle Jurassic deltaic coastal and deltaic succession in Yorkshire serves as an approximate analogue to the Brent Group in the Viking Graben," he explains.

At the beginning of the Jurassic, some 200 million years ago, this region was covered by sea, as was the whole of Europe. The Lower

The North York Moors National Park encompasses two main types of landscape, the predominantly green areas of pasture land and the purple and brown heather moorland, two kinds of scenery that are the result of differences in the underlying geology.

The heather moorland, with its purple colours when blossoming in late summer, has made Yorkshire famous.

Visitors to the City Art Gallery in York are welcomed by columns made in local sandstone of Middle Jurassic age. In these, geologists will discover primary sedimentary structures, including sets of tabular cross stratification, produced by small, straight crested dunes in the lower part, and trough cross stratification produced by more irregular dunes in the upper part.

The Brent Group

The Brent Group makes up the most important reservoir in the North Sea. It represents a regressive –transgressive wedge of diachronous, coastal and shallow marine sediments, which record the outbuilding and subsequent retreat of a major wave dominated delta fed from the south. The Brent Group clastic wedge locally exceeds 500m in thickness.

K.W. Glennie; *Petroleum Geology of the North Sea: basic concepts and recent advances*

Jurassic succession thus consists predominantly of shales.

In the Middle Jurassic, about 30 million years later, the ocean receded from this area, leaving a series of coastal deltas. The rocks of this period are therefore predominantly sandstones, but as the sea level fluctuated we also find intermittent shales. These sandstones are analogues for the Brent Group, which is the reservoir in many fields in both the UK and the Norwegian sector, including Statfjord and – of course – Brent.

At the onset of the Late Jurassic, the sea once again invaded the area, now dominated by friendly ammonites and scary plesiosaurs. The rocks from this period are dominated by shales and are known as the Kimmeridge Clay Formation, which has sourced most, if not all, of the oil in the North Sea.

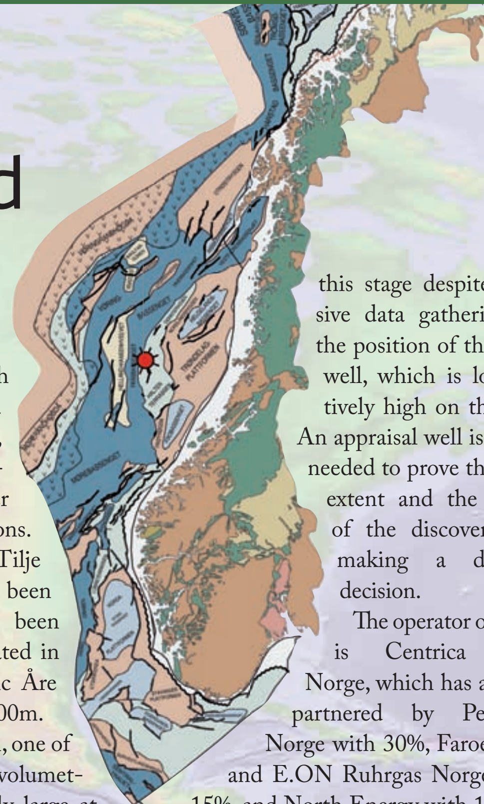
In the Late Cretaceous, the sea level rose considerably, flooding the continents. In the warm climate lived countless billions and trillions of minute plants and animals, of which the coccoliths are most famous. Chalk is made up of the remains of these animals, which consist of pure calcium carbonate. Several fields in the North Sea Central Graben, including Ekofisk, have chalk as reservoir.

Dinosaurs lived on the Middle Jurassic deltas and sandbars that are now exposed along the Yorkshire coast. They thrived on the abundant plants that grew here, and left their three-toed footprints, some of which are half a metre in size, on the sand and silt and mud of the beaches and deltas. Few fossil remains have been found, but this coastal stretch is still nicknamed the 'Dinosaur Coast'.

ENDING THE JOURNEY

York, about 60 km from the Yorkshire coast, was transformed in size, in appearance and in its economic role while under Viking control, but the evidence needed to reconstruct this culture was fossilised and hidden under several layers of clay for the next thousand years, until discovered in modern times. Most remarkable is the Viking Dig in Coppergate (named because it was the place where cups were made for export) where important excavations occurred between 1976 and 1981. The results of these can be seen in the Jorvik Viking Centre in York. It is the natural place to end an excursion into the geological and human history of North East England.

