VOL. 7, NO. 6 – 2010

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GEOSCIENCE & TECHNOLOGY EXPLAINED

Geotourism: India - Deccan Traps

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The Bay of Bengal

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EXPLORATION
Is the 'Shale Gale' Blowing Itself Out?

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COLUMNS

FEATURES

Photo: Jamaica Tourist Board

The beautiful Caribbean Island of Jamaica was home to pirates and their loot in the past, but is there treasure of a different sort in its sparkling waters? Data collated for a new bid round, due to close in March 2011, suggests that there may well be.

© BP Archives

The North Slope of Alaska is a cornerstone of US oil production with several giant fields, notably Prudhoe Bay, Kuparuk and Endicott, plus extensive heavy oil at Ugnu and West Sak. The generation that discovered these fields is almost gone; what can we learn from their efforts?

THIS YEAR'S FRONTIER – NEXT DECADE'S PAYMASTER

The Arctic and the Bay of Bengal are two exciting but very different frontier areas, both suggesting great potential, but offering many challenges to the hydrocarbon industry.

In order to exploit the Arctic, it is not just the technical issues involved in exploring in such harsh and extreme conditions that must be faced. Some of these issues, in fact, have already been investigated, and both service and exploration companies are moving closer to being able to successfully discover and produce oil and gas from this frozen environment. But the industry faces many questions, and hard political, financial and environmental decisions will need to be made.

Successful exploration in the deep waters off Ghana means the area is no longer considered 'frontier'

The Bay of Bengal faces very different challenges. Surrounded by some of the fastest-growing populations and economies in the world, the Bengal Fan is the world's largest fluvio-deltaic-slope fan complex, yet it is largely unexplored. Now that exploration has moved successfully into deepwater, the issues here again are not technical, but political. The maritime boundaries between the countries surrounding the Bay of Bengal – India, Bangladesh and Myanmar - are under dispute, as they have been for many years, and until these are established, they will not be able to fully exploit the potential hidden under their shared ocean.

If these countries, encouraged by the oil industry and the promise of wealth beneath their waters, resolve their differences, we may not refer to the Bay of Bengal as a frontier area for long. Until a few years ago, the offshore West African Transform Margin, west of the Niger Delta, was so little considered that it would be hard to have even called it 'frontier'. Now, after a string of major discoveries off Ghana, Liberia and Sierra Leone, it's one of the hottest properties in town, as evidenced by the overcrowded rooms at recent conferences whenever a paper is given on the area. The East African Rift looks set to follow in its footsteps.

So look carefully at frontier areas; they may be paying your salary soon!

Jane Whaley
Editor in Chief

ARCTIC EXPLORATION

ION Geophysical spent three seasons working in the Arctic Beaufort and Chukchi Seas, investigating ways of extending the very short ice free season. They achieved this by towing the streamer below the ice, with an ice breaker travelling in front of the source vessel, and can now work in the Arctic for up to nine months of the year.

Inset: The Taj Mahal is India's most famous tourist attraction, but there are plenty of other fascinating places to visit, including the Elephanta Caves, near Mumbai, where the basaltic Deccan Traps have been carved into temples and statues.

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GEO EXPRO is published bimonthly for a base subscription rate of GBP 50.- a year (6 issues).
We encourage readers to alert us to news for possible publication and to submit articles for publication.

Cover Illustration:
ION
Inset: Molly Wrigley

Layout: Skipnes Kommunikasjon
Print: NXT Oslo Reklamebyrå

ISSN 1744-8743

Industry Responds to Macondo

International co-operation can help prevent such an accident happening in the future

As the furore over the Macondo disaster in the Gulf of Mexico finally begins to die down, governments, regulatory authorities and oil and gas companies are getting together throughout the world to ensure, as far as possible, that such an accident in deep water can never occur again.

In the report BP published on the blowout, it cited eight barriers which should have prevented the accident happening that were crossed – interestingly, none of them actually strongly related to deepwater. And according to Mark McAllister, Chair of the Oil Spill Prevention and Response Advisory Group (OSPRAG), set up by the UK to look at lessons to be learnt from Macondo for the North Sea, the majority of these were about human responses to incidents, rather than technology.

"The North Sea actually has a remarkable safety record, with an incident record much lower than comparative industries such as mining – and actually less than the retail industry!" he explains. "The issue is personal safety versus process safety: we have to ensure that the processes are in place that will prevent accidents happening. But any response has to be carefully analysed – we must beware of the poorly thought through knee-jerk reaction which could potentially be the source of the next tragedy."

OSPRAG was setup to provide a focal point for the sector's review of the industry's practices in the UK, involving all stakeholders, including major and small independent exploration companies, contractors of all sizes, the Government Department of Energy and Climate Change, the coastguard authorities and Trade Unions. It has four specialist review groups: a Technical Review group, looking at ways to make the possibility of a similar disaster happening as low as possible; Oil Spill Emergency Response, outlining plans in the event of a major spill; an Indemnity and Insurance Group, to ensure that there would be sufficient funds to cover the costs of a clean-up operation (as Mark pointed out, most small companies in the North Sea would have been destroyed by payouts similar to those being made by BP); and an International Group, to liaise with other countries in the region to provide pan-North Sea regulations and response mechanisms.

OSPRAG has been instrumental in developing a new well-capping device, which will be kept in Aberdeen along with vital cutting equipment, all available immediately in the event of a spill. The device is in the detailed design stage and will be able to be fine-tuned rapidly to deal with any blowout preventer. BP have contributed towards this and have also given a lot of advice to the groups, based on their Gulf of Mexico experience. The organisation plans to test the National Contingency Plan in May 2011.

The Oil and Gas Producers Association has set up its own Global Industry Response Group, and OSPRAG is in communication with this, ensuring that we share resources and information, so, for example plans for the well-capping device will be shared internationally.

As Mark, who is Chief Executive of Fairfield Energy Ltd., pointed out; "the oil industry has been responsible for the biggest global growth in wealth in human history. By working together like this, we can ensure that it remains an industry we are proud to work in."

© BP plc

Drill floor workers remove the drilling equipment that completed the relief well and made the intersection to seal the Macondo well, onboard the Transocean DD III in the Gulf of Mexico on 16 September 2010

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

URUGUAY: Second Offshore Round Announced

An new exploration Licensing Round has been announced for Uruguay, with opening of bids scheduled for April 2012.

After 30 years of limited exploration activity in Uruguay, in 2008 the Government, through the state oil company ANCAP and the Norwegian geophysics company Wavefield-Inseis ASA (since acquired by CGGVeritas), conducted a 7,000 km 2D regional seismic survey in the offshore Punta del Este Basin. Supplemented by a 2D seismic infill, this excellent quality data has helped remove the geological and geophysical veil of uncertainty that remained over this sedimentary province along the occidental margin of the South Atlantic.

Based on these promising results, the Uruguayan Government decided to launch the first Uruguay Round in 2009. Now, Uruguay Round II has been announced with opening of bids scheduled for April 2012.

Bidding Round I Interest and Terms

The first bidding round awarded contracts in areas on the Uruguayan continental shelf on a PSC (Production Sharing Contract) basis. The contractors bear all the risks and costs of the activity and no royalties, signature bonus, production bonus or surface rentals are applied. The offers, which could only be placed by oil companies qualified through their technical, economic and legal background, were compared based on the exploratory program and the economic terms offered. The winners were a consortium of YPF, Petrobras and GALP, which submitted offers for blocks 3 and 4 in the Punta del Este Basin. The contracts between ANCAP and the consortium have already been signed and the exploratory work is starting.

Santiago Ferro, the Chief of E&P Administration and Contracts for ANCAP says, "Uruguay understands the vital importance of keeping a constant level of promotion, likewise to present to the upstream industry exploration opportunities regularly. ANCAP will present another bidding round in 2011, the Uruguay Round II."

Round II Interest

The first Round II informational presentation was held in Rio de Janeiro in November 2010 and drew major players from the oil industry. Exxon Mobil and El Paso (USA), Petrobras and Vale do Rio Doce (Brazil), ONGC Videsh (India), Statoil (Norway), Perenco (UK), Karoon Gas (Australia), and ENI (Italia), as well as service companies such as Fugro and Ion/GX Technology all attended. Uruguay Round Coordinator, Santiago Ferro, together with geologists from the ANCAP Exploration and Production Division, presented the main data related to the geological and exploratory potential of Uruguay offshore, as well as the general contracting terms of the Uruguay Round II bidding process.

"The interest shown in the general presentation continued on to meetings that the companies of oil sector requested of the ANCAP technical staff," says Santiago Ferro. "They wanted more detailed information related to oil systems and models, direct and indirect indicators of hydrocarbon presence, and definition of oil and gas leads and prospects. During the following months ANCAP will continue to promote Uruguay Round II in world relevant events and centers for the oil industry, including Houston and London."

Prospective Offshore Basins

Three basins are recognized offshore Uruguay: Punta del Este, Pelotas (southern portion) and Oriental del Plata. These basins are genetically related to the Western Gondwana breakup, produced nearly 130 Ma ago, and the subsequent development of the Atlantic Ocean.

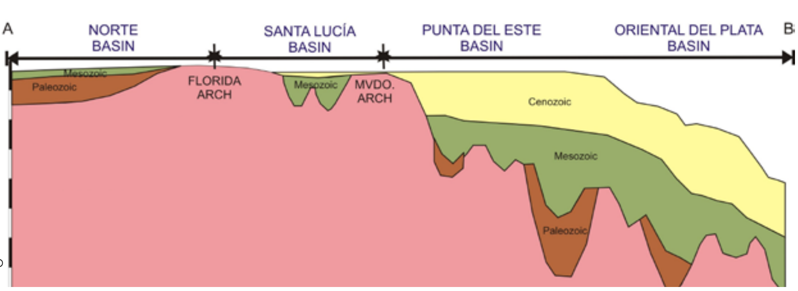
The Punta del Este Basin is a NW-SE trending aborted rift, perpendicular to the continental margin, whereas the Pelotas Basin belongs to the flexural border of a precursor rift structure. The Oriental del Plata Basin developed in the Paleocene, when the Punta del Este and Pelotas Basin began functioning as a single sedimentary environment.

The stratigraphy of Uruguayan offshore basins is represented by large depositional sequences, which overly both Paleozoic sedimentary rocks and Precambrian crystalline basement rocks. The synrift sequence (Jurassic-Neocomian) includes alluvio-fluvial and lacustrine deposits, interbedded with volcanic rocks. The postrift sequence starts with a transgressive transitional sequence (Barremian-Aptian), followed by regressive deposits (Late Cretaceous). During the Cenozoic the sedimentation was controlled by eustatic oscillations of sea level, corresponding to cyclic regressive and transgressive sediments from the Paleocene to the present.

Petroleum System Model

According to the tectono-stratigraphic model established for the Uruguayan offshore basins, potential source rocks are associated with the prerift, synrift and early postrift (transition) sequences. The early postrift sequence (transition) shows a clear transgressive character with the development of Barremian-Aptian marine sequences with very good source rock potential equivalent to the transitional sequence of the Orange Basin (offshore Namibia and South Africa) and other productive South Atlantic basins. The most important reservoir rocks are related to the alluvio-fluvial systems of the synrift sequence and the lowstand deposits of the Cretaceous postrift Paleocene, Eocene and Oligocene sequences. In different stratigraphic levels, rocks with both local (e.g., lacustrine pelites) and regional seal characteristics are present. Different structural, stratigraphic and combined plays are recognized in the Uruguayan offshore basins, in shallow, intermediate and deep water depths.

In the Uruguayan continental margin there are several direct and indirect evidences of the occurrence of hydrocarbons, which confirm hydrocarbon generation and the presence of an active petroleum system. The most important is the detection of fluid inclusions of light oil and gas in cuttings from the Lobo and Gaviotín wells that were drilled on structural highs in the Punta del Este Basin, the identification of gas chimneys, amplitude anomalies and velocity anomalies in seismic lines, and the interpretation of oil seeps in satellite photos.



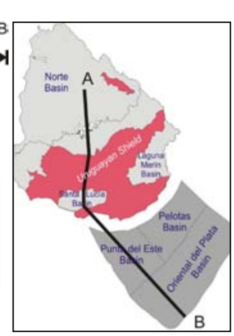


Image: modified after ANCAP

Geological cross section of Uruguayan onshore and offshore basins

ANDREI BELOPOLSKY, BP

New Plays in the Eastern Mediterranean

The Eastern Mediterranean region is known for its long and colourful history and as a great place to go on holiday. Can it also hold vast amounts of oil and gas?

The Geological Society conference "New and Emerging Plays in the Eastern Mediterranean" addresses this question by bringing together leading scientists from academia, top explorers from the oil and gas industry, and seismic companies promoting new data in the region. The conference is taking place on February 23-25th at Burlington House in London, home of the Geological Society for 135 years. Sponsorship is provided by OMV, BP, Spectrum, PGS, ENI and Hess and over 50 technical presentations have been already submitted for the conference programme.

Situated at the junction of the African, European, and Arabian plates, this is a tectonically complex region and the origin and history of the individual basins are much debated. Presentations by experts on the regional tectonics will discuss crustal models and the timing of the opening of the Eastern Mediterranean. A keynote talk by Hugh Jenkins from Oxford University will address the distribution of the Mesozoic source rocks in the region.

The Eastern Mediterranean region already has significant hydrocarbon resources in the shallow waters of the Pelagian Basin, with fields like Miskar offshore Tunisia (800 Bcf gas condensate in-place), and Bouri offshore Libya (5 Bbo in-place) sourced from lower Eocene Bou Dabbous shales; and also in the shallow Adriatic Sea off Italy, and offshore south-east Sicily, where large fields like Vega (1 Bbo in place) with oil sourced from upper Triassic/lower Jurassic source rocks were found in Upper Jurassic limestones.

There was a significant gap in exploration from the mid-80s until a few years ago. The renewal of exploration activity can be explained by stable oil prices and advances in both drilling technology, allowing deep water drilling, and in seismic imaging. The Messinian (Late Miocene) event in the Mediterranean resulted in a rapid and very substantial drop in sea level, which led to significant erosion and the deposition of the evaporitic rocks that now cause severe seismic imaging problems. Several presentations will address the techniques for seeing below the Messinian evaporates as well as the distribution and nature of these deposits.

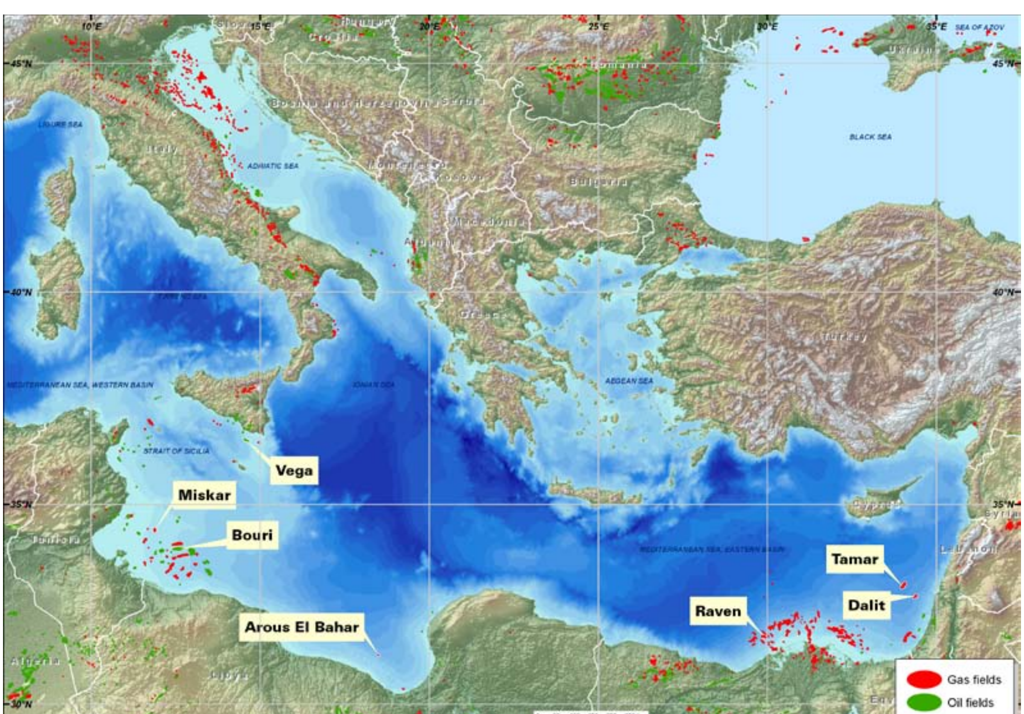
Exciting discoveries

Throughout the region, current exploration activity is resulting in new and exciting discoveries. Recent finds of wet gas below the Messinian in offshore Egypt's Nile delta (e.g. Raven field, see *GEO ExPro* Vol. 5, No. 1) are allowing the first glimpses of the large potential of that basin. Several presentations will address aspects of this play, from the regional perspective to the reservoir architecture scale.

Some of the most exciting discoveries of the last decade were the deepwater Tamar and Dalit gas finds offshore Israel by Noble Energy, which have thrown the unexplored Levant basin into the spotlight. Many kilometres of new seismic data have been shot, identifying large structures in the area. At the conference, a session on the Levant basin will include presentations showing the new data and describing the new concepts offshore Cyprus, Syria, Lebanon and Israel.

Until a few years ago, exploration in Libya had been restricted by UN sanctions, but since these were lifted, a large area offshore Libya has been licensed. New seismic data have been acquired, and technological advances in seismic imaging have allowed us for the first time to see the deeper structure and stratigraphy of the basin. Although several dry holes in the offshore Sirt basin were disappointing, Hess's gas and condensate Arous Al-Bahar discovery has proved the presence of a working petroleum system in the area. Several imminent wells by BP, Gazprom and other companies will undoubtedly test the new plays in the offshore.

The companies are also returning to areas that had not seen much exploration activity for a couple of decades. Several talks will examine the petroleum potential and the new plays offshore Malta and Sicily, as well as the prospectivity of the Adriatic Sea. New seismic data combined with the new ideas will be driving the exploration activity in this region proximal to the European energy market.



Recent major discoveries in the Eastern Mediterranean have reawakened interest in the area

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

Market Sensitive to Political Instability

Since the Jackson Hole meeting in late August, confidence and the appetite for riskier assets have been growing steadily as the Fed indicated that new steps to boost the economy would come. Brent oil prices rose by around 20% since then and reached a six month high in early November after the US Federal Reserve announced its second quantitative easing programme (QE2). Oil demand has grown more than expected in both the US and Europe this autumn and the Fed's attempt to encourage economic growth by announcing the QE2 programme has spurred expectations about US oil demand going forward.

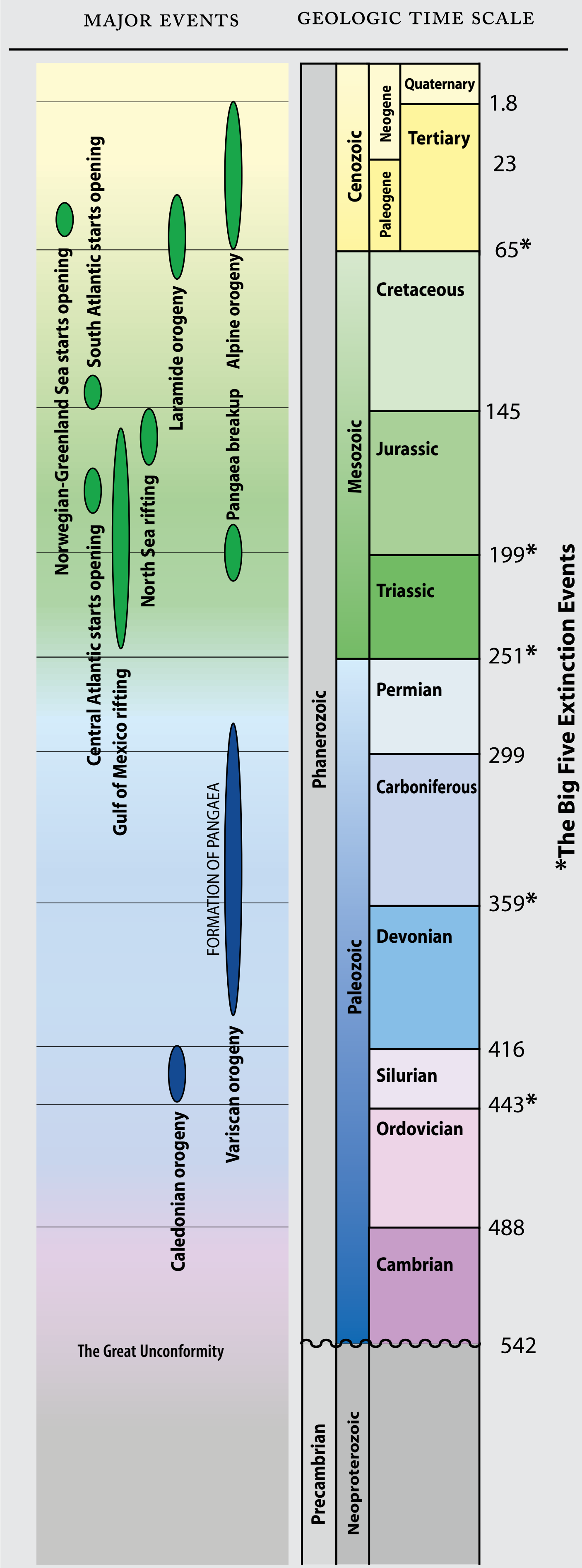
However, both investors' exuberance and oil prices have retreated somewhat over the last week, as worries that Ireland's debt problems may spread to other European economies and Beijing may need to take further steps to tame inflation have taken centre stage – at least for a while.

We expect the Indian economy to continue to grow at a healthy rate at 8.8% for 2011 – the country accounts around 4% of total world oil consumption and is the fourth largest oil consumer in the world. This indicates that the need for energy will continue to grow as living standards increase and the need for energy and transportation fuels continues to grow. India has approximately 5.6 Bbo of proven reserves, the second-largest in the Asia-Pacific region after China. The combination of increasing oil consumption but only moderate production growth has left India increasingly dependent on imports to meet its oil demand, and especially high subsidised prices of petrol and diesel have pushed up the demand for oil.

India is the fourth largest oil consumer in the world

The growing tension between North Korea and South Korea has again reminded us how sensitive the oil market is to political instability. South Korea is the eight-largest oil consumer in the world, but with its lack of domestic reserves, it is the fifth-largest oil importer. The country has no international oil pipelines, so it relies exclusively on tanker shipping of crude oil. Despite the lack of large domestic oil reserves, South Korea is the home of one of the largest oil refineries in the world. The political tension between North Korea and South Korea increases the worries about shipping in the Yellow Sea and the deliveries of crude oil to the ports.