NORWAY:
Gas and Condensate Find



Despite being considered relatively mature in terms of exploration, hydrocarbon discoveries are still being made in the waters off Norway. Well 6506/9-2S, is reported to be a substantial gas and condensate discovery, possibly holding as much as 530 Bcfg (95 MMboe). The well is on the Halten Terrace of the Norwegian Sea in 281m water depth, 250 km north-west of the town of Kristiansund. The producing Åsgard complex, where large quantities of gas and condensate are processed, lies 18km to the south-east.

The well was investigating the Fogelberg prospect, which is thought to be structurally similar to the 70 MMboe Morvin oil and condensate discovery, 10 km to the southwest, which was successfully appraised in 2006 by Statoil and is expected to come on stream towards the end of 2010, producing as a sub sea satellite to Åsgard.

Drilling commenced on 11th February, using the West Alpha semi-submersible drilling rig, and the well found gas and condensate in the Middle to Upper Jurassic Garn and Ile formations. The lower Jurassic Tofte and Tilje formations, which had also been targeted, are thought to have been water bearing. The well terminated in late April in the Lower Jurassic Åre formation at a depth of over 4,700m.

According to Faroe Petroleum, one of the partners on the block, the volumetric uncertainty remains relatively large at this stage despite an extensive data gathering, due to the position of the Fogelberg well, which is located relatively high on the structure. An appraisal well is likely to be needed to prove the down-dip extent and the actual size of the discovery prior to making a development decision.

The operator of the licence is Centrica Resources Norge, which has a 28% stake, partnered by Petro-Canada Norge with 30%, Faroe Petroleum and E.ON Ruhrgas Norge each with 15%, and North Energy with 12%.

GULF OF MEXICO:
Disaster at Macondo Well

Photo: © US Coast Guard

One of the reasons that the leaks resulting from the explosion on well MC 252 1S0B in the Gulf of Mexico on 20th April are proving to be so difficult to stem is because it was one of the largest finds in the region this year. With original 2P recoverable reserves reported to be in the region of 225 MMboe, BP were on the point of announcing a significant discovery when the disaster happened.

The **Macondo** prospect is located on Mississippi Canyon Block 252 in the Gulf of Mexico in a water depth of 1,522m.. The well was originally spudded in October 2009, but was halted at the end of November when the semisub was damaged by Hurricane Ida. The original rig was replaced in February by the Deepwater Horizon, and it is reported that drilling operations had reached target TD of nearly 5,500m when the explosion happened. The blowout claimed the lives of 11 men, and injured a further 17.

BP as operator of the block has been spearheading the attempts to close off the leaks from the well, which media reports to be as much as 5,000 bopd, although a number of commentators dispute this figure. BP has a 65% interest in the block shared with Anadarko (25%) and MOEX 2007 (10%).

Only Shell's March discovery, **Appomattox**, also in the Sigsbee Canyon area, is reported as a larger find in the Gulf of Mexico this year. Well MC 392 1S2B0 in Mississippi Canyon Blocks 391 + 392 in the Eastern Gulf, found an estimated (2P) 300 MMbo and 180 Bcfg following the drilling of an exploration well and two appraisal sidetracks. A vertical thickness of about 130m net of oil in excellent quality reservoir rocks was found, with one appraisal well encountering an additional 110m of oil pay. The well is situated in water depths in excess of 3,000m and is about 250 km south-east of New Orleans.

Shell is operator of Appomattox with 80%, partnered by Nexen with a 20% stake.

Jane Whaley

FALKLANDS: 1st Commercial Oil?

One of the first wells to be drilled in the South Atlantic waters off the Falkland Islands for over a decade has been announced as an oil discovery, which may prove the first commercial find in the North Falkland Basin. As reported in GEO ExPro 2010 no 2, this basin is thought to contain a world-class Late Jurassic to early Cretaceous lacustrine source rock, which may have expelled as much as 100 billion barrels of oil into Cretaceous fluvio-lacustrine and lacustrine sands.

Photo: Falkland Islands Government

Long Island lies in a deep inlet, about 20 km north-west of the capital of the Falkland Islands, Stanley.