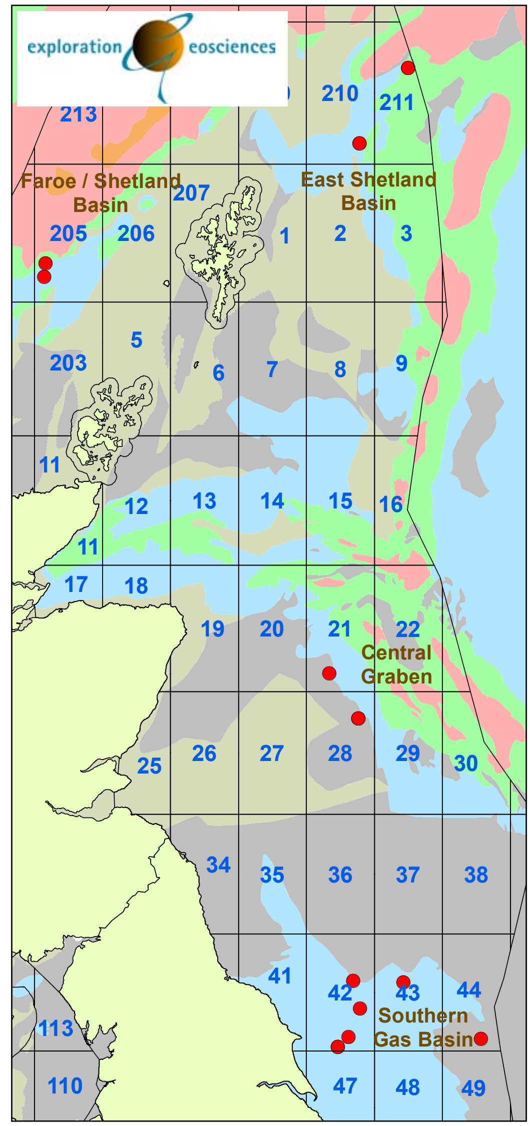
Political tension puts oil production at risk in other parts of the world. Royal Dutch Shell Plc declared *force majeure* on Bonny Light oil exports from Nigeria on Friday, as rebel groups have damaged an oil transport pipeline, reminding us again of the political risk in Africa's largest oil-producing country, which supplies the global oil market with 2.6% of total oil production. The Nigerian economy is heavily dependent on the oil sector, which accounts for around 95% of total export earnings and about 65% of government revenues. Local militant groups attacking oil infrastructure has led to a shutdown of almost one-fifth of the oil production in Nigeria since early 2006.



ALAN DRISCOLE, EXPLORATION GEOSCIENCES LTD.

New Plays Proven in UKCS

A round-up of recent Exploration and Appraisal drilling on the UK Continental Shelf.



Sites of recent successful exploration and appraisal wells on the UK continental Shelf

As the opportunity for proving significant reserves in traditional North Sea plays has diminished, exploration focus has shifted to new reservoir objectives and play types, commonly supported by seismic amplitude and AVO anomalies. Several high-impact exploration and appraisal wells drilled and drilling during the second half of 2010 emphasise this shift and help to define future trends. These include the Upper Jurassic in the East Shetland Basin, a new Eocene light oil province along the western flank of the Central Graben, and Carboniferous and Lower Permian plays in the northern part of the Southern Gas Basin.

New plays

West of Shetlands, the **Langavulin** exploration well continues to drill as a high-risk rank wildcat on a large dip-closure with objectives in the Upper Jurassic, Cretaceous and Paleocene.

In the East Shetlands province, **Cladhan** discovery well 210/29a-4 (Sterling, 2008) proved a pure seismic amplitude / AVO play, envisaging stacked turbidite sands sourced from the western basin margin. No previous nearby wells had encountered significant sand within the Kimmeridge Clay. The discovery well, located towards the northern fan margin, was re-entered in August this year, with two appraisals confirming higher-quality reservoir both up-dip, and down-dip towards the fan axis. Having not encountered an oil-water contact, further appraisal of Cladhan (potential reserves 100-200 MMbo) is required.

Towards the northern end of the UKCS, Valiant drilled two contiguous discoveries in the Magnus Sandstone with their 211/8c-4 and 211/8c-4Z wells on the **Tybalt** prospect. The main hole proved 38-40° API oil on a stratigraphic pinch-out along the eastern flank of a Jurassic graben, whilst the sidetrack encountered three stacked oil columns, separated by thin shales, in a simple dip-closure. Although net reservoir thickness was lower than anticipated, log data show the upper accumulation to be in pressure communication between the wells, with oil below the structural spill point indicating a stratigraphic component, again requiring further appraisal.

Encore's 28/9-1 **Catcher** discovery opened up a new exploration area, with light (30° API) oil at between 1,300 and 1,500m, contrasting with the heavy, biodegraded oils seen in several Tertiary sands at similar depths along trend. Reservoir at Catcher is the basal Eocene Cromarty Sandstone; a mounded turbidite fan sand with closure over a north-north-east trending fault block structure. The main hole encountered 25m of oil pay, with 20m pay in the appraisal well and a common contact at 1,428m TVDSS. The 28/9-1Z sidetrack was deviated to Catcher East, an injectite sand into Middle Eocene claystones. Downthrown against the Cromarty reservoir, Catcher East proved to be in pressure communication, with 25m of net oil sand and no contact. Total oil in place for the Catcher discoveries may reach 300 MMbo.

These discoveries confirm the pre-drilling seismic model, with light oil indicating active long-distance migration into the area from the Central Graben kitchen. With several structural / amplitude plays recognised in Cromarty and Middle Eocene injectites, a four-well exploration programme on block 28/9 is imminent.

Traditional Traps

North of Catcher, Wintershall proved oil in a more traditional Middle Eocene trap with the 21/27b-7 **Blakeney** well. No well details are released, but high amplitudes in the Upper Tay Sandstone correspond to a small dip-closure with potential reserves of 20 MMbo.

Although based on old discoveries, **Cygnus** and **Breagh**, two commercial gas projects located along the periphery of the Southern Gas Basin province, have stimulated exploration and appraisal drilling during 2010 to a variety of exploration objectives in Quadrants 42, 43 and 44. These include the Lower Carboniferous Scremerston Formation (e.g. 42/14-2, **Macanta**), the Namurian (43/13b-6, **Pegasus**) and Westphalian (44/28a-6). Other wells have targeted the Lower Leman Sandstone, including 42/28d-11 (**Tolmount**) and 42/29a-10 (**Monkwell**) and the Lower Triassic Bunter Sandstone (42/19a-1, **Airidh**).

West of Shetlands, Hurricane have successfully chased the Precambrian (Lewisian) fractured basement play, with well 205/21a-4Z (**Lancaster**) testing 34-39° API oil at 2,350 bopd, indicating reserves of 147 MMbo, and well 205/21a-5, on the **Whirlwind** prospect, encountering gas shows in basement fractures and hydrocarbon saturation in overlying fractured Lower Cretaceous limestones. This well was suspended for later re-entry and additional formation evaluation.

Still much to learn about this mature province.

Offshore Workers Getting Younger!

Contrary to everything one hears about the aging workforce in the oil and gas industry, it would appear that offshore workers in the UKCS are actually getting younger.

According to Oil & Gas UK's latest offshore workforce demographics report for 2009, the average age of offshore workers is 40.4 years old - the lowest since the industry body began compiling data in 2006 - and there are more people travelling offshore to work than at any other time in the last four years. The total number of 'core' workers (those who spend more than 100 nights offshore annually) has increased dramatically, up by 13.4% on the previous year. There is also evidence of much younger workers taking up positions in key areas, with increases in the numbers of 18 to 29 year olds working in areas such as deck crew, drilling, electrical, management, production, rigging and scaffolding.

Although there has been an increase in the number of women travelling to work offshore from the previous year, it is only marginal. The report finds that out of a total offshore workforce of over 51,000, less than 4% are women, with a third of them employed in catering.

As Robert Paterson from UK Oil and Gas points out: "The North Sea may be a 'mature basin', but anyone who thinks that operations are winding up and coming to an end is mistaken."

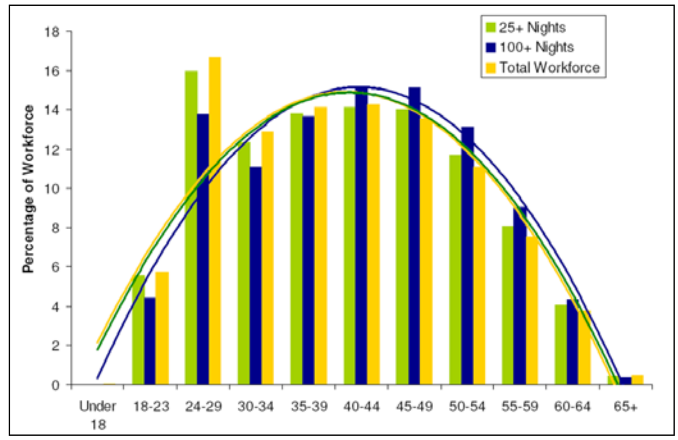


Image: Oil and Gas UK

Age profile for UKCS workers

Revolutionary New Seismic Survey

In October WesternGeco began a multiclient survey in the Gulf of Mexico using its Dual Coil Shooting acquisition method commercially for the first time. The Revolution survey will cover the East Breaks and Garden Banks areas of the Western Gulf of Mexico and will provide full azimuth (FAZ) coverage for over 130 Outer Continental Shelf (OCS) blocks.

Dual Coil shooting produces full azimuth data with ultra long offset by using four vessels following a circular path, which gives greater azimuth coverage and **increases** signal-to-noise ratio. WesternGeco believe that this provides better target illumination in challenging environments and also enables greater coverage, and the aim is to increase the quality of imaging of complex sub-salt structures in the Gulf of Mexico.

WesternGeco will apply the latest seismic data processing techniques to this survey, including true-azimuth 3D Generalized Surface Multiple Prediction (3D GSMP) and anisotropic reverse time migration (RTM).

GEO ExPro Magazine apologises for the error in this section in the last edition, which incorrectly stated that Dual Coil reduces signal-to-noise ratio

Subsea gas compression system for Åsgard

On 1 December, Aker Solutions signed the world's first gas compression contract, for Statoil's Åsgard Field in the Norwegian Sea, in a development considered a major technological leap for the industry. Installing compressors between the reservoir and the receiving platform will reduce the pressure where the wellstream enters the seabed unit, which in turn will boost production by enhancing the pressure difference between reservoir and seabed receiving installation. Through the compression process, the gas acquires sufficient additional pressure for it to be transported through the pipeline to the receiving platform.

Aker Solution's scope of work for the system includes a subsea compressor manifold station, subsea compressor station, template structure, three identical compressor trains, all electrical control systems, high voltage electrical power distribution system, topside equipment, and tooling, transport and installation equipment.

The alternative to subsea compression on Åsgard would be to build a new platform with conventional surface compressors.

Photo: Kåre Spanne/Statoil

Installation of subsea compressor at the K-lab testing facility, prior to contract award.

New Vessels for Polarcus


Image: Polarcus

In November Polarcus, the Dubai-based marine geophysical company specializing in high-end towed streamer data acquisition, placed an order for two new seismic vessels. These will be used for the acquisition of 14-streamer 3D seismic, and are based on the proven design of the existing Polarcus fleet.

The vessels, which have a total estimated project capital expenditure of US $168 million each, will be built in Norway to avail of significant and advantageous financing from the Norwegian Institution for Export Financing, Eksportfinans ASA. They are expected to be completed in the first half of 2012. The announcement increases the size of the Company's seismic fleet to seven vessels.

New Frontier Opened

Danish company Maersk Oil has been awarded a license covering Block 9 in Baffin Bay, offshore West Greenland, opening up a new exploration frontier. The block covers over 11,800 km^2, about a quarter of the size of Denmark. The news marks a culmination of several years of keen interest, work and talks with the Greenland authorities. Drilling is unlikely to happen for several years as Maersk investigate ways of ensuring a safe and environmentally responsible operation in this sensitive environment.

Work will begin immediately, however, on plans to establish a field research facility in the Baffin Bay area, to be made available for use to the authorities, the industry and the entire scientific community in order to benefit Greenland and the environment as a whole. Maersk will then plan the acquisition, processing and interpretation of quality seismic data, and if exploration activities lead to the discovery of commercially viable field development, oil production could commence in ten or fifteen years time.

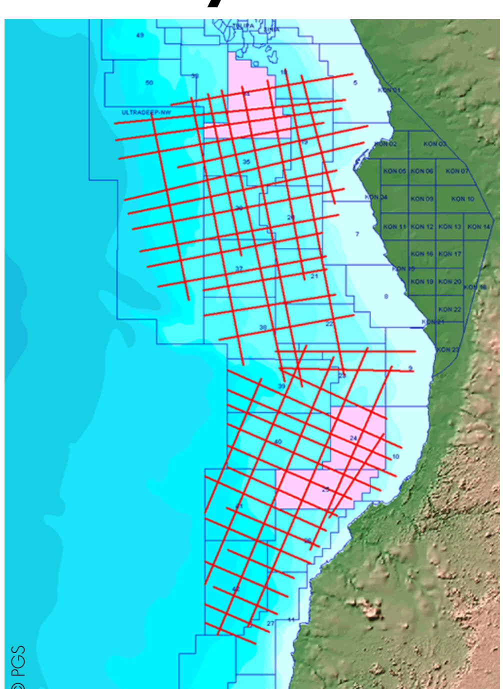

Maersk Oil

Nioqornat, a small settlement in north-west Greenland.

New Angola GeoStreamer Survey

PGS, in conjunction with Sonangol, is about to start acquisition of a large new MultiClient 2D program in Angola's Kwanza Basin. The survey, which already has industry pre-funding, will use a long offset configuration and PGS GeoStreamer broadband technology to map 10,000 km of the pre-salt in the Kwanza and Benguela Basins, where multiple pre-salt targets have been identified. This is the same technology which successfully unlocked the potential of the pre-salt in Brazil on the other side of the Atlantic Ocean.

In 2008 Angola took over from Nigeria as Africa's largest producer of oil, but the area covered by this new survey still remains relatively unexplored.


© PGS

AGI Technology Delivers Value

In more and more projects throughout the world, the Gore Amplified Geochemical ImagingSM survey is proving its worth. In recent months major frontier projects have been successfully completed and valuable charge assessment data delivered in acreages as far apart as eastern Canada, Greenland and Madagascar. Exploration prospectivity decisions have benefitted from the results in areas as diverse as Russia, Australia, Peru and Romania; both onshore, nearshore and offshore.

In India, the harsh terrain of Mizoramin in north-east India, and the challenging logistics of Ganga, in North India up against the Himalayan foothills in the Ganges flood plain, have both been areas where GORE® Surveys has again delivered valuable geochemical data in a very cost effective manner.

Increasingly, the international exploration industry has come to appreciate the value of adding the unique capability of the Gore AGI survey to its exploration toolbox.

The Next Global Frontier

The Arctic is the next, and maybe the most challenging, global frontier – but how can it be effectively explored with only a two-month ice-free season?

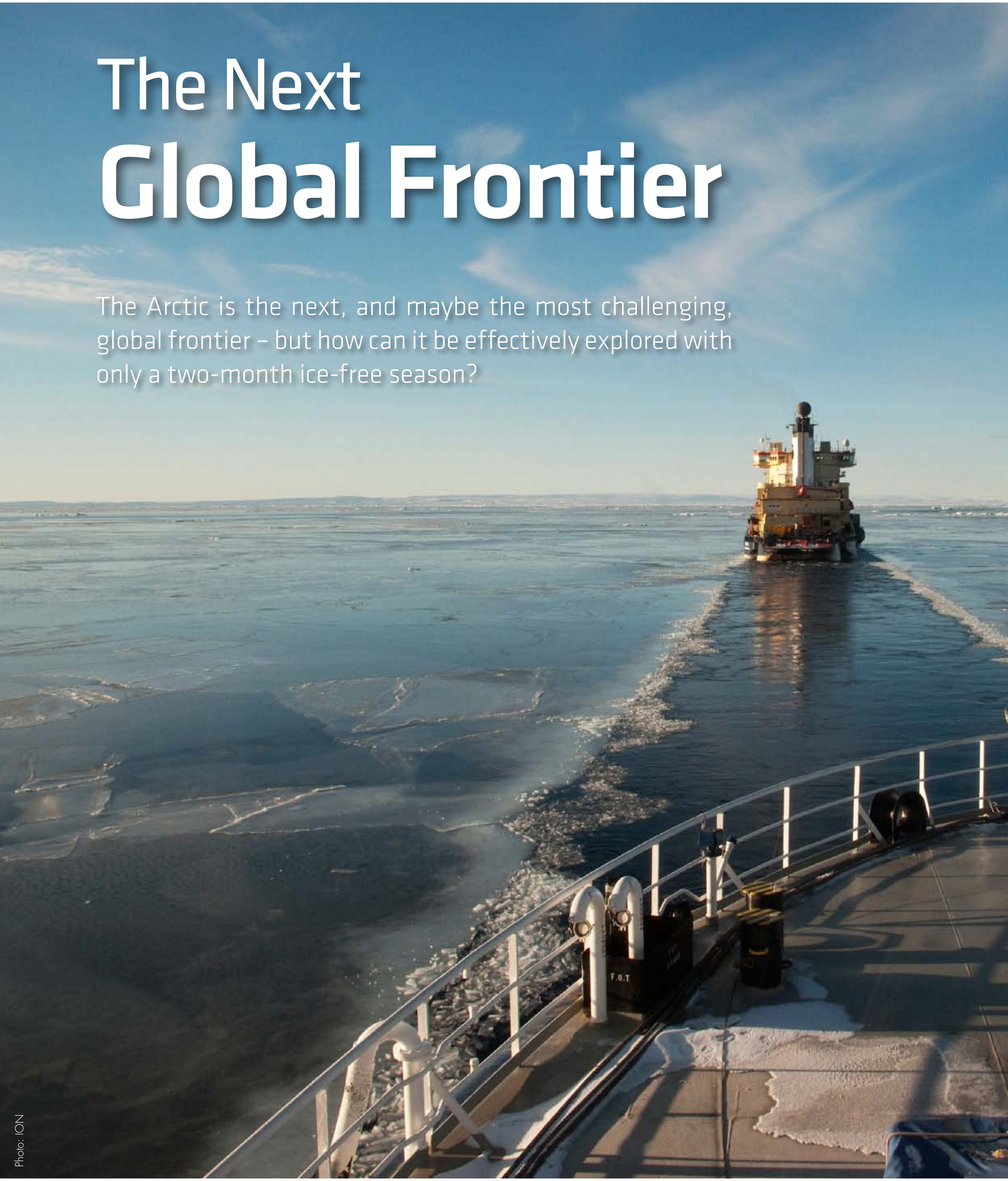


Photo: ION

JANE WHALEY

"The Arctic is surely the next large global frontier, but it is going to take time and effort to effectively explore," says Joe Gagliardi, Director for Arctic Solutions and Technology for seismic solutions company, ION Geophysical. "For some time, we have been working to help companies understand this vast area and assist them with their strategic analyses. But to do that, we need to fill the exploration time gap. If we are to take Arctic exploration further, we can't rely on the limited period of open water in these frozen seas – one to two months at the most. We have to rethink and modify our methods of marine seismic data acquisition."

To better understand how to operate in this extreme environment, from 2006 to 2008 ION worked in the Arctic Beaufort and Chukchi Seas. "Technologically, the challenge has been to develop seismic methods that work in and under the ice," explains Joe. "This has also given us a great opportunity to understand the additional factors involved in Arctic exploration - geopolitics, working with local communities, ensuring the welfare of marine mammals, and many other dynamics that need to be addressed when planning programmes in this complex arena."

"Those three years of investigation gave us the knowledge and confidence to develop a purpose-built solution for acquiring seismic data in the ice for up to nine months of the year, depending on which Arctic basin we are focusing on. We have combined our operational experience with purpose-built seismic equipment and Arctic-focused imaging algorithms."

COMPLEX CHALLENGES

"In 2009, we became the first company to shoot long offset seismic under the ice. To do this requires a very stable acquisition platform with no surface features," Joe continues. "That includes no gun floats or tail buoys. Solving these mechanical issues, however, leaves us with complex noise events, very different from those seen in open water. For example, when operating in the Arctic, an ice breaker vessel sails the line just ahead of the seismic boat clearing its path and, as you can imagine, the noise created sets up some very complex reflections. Completely new algorithms were built and have been incorporated into the processing system in order to deal with this and similar issues. However, from the point of view of the end user, the data looks the same as that acquired from more conventional areas – but considerably better than any previously obtained in this area."

Developing ION's Intelligent Acquisition [IA]™ Arctic Solution required collaboration

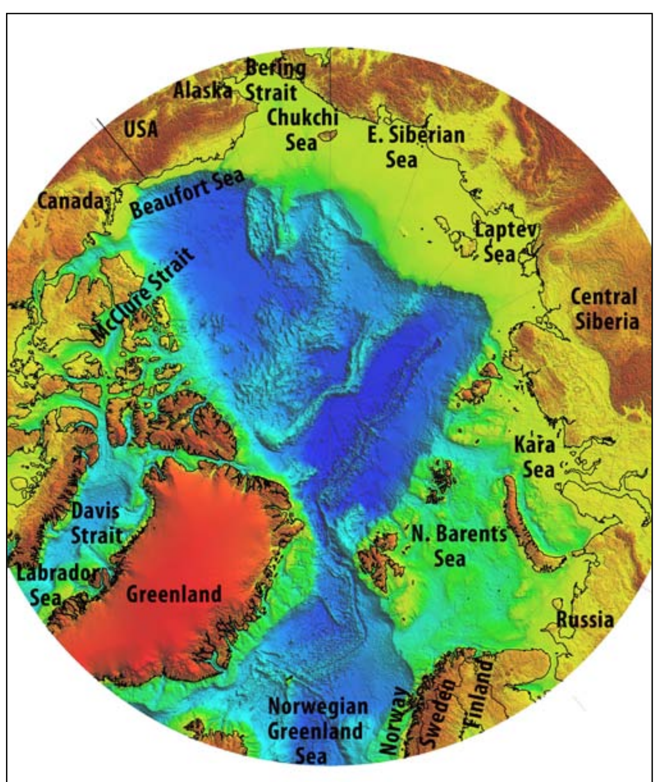


Image: GeTech

The Arctic Ocean covers an area about one and a half times the size of the United States and lies almost entirely above the Arctic Circle. Nearly surrounded by land, its only outlets are the Bering Strait between Alaska and Russia, the Davis Strait between Greenland and Canada, and the Denmark Strait and Norwegian Sea between Greenland and Europe.

The HMS Investigator made two voyages to the Arctic in the 1850s and had to be abandoned in 1853 after becoming trapped in the ice in the notorious McClure Straits. Her wreckage was found in July 2010, shortly before ION commenced the first ever seismic survey in the area.

MV Geo Explorer working in the ice in the Arctic.

across all the business units within ION, including its GX Technology (GXT) data processing group and its Marine Imaging Systems Division, which makes the streamers. Within ION there are also in-house scientists who specialise in forecasting Arctic ice conditions and regional experts who help create the ideal survey designs for positioning and shooting long seismic lines in these extreme conditions.

"We believe we have amalgamated the best expertise in the world for this niche market," Joe adds. "By having an icebreaker precede the seismic vessel, long straight lines can be the shot. We are now obtaining high quality long offset data that is beginning to unlock the exploration potential of previously under-explored basins."