The well, 14/10-2, which was spudded on 16th April, was investigating the **Sea Lion** prospect on Licence PL032, which is 100% owned and operated by **Rockhopper Exploration**. Sea Lion is a basin floor fan prospect and is estimated to contain 230 MMbo recoverable. The well is reported to have encountered a 150m gross interval of sand and shales, with 53m of net pay in multiple sand zones, the thickest of which is 25m. Average porosity is 19%, with peaks of 28%, and the logs show excellent permeability, ranging between 200 and 500 mD, peaking at over 1,000 mD. In addition, no oil water contact was encountered when the well terminated at a depth of 2,744m.

Rockhopper will continue collecting logging information before deciding whether to drill an appraisal well, suspend the well for future testing or plug and abandon it.

Shell drilled six wells in the North Falklands Basin in 1998, five of which found hydrocarbons, but the price of oil at the time was too low to make further exploration commercial. All of these wells tested a single play concept, but according to Rockhopper there are at least four different types of plays to be explored in Block PL032 alone. These include inversion trends and downthrown faults in addition to the basin floor fans, and the company has identified at least 10 further prospects with a total of about 1.4 Bbo recoverable in this block alone.

Rockhopper Petroleum was established in 2004 to explore for hydrocarbons in the Falkland Islands, and only has licences in the North Falklands Basin. Before drilling commenced earlier this year, it undertook extensive 2D, 3D and CSEM surveys of its acreage.

Meanwhile, **Desire Petroleum**'s Liz well, 14/19, about 30 km south south-west of Sea Lion in Block 003, was plugged and abandoned as a gas discovery. The target horizon was the Cretaceous and the initial unrisked recoverable reserves had been put at over 600 MMboe. The well found hydrocarbons at two levels, with 17m of net pay and hydrocarbon shows recorded over a wide interval, but although more sandstone was encountered that anticipated if was typically of poor quality. The company will now try to determine whether better quality reservoir may be developed up dip before determining where to drill next.

Disputed History

Desire Petroleum is named after the ship captained by English navigator John Davis, who first discovered the Falkland Islands in 1592. The French were the first to build a settlement, in 1764, but were forced to give sovereignty to the Spanish. A British exploratory expedition then claimed the Islands in 1765, but by 1820 few settlers remained and the nearest country, Argentina, claimed them as the Islas Malvinas. The territorial dispute between the two countries has never been satisfactorily resolved, but the paucity of natural resources on the island meant there was little pressure to achieve an agreement. Not, that is, until the potential discovery of large reserves of oil and gas.

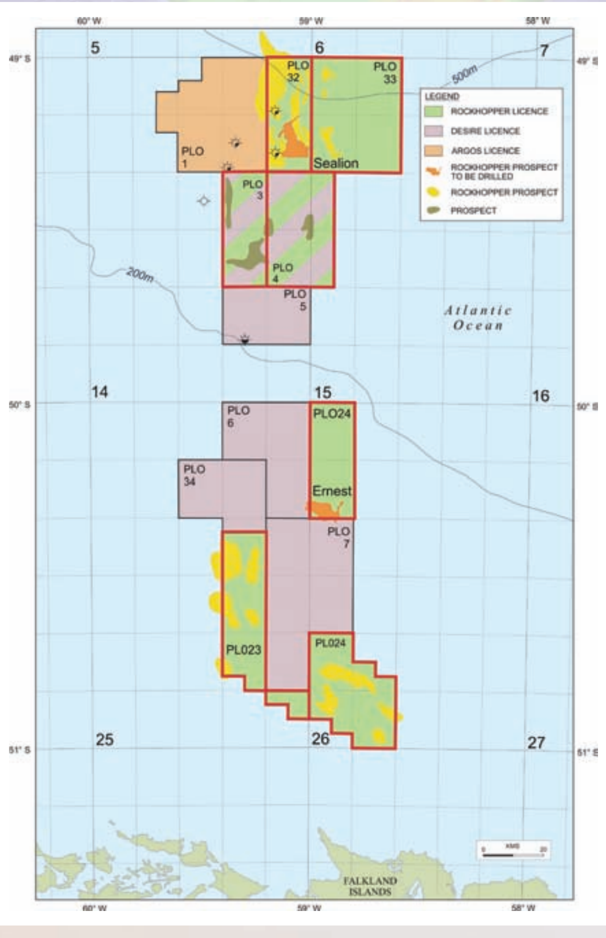


Image: Rockhopper Exploration

A number of interesting prospects have been identified in the North Falklands Basin

KURDISTAN: Another Discovery

As reported in GEO ExPro 2010 no 2, the Kurdistan Region of Iraq has recently become a very exciting place to be exploring for hydrocarbons. This was confirmed in March this year with the announcement of a discovery in the **Akri Bijeel Block** in the northern part of the region, part of the North Iraq Zagros Fold Belt. The Bijeel-1 well, which spudded on 11th December, successfully tested oil, with flow rates of up to 3,200 bpd of 18° API oil and associated gas rates of 933,000 cfgpd.

The well was targeting prospective intervals in the Cretaceous – the most prospective level in Kurdistan - and also the Jurassic, and the discovery announced in March was in the Upper Jurassic at a depth of 3,831m. The well will continue drilling to the target depth of 4,400m, to investigate the lower prospective horizons, and was originally predicted to take between four and five months to complete.

Akri Bijeel Block lies immediately to the east of the Shaikan Block, where a significant discovery was announced in August 2009, near the city of Dihok, about 200km north of Kirkuk. Shaikan-1 has estimated on place volumes of more than 1.5 Bbo.

The operator of the Akri Bijeel Block is Kalegran Ltd., a 100% subsidiary of MOL Hungarian Oil and Gas Plc, which holds 80% interest in the production sharing contract, the remainder being held by Gulf Keystone Petroleum International. The Kurdistan Regional government has an option to nominate a third party interest of up to 20% in the PSC, with a further option to nominate a government interest of up to 20% following a commercial discovery.

Gulf Keystone, which is focused on exploration in the Kurdistan region of northern Iraq, is a major partner in the Shaikan Block and also in two further blocks to the west of Shaikan. A number of further wells are planned on the acreage.

Seismic trucks undertaking a survey in the Kurdistan Region of Iraq

Drilling the Bijeel-1 well on the Akri Bijeel block.

Probing the Riches in the Barents Sea

In late April it became known that Norway and Russia had agreed upon a common marine border in the Barents Sea. An area equivalent in size to the North Sea fairway was made available overnight. Fugro Multi Client Services has an extensive data base and good geological knowledge covering both sectors of the Barents Sea and Idar Horstad, General Manager, volunteered to share his thoughts about the prospectivity of this huge area.

First of all, Idar, can you give us an idea about the size of this previously disputed area?

The previously disputed area is approximately 175,000 km^2, or roughly the size of 500 Norwegian Barents Sea blocks. This will be split roughly 50:50 so we should have another 250 blocks to evaluate and explore, meaning that this area will play a key role in future licensing rounds in Norway.

Size matters, but more importantly, does it have a petroleum system favourable for large accumulations?

The Barents Sea is an enormous area, covering more than 1,400,000 km^2 and the geology varies significantly across the region. Despite the limited exploration success to date on the Norwegian side, most of the area can still be regarded as a frontier basin. Source rocks and reservoirs are present at many levels, and exploring structures that potentially could be sourced from the same source rock kitchen as the Shtokman field will be exciting.

Source rock is a prerequisite, of course - do we have several possibilities?

Absolutely. Oil and gas prone source rocks are present from the Devonian and into the Tertiary in the Barents Sea. However, the scarce sampling and the complex burial and uplift history complicates the petroleum system and I think the key to success in the Barents Sea is a detailed understanding of the regional geology and how this has controlled the generation and migration of petroleum through time. The present structural setting represents only a snap shot that might be very different to the setting at the time of migration from the various source kitchens.

Then we also need reservoir rocks. Are we talking about clastics or carbonates, and which formations seem to be most promising?

To quote Winnie the Pooh when he was asked whether he would like condensed milk or honey on his bread - "Both". There are many different reservoir levels but the thick Triassic section will make exploration in the Palaeozoic an expensive and high risk adventure in most of this area.

Published maps indicate that there are many huge structures, some of which could play host to supergiant fields. Is this true?

I think all geologists who have visited Russia have seen maps with large yellow and red dots. However, the amount of information is limited and we cannot assess the full potential until we have more modern data and a few key structures have been drilled to get a better understanding of the petroleum system in the border area on both sides. If the potential isn't huge I would say it is very high - and getting access to new frontier regions is always good for the industry.

It is also said that the Russians have proved a giant gas field next to the median line. That must be good news for the whole area?

Previously we called this "oil on paper". You haven't proved a discovery until you have drilled and tested it, and you don't make money until you develop, produce and sell it. Observations from seismic or other technologies, such as CSEM, can be applied to reduce the risk but these have less value if they aren't calibrated by wells in the region.