RISKS REDUCED

Joe Gagliardi points out that the IA Arctic Solution that ION has devised can significantly reduce key risks in Arctic exploration. "These systems lessen operational risk by giving companies the ability to conduct seismic exploration in transitional ice regimes without concern for the disposition of first year ice," he explains. "We have been able to expand the operational window in the Chukchi Sea, an area with an estimated 29 Bboe of recoverable reserves, from just two months, July and August, to five or six months, working right into November or even December."

"This also means that we can conduct seismic operations in environmentally sensitive areas after the ice has begun to form, when many protected species have completed their summer activities and are moving away to warmer areas, and also without interfering with the summer prime hunting season for the indigenous people."

"Technical risk is also reduced. We have had very little technical downtime during our Arctic surveys, usually something in the order of only 2%. Average seismic vessel downtime in the industry is 7 – 10%."

VIRGIN TERRITORY

Since 2006, ION has shot about 45,000 line kilometres of seismic data in the Arctic, covering waters belonging to Greenland, the US, Canada and Norway. Much of this is in areas where there was either no seismic data, or the quality was too poor to be used for exploration purposes. In 2010, two crews worked the Arctic using the [IA] Arctic Solution, producing excellent images of the sub-seabed in Northeast Greenland and the Canadian Beaufort Sea and McClure Straits. The latter is particularly virgin territory, having ice conditions that stopped the SS *Manhattan* in 1969, and was the final resting place for the HMS *Investigator* in 1853.

The results of ION's Arctic surveys have been combined in its ArcticSPAN™ multi-client data program that covers the Beaufort-MacKenzie, Banks Island, Chukchi, East Greenland Rift, and Danmarkshavn basins. The program gives geoscientists a basin-level tool for interpreting new petroleum systems in the offshore Arctic region. Joe and his colleagues believe that such basin-wide studies will help exploration companies to focus their resources, as the lines transect key geological features and also wells, where present, to place the geology in a basin-wide context.

PRODUCTION IN TEN YEARS?

With an estimated 90 billion barrels of oil and possibly a third of the world's undiscovered gas reserves, the Arctic is heating up for oil and gas exploration, and is surely the next, and possibly the last, great frontier region. With so little good quality seismic data available, oil companies need all the help they can get to evaluate this fascinating but challenging area.

"Companies love the data they can get from our new under ice acquisition techniques," Joe says. "But exploiting this area will not be rapid; we estimate that it will need significant investment now on the part of the oil companies, in order to see production in ten years time.

"We believe that by obtaining high quality data over a longer annual survey period, companies can move closer to achieving the goal of producing oil and gas from the Arctic waters," says Joe.

Joe Gagliardi is ION Geophysical Corporation's Director of Arctic Solutions & Technology, where his focus is on the development of proprietary solutions (equipment & procedures) for the acquisition of Multi-client and proprietary seismic surveys in the global Arctic region. He is a graduate of Rice University's Executive MBA program and holds a B.S. in Geological Oceanography from Florida Institute of Technology.

Mining Heat

Since the time of the Romans, Cornwall, in the extreme southwest of the UK, has been known for mining minerals, especially tin. Could the future of this region be in mining heat?

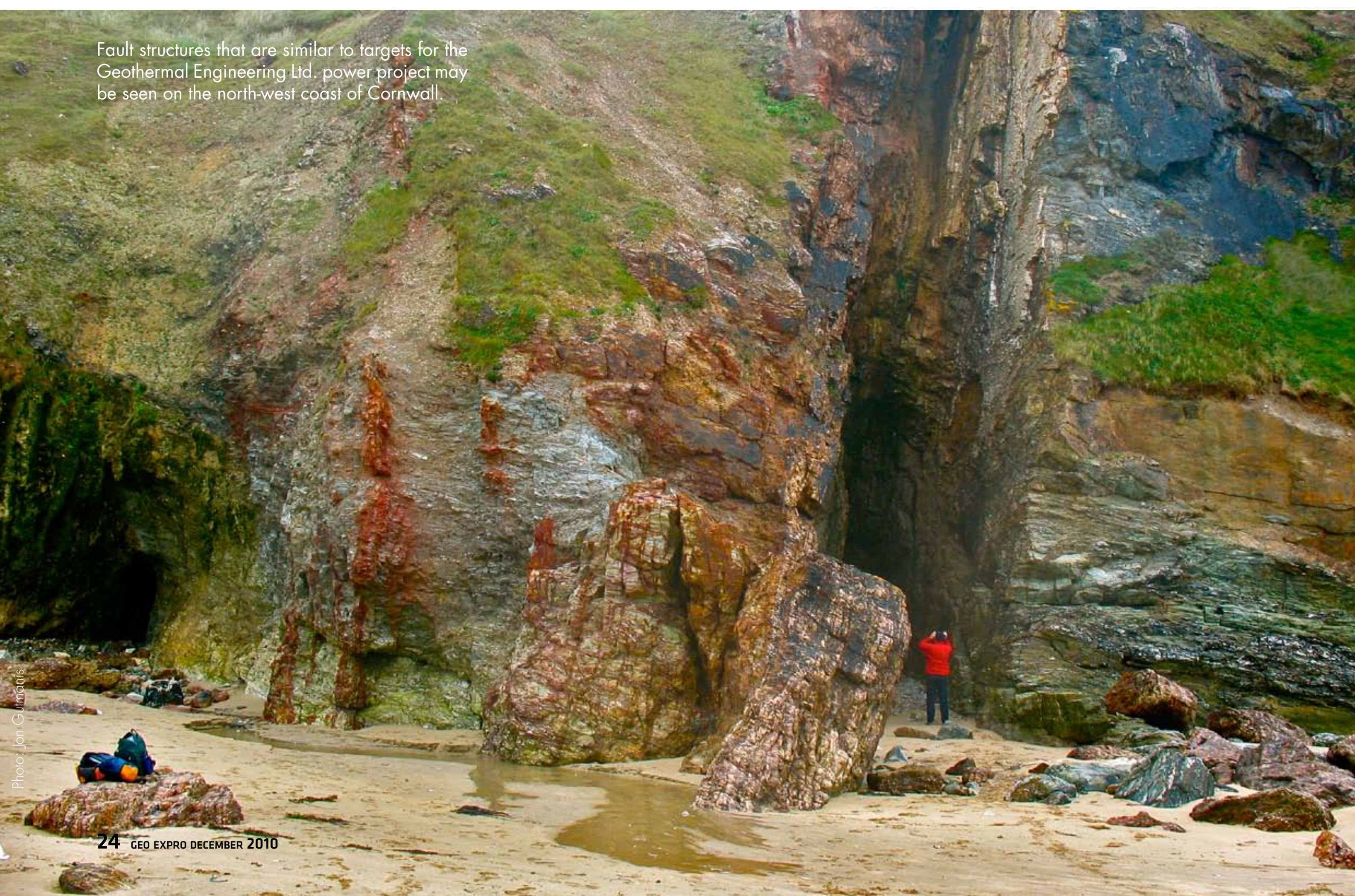
PAUL WOOD

Renewable energy sources are in the news these days. Although projections by bodies such as the International Energy Agency (IEA) say that hydrocarbons will be around for many decades to come, conventional resources are more elusive and unconventionals like tight gas are costly to develop. Renewables are becoming economic and have the added benefit that they do not produce emissions. But they also have problems. Wind turbines are often intrusive, noisy and may disrupt wildlife. Large scale projects like tidal power stations are accused of potentially huge environmental impact. Solar needs large spaces and is not efficient, particularly in northern latitudes. Crucially, they do not operate continuously - they are not 'always on'.

HOT DRY ROCKS

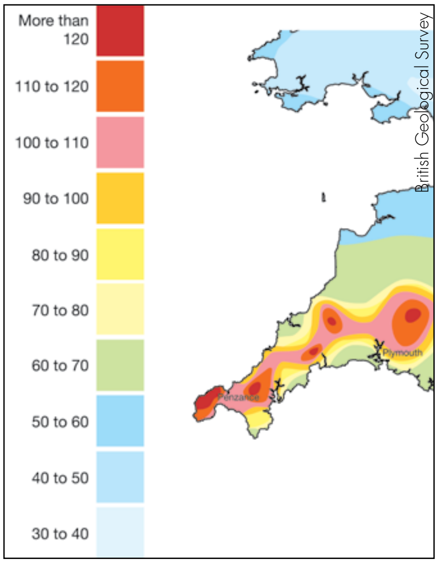
But what if it were possible to have a reliable and constant energy source that produced no emissions and had a minimal impact on the environment? That is just what a research group based at the Camborne School of Mines in Cornwall at the south-western tip of the UK aimed for in the 1970s and 1980s. Their 'hot dry rocks' project, sponsored by the UK Department of Energy (DoE), looked at the possibility of taking advantage of the highest heat flow in the UK, as measured by the British Geological Survey (BGS).

The geology of Cornwall is dominated by igneous rocks, mostly granite. The granite contains radioactive minerals that add to the background geothermal gradient, making the Cornish rocks a UK hot spot. In addition, the



Fault structures that are similar to targets for the Geothermal Engineering Ltd. power project may be seen on the north-west coast of Cornwall.

Photo: Jon Gutmanis



Heat flows in the South-West of England (mW/m²)

history of mining for tin and other minerals over hundreds of years means that there is a lot of geological information about the sub-surface, including knowledge of the strike-slip fracturing systems that the miners called 'cross-courses'.

The hot dry rocks project succeeded in demonstrating the feasibility of pumping water through these natural fracture systems, but did not reach sufficient depths to access the temperatures that would be needed to generate power. With the data from the project, it was estimated that wells 6,000m deep would have to be drilled, which at that time was uneconomic. A number of technical issues still remained to be addressed, so the DoE decided to focus on the European Commission's (EC) joint European geothermal project, which has a pilot plant at Soultz near Strasbourg in France.

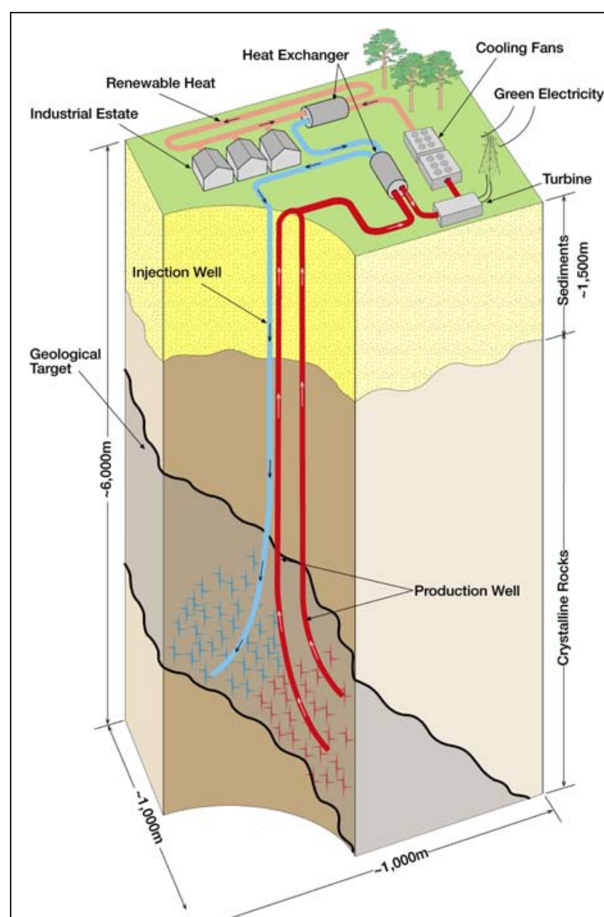
One of those involved in these early stages, initially on the hot dry rocks project, and then as Geothermal Technical Coordinator for the EC, was Peter Ledingham, now Operations Director with UK consultancy company GeoScience Limited and based at Falmouth in Cornwall. "Everywhere on the planet, it is hot at depth, eventually," says Peter. "Hot dry rocks have been reinvented as EGS - enhanced or engineered geothermal systems. What we are looking for in Cornwall is something between hydrothermal, where hot water or steam exist naturally underground, and true hot dry rocks where you have to make the reservoir yourself by fracturing it."

GEOTHERMAL ENGINEERING

With higher energy prices and the increased importance of low carbon sources, the idea of EGS is more prevalent and people are again prepared to invest in it. Geoscience Ltd was initially formed as a geothermal company in 1985 but has since branched out into the oil and gas business. As well as geothermal engineering, the company offers specialist services such as wellbore stability, sand production and in-situ stress assessments, and also fractured reservoir characterisation and stimulation analyses. A few years ago, Geoscience Ltd was approached by Ryan Law, an Oxford-trained geologist who is now Managing Director of the specialist company Geothermal Engineering Ltd. Ryan had taken the lessons learned from the Camborne project and tried to see where it might be possible to set up an economic geothermal power project.

GeoScience Ltd is now a partner and technical adviser to Geothermal Engineering. They have brought a lot of geology and engineering expertise into the project and especially their knowledge of fractured reservoirs. Peter Ledingham is also a Director of Geothermal Engineering. The joint studies of the two companies have highlighted an area near Redruth, about 10 km north-west of Falmouth, that combines one of the hot spots of heat flow from the Geological Survey map with a fault system that can be seen on the coast and mapped from the mining data. Standing on a currently deserted industrial site within an old mining area, Peter explains how the power plant should work.

"We will drill three boreholes," he says. "One will be the injector well and there will be two production wells. This will give us an improved fluid flow and the production needed for a plant of 10 megawatts capacity. Our modelling tells us that we need to achieve 150 kg/sec circulation and we expect the circulatory system to be in natural fractures in the faulted structure, though we don't rule out having to apply some hydraulic fracturing." Water will be pumped into the injector well and then flow through the fracture system, picking up heat until it is at about 200°C. It will then flow back through the production wells and into a heat exchanger, with surface temperatures at about 175°C. From the heat exchanger, hot fluids feed into a turbine that will produce 10 MW gross power, with around 7 MW expected to be delivered into the electricity grid. Up to 55 MW of thermal energy at around 60-70°C could also be available for industrial or domestic space heating in the area if the infrastructure is put in place.



Schematic diagram of geothermal circulation system and power plant

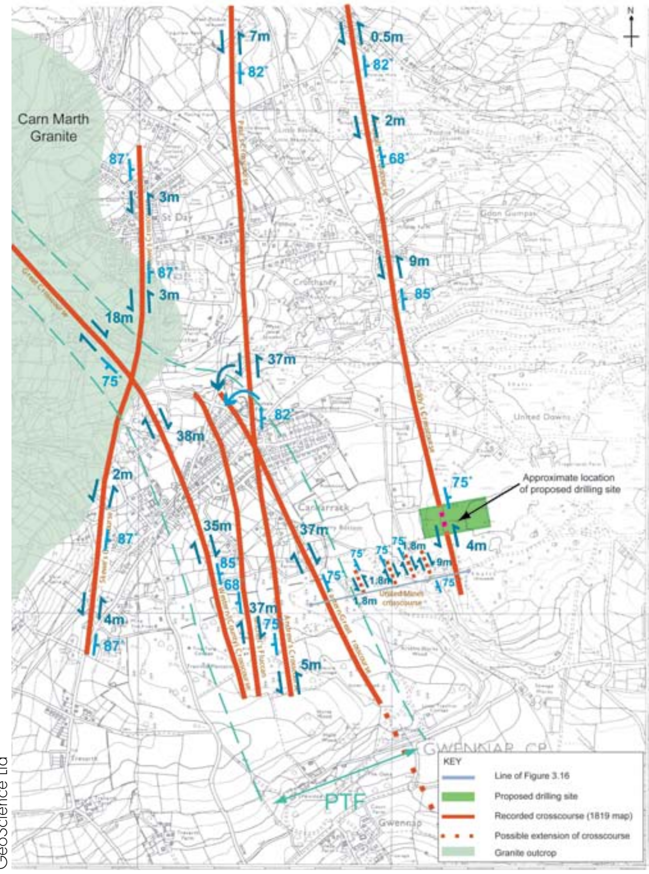
UNCERTAINTIES AND CHALLENGES

There are several uncertainties in the project, the main one of which is the presence of a good enough fracture system at the depths where the right temperatures are expected. A number of seismic lines were shot both before and during the hot dry rocks project. But mostly the interpretation relies on surface mapping and geological records from the mines, though the deepest of these are only 900m below the surface.

Jon Gutmanis, Chief Geologist at GeoScience Ltd and a specialist in fractured reservoir characterisation, has interpreted a fault zone across Cornwall that is well defined on the north coast and can be seen in outcrop in cliffs near Perranporth. He says "the cross-courses are mainly strike-slip faults - the family of late Variscan structures that cut across South-West England. Cross-course was the miners' term for these faults because they are orthogonal to the east-north-east to west-south-west trending mineral lodes, and shift them sideways. On the geological map we have indicated the interpreted fault zones near the drilling site. The blue dashed lines show the structural zone that constitutes our target. At the surface, this is the Porthtowan Fault Zone. Our plan is to intersect it at around 4.5 km depth."

Some hydrothermal projects have in the past encountered problems with dissolved minerals dropping out of solution as the fluid temperature decreases. The project team members do not expect a lot of mineralisation here though, nor do they expect problems with fluids leaking away from the fracture system as it is relatively well confined. A challenge they will have, however, is on the drilling side. The wells will have to be drilled through about 1,000m of low-grade metamorphic rocks (Devonian slates) before encountering the granite and will still then have 4 km or more of that to penetrate. The target is a steeply dipping fault zone and there is some positional uncertainty. More geoscience techniques could be brought into play here as they may conduct downhole seismic surveys to help steer the well to the target. One thing they will do is augment an existing BGS microseismic system to improve it as a network to monitor 'environmental' events. They will also install their own 'engineering' network to monitor and manage reservoir growth.

Drilling will as far as possible use standard oilfield techniques and hole sizes, the need for an economic fluid circulation volume dictating that the bottom hole section diameter should be 8½ inches. The Camborne project, which reached nearly 3 km drilling depth, has provided some experience, but the remaining uncertainties mean that funding the project has been difficult. Many parties have shown interest but full funding has yet to be obtained, delaying the project start until 2011. Geothermal Engineering Ltd plan to drill the first hole, then evaluate the results and possibly conduct some stimulation tests. Once they have demonstrated the viability of the project, they are confident that funding will not be a problem.



Map of the interpreted fault structures near the proposed geothermal plant

GeoScience Ltd

DOUBLING THE CAPACITY

A hurdle that still remains is political. In other countries, including the USA, Germany and Australia, there are incentives that make it attractive to pursue geothermal technologies. World-wide there is around 10 GW of installed geothermal capacity and it is expected this will double in five years. But there are still no geothermal leases in the UK and no legislation. Heat is not a physical commodity, so it is not yet clear how ownership will be determined.

So is this a good business for geoscience students to try to get into? "At present the UK is not running any geothermal student programmes," says Peter. "But if we can do what we want to do, we will be hiring." He concludes, "globally, geothermal should and could be much more important than it is. The potential for the south-west of the UK is for 300 MW electricity, enough for half a million homes. The game has changed."

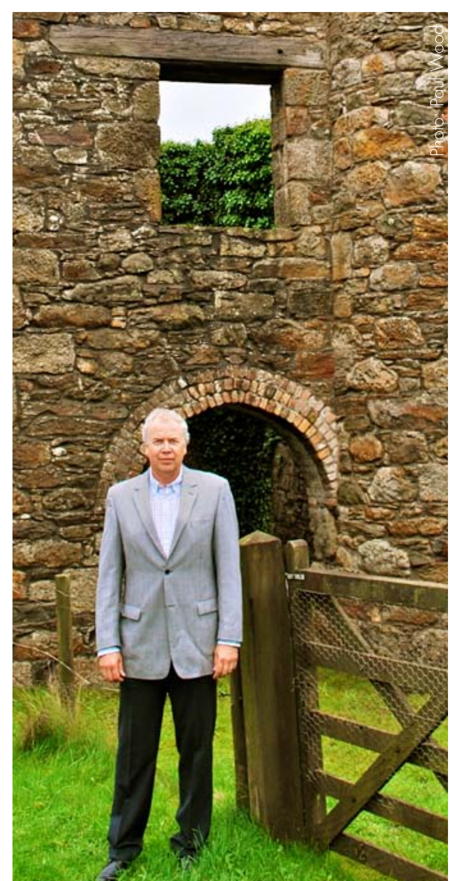


Photo: Paul Wood

Peter Ledingham at an abandoned mining engine house near the site of the geothermal project.

BAY OF BENGAL:
Many Possibilities and Challenges Ahead

Flanked by the young, growing and energy hungry populations of India, Bangladesh and Myanmar, the Bay of Bengal finds itself an increasingly hot property in the search to discover new hydrocarbon reserves.