Which, if any, would be the most negative geological factor for the prospectivity of the area?

Based on Fugros' evaluation of the modern data I think the uplift and restructuring of the area offers a great challenge in addition, to the volcanic intrusions we see on the Russian side. The data are accessible and you can judge for yourselves.

Finally, Idar, I reckon you like the business opportunities this new situation presents. Are you ready?

Fugro is the only western contractor that has acquired and can offer modern long offset seismic data on both sides of the former disputed area. Old NPD and Russian 2D data were acquired with very short streamers and are inferior to these new data. At one stage Statoil was our only client, but we have had several people working in the Barents Sea since 2001, Today more than 30 companies have licensed the whole or parts of our new NBR long offset survey in the Barents Sea. This area represents a natural extension and as soon as the area opens for exploration Fugro will participate with our vast resources to collect geological and geophysical data.

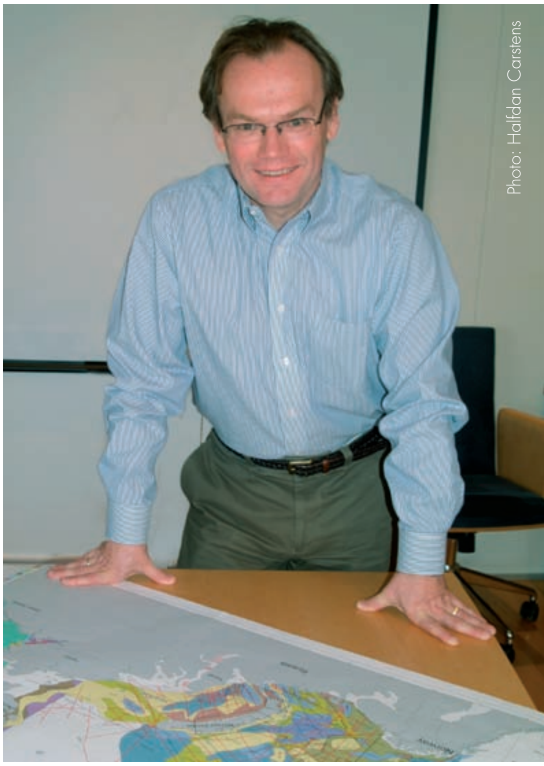


Photo: Halfdan Carstens

Idar Horstad holds a MSc. and PhD. in Sedimentary Geology from the University of Oslo. His work at the University was focused on the understanding of the migration and emplacement of hydrocarbons on the Norwegian Shelf. He spent 10 years in the Exploration Group in Saga Petroleum before he joined Fugro in 2000. For the past 10 years he has been the Managing Director for Fugro Multi Client Services with a global responsibility for multi client seismic acquisition in Fugro.

Don Herron, PGS

Prolific Miocene Trend Hurt by Blowout

Miocene deep water sands were the target for the Macondo well in Mississippi Canyon Block 252, and it is probably from one of these sands that the blowout originates.

The recent blowout of an exploration well on April 20 on BP's **Macondo Prospect** in Mississippi Canyon[1] Block 252 has attracted media attention for the potential environmental consequences of the incident. The well is located in the northeastern part of the Gulf of Mexico, approximately 85 km (52 miles) southeast of the bird's foot delta of the Mississippi River.

The Mississippi Canyon protraction area is one of the most prolific sectors of the Gulf of Mexico outer continental shelf (OCS), being home to many producing fields, including BP's deep water **Thunder Horse field**, a world-class giant with capacity to produce 250,000 bopd through the world's largest semisubmersible production-drilling-quarters (PDQ) facility in 1844 m (6050 ft) of water in Mississippi Canyon Block 778.

The production facility nearest to Macondo is Shell and BP's **Na Kika complex**, located in Mississippi Canyon Block 474 approximately 25 km (15 miles) south-southeast of the blowout. The Na Kika facility is the collecting point for six (originally five) separate fields that produce both oil and gas from Miocene deep water sands. This facility, which is a semisubmersible host permanently moored in 1935 m (6350 ft) of water, is designed to recover up to 300 MMboe from its contributing fields.