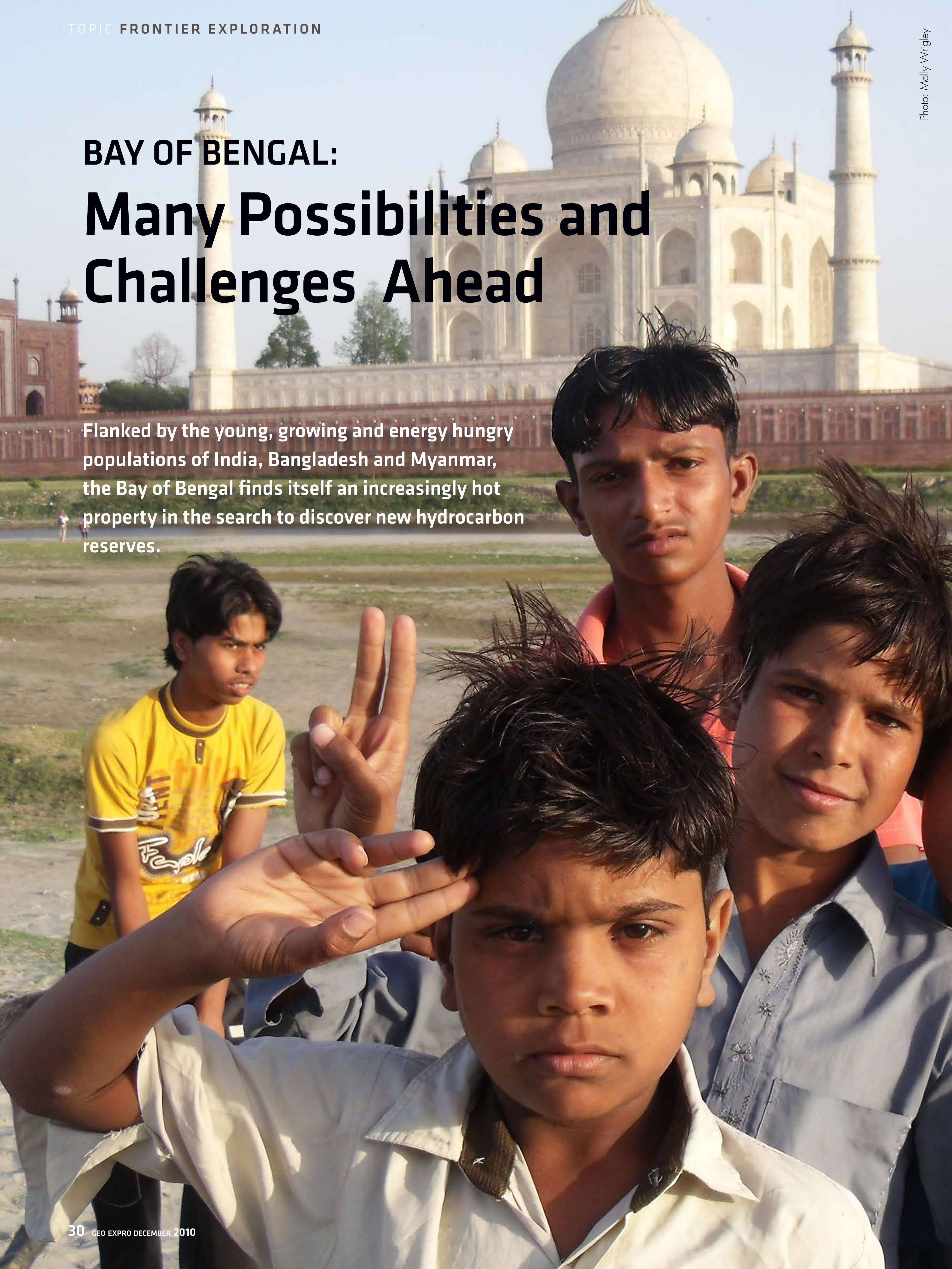


Photo: Molly Wrigley

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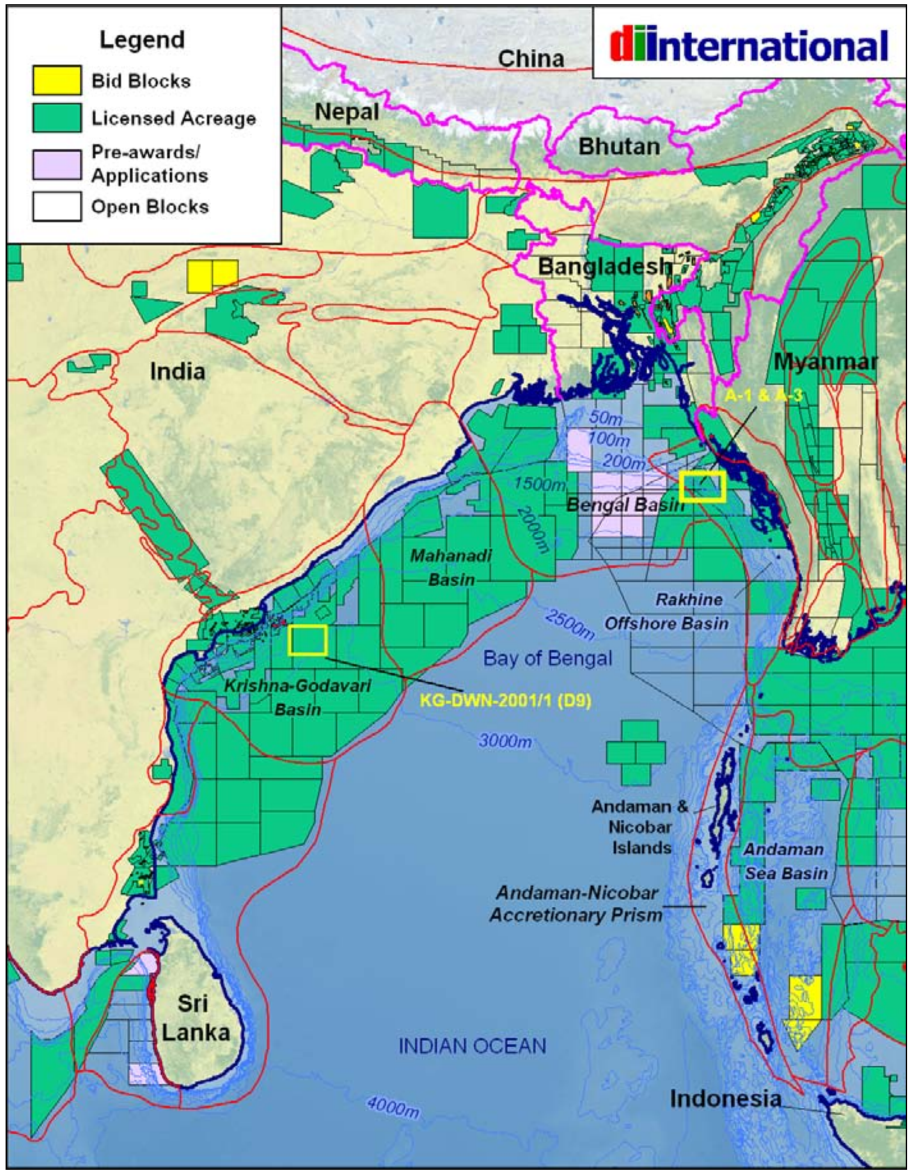


The major sedimentary basins and current blocks under lease in the Bay of Bengal.

Located in the north-eastern part of the Indian Ocean, the Bay of Bengal was largely ignored by international oil and gas companies until the turn of the decade. Since the late 1990s, however, India's revamped New Exploration Licensing Policy (NELP) has led to more than 60 offshore exploration blocks being issued along its east coast. Exploration has yielded some significant gas discoveries, with Reliance Industries Ltd commencing production from its hugely significant **Dhirubhai** deep water gas development in April 2009. Production now stands at 2.1 Bcfpd and has virtually doubled India's gas output.

East of India lies **Bangladesh** and the **Bengal Fan**, *the world's largest fluvio-deltaic-slope fan* complex. The country has only one producing gas field in the Bay of Bengal and efforts to lease the offshore are hampered by unresolved maritime boundaries with India and Myanmar. ConocoPhilips, however, signed a preliminary deal with Petrobangla (Bangladesh Oil, Gas & Mineral Corporation) in October 2010 to explore deep water blocks in the Central Bay area, which could signal a change in leasing policy.

Finally, exploration of the eastern portion of the bay is heating up along the west coast of **Myanmar**. Much of their offshore acreage remains underexplored and some basins are still considered to be frontier areas. Recent gas discoveries have led to very active leasing offshore, but disputes over maritime boundaries could again slow exploration.

Off India's East Coast

Of all the basins in the Bay of Bengal, the **Krishna-Godavari (KG)** is probably the best understood geologically and the most explored. It stretches 500 km along the east coast of India and extends more than 200 km offshore. Geologic settings include coastal, deltaic, shelf-fan, deep-sea channel and a deep water fan complex.

Cairn Energy made the first deep water discoveries in the Basin with a number of small oil and gas fields on block KG-DWN-98/2 prior to transferring operatorship to India's state owned oil and gas company, ONGC. The discovery of a supergiant gas field in 2002 by India's largest private sector E&P company, Reliance Industries Ltd, along with a number of smaller gas fields, has helped the basin emerge as an attractive exploration area. The in-place resource for the KG-DWN-98/3 (D6) deep water block, which incudes the Dhirubhai discoveries, currently stands at an impressive 25 Tcf. Gas production commenced in April 2009.

Most of Reliance's reserves are found in Pliocene-Miocene reservoirs. They have a three tier exploration play for the basin; biogenic gas in Pliocene to Pleistocene reservoirs, a Miocene turbidite fairway and a thermogenic petroleum system within the Paleocene and Upper Mesozoic. The company is actively using sequence stratigraphy to link the depositional elements, ranging from fluvial to deepwater, on a regional scale.

Other significant gas discoveries in the KG Basin have followed. Gujarat State Petroleum Corporation Ltd (GSPCL) discovered the **Deen Dayal** gas field with an in-place resource of 2-3 Tcf in 2005. Since then, they have made eight additional discoveries in Cretaceous reservoirs.

Reliance has also been actively exploring the basin north-east of the KG Basin, the **Mahanadi Basin**. This formed as a result of rifting during the Jurassic and Early Cretaceous. Early Cretaceous basaltic volcanism separates a younger drift phase of Late Cretaceous to Early Tertiary age. Reliance is exploring for biogenic gas in Miocene to Pliocene Bengal Fan sediments and has a thermogenic play in deeper water. They have found about 3 Tcf gas in eight discoveries in shallow water off the coast of Orissa. ONGC has drilled 11 exploratory wells targeting both the shallow and deep water plays, resulting in three gas discoveries.

A third basin off India's east coast is the **Bengal Basin**, north of the Mahanadi Basin. More than 40 wells have been drilled with no discoveries to date. It looks at this time that a viable petroleum system has not developed due to poor source and reservoir rocks and a lack of major structural features.

ATTRACTIVE FUTURE FOR OFFSHORE INDIA

The success that Reliance, GSPCL, Cairn Energy and ONGC have had in exploring the east coast of the country cannot be disputed. Their exploration efforts have resulted in an *estimated in-place resource of over 40 Tcf*, with significant upside expected from both the Krishna-Godavari Basin and Mahanadi Basin over the next few years.

Reliance, in particular, has high expectations from its KG-DWN-2001/1 (D9) and MN-DWN-2003/1 (D4) deep water blocks. On D9 they have identified leads in the Pliocene-Miocene, Oligocene and Cretaceous as aerially large structural closures in the northwest corner of the acreage. A Pleistocene channel in the south-east portion of the block in ultra-deep water is a fourth target. Initial exploration will focus on amplitude anomalies within structural closure in the Miocene and Pliocene. Their first well was plugged and abandoned in October 2009 where the targeted Miocene slope fan sands were of poor reservoir quality. In their D4 Block, three drilling locations have been selected to target multiple reservoirs in a deep-water fan system.

ONGC is also hoping to increase the current in-place resource (6.5 Tcf) of its KG deep water blocks through a committed appraisal program. They are seeking to develop both the Northern Discovery Area (3 Tcf) and the Southern Discovery Area (3.4 Tcf) of the KG-DWN-98/2 block – the southern part concentrating on the development of its UD-1 ultra deep water gas discovery, which lies in a water depth of 2,840m.

The recent discoveries have brought in several international E&P companies new to the area, including BG, BP, Eni, Petrobras, Santos and StatoilHydro – most of whom gained a foothold on the east coast through farm-in deals and asset swaps with ONGC. Results have been mixed, with BG, Petrobras and StatoilHydro pulling out of some of their deep water holdings, which could represent a setback for ONGC and its plans for developing a string of discoveries.

BANGLADESH

Offshore Bangladesh sits the great Bengal Fan and the Bengal Basin. Exploration efforts to the west in India have been discouraging in the basin and offshore leasing has been hindered by maritime boundary disputes with both India and Mymamar.

Bangladesh has only one producing field in the Bay of Bengal – the **Sangu Field** operated by Cairn Energy (Capricorn Energy), which

Formation of the Bay

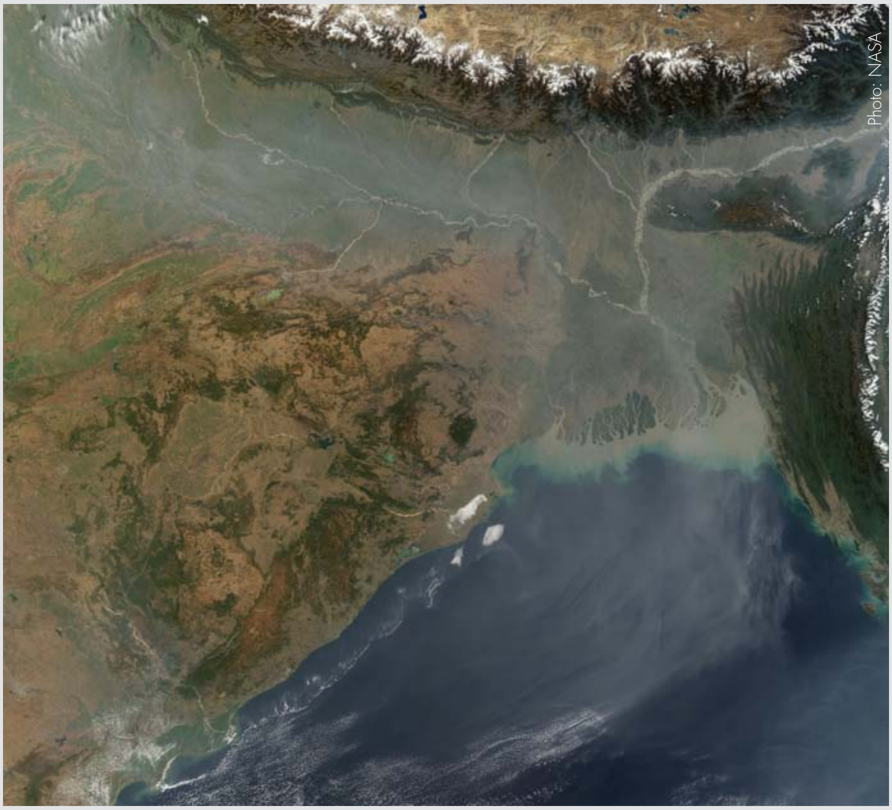
Occupying over 2 million km², the triangle-shaped Bay of Bengal is the largest bay in the world. Along with its size, the geology is complex and varied. The formation of the Bay and its sedimentary basins is a tale of two tectonic regimes: classic passive margin basins on the west side vs. complex fore-arc/back-arc basins on the east side.

Prior to the breakup of Gondwanaland, parts of Antarctica were placed against the east coast of India. Rifting in the Late Jurassic led to the separation of eastern and western Gondwanaland and the development of the Indian Ocean. Subsequent Late Jurassic to Early Cretaceous rifting resulted in the horsts and grabens formation in the Krishna-Godavari Basin and initiated the creation of the Mahanadi Basin off India's east coast. During this time, the junction of India-Antarctica was a five armed rift, a very rare event in plate tectonics. Three of the rift arms failed and rifting along the remaining two arms led to the separation of the once-joined landmasses. The failed rift arms formed aulacogens (furrows) into the India craton that have been exploited by the Mahanadi, Krishna, Godavari and Cauvery river systems which drain eastern India.

Later in the Early Cretaceous, the South Atlantic spreading system became connected to the Eastern Indian Ocean spreading system that was separating Madagascar and Greater India from East Antarctica and Australia, creating a proto Bay of Bengal Ocean. Associated sedimentary basins formed along this rifted passive margin, including rifted grabens and marginal sag basins.

Greater India initially collided softly with Eurasia in the Paleocene. In the early Miocene, it continued its northward drift, resulting in the Himalayan uplift and sediment flow into the Bay of Bengal. Significant increases in sedimentation continue today, extending into the offshore and the deeper waters of the bay.

In contrast with the passive margin along the west side of the Bay of Bengal, the sedimentary basins in the eastern portion of the Bay of Bengal are typical fore-arc/back-arc types. These basins lie east of Andaman and Nicobar islands, an island arc chain that has formed near the boundary between the Indian Plate and Burma microplate. The oblique convergence between the plate boundaries of the Indian Ocean and the Southeast Asian Tectonic plates was initiated in the Early Cretaceous and continues today. This area is very seismically active and the devastating 26 December 2004 Sumatra earthquake occurred along the southern extent of the boundary between the Burma microplate and the India plate.



is on decline and producing just 35 MMcf/d. The offshore, however, remains a vastly underexplored landscape, with only 17 new field wildcats in an offshore area covering 63,000 km^2. Cairn and recent joint venture partner, Santos, were responsible for the drilling of two multi-Tcf prospects (**Magnama** 3.5 Tcf, **Hatia** 1.0 Tcf) surrounding the Sangu Field in late 2007/early 2008, but both were disappointing and require further appraisal. Magnama 1 encountered a number of thin, normally pressured gas bearing sands (20-40m) which may thicken on the flanks of the structure, while Hatia 1 found non-commercial volumes of hydrocarbons and was suspended pending possible re-entry after evaluating the up-dip potential.

The Bangladesh Government finally launched its long-awaited Third Licensing Round in February 2008 – a total of 28 offshore blocks (20 deep water, 8 shallow water) extending up to 200 nautical miles into the Bay of Bengal being offered for competitive bidding. A Fourth Licensing Round, expected in 2011, will include onshore acreage and offshore blocks not taken up in the Third Round.

Two deep water blocks in the Central Bay Area and one shallow water block alongside the Bangladesh-India maritime boundary were awarded respectively to ConocoPhillips, which signed in October this year, and Tullow, but only on the condition that neither company undertakes

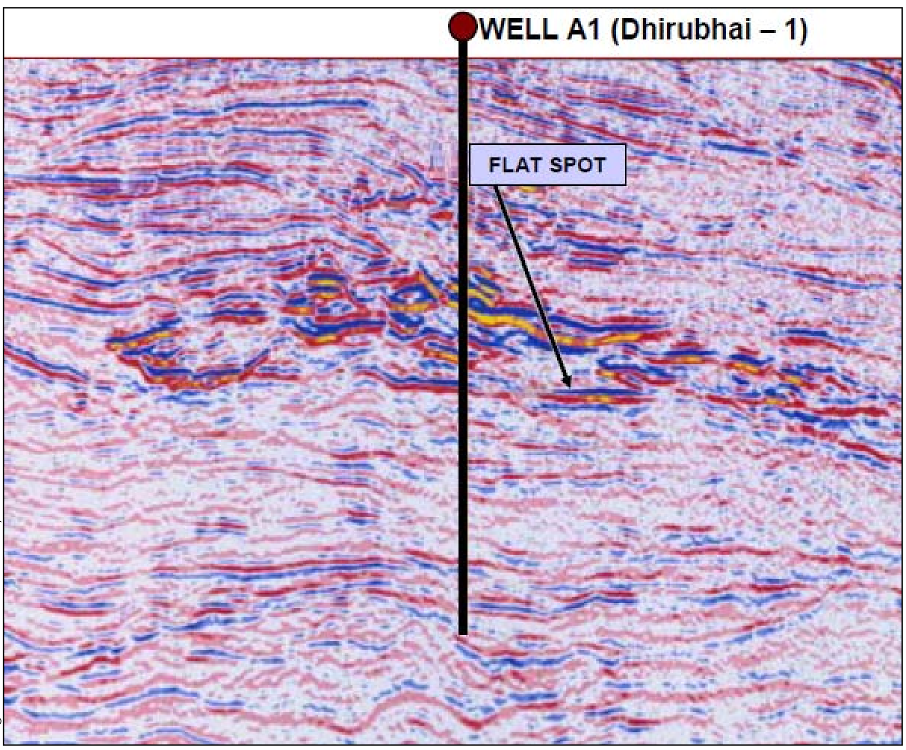


Image: Directorate General of Hydrocarbons (DGH)

Seismic line across the large Dhirubhai 1 discovery drilled on the KG-DWN-98/3 (D6) deep water block in the Krishna-Godavari Basin, offshore eastern India.

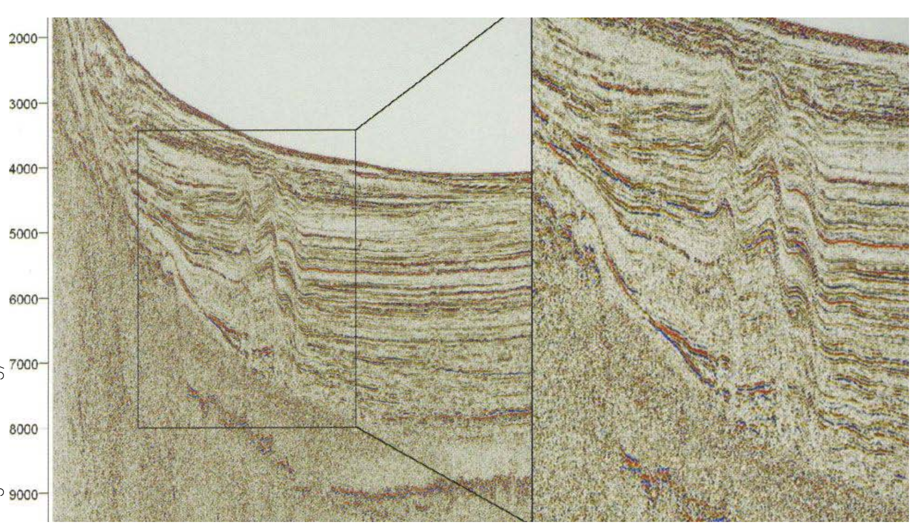


Image: GX Technology

Seismic line showing slope fan prospects in the Krishna-Godavari Basin.

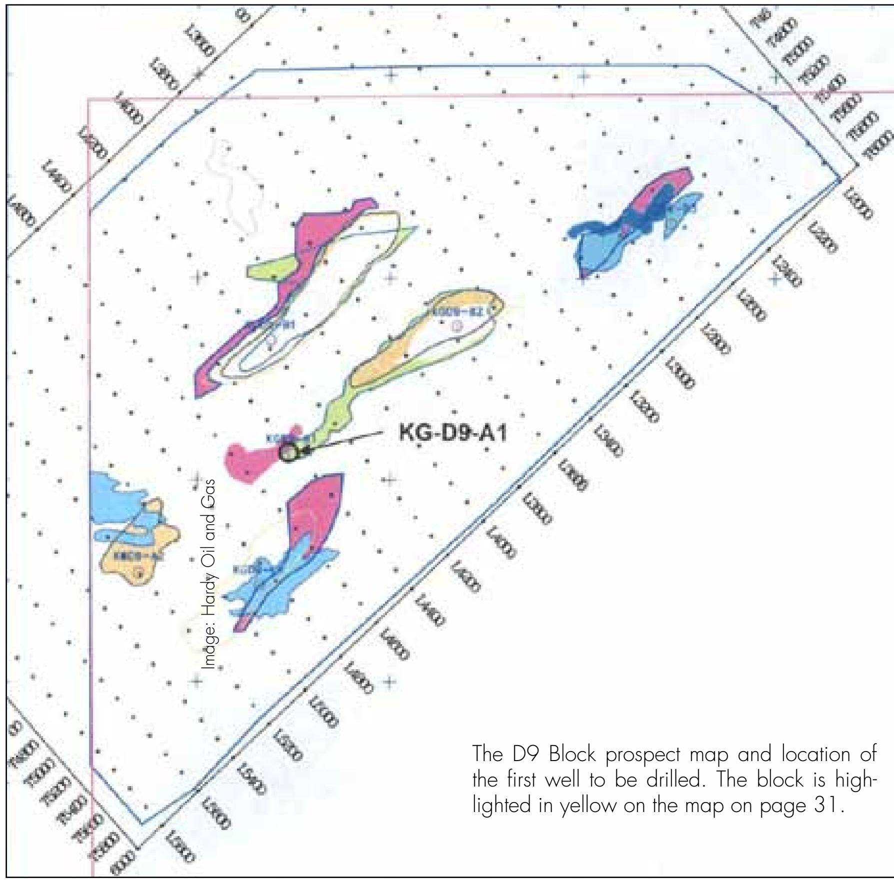
exploration in any internationally disputed maritime area until the dispute is resolved. No PSC has been signed for any of the blocks yet – they have only been approved for award.

MYANMAR

The last piece of the Bay of Bengal pie goes to Myanmar, whose oil industry dates back to the 19th Century when the Burma Oil Company started producing oil from the **Yenangyaung** Field in 1887. Yearly production primarily from three onshore basins peaked at 11.2 MMbo during 1984-1985. Now, major exploration and production activities concentrate on the offshore basins, with production of gas for export beginning in 1998 from the **Yadana** Field. A second major gas field, **Yetagun**, came online in 2000.