The mega-regional geologic history of the Gulf Coast basin has been controlled through time by the close interaction of sedimentation and salt tectonism in an overall extensional setting. Within this setting the intensity of deformation in the northeastern portion of the basin has been relatively low. In contrast, in the central and western parts of the basin the Tertiary section is much thicker and the structural complexity is greater, including stacked salt sheets and welds, large listric growth faults, and compressional folds and reverse faults at the downdip toes of major extensional fault systems.

The 2D seismic line, due south of the Macondo prospect, traverses through one of the Na Kika fields and clearly shows features that are typical of the extensional structural style related to basin formation and the movement of salt in response to sediment loading in this part of the Gulf of Mexico.

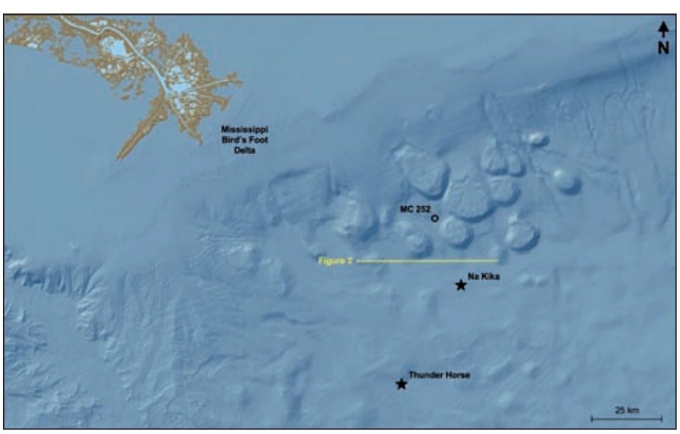
Immediately following rifting of continental crust in Early-Middle Jurassic time, the so-called "post-rift" **Middle Jurassic Louann Salt** was deposited unconformably on Lower Jurassic - Triassic (?) "syn-rift" sediments in the nascent Gulf Coast basin. This salt was mobilized by subsequent sediment loading beginning in Late Jurassic time and continuing intermittently through to the present day.

A distinctive sea-floor signature of bathymetric highs has resulted (**see bathymetric map**), corresponding to individual shallow salt bodies that have not coalesced to form large salt sheets or canopies as has occurred farther to the west. The sea-floor expression of shallow salt bodies (highlighted in red) is also evident at both ends of the seismic line.

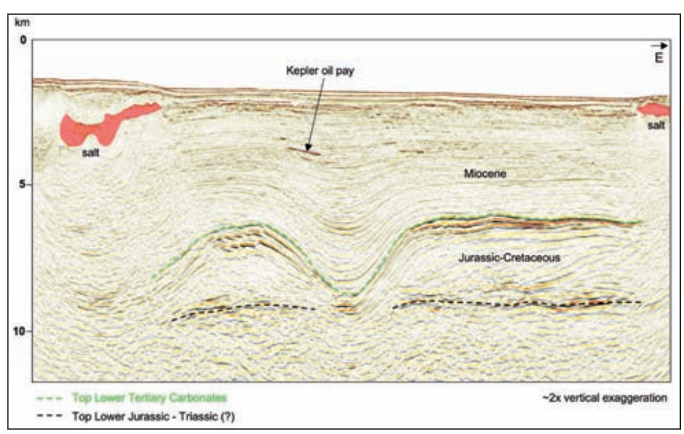
The pronounced syncline evident in the center of the seismic line separates two so-called "turtle" structures that formed in response to withdrawal of the Louann Salt in Late Jurassic - Early Cretaceous (?) time (hence the expanded Upper Jurassic - Lower Cretaceous section annotated on the line).

The thick Miocene section above the "Top of Lower Tertiary Carbonates" reflection contains the reservoir sands that are producing in Na Kika and other fields in the area. Miocene sands also were the targets on Macondo, although it is not known how these sands, including the one from which the blowout originated, correlate to nearby producing Miocene reservoirs.

Plio-Pleistocene sediments are relatively thin in this part of the Gulf of Mexico, but thicken markedly to the west where they serve as excellent reservoirs in major oil and gas fields.



Shaded topographic map of the sea floor of the northeastern Gulf of Mexico.



2D depth-migrated seismic line through one of the Na Kika fields, Kepler, on which the main oil pay sand in the field is highlighted by an anomalous high amplitude seismic reflection. The Macondo feature is approximately 16 km (10 mi) north of this line.

[1] The **Mississippi Canyon** is an undersea canyon south of Louisiana. With an average width of 8 km and a length of 120 km it is the dominant bathymetric feature of the north-central Gulf of Mexico.