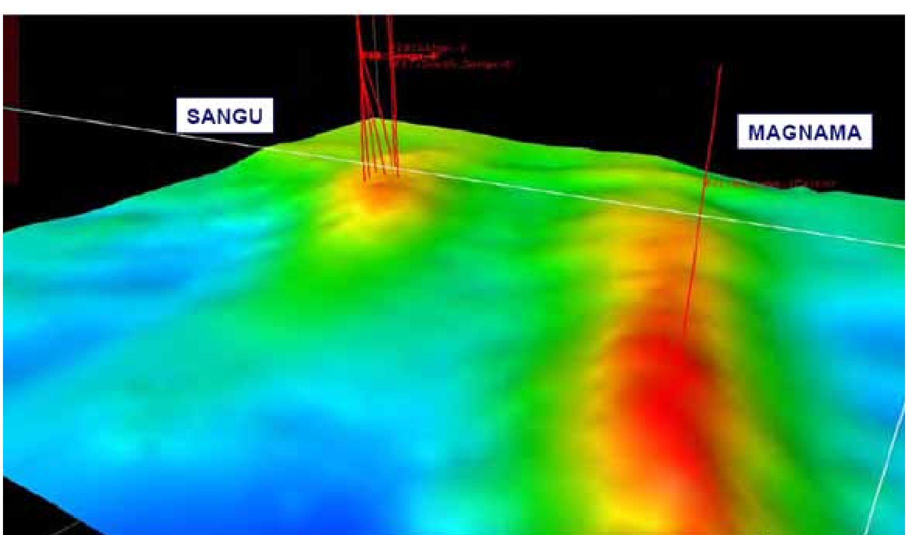
Myanmar's prospective offshore basins are located in a fore-arc/back-arc setting with the Andaman basin separated from the rest of the Bay of Bengal by an island arc system, contrasting with the passive rift basins off of east India. For a detailed overview of the Myanmar fore-arc basins see *GEO Expro* Vol. 7, No. 5, pp. 30-34.

While a number of exploration campaigns were conducted offshore **Rakhine Basin** in the 1970s, it was South Korean company, Daewoo International Corporation who unlocked the potential of this previously non-producing basin. They drilled a deep marine turbidite, Plio-Pleistocene play, resulting in the **Shwe** (2003), **Shwe Phyu** (2005) and **Mya** (2006) discoveries. The in-place resource of the Shwe structure is estimated to be 3.5-5.5 Tcf, while the northern, smaller Shwe Phyu has an in-place resource of 0.5-1.2 Tcf. The southern Mya structure is estimated to have an in-place resource of 1.8-3.4 Tcf. These were the first major discoveries since the Yetagun gas find, 12 years earlier. The company is continuing to explore the area with mixed results.



The D9 Block prospect map and location of the first well to be drilled. The block is highlighted in yellow on the map on page 31.

As a result of Daewoo's success in opening up the Rakhine Basin, virtually all offshore western Myanmar is now under license to international E&P companies, including CNOOC, CNPC, Daewoo Petroleum, and ONGC Videsh Ltd.



• Sangu Gas Field	300m vertical	58 sq. Km SE trending Anticline.
• Magnama	700m vertical	200 sq. Km SE trending Anticline.

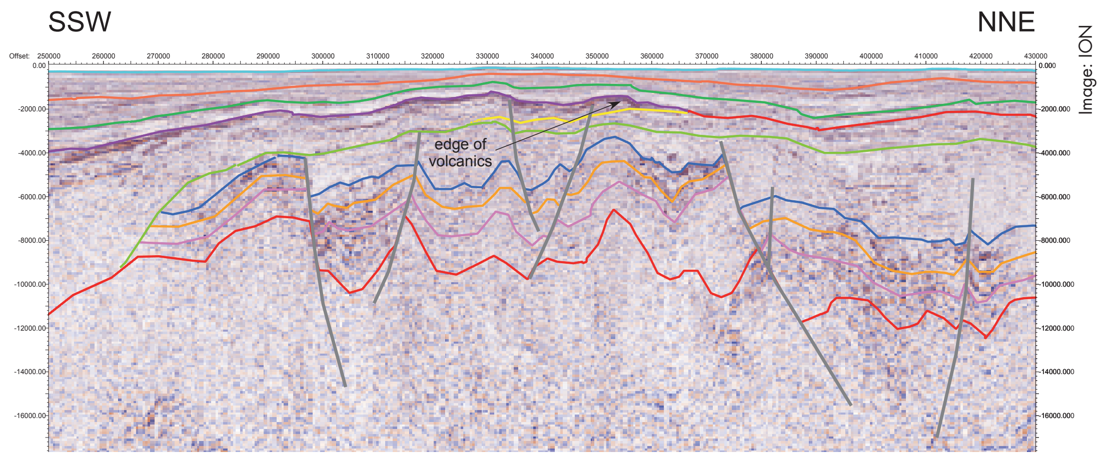
Near Sangu, Bangladesh's only producing field in the Bay of Bengal, drilling of the Magnama prospect was disappointing. New 3D seismic is being evaluated for a 2011 drilling campaign in the area.

UNRESOLVED FUTURE

Recent discoveries in both India and Myanmar point to a promising exploration future for the Bay of Bengal, a future that is burdened with both sub-surface and above ground challenges. The lack of an internationally recognised maritime boundary between India-Bangladesh and Bangladesh-Myanmar is beginning to have a major impact on exploration efforts. The situation between these three energy-starved countries has escalated and intensified in recent years as both India and Myanmar have rushed headlong into offering offshore areas for oil and gas exploration. The recent high profile discoveries in both countries have attracted many international E&P companies to the region, pointing even more for the need to establish officially recognized maritime boundaries.

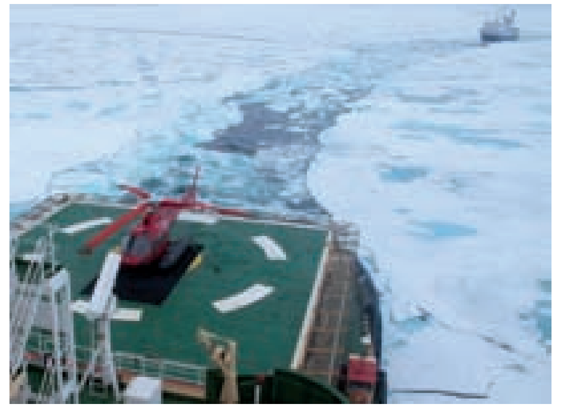
The NE Greenland Continental Margin

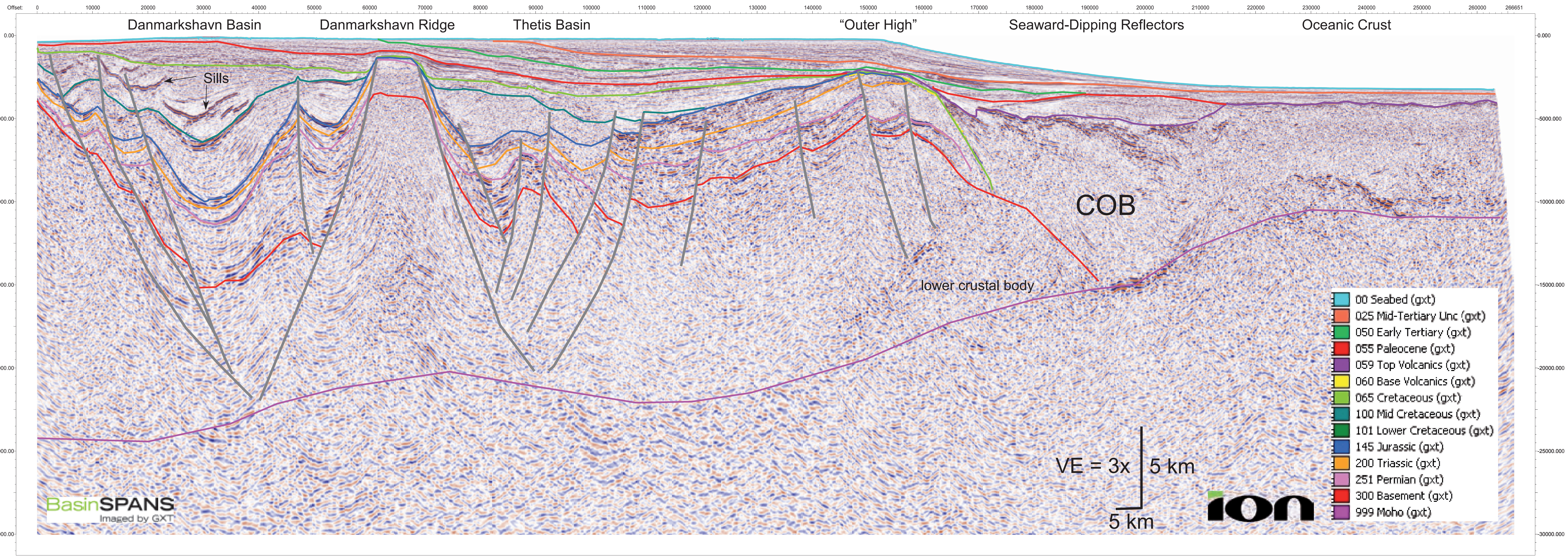
Recently completed regional 2D seismic reconnaissance data adds new insights on the hydrocarbon potential of this challenging unexplored frontier area.



Seismic line 3 showing the continuation of a thick Mesozoic basin beneath lava flows of the Northeast Greenland Volcanic Province. The southern extent of the Danmarkshavn Basin quite clearly underlies the northern part of the Volcanic Province, where Palaeozoic through Cretaceous rocks can be mapped beneath the edge of volcanic cover. The northern edge of the volcanics consists of relatively thin lava flows and there does not appear to be a well-developed volcanic escarpment in this area. (legend on foldout image, line position shown on map on page 39).

Obtaining high quality seismic in and under the ice in Arctic conditions presents many challenges - see page 20.





Representative full crustal seismic profile (PSDM) across the NE Greenland Shelf illustrating the relationships of the Danmarkshavn Basin, Thetis Basin, and oceanic crust. Of particular note are the thickness of the stratigraphic section and the interpreted presence of a Mesozoic section in the Thetis Basin which is evident on the new data. The likely presence of Mesozoic strata is strong evidence that rich oil-prone Jurassic source rocks are present in the outer Greenland shelf area. The survey also images intra- and sub-basalt reflectors on the volcanic margin where seaward dipping reflectors (SDRs) are interpreted. Line position shown on map on page 39.

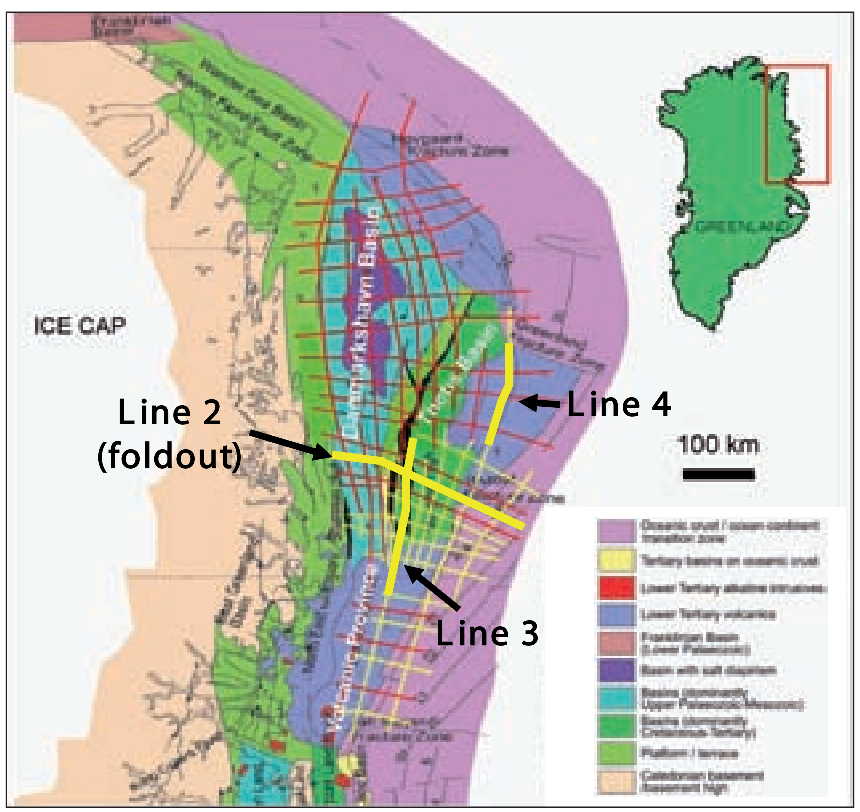
Under the Ice Floes of Greenland

MENNO G. DINKELMAN, JAMES W. GRANATH AND RICHARD WHITTAKER

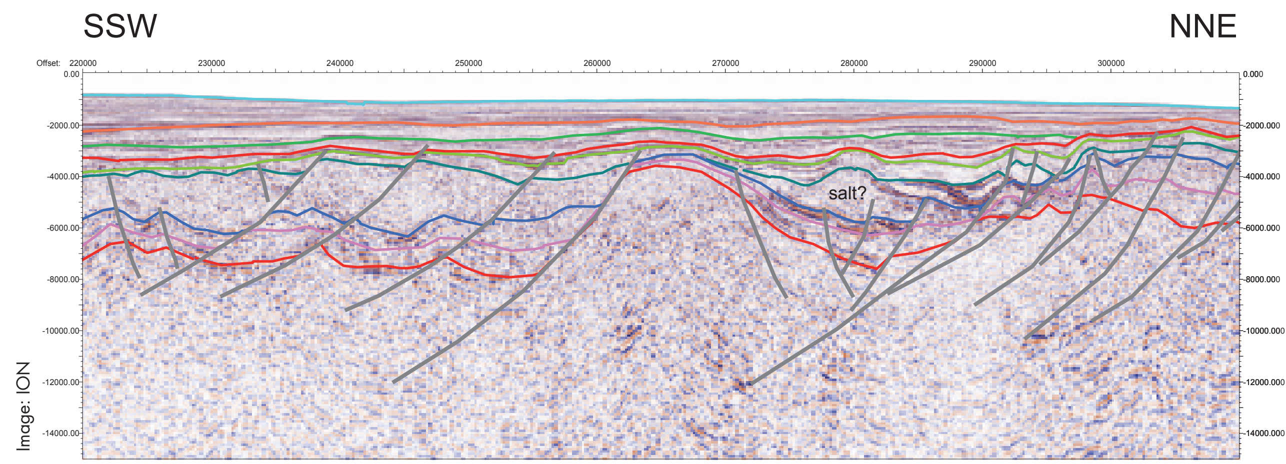
With an estimated 31+ Bboe of oil and over 86 Bcf of undiscovered gas resources, exploration across the Arctic is heating up, notwithstanding the area's sparse geotechnical data base, considerable geological uncertainty, harsh and often rapidly changing weather and oceanic conditions and the enormous technical challenges.

The North East Greenland shelf and slope is the conjugate margin to the Lofoten and Vøring Margins of Mid-Norway and the adjacent region. Pre-stack depth migrated (PSDM) seismic lines were used for the interpretation, which was tested iteratively against gravity and magnetic modeling. The seismic data also images intra- and sub-basalt reflectors in the volcanic province and on the marginal high where seaward dipping reflectors are interpreted. Several of the lines cross the Continent Ocean Transition (COT) where they clearly show deep reflectors at around 10 km which may represent the Moho. These deep reflectors plunge west to about 22-25 km depth towards the Greenland continental crust.

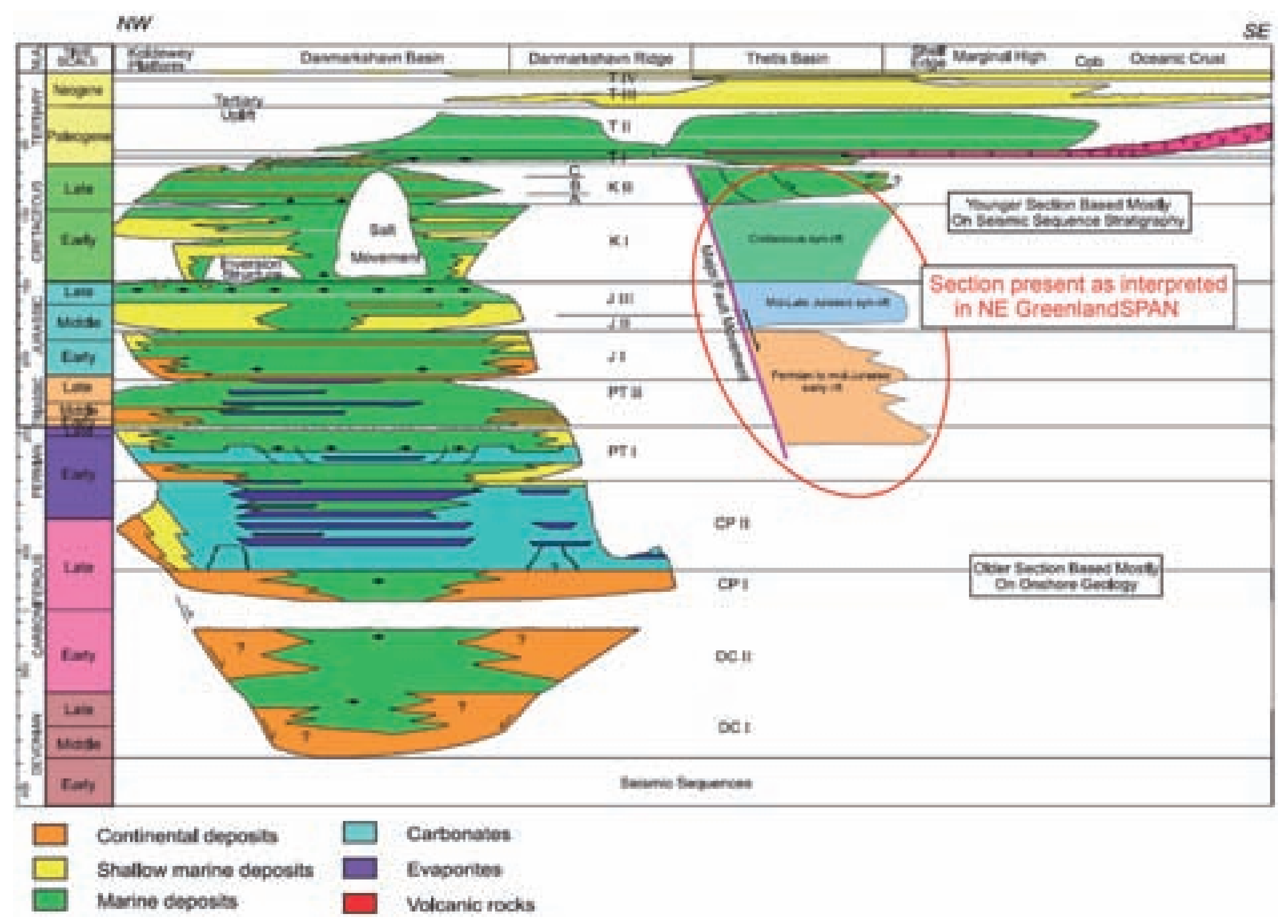
The data show a very thick sedimentary sequence in the southern part of the Danmarkshavn and Thetis Basins which is at least 9 km. Both basins are interpreted to include a thick Mesozoic section. Older Palaeozoic sediments are also thought to be present in the Danmarkshavn Basin and subcrop along the Danmarkshavn Ridge which forms a prominent structural high separating the two basins. Extensive syn-rift faulting is interpreted along the eastern and western margins of the Danmarkshavn Ridge and large scale folding and doming have affected the area since break-up, leading to the development of potentially large hydrocarbon traps. These observations, together with comparisons with the conjugate Mid-Norway margin, reinforce previous interpretations that the area has excellent hydrocarbon potential. Information gained from the new deep long-offset seismic survey in NE Greenland also provides input for a revised plate tectonic model of the North Atlantic.



Tectonic elements in NE Greenland (after Hamann et al, 2005) with the location of the Phase 1 (yellow) and planned Phase 2 (red) NE GreenlandSPAN seismic surveys grids. The main objective of the Phase 1 of the survey was to provide a better understanding of the basin architecture at the crustal scale and the petroleum systems in the offshore areas ranging from the North-east Greenland Volcanic Province in the south, north into the southern Danmarkshavn Basin, and eastward into the Thetis Basin and along the continental slope.



Seismic line 4 from the outer part of the NE Greenland Shelf showing a relatively thick Mesozoic section with volcanic and possible salt intrusives. A phase of intra-Cretaceous rifting is also interpreted. Recurrent faulting has controlled the post-Caledonian sedimentation, which also appears to have been reactivated during opening of the Atlantic. Extensive synrift faulting is interpreted along the eastern and western margins of the Danmarkshavn Ridge, and large scale folding and doming have affected the area since break-up, leading to the development of a wide variety of potentially large hydrocarbon traps. (legend on foldout image, line position shown on map on page 39).



Stratigraphic architecture of the NE Greenland Shelf (after Hamann *et. al.*, 2005), modified in the highlighted area based on the interpretation of the new seismic data. These new data show a thick sedimentary sequence (>9 km) in the southern part of the Danmarkshavn Basin and indicates the presence of a similar stratigraphic section in the Thetis Basins. Both basins are interpreted to include a thick Mesozoic section, as well as older Palaeozoic sediments that subcrop along the Danmarkshavn Ridge.

A LONG AND WINDING ROAD

© BP plc

The 1,300 km long Trans Alaska Pipeline System carries oil from the North Slope of Alaska to Valdez, the northern most ice-free port in Alaska. It was completed in 1977 and crosses three mountain ranges and over 800 rivers and streams.

The North Slope of Alaska is a cornerstone of US oil production with several giant fields, notably Prudhoe Bay, Kuparuk and Endicott, plus extensive heavy oil at Ugnu and West Sak. The generation that discovered these fields is almost gone; what can we learn from their efforts?

"Success has many fathers, failure is an orphan" is an adage that applies very well to exploration. In addition, there seems to be a tendency for successful explorers to attribute their past discoveries to rapier-like thought and dynamic execution, whereas reality is often more complicated. The history of exploration efforts on the North Slope of Alaska illustrates this quite well.

SEEPS WELL KNOWN

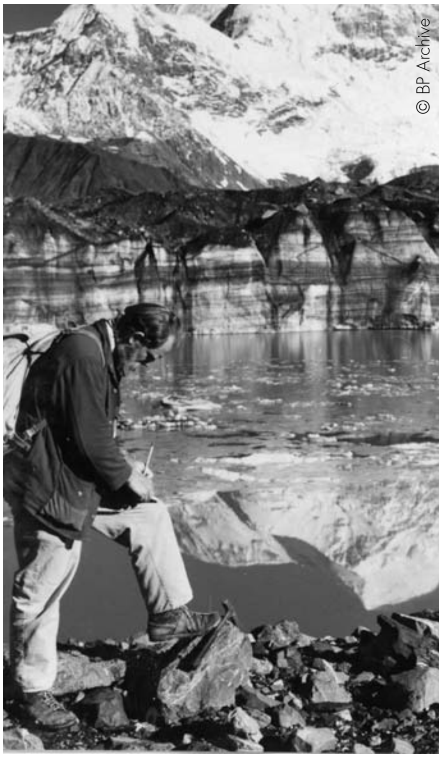
In 1826, a British naval polar expedition under John Franklin sailed into a small inlet on the north-eastern coast of Alaska and named it Prudhoe Bay, after a small village in north-east England. Long before this, however, the Eskimos had known about and utilised oil and gas seeps along the north coast of Alaska, east of Prudhoe Bay. These were examined by prospectors and the US Geological Survey (USGS) from 1917-1921, after which some oil claims were staked.

Following World War 1, the US Department of the Navy financed USGS field work to establish the geological framework of the North Slope region. A significant report was written in 1930 but by this time interest had waned, as there were prolific oil sources elsewhere. However, in 1943, with supplies under pressure in the midst of World War II, the US Navy launched a rigorous assessment program which encompassed extensive geological mapping, gravity and magnetic surveys, widely-spaced reflection lines, and drilling (a total of 45 core holes and 37 wells), leading to the discovery of three modest oil accumulations and two gas fields, mostly in the folded foothills.

This information, coupled with the experience of how to operate in Arctic conditions, became available in the early 1960s and was invaluable to the imminent exploration of the region.

OIL COMPANIES ARRIVE

BP's interest in Alaska stemmed from a strategic ambition to diversify away from its main source of crude oil, namely Iran, where its reserves had been nationalised (for a while) in the early 1950s. The company's experience and success in the Zagros foldbelt of Iran and Iraq influenced the choices made, one of



A BP party leader in 1961 taking geological notes with the Agassiz Glacier and small glacial lake in background. Behind is Mount St Elias, the third highest mountain in North America

which was the North Slope.

In late 1959, BP formed a joint venture with the Sinclair Oil and Gas Company, a significant USA downstream operator with almost no access to crude oil, whereas BP had copious supplies from the Middle East. As an adjunct to this supply agreement, the two companies agreed to work together on exploration and this eventually led to activities in Alaska, where BP's true and tried exploration concepts were to be applied.

These concepts were, simply stated, to drill the big obvious anticlines, if at all possible near oil seeps. This approach defined a first exploration phase, when the large and obvious foothills anticlines which were at least indirectly associated with oil seeps were drilled. Apparently, the US Navy's data on reservoir presence was not reviewed and structural interpretations were weak - seismic data was generally of little value at this time.

This early program was a failure; only one marginal gas discovery was made, although numerous oil shows were found.

The next step for the joint enterprise was exploration on the coastal plain of the Central North Slope. The first North Slope lease sale was held on 9 December 1964. The prevailing industry wisdom had become that the highest structure in the area, the Colville feature, was the best prospect, with the Prudhoe Bay feature second. Accordingly, BP/Sinclair bid more strongly on the former and won whilst losing the crest of the latter to Richfield/Humble (later Arco and Exxon) – but with BP winning the flank acreage - Sinclair had apparently gone cold on the area.

In 1965 BP/Sinclair drilled the Colville No. 1 well on the Colville High. Whilst it established the presence of oil shows in pre-Cretaceous rocks offering the best reservoirs seen to date on the North Slope, the well was deemed disappointing and also a negative signal for prospectivity at Prudhoe Bay. There was then a serious possibility that BP would opt out of the entire basin, dependent on the result of Richfield/Humble drilling their crestal Prudhoe acreage. Thus, when a January 1967 lease sale offered the remainder of the crestal Prudhoe structure lying offshore, it was scooped up by Richfield/Humble against little opposition.

A DISCOVERY AT LAST!

Also in January 1967, having drilled a dry hole in the foothills - and resisting corporate pressure to abandon their North Slope exploration program - Richfield/Humble moved their rig to the location of the Prudhoe Bay State No. 1 well. They commenced drilling in April and were to continue for most of the year.

After an offer to buy BP's flanking acreage - long considered, debated and finally spurned by BP - Richfield/Humble announced a discovery in January 1968, testing oil in the March of that year.

Throughout 1968 progress was still relatively hesitant, in retrospect because the discovered hydrocarbon phase was much more gassy than anticipated. However, Richfield/Humble announced in June 1968 that they would drill a confirmation well, Sag River State No. 1, 10 km south-south-west of the Prudhoe Bay discovery well. Finally, BP mobilized a rig to the flanks of Prudhoe Bay which spudded the Put River #1 well in November, and discovered an extensive oil column.

What had until then escaped everybody in the industry – and appears so obvious with the benefit of 20/20 hindsight – was that the Prudhoe Bay field, which is what had been discovered, had an enormous gas cap and that it was the flanking acreage which covered the vast oil rim. A 'foreign oil company' had secured the major oil discovery with around 30 billion barrels in place in a province where gross oil production would peak at around 2 million barrels per day: in the era where BP was known as a "two pipeline" company, the North Slope of Alaska would provide one of them.

From 1969 onwards, there were many lease sales and many companies arrived in Alaska to try their luck. And as mentioned before, there were many large discoveries and, given

the extensive well and seismic data base, sophisticated insights on chronostratigraphy, sedimentation, structural models, source rocks and petroleum systems, the province was soon thoroughly understood.
Or was it?

MUKLUK

By the time of the 1983 OCS 71 lease sale, the industry had identified the huge offshore prospect known as Mukluk for over ten years. An extensive seismic grid was now available and several wells had been drilled onshore which could be extrapolated to the offshore. Mukluk was seen as an areally huge, relatively subtle structure with a maximum of 100m of closure through which or into which oil had unquestionably migrated.

To develop its interests in North America, and in particular to facilitate its Alaska developments, BP had by this time bought 53% of SOHIO, a Cleveland-based, dominantly downstream, company. SOHIO took over Alaskan exploration and production, running it from its Western Region offices in San Francisco, directed by its corporate office in Houston. SOHIO executives saw Mukluk as enormous – bigger than Prudhoe Bay itself – and attached a 50% chance-of-success to it. The OCS 71 lease sale was a frenzied affair in which over US$ 2 billion was spent in bonus bids, about half of this by SOHIO, with nearly US$ 0.5 billion on just three blocks at Mukluk.

This frenzy was nothing compared with the rush to drill! By November 1983, a drilling island had been built in 20m of water at a cost of US$ 20 million and Mukluk #1 spudded. Development and construction teams had already been established and hiring had commenced. All those with access to the drilling results had been sworn to secrecy and pledged not to trade in relevant companies' stocks, all under signature.

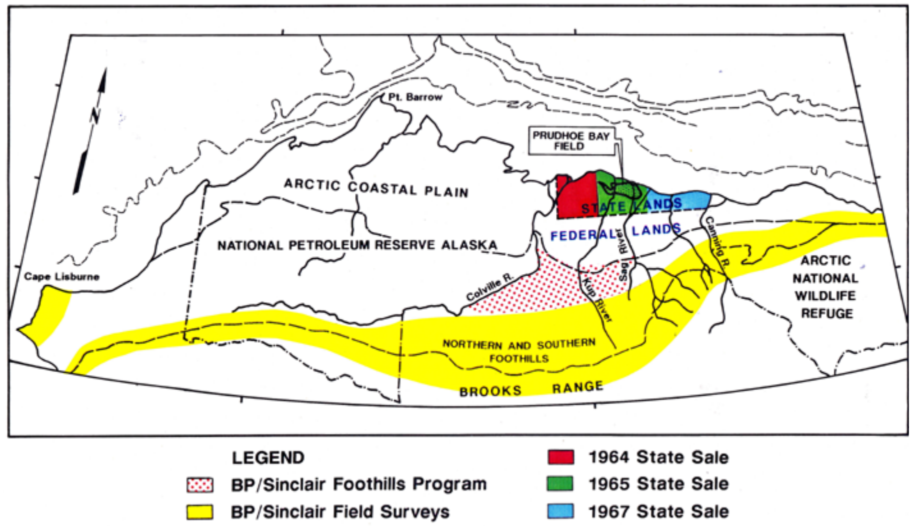


Image courtesy of W. Bischoff

North Slope Exploration from 1960 – 1969

By coincidence, I arrived in San Francisco as the well was drilling to do some weeks' work on a completely unconnected lease sale: before I left BP London I had heard that the prospect was huge but that SOHIO management were perhaps slightly over-optimistic. After a couple of weeks, two things dawned on me: firstly, that I had never been in a place where such unbridled optimism was both present and expected; and secondly that there were a couple of geoscientists who had had considerable reservations about whether any Mukluk palaeo-structure had existed at the time of oil migration, or whether any palaeo-trap had been subsequently breached….and had been ignored.

The well results arrived whilst I was there, first cores and then logs. Although reservoir quality was good, the reservoirs were water-bearing. SOHIO had drilled the world's most expensive dry hole, at least up to that point.

I will pass over what happened next – dubious plans to drill Mukluk #2, poor public relations, the passing down of blame from SOHIO executive management to the geoscience teams, the SOHIO redundancy programs. What I can say, again based on my own experiences a few years later in Houston, is that I found that SOHIO had some excellent geologists, geophysicist and engineers.

© BP plc

Located about six miles northwest of Prudhoe Bay, BP's Northstar field is the first Arctic offshore field connected only by pipeline to shore. It was discovered by Shell in 1983, but did not begin production until 2001 because of economic challenges.

THE LONG ROAD

This tale is based on many discussions with colleagues, a lot of whom would point out that I have told the story too simply and that there were many more twists and turns in the road than those I have described: I am sure this is true.

This tale illustrates a few important things. First of all, allowing executive management to choose prospects to drill is not necessarily the right thing to do. Secondly, although there is nothing like the feeling of having an exploration success, learning from our failures is probably more important. One thing I have found is that oftentimes an alternative view, interpretation or model has been generated within an exploration team but that this has been ignored, or included grudgingly in the 'risk': but it turns out not to be a 'risk' but a 'loose end' and is the reason why the prospect fails.

Meeting Operational

Photo: Jane Whaley

Challenges

Jim Thompson wandered into the oil industry after 'meeting a guy in a bar'. That chance meeting has led to a rewarding career in the seismic business, progressing from doodle-bugging to heading up operations for Fairfield Nodal.

"That is what actually happened. I met this guy in a bar in my home town of Jackson, Missouri. He was working on seismic boats and told me what a great life it was," Jim explains. "I'd finished college and was wondering what to do with my life. He said 'we're hiring' – and a week later I found myself on a boat in Nantucket, Massachusetts, going to sea with nothing except the clothes I stood up in, as my bags had got lost en route!"

Despite this somewhat inauspicious beginning, Jim took to the life of a 'doodlebugger' (for the uninitiated, a slang term for a member of a seismic crew) and, nearly 30 years later, he is still in the business. Nowadays, however, he is more likely to be organising seismic surveys in his position as VP Operations for Fairfield Nodal, rather than working on the back deck of a boat.

"I joined Digicon in 1981 and worked all over the world - North Sea, Gulf of Mexico and West Africa from Senegal to Gabon. As a young man working in these countries it was very exciting. For example, on one occasion we were in Liberia, Monrovia, during a dictator assassination and were confined to our hotel for days.

In 1989 the company asked me to move to Singapore as Operations Manager, where I found myself managing three 2D streamer crews. For a while we controlled the 2D market there, and then began to move into 3D; in fact, we shot the first ever 3D survey in the area for Digicon." Singapore suited Jim. "I loved it there," he says. "I arrived with two suitcases and left four years later with two 40 foot containers – and two kids!"

DIRECTING OPERATIONS

Since then he has remained in the Operations field, mostly back in Houston, where he was managing the US survey teams with Digicon, who had been taken over by Veritas in 1996. "Although I was very happy with Veritas, Fairfield made me an offer I couldn't refuse, so I moved to become VP Operations soon after the takeover.

So what makes a good operations manager?

"It's important to know the crews and stay in touch with them all the time, and not to be aloof," explains Jim. "They know that I have worked offshore and understand the issues, and I believe that helps. It's one thing to know what a piece of equipment does, and quite another to know how to handle it. They understand that when I ask them to do something, I realise the processes and difficulties involved. And when they come back to me with comments or problems, I know where they are coming from. As an Operations Manager it is important to keep flexible at all times, and be ready with a new plan if circumstances change."

"I also think that I have been fortunate with the managers and companies I have worked with, which are small enough to react rapidly to market forces and changes," he adds. "For example, in the downturn in the industry in 1998, we had to drop from running three crews to running no crews, and survived on selling spec data for several months. But when things started to improve we were in a position to get up and running fast, with new ideas and techniques."

CHALLENGING TIMES

These new ideas included undertaking 4C (4 component) surveys, harnessing the S (shear) wave part of a seismic echo, as well as the P (pressure) component, which is now the backbone of Fairfield Nodal's operations. "This technique is ideal for some of the more difficult areas the industry is working in nowadays, particularly the gas provinces and areas where salt is a major feature – but these are the main and also the most exciting plays at the moment," Jim says. "It has proved particularly successful in the North Sea and the Gulf of Mexico, but the operations group also has supporting teams in Saudi Arabia, where we are training crews in the use of our Z700 shallow water technologies."

"With Fairfield Nodal data acquisition we only deal in marine operations – but by putting receiving nodes onto the seabed, rather than towing streamers, it is as though we are doing land seismic in the water."

"These sorts of techniques are very important for the future of the oil and gas industry," Jim continues. "All the easy stuff has been found, all the major Gulf of Mexico fields; now we must look deeper and harder. It's a challenging time for the industry, and the technology must keep up with it. But there are also exciting emerging markets, like deep-water Brazil and West Africa.

MANY CHANGES

Jim hasn't been offshore now for several years and admits that he misses the life, although he enjoys what he is doing and the contact with the crews. "I get involved in many aspects of the business, from advising on the practical design for seafloor nodes to looking at seismic survey plans. It's all very interesting."

Jim has seen many changes in operations since he first started working on the back deck. "We were much less aware of health and safety issues then – some would say more careless! Everything was done by hand, from stacking cables to retrieving buoys from the sea by leaning out with a grappling hook. It's much less physical now, with many jobs done by automation and using remote controlled vehicles, so it's a much safer environment to work in.

Grabbing a Larger Share of the Market

It's time consuming. It's expensive. But when it comes to accuracy and quality, it's surpassed by no other technology, the innovator claims.

HALFDAN CARSTENS

"While we initially considered shear waves to be of greatest importance for the purpose of predicting lithology and fluids, it has turned out that the breakthrough in 4C seismic has been to produce improved imaging from full azimuth PP data," says Eivind Berg, Business Development Manager of SeaBird Technologies, out of Trondheim, Norway, a wholly owned subsidiary of SeaBird Exploration.

The innovative Norwegian geophysicist has been instrumental in developing 4C seismic using nodes planted on the sea bottom instead of cables (OBC) since the technique was first introduced in the 1990s, and he is still a key person in a continuous, ongoing process of improving the node technology and operational efficiency while serving a market that finally seems to appreciate geological details.

Without Berg's enthusiasm, knowledge and determination, 4C seismic would be way behind its current level.

QUALITY COMES FIRST

The need for high quality data is a strong, driving force in the geophysical industry. This is certainly true in exploration with the increased use of 3D seismic, CSEM and potential field data. Consequently, contractors present incremental improvements on a continuous basis.

The need for high quality data is even higher in exploitation. With the increased price of oil as an important incentive, the

Photo: Halfdan Carstens

Thanks to Eivind Berg, 4C/4D is now about to come of age. Berg is the true inventor of this technology as he was the first to start experimenting with nodes in the late 1980s.

sensible operator will focus on getting the last drop of oil out of the reservoir. That requires detailed reservoir models, in the first place, then seeing and understanding how the fluids move within the reservoir, in the second place.

This is why 3D followed by 4D (time-lapse) seismic data is taking an ever larger share of the seismic market. In addition, 4C seismic data with receivers on the sea bottom, recording both PP and PS-waves instead of only PP-waves, as happens with streamers in the water, is also increasing in popularity. For good reasons, it turns out.

"We know that we are serving a niche in the seismic market, but we do see that the use of 4C seismic is increasing. The oil companies are slowly starting to see the value of high quality data. Moreover, they are now willing to pay for the added value," says Berg.

"What we are also seeing is that the oil companies have 4D in their mind when they are planning an initial 3D over a field, even if repeated surveys are not yet part of a plan for increased recovery, or budgeted for. That realisation actually means that the operators will benefit from doing some long-term planning, and make a decision whether to use streamers, ocean-bottom cables or nodes in the very first survey," Berg says.

While a series of companies offer streamers in a 3D configuration, and a few have specialised in ocean-bottom cables (OBC), Berg and SeaBird are offering a technology which is in competition with only two other companies.

4C-aquisition, as done by SeaBird, involves nodes firmly planted into the seabed and deployed in a regular grid on the seabed. The customer has two choices, square or hexagonal, the latter being more time-efficient. Each of the nodes is fitted with three fixed geophones and one hydrophone; two of the geophones are used for particle velocity measurements in horizontal directions, one is used for particle velocity measurements in the vertical direction, and the hydrophone for pressure measurements. This setup enables the recording of reflected shear-waves (S-waves) on the horizontal components that cannot travel in liquids.

OPERATIONAL ADVANTAGES

"Up to now, the main interest in our data has been in using the PP-waves, but we are now also seeing oil companies starting to request PS-waves," Berg says, fully aware that SeaBird then has a competitive edge over marine streamers.

The whole system can be operated with nodes and source on a single vessel, but for larger surveys it pays to use one source vessel and one node-operating vessel working simultaneously. The main operational method for deep waters is to use a basket with several nodes which is lowered towards the sea bottom where an ROV will deploy or retrieve the nodes one at a time. For shallower depths the nodes are deployed and recovered directly from the node handling vessel.

The recorded seismic signals are stored on a hard-disk within each node until it is on deck and the data can be downloaded. The disk has a capacity for 65 days of uninterrupted operation.

Auxiliary signals used for quality control are sent from the transducer by hydroacoustic waves directly to the source vessel through the water. Berg is proud to say that SeaBird is the only technology provider capable of doing this.

Operationally, the main advantage with using nodes is flexibility in areas with infrastructure like platforms, oil tankers and other obstacles. The vessels can safely be located outside the security zone without the need to move around and make life difficult for the production facilities.

PP and PS

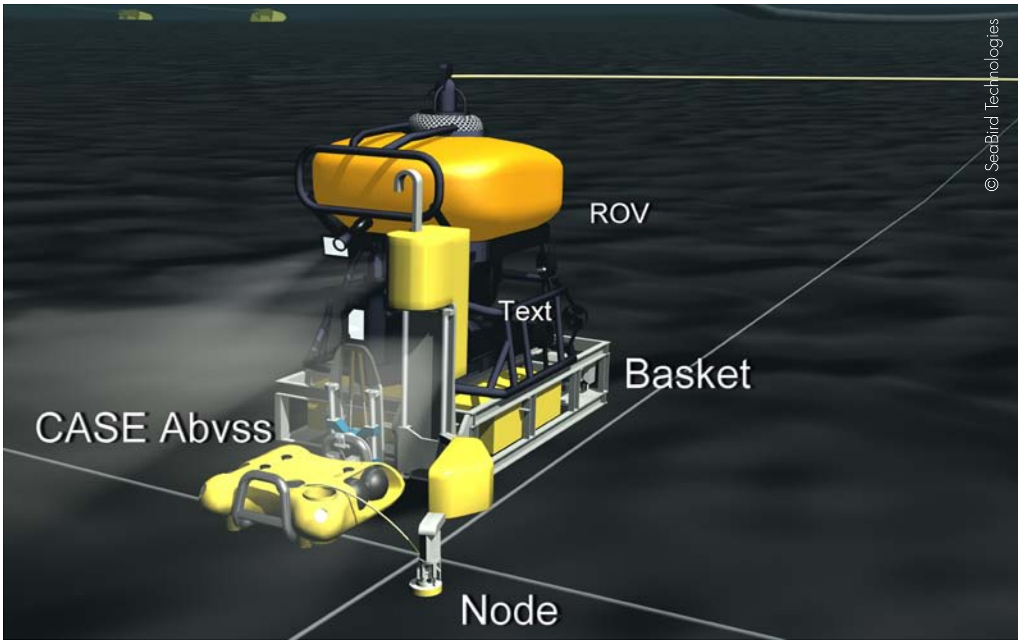
P stands for compressional waves, while S means shear waves. By PP we mean P-waves originating in water and which is also received as P-waves by the recording instrument. By PS we mean P-waves that are recorded as S-waves after having been reflected back as converted S-waves.

IMPROVED IMAGING

Berg admits that using nodes planted on the sea bottom is time consuming compared with using streamers. But he also maintains that the operational advantage in congested areas, as discussed above, and the greater accuracy that can be obtained resulting in higher data quality, may fully compensate for the disadvantages.

"When doing reservoir monitoring, accuracy is of primary importance, and we have demonstrated our capability to re-find the receiver locations for the individual nodes. Actually, in some cases we have even seen imprints from a previous survey on the sea bottom with the video camera when moving towards the location."

"At the SEG conference in Denver last fall, representatives of both BP and Shell gave talks stating that the accuracy of nodes is as good as permanent cables buried into the sea bottom," Berg proudly says. The overall theme of that conference was "Imaging our Future", which is actually what SeaBird Technologies is working towards. One session was dedicated to the use of nodes in seismic acquisition, and Berg – a receiver of the Virgil Kauffman Gold Medal (Society of Exploration Geophysicists) in 1999 – gave the keynote, entitled "Origin



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4C seismic using nodes planted on the sea bottom allows for both PP and PS waves to be recorded based on signals from air guns in the water. Here we see the CASE ("Cableless Seismic") Abyss nodes being moved towards the correct location by an ROV and planted on the sea bottom in a predetermined position.

and Advances of the Planted 4C Seismic Node Technology".

Accuracy with respect to careful planting and geographic location of the receivers ensures repeatability. SeaBird has demonstrated that both these factors are crucial when it comes to frequency content and data quality.

"In our view, there is no doubt that increased accuracy in positioning improves imaging," Berg says.

A LONG WAY

Starting companies that are introducing new technology is not the easiest thing to do – there are better ways to grow grey hair!

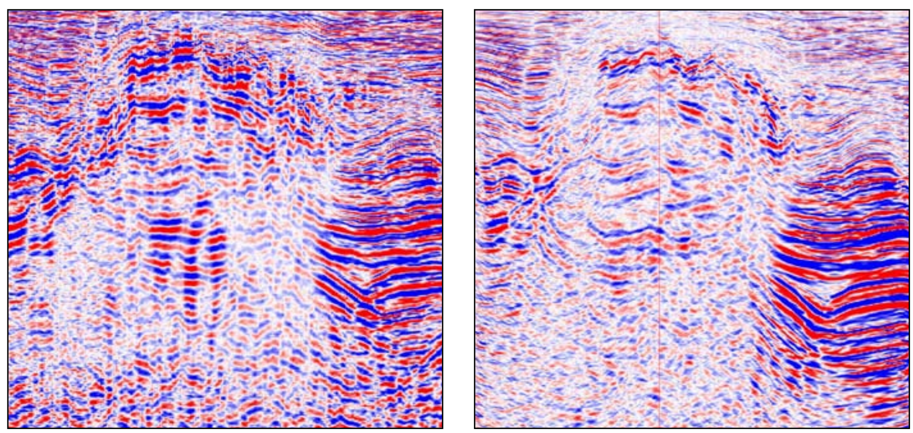
"The lead time for acceptance of our node technology has been long and difficult," Berg admits. He has been dealing with this concept since the 1980s when working for Statoil. In the geophysical industry it is well known that 4C, using nodes, is his brainchild. "The original idea leading to the node technology concept was a proposal to use a submarine with a streamer behind to acquire data under the ice offshore Greenland. However, it soon became clear that it should be possible to obtain better data if the sensors were fixed to the seabed." By placing the sensors at the interface between the solid sediments and the water layer, the introduction of a four-component concept became a natural consequence.