Halfdan Carstens

More Oil than Gas

Giants may be found in the highly controversial exploration provinces offshore Lofoten and Vesterålen along the margins of the Norwegian Sea, according to a recent report.

On assignment from the Norwegian Parliament (Stortinget), the Norwegian Petroleum Directorate (NPD) has acquired seismic data in the areas off Lofoten, Vesterålen and Senja (Nordland VII and Troms II). During the summers of 2007, 2008 and 2009, the Directorate acquired 2D and 3D-seismics as well as CSEM data in the area, which had not previously been opened for petroleum activities.

The purpose has been to increase our knowledge of potential petroleum deposits in these areas, and a comprehensive report was presented to Minister of Petroleum and Energy Terje Riis-Johansen in April.

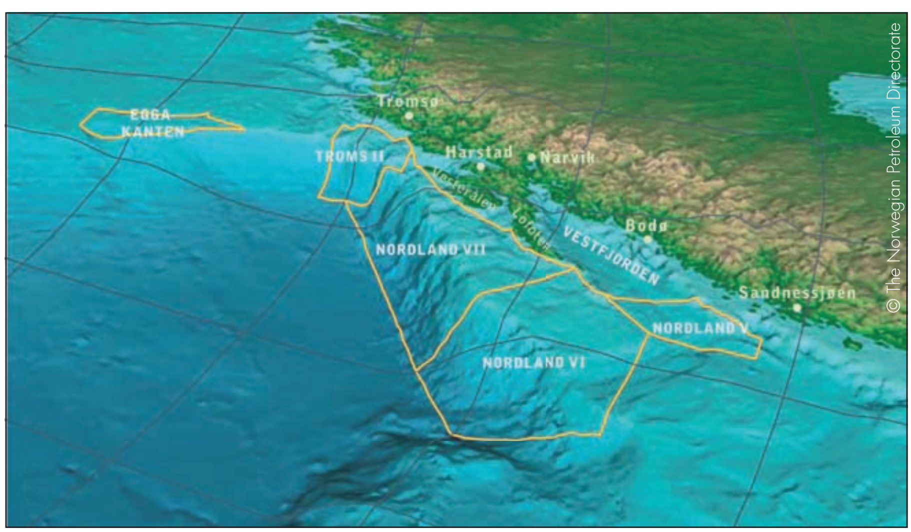
Although the industry has not yet seen the data, it is expected that this is a significant contribution to increase understanding of the geology in this complex areas with severe tertiary uplift.

Based on the new knowledge and previously acquired data, the NPD has mapped the areas and estimated the resource potential. The evaluation also covers Vestfjorden, the unopened part of Nordland V, Nordland VI and the Eggakanten area in the southwestern part of the Barents Sea.

The main conclusions are that Nordland VI appears to be the most prospective area for petroleum resources, Nordland VII and Troms II have a total expected resource estimate which is about the same as what is expected in Nordland VI, and that the resource estimate for oil is larger than for gas in Nordland VI and VII. In Troms II, gas appears to be the most likely possibility.

A total of 50 prospects have been mapped in Nordland VI, VII and Troms II. Estimated recoverable resources are based on an analysis of play models. The petroleum resources are expected to amount to 202 million Sm³ of oil equivalents (about 1300 MMboe). The range of uncertainty in this resource estimate is expected to lie between 76 (480 MMboe) and 372 million Sm³ o.e (2340 MMboe). The figures refer to recoverable oil and gas. For comparison, the original oil reserves of the Statfjord field exceed 4000 MMbo. According to NPD, some 2 or 3 fields may be giants, i.e. exceeding 500 MMboe of recoverable fluids.

As can be expected, some of the oil companies have come up with different estimates based on a less extensive database. The most optimistic estimate to date is 3500 MMboe of recoverable oil and gas.



Five designated areas have been evaluated by the Norwegian Petroleum Directorate offshore Lofoten and Vesterålen. While 33Bboe has been produced on the Norwegian continental shelf so far, it is expected that these areas contain 1.3 Bboe of recoverable oil and gas.

Proved reserves

"The estimated quantities of oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under current economic and operating conditions."
BP Statistical Review of World Energy

CONVERSION FACTORS

Crude oil
1 m³ = 6.29 barrels
1 barrel = 0.159 m³
1 tonne = 7,49 barrels

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

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

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

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

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

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

Historic oil price