The breakthrough for the node (and ocean bottom seismic as a whole) was the full scale 4C-2D pilot survey on a small field in the Central North Sea in 1993. It demonstrated for the first time that it was possible to image the reservoir through a gas chimney by using converted shear waves (PS).

For the impatient Berg, the time was now right to leave Statoil, and together with a colleague he formed SeaBed Geophysical in Trondheim and embarked on an extensive research and testing program, using the deep Trondheimsfjord with unconsolidated sediments above basement.

© SeaBird Technologies

During deepwater operations several **CASE *Abyss*** units are placed in a launch and recovery basket. Aided by an ROV, the units are taken out, one by one, and installed on their respective, planned locations. The **CASE *Abyss*** is more compact than its predecessor, allowing huge numbers to be stored on the combined source and data recording vessel. The unit is designed for both deep and shallow water use.



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Comparison of PP OBC (left) and PP node (right) data from the Cantarell Field in the Gulf of Mexico.

But the node still needed further development to make it a reliable and cost-effective seismic acquisition system for the future. A new compact node was developed and extensive testing showed that all three geophones gave stable and robust results independent of seabed conditions.

"The first demonstration with autonomous nodes was on the Statoil operated Volve Field in 2002. The operational flexibility and efficiency of node deployment and retrieval exceeded all expectations, and resulted in high quality PP and PS data," Berg says.

Their first commercial job was for Pemex in the Gulf of Mexico on the Cantarell Field in 2003/2004. Imaging was difficult, which is easy to understand knowing that the reservoir consists of fractured carbonate in a field influenced by both salt movements and overthrusting. "In addition to acquiring full azimuth data, we clearly demonstrated that the nodes could be placed as planned independent of obstacles and infrastructures on the field, without leaving holes in the final image," Berg says. "Compared to previous OBC, the node data produced a PP image of increased resolution," he says. In short, Pemex

© SeaBird Technologies

One of the advantages using nodes for 4D data acquisition is that it can be operated over fields with a complicated infrastructure.

Editorial and Events Calendar 2011

No 1 **New and Emerging Plays in the Eastern Mediterranean**, London, UK, February 23 – 25
APPEX, London, UK, March 1 – 3
Focus on the Eastern Mediterranean and Exploration

No 2 **AAPG Annual Meeting**, Houston, Texas, USA, April 10 – 13
Focus on North America and Australia and Geophysical Technologies

No 3 **EAGE** Annual Meeting, Vienna, Austria, May 23 – 26
Focus on North West Europe and Reservoir Management

No 4 **PESGB Africa Conference**, September 7 – 8
SEG, Annual Meeting San Antonio, Texas, USA, September 18 – 23
Focus on Africa, Geophysics and New Technologies

No 5 **ATCE** Denver, Colorado, USA, October 30 – November 2
AAPG International, Milan, Italy, November 23 – 26
Focus on Europe and Exploration

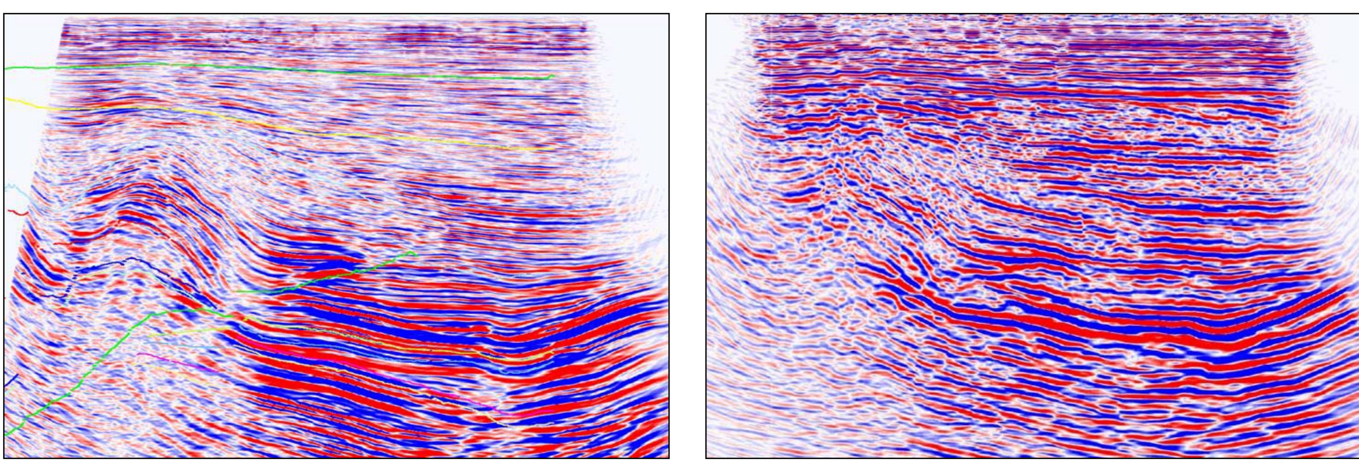
No 6 **Prospex 2011**, London, UK, December 14 – 15
NAPE 2012, Houston, Texas, USA, February 17 – 18, 2012
Focus on North and South America and Frontier Exploration

While we do not anticipate schedule changes, they may occur without notice.

Schedule

	Ad Material Deadline	Publication Date
2011 GEO ExPro 01	January 28	February 14
2011 GEO ExPro 02	March 4	March 21
2011 GEO ExPro 03	April 15	May 9
2011 GEO ExPro 04	August 12	August 29
2011 GEO ExPro 05	September 30	October 17
2011 GEO ExPro 06	November 18	December 5

GEO ExPro
GEOSCIENCE & TECHNOLOGY EXPLAINED



PP (left) and PS (right) images after PSTM from the Cantarell Field. PS compressed to PP time. Upper right part: Note topset that are now visible. Lower left part: Note difference between PP and PS, indicating the possibility of seismic hydrocarbon indicators below the overtrhrust (not visible on PS-data).

© Pemex/SeaBird Technologies

was pleased. The technology proved that it had a merit on the Cantarell field.

Since then, the company has acquired five surveys; in North West Europe, offshore West Africa and in the Gulf of Mexico. Their only crew has been operating continuously for the last 2 years. When *GEO ExPro* was preparing this article, Berg was busy putting together a new tender for an existing customer. Naturally, he was quite excited about another opportunity. Repeat customers are as good as repeat surveys.

MULTIPURPOSE USE

"We are certainly pleased to see that the technology is making its way, but we are, nevertheless, still focusing on improvements in both the technology itself and in more efficient operations," Berg maintains.

Future trends clearly indicate that more efficient operations are required to cover larger and larger fields with more complex and advanced reservoir mapping challenges (e.g. fracture prediction in carbonate reservoirs) with the use of shear waves (PS).

"In the future we see node technology being capable of handling larger fields through more efficient operations, both in shallow and ultradeep waters, as well as resolving more complex mapping challenges by combined use of PP and PS data for lithology and fluid prediction," Eivind Berg concludes.

The underdeveloped and beautiful Treasure Beach on the south-west coast of Jamaica is underpinned by Miocene Newport limestone, while much of the local scenery is based on the overlying coastal group of Pliocene age. There are a number of uplifted Pleistocene coral reefs.

Buried Treasure in JAMAICA

The beautiful Caribbean Island of Jamaica was home to pirates and their loot in the past, but is there treasure of a different sort in its sparkling waters? Data collated for a new bid round, due to close in March 2011, suggests that there may well be.

Travelling around Jamaica's emerald green and hilly interior or along its bright, sunny and tropical shoreline, it is very hard to imagine why in the 1950s the grey, misty, dank and cold shores of another island much further north held so much attraction to thousands of Jamaicans.

Of course, the reason was economic, and in those days Britain had very good ties with Jamaica, although nowadays less so, as the UK looks to larger countries with which to trade and explore for minerals, oil and gas. In the interim Jamaica developed strong trade relations with the USA and the rest of the Caribbean.

But did Britain leave treasure behind when Jamaica secured independence in 1962?

DISCOVERIES AND RE-DISCOVERIES

Many arrive in Jamaica via Norman Manley International airport on a spit that was once the home of infamous pirate gangs - before the massive earthquake of 1692 swallowed Port Royal and all the gold and plunder taken on the high seas disappeared in a dangerous thixotrophic sandy mix. Sitting on the wooden veranda of the Morgan's Harbour Hotel (of 007 fame), looking across Kingston Harbour toward the majestic Blue Mountain's peaks, thoughts move to what other treasures lie below the surface.

In 2003 Petroleum Corporation of Jamaica Group Managing Director, Dr Raymond Wright, placed a small advertisement in a leading industry newspaper to say that he would be in London seeking investment in the petroleum industry in his country. Not since 1983, when a Canada Overseas Assistance program ended, had any exploration occurred in Jamaica.

What followed was a remarkable series of re-discoveries as, of the 11 wells drilled both on and offshore between 1956 and 1983, all but one had oil and or gas shows. The deepest, Arawak #1, had been drilled offshore in 1982, 100 km south-west of the island, on the flanks of the Pedro Bank. It TD'd at 4,588m in the Tertiary, while much shallower wells in the northern part of the island reached the Lower Cretaceous. There were gas shows and reported seeps and several hundred meters of super-rich Eocene source rock cores held in the Petroleum Corporation of Jamaica (PCJ) Core Repository. None had been visited for over 20 years, save by Professor Simon Mitchell of the University of West Indies at Mona, whose painstaking work mapping the onshore revealed over 10,000m of Tertiary and Cretaceous section. His findings included the discovery of quartz-rich sandstones in the Eocene. Dr. John Milsom's gravity surveying in 2004, as part of the JEBCO Alliance project, confirmed that an equally thick section existed offshore in the Pedro Bank and Walton Basin areas and, astonishingly, the recent seismic shot in 2009 (CGGVeritas) revealed yet more thick sections in the deep waters further to the south-east, in the large area which is the focus of the 2nd Round.

PLATEWIDE GEOCHEMISTRY

Simon Mitchell remarked that Jamaican geology is complex and as the island is small it was generally ignored by the plate reconstructionists. Yet, as he pointed out, it is only on Jamaica that one can work out how the Caribbean came to be.

Jamaica is at the eastern end the pre-Cambrian to Palaeozoic block of oceanic crust known as Chortis. As the Caribbean plate moved from its original Pacific Ocean setting from the late Cretaceous to where it is now, large geological blocks were jostled, some downthrown and others uplifted. John Milsom summed up the enormity of this continuing force in the field by declaring that the Blue Mountains were far too big and should not be there, as they were not in isostatic balance.

The extreme eastern end of Jamaica is in fact a piece of the Lower Nicaraguan Rise (Siuna Terrane) that has become detached and as such allows us to examine in part what geology we might expect in the undrilled and new license areas. The eastern area was tested by PCJ in 1984 with a deep core hole and gilsonite (a now solid hydrocarbon) was recorded in the test core. Budgets were never sufficient to collect and extract the hydrocarbons that may be trapped within the matrix, and that must now be an adventure for another petroleum geochemist. What is the character of the probable offshore source? Could we have an Upper Cretaceous source as we must have to the east in the Dominican Republic? A few simple experiments and some forensic work would reduce this risk significantly.

Remarkably, the three broad elements that comprise the essence of the Caribbean plate (the Lower Nicaraguan Rise, or Siuna Terrane; the Upper Nicaraguan Rise, or Chortis; and part of the Great Caribbean Arc or northern periphery of the Caribbean plate

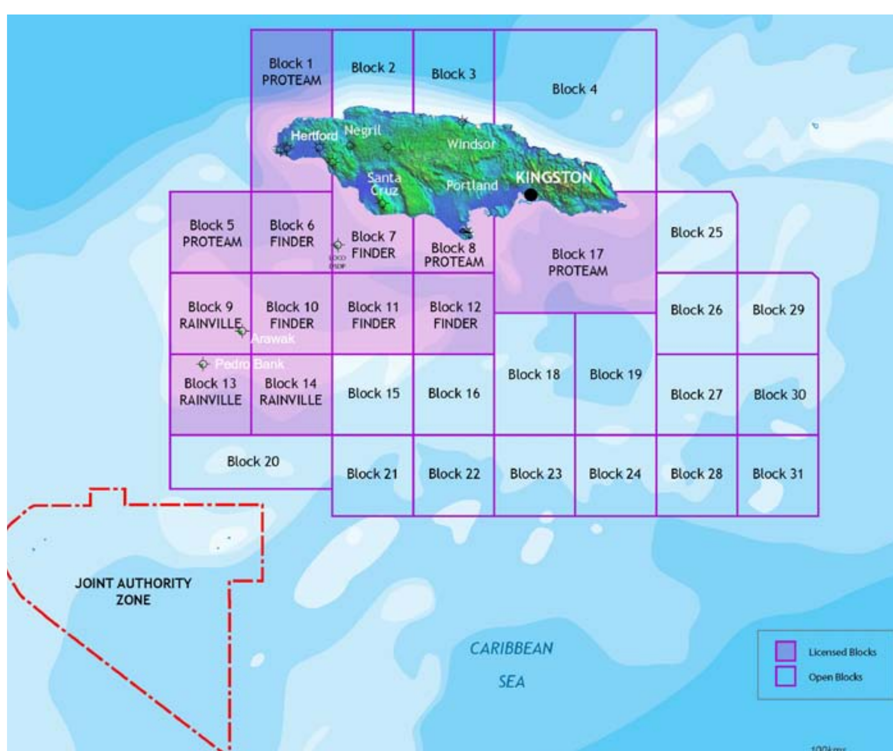


Image: Petroleum Corporation of Jamaica

All remaining open blocks are offered in the 2nd Jamaican Licensing Round

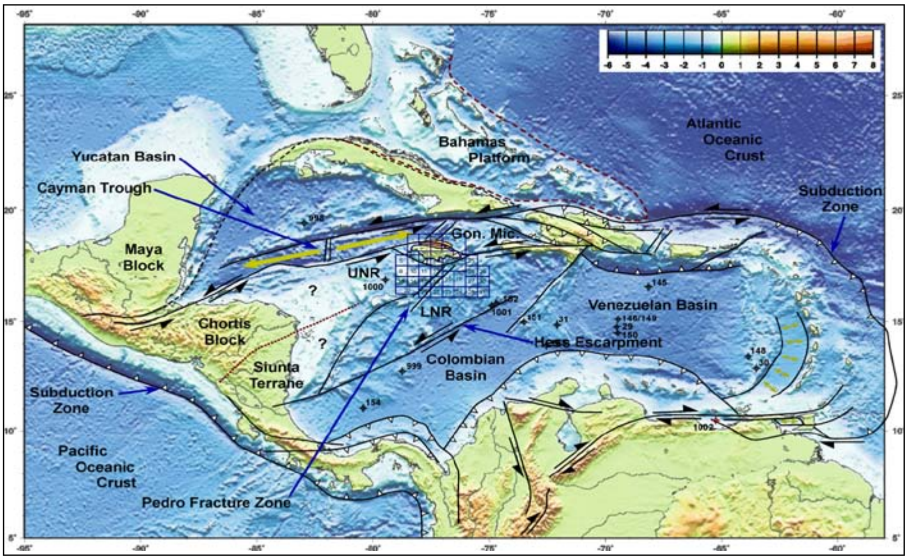


Image: Prof Simon Mitchell., 2010 2nd round road show

Main tectonic elements of the southern Caribbean.

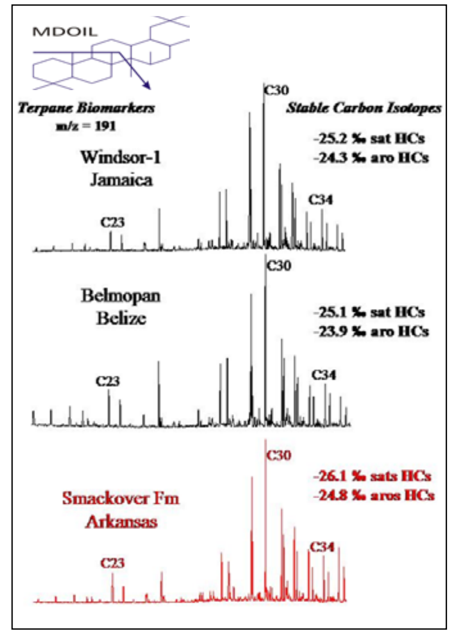
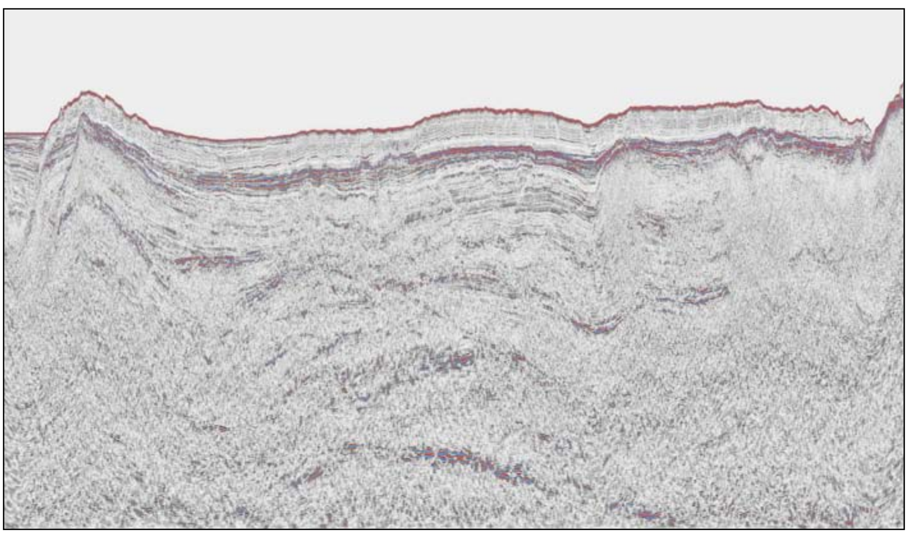


Image: Jebco Alliance report 2004

Comparison of the Windsor #1 oil with a Belmopan field oil (onshore Belize) and a Smackover Formation oil from Arkansas, USA



CGGVeritas

New offshore seismic shot by CGGVeritas to the south of Jamaica has revealed over 5,000m of sedimentary section

or platelets) can also be identified though petroleum geochemistry. Windsor #1 well in the north of the island was drilled in a terrain that has strong affinities with the geology of the Yucatan in Mexico. If one compares the oil fingerprint, using gas chromatography-mass spectrometry and stable isotope ratio distributions, there is a near identical match with the Belmopan oil found in Belize, 1,000 km to the west. The match is so close that it is as if the Belmopan field has been cut in two, with one portion perhaps residing on the North Coast of Jamaica in what is called the North Coast Block.

The Belize and Windsor oils are in turn very similar in origin to the prolific Jurassic marly source found to the north in the Gulf of Mexico and onshore Texas, Arkansas to Florida play.

First Bid Round in 2004

The remainder of Jamaica and the offshore area to the south and west, most of which was covered by the first round in 2004, belongs to the Upper Nicaraguan Rise. With the exception of Windsor, all wells to date have been drilled in this terrane. One well, Hertford, had no shows, but elsewhere several gas seeps are recorded within the Cretaceous inliers and an oil seep was recorded in the Marchmont Inlier. On the Pedro Bank Occidental asphalts were encountered in the granodiorite wash in Pedro Bank #1. Arawak #1, also on the northern side of the Pedro Bank, encountered shows towards TD in a sandy section at the base of the Yellow Limestone Group series. Fishermen have recorded oil on their anchor ropes when moored off the north flanks of Pedro Bank and Flow Petroleum (Formerly Gippsland Offshore), one of the three current acreage holders, commissioned a satellite study in which several SAR slicks were recorded.

Plans are afoot by UK based Oilsearch plc to map the offshore seeps in more detail for the 2nd Round, using Oilsearch's Seepfinder™, which is a sophisticated airborne technology that uses the fact that the aromatic components of crude fluoresce when excited by solar energy. The returned light is recorded and mapped. When coupled with tide, current and wind data, areas of seepage can be mapped.

In 2004 JEBCO UK and GeoInsight Ltd. were invited to assist with Jamaica's 1st Round, and with the support of PCJ produced a petroleum geological review that has become the basis of all recent exploration. Some 11,000 km of the total 16,126 km of offshore seismic shot was reconstructed and navigation corrected; files for the 11 wells were digitised and the relevant content of the PCJ library scanned and all made available to support the round. The 641 line km of onshore seismic for the island has not yet been reviewed. In 2007 PCJ had the seismic data for Morant and Formigas basins to the east of Jamaica reconstructed (1,074km) and navigation corrected. In addition to Australia's Flow Energy, Calgary based Rainville (now Sagres Energy) bid and won acreage positions in this round. Flow Energy acquired 6,968 line km of long offset seismic and 23,974 line km of gradiometry data. Both Flow Energy and Sagres Energy have mapped giant sized prospects in the Walton Basin and beneath the Pedro Bank. ▶

Oil company geologists viewing the thick Tertiary Guys Hill sandstones exposure at Mountain River

In an interim round Hong Kong based Proteam secured acreage. In 2009 Wavefield Inseis, now part of CGGVeritas, collected 6,118km of seismic over the open areas and 2,594km for Sagres Energy. The deep water geology revealed by the new 9 km cable length seismic was something of a surprise. It was previously thought that much of the new acreage hosted only a thin sedimentary section above oceanic crust, but over 10 km of sedimentary section was revealed, along with several multibillion barrel potential structures.

Investment in Jamaica is being actively pursued by the PCJ though the round, a December field trip and through presentations and data packages. There is a growing domestic market for energy from oil and gas, both to support the economic growth of Jamaica and to re-invigorate the bauxite industry, one of Jamaica's long term sources of revenue.

COME AND SEE!

Jamaica's exploration industry perhaps started some 100 years ago in a bend in the St Ann's Great River on the north coast of Jamaica, where a gas seep has been burning, it is said, for over 100 years. The seep is of dry gas and is guarded enthusiastically by a local Rastafarian. My attempts to sample the gas in 2006 were met with some resistance as using a gas syringes in the sacred spring was considered offensive until some Jamaican dollars were presented. The gas proved to be very dry, almost pure Methane, but with an isotopic signature that suggests that it is thermogenic in origin. The origin is unknown, but a Cretaceous or older source is indicated. The St Ann's Great River Inlier is one of the 26 Cretaceous inliers that occur on the Island in an otherwise Tertiary settings.

There is a lot more to be discovered on and off the Emerald Island - not just Blue Mountain coffee, reggae, Naomi Campbell, the union leader Lord William Morris of Handsworth, and definitely not last, the fastest man on earth, Usain Bolt.

Photo: Chris Machette-Downs

A gas seep in North Jamaica is reported to have been burning for over 100 years.

Perhaps its time you had a look yourself.

Chris Machette-Downes is a geochemist with many years experience of the oil industry working throughout the world. In recent years he has built up a particular expertise in East Africa and the Caribbean.

Is the **'Shale Gale'** blowing

Are low gas prices and environmental issues taking the wind out of the 'Shale Gale'?

Lebien LE1 was drilled in the Baltic Basin of Northern Poland earlier this year to evaluate the potential of shale gas production.

DAVID BAMFORD

Vast amounts of shale gas promise a new energy future for North America, perhaps even for Europe. However, recent developments indicate that whilst the gas is undoubtedly there, the transformation of energy markets is unlikely to happen overnight – a long view is necessary.

GLOBAL GAS RESERVES

The 2010 BP Statistical Review of World Energy noted that global proved reserves of natural gas grew by 2.21 Tcm (78 Tcf) in 2009, driven by increases in Russia, Venezuela and Saudi Arabia. The global R/P ratio increased to 62.8 years, representing the length of time that those remaining reserves would last if production were to continue at the previous year's rate.

Proved reserves of natural gas are those that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions.

So even under these quite conservative assumptions, global gas *reserves* are considerable. Global gas *resources*, dominated by all manner of unconventional gas sources that are yet to be proven commercial, are vastly more. Unconventional gas includes Tight Gas, Coal Bed Methane, Shale Gas and – potentially – Gas Hydrates.

Gas reserves are dominated by the Middle East, Europe and Eurasia (i.e. Russia) and Asia Pacific. In contrast, gas resources (excluding gas hydrates) are dominated by North America and then the FSU. Shale gas is the dominant contributor in North America, China, Latin America, the Middle East/North Africa and

itself out?

the rest of the world, which excludes the former regions and the FSU and Western Europe (Stevens, 2010).

SCIENCE AND TECHNOLOGY BEHIND SHALE GAS

The fundamental idea behind the exploration and exploitation of shale gas is that in some cases, rich oil-prone source rocks buried at the centre of a basin will have passed into the gas generation 'window' and that most of the gas, rather than being expelled and subsequently migrating into conventional traps, will be retained trapped in the source rock itself. This basin-centred saturation concept can be applied to shale oil as well, where a source rock has entered into and then remained in the oil generation 'window'. Some pundits argue that up to 75% of the generated hydrocarbons remains in the source rock.

These plays involve considerable risk and it seems that as many as 75% of wells are non-commercial at current North American gas prices. Great emphasis is placed on engineering ideas and technology, but actually geological and geophysical insights are the key to success, and appropriate "know how" is uneven among shale players. All shale plays are different and require a thorough understanding of thermal maturity, structural geology, rock fracturability, the presence of silty or sandy beds within the shale package, and sweet spots.

The intensity and scope of drilling and completions activity necessary to exploit shale gas is revealed in one of the established US plays, the Haynesville/Bossier, which covers nearly 20,000 km^{2}in Texas and Louisiana. It has been drilled by 860 wells to date. Typically, a five horizontal well development program for Barnett Shale gas, will produce from three different zones in the Barnett and lead to a high gas recovery factor. In this play typical wells have average true vertical depth of around 3,500m, and the average measured depth is 4,650m.

As natural permeabilities in shales are very low, hydraulic fracturing is applied, in which high pressure water is injected to cause fractures to open in the reservoir, and a so-called propant is then used to keep them open; a typical 'frac' job in a horizontal well bore will have at least seven, and in some cases as many as 12 or even 15 stages. Hydraulic fracturing is intense, with 600–750 lb sand/lateral foot pressure in horizontal boreholes.

These powerful completion technologies allow gas to be extracted from exceedingly low permeability rock and the accessing of extensive areas.

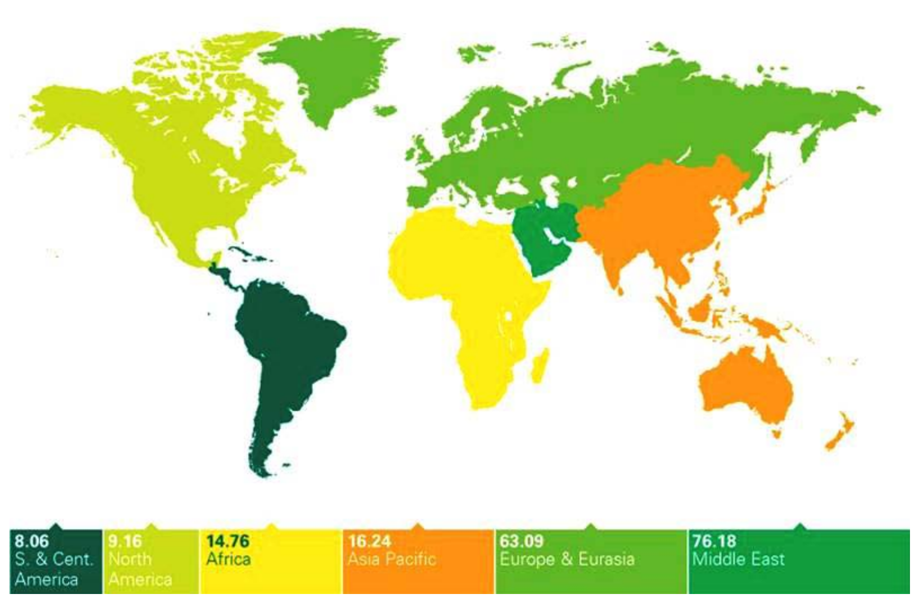
USING ALL TECHNOLOGIES

Achieving these increases in practice, in any one real development, is underpinned by a profound understanding of the geology and rock mechanical properties of the rocks that are going to be developed, from initial deposition, through their burial history, with emphasis on the use of, for example, X-Ray tomography to demonstrate connected pore volumes.

Having understood the target shale at the connected pore volume level, the next step is to select targets for multi-lateral horizontal wells by building a detailed 3D geological model. Here conventional 3D seismic has a major contribution to make, with the additional nuance that description of fracture density and preferred orientation (if any) is important.

There is a final seismic contribution in monitoring the efficiency and effectiveness of a series of 'frac' jobs, because each 'frac' acts as a small seismic source which can be accurately located in the three-dimensional sub-surface, provided a recording network of sufficient areal extent is deployed. This technique can demonstrate that two reservoirs have stayed independent, or that fractures have not spread into surrounding sealing rock or reached out as far as distant aquifers that provide water for human consumption.

None of these technologies are 'new', they are widely available from oil field service companies. Equally, it is clear that the applica-



BP Statistical Review of World Energy

Proved reserves at end 2009

tion of each of them involves a learning curve and that it is highly likely that some companies, although not all, will become very smart appliers of these technologies, in an integrated fashion, with proprietary models and insights.

SHALE GAS IN THE US

Shale gas represents a huge resource, especially in North America, but the very size of the resource seems to be having a dampening effect on gas prices, and hence on developments, and there is evidence of a rising regulatory and environmental 'push back' at the local level.

What can we say about what has happened recently?

A huge amount of shale gas is being documented and shale gas-oriented companies are rising up the list of North American gas reserve holders. For example, Chesapeake Energy, with 13.5 Tcfg, is now the second largest holder of US gas reserves, and XTO Energy, with 12.5 Tcfg, is third. In 2009, Chesapeake, XTO and EOG Resources reported 4.5, 2.2 and 1.9 Tcfg of extensions and discoveries. The reported total volumes of US gas resources quoted are truly staggering – in excess of 1, 000 Tcf!

On the other hand, EOG Resources, one of the leading lights of the Texas/Louisiana shale gas 'plays', is reportedly farming down its gas positions to focus more on shale oil, quoting the significantly inferior economics of the former relative to the latter.

Meanwhile, regulatory authorities are reacting to the 'Shale Gale' in two ways.

First of all, via taxation, with the rationale of recognising that whilst shale gas exploitation in their region will create jobs, it will also exert pressure on infrastructure, government and social services which local governments are financially ill-prepared to deal with.

Secondly, a number of well-publicised incidents have heightened focus on the environmental issues associated with shale gas exploitation, raising fears as to the consequences of massive amounts of hydraulic fracturing, the sourcing, use and disposal of massive amounts of water and so on. Environmental regulators are responding to local concerns by becoming much more active. For example, the Pennsylvania Independent Regulatory Review Commission has introduced stringent new treatment regulations for the recycling of flowback and produced water in the Marcellus shale (estimated to contain almost 500 Tcf) and the Arkansas Department of Environmental Quality has demanded heavily evidence-based demonstrations of companies' abilities to treat wastewater from Haynesville shale gas drilling, to a point where the processed water is so clean it may actually benefit rivers into which it is fed.

EUROPE AND NORTH AFRICA?

Nowadays, of course, ideas travel at the speed of light and there are already a significant number of companies promising to pursue unconventional gas, especially shale gas, in all sorts of places, including the British Isles, Poland and North Africa.

And at first glance, it would seem reasonable to expect that a prolific source rock such as the Kimmeridge Clay, the Bazhanov Shale or perhaps the Silurian of North Africa would provide opportunities to apply the basin-centred saturation concept developed in North America.

Hill & Whiteley (2010), for example, have reviewed the opportunities that might exist in North Africa and have concluded that there is considerable shale gas potential in the region – an estimated un-risked GIIP of 5,250 Tcf - with the Palaeozoic (Silurian) the most promising target, but Carboniferous, Devonian and Ordovician locally prospective. However, in one key point, their observations are similar to those from some parts of Europe itself, notably Poland, namely that the gas content per unit area is generally significantly lower than that for both conventional gas resources and economic North American examples. This indicates the need for a drilling and completions effort that is even more intensive than that seen in the USA, making the economics of shale gas even more precarious. It is difficult to see that developments of such shale gas will be economic at current European gas prices.

Whilst much of the technology used in North America is available 'off the shelf' from oil field service companies, Europe as a whole cannot muster rigs and completion equipment in the number that is tackling just one region in the USA. It is believed the total number of onshore rigs available in Europe, outside the FSU, is less than 100, compared with almost 1,500 in the USA. There will be a similar discrepancy in the number of skilled drilling, completions and production engineers.

Also, much of North America consists of 'wide, open spaces' and, despite the issues previously mentioned, water is freely available: neither is true in Europe, and the latter is certainly untrue for North Africa.

Finally, as is clear from the North American experience, exploration for and development of shale gas requires a very high intensity of geological effort - on a scale that it is difficult to envisage in a company newly arrived on the European shale gas scene.

TAKING A LONG VIEW

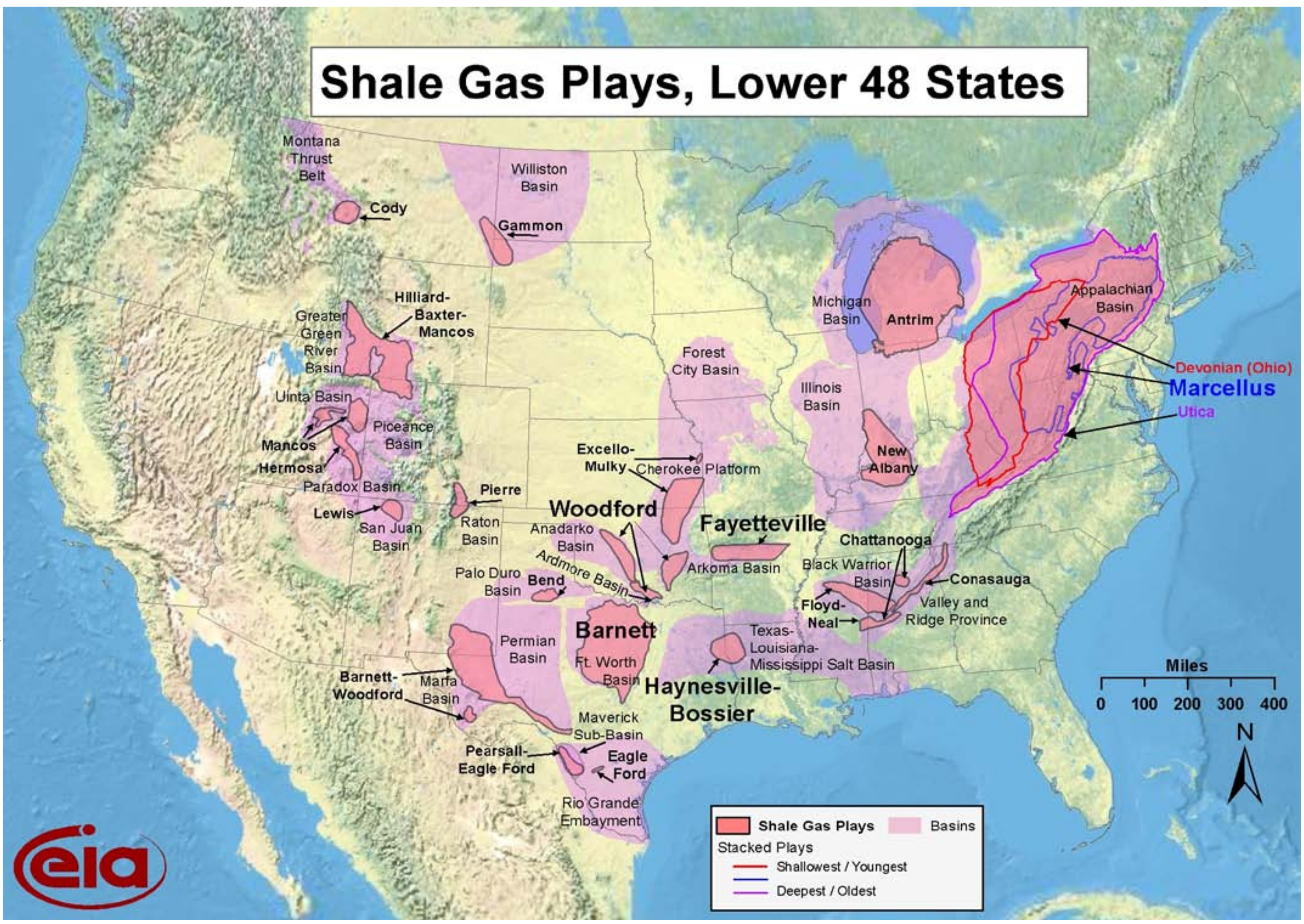
Exploitation of shale gas reserves is an established fact in North America. It requires intensive geological effort, considerable drilling and completions "know how", careful attention to environmental issues and

Natural gas is the lifeblood of North America then an economic gas price. With especially richly endowed shales, such as the Barnett, it is possible for a significant company such as EOG Resources to flourish although even they have diversified into shale oil which is presumably more economic.

Given the fundamental points that there are vast amounts of gas that can be exploited with today's technology and that gas prices are currently weak, is it sensible to see shale gas as a long-term game to be played by the 'big boys'? ExxonMobil have clearly taken such a long-term view with their purchase of the North American unconventional gas player XTO.

It may well be that a similar story will develop in or near to Europe, with prolific shale gas accumulations being identified and the various oil field equipment, manpower and environmental issues being overcome. However, in my opinion, this has the look and feel of an even longer term game for the 'big boys' and that therefore it would be foolish for investors to imagine that AIM-sized companies are going to make a killing in a second 'Shale Gale'.

At a time when gas prices are low, government and local authority budgets are being massively constrained, and yet awareness of environmental issues is rising, perhaps the shale gas revolution will start of as little more than gentle breeze - taking the long view is recommended!



Source: EIA based on data from various published studies

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Stevens, 2010: The 'Shale Gas Revolution': Hype and Reality; Chatham House

Marine Seismic Sources

PART V: THE HEARING OF MARINE MAMMALS

Oh, the rare old Whale, mid storm and gale,
In his ocean home will be
A giant in might, where might is right,
And King of the boundless sea.

Anonymous

We discuss sound pressure levels in terms of *frequencies*, partly because this is how our ears interpret sound. What we experience as "lower pitched" or "higher pitched" sounds are pressure vibrations having a low or high number of cycles per second, or frequencies.

Hearing sensitivity, and the frequency range over which sound can be heard, varies greatly from species to species. The human ear has evolved to detect frequencies of sounds that are most useful to humans, and has a maximum frequency range of about 20 Hz to 20 kHz. Infrasonic describes sounds that are too low in frequency, and ultrasonic, sounds too high in frequency to be heard by the human ear.

However, for many fish, sounds above 1 kHz are ultrasonic. For those marine mammals that cannot perceive sounds below 1 kHz, much of the signal of an air gun may be infrasonic. These considerations indicate the importance of considering hearing ability when evaluating the effect of underwater signal or noise on marine animals. In this issue of *GEO ExPro* we give an introduction to the auditory capabilities of marine mammals.

All marine mammals have special adaptations of the external and middle ear consistent with deep, rapid diving and long-term submersion, but they retain an air-filled middle ear and have the same basic inner ear configuration as terrestrial species. Each group has distinct adaptations that correlate with both their hearing capacities and with their relative level of adaptation to water.

MEASURING HEARING

An *audiogram* is a graphical representation of hearing thresholds at several different frequencies, showing the extent and sensitivity of hearing.

To obtain an audiogram, sound at a single frequency and at a specified level is played to the subject, by means of loudspeakers or headphones in air, or underwater loudspeakers in water. A button is pressed when the tone can be heard; the level of the sound is reduced, and the test repeated, until eventually, a level of sound is found where the subject can no longer detect it. This is the threshold of hearing at that frequency. The measurement is typically repeated at different frequencies and the results are presented as the threshold of hearing of the subject as a function of frequency; the subject's audiogram.

Typically plotted on a logarithmic frequency axis, audiograms have the appearance of an inverted bell-shaped curve, with a lowest threshold level (maximum hearing sensitivity) at the base of the curve and increasing threshold levels (decreasing sensitivity) on either side.

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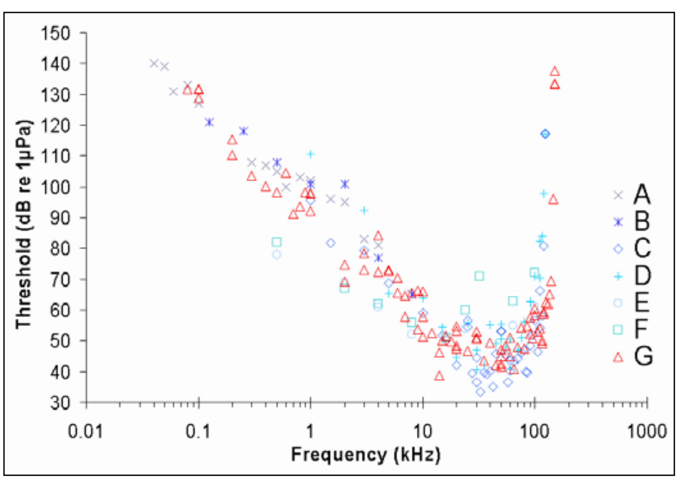
Animal	Frequency (Hz)	
	Low	High
Humans	20	20,000
Cats	100	32,000
Dogs	40	46,000
Horses	31	40,000
Elephants	16	12,000
Grasshoppers	100	50,000
Mice	1,000	90,000
Bats	2,000	110,000
Whales	5	200,000
Seals and sea lions	200	55,000

Photo: George Shuklin

Frequency range of hearing for humans and selected animals. Bats are the land animal with the broadest hearing span (see *GEO ExPro* Vol. 7, No. 4). The squeaks that we can hear a mouse make are in the low frequency end and are used to make long distance calls, as low frequency sounds travel further than high frequency ones. Mice can alert other mice of danger without also alerting a predator like a cat to their presence, if the predator can not hear their high-frequency distress call. Marine mammals have a mammalian ear that through adaptation to the marine environment has developed broader hearing ranges than those common to land mammals. As a group they have functional hearing ranges from 5 Hz to 200 kHz.

Photo: Louise Murray / Science Photo Library

Dolphins are highly intelligent animals and can be trained to respond to tones, using the same step procedure as when testing humans. The US Navy also trains them to detect underwater mines, deliver equipment to divers and locate lost objects. This bottlenose dolphin is holding a biteplate, which can contain surveillance equipment or be used to hook a tethered line onto an underwater object.



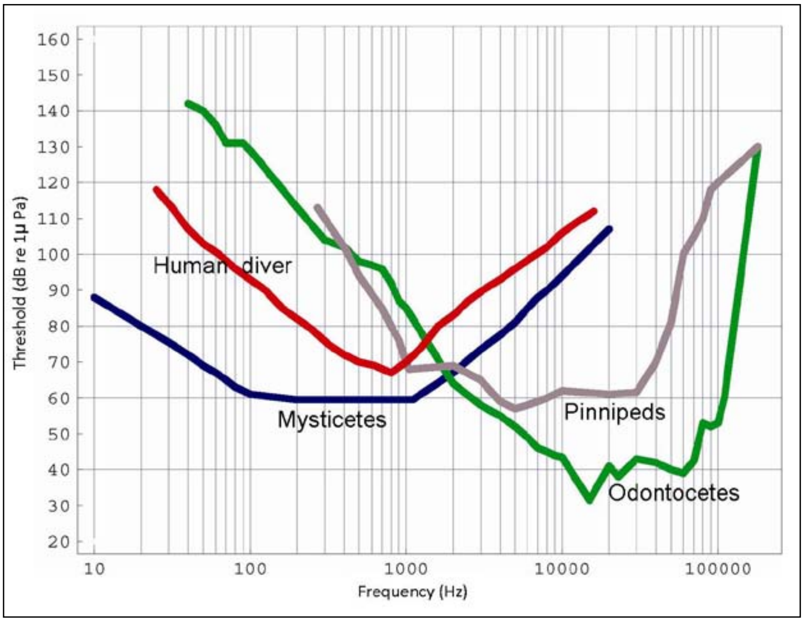
Reported hearing threshold for white whale (various experiments A,B,C,D, E and F) and bottle nose dolphins (red triangles G). Inevitably, marine animals will have varying acuity of hearing between individuals. Consequently, the number of individuals tested in any given audiogram measurement has to be sufficient to establish reasonable confidence in the quality of the measurement. The white whale audiograms A-F have been measured by different authors, under different experimental conditions, using individuals drawn from different stocks, thus increasing the degree of confidence of the data.
Diagram from http://www.onlinezoologists.com/cs/node/21 by Wesley R. Elsbury.

HOW TO TEST A DOLPHIN?

The hearing of dolphins or small whales can be tested through traditional behavioral studies or through auditory brainstem response (ABR) experiments.

Most behavioral hearing studies are performed on mammals in captivity, so the behavioral hearing information that is available tends to be for the smaller marine mammals such as pinnipeds (seals, sea lions and walruses), sirenians (manatees and dugongs), and odontocetes (toothed whales, dolphins and porpoises). Very few, if any, behavioral hearing studies have been done with the large baleen whales because they are not kept in captivity, and it is very difficult to perform hearing tests with animals in the wild.

The behavioural studies are in many respects similar to the way we test the human hearing threshold. The animal is schooled to stay underwater while a sound is played. If it hears the sound, it is trained to respond in a particular way, and if it does not hear it, or if no sound is played, it responds differently. Each time a sound is presented, and the animal is right, it is rewarded. The sound is reduced until the animal can no longer hear, and "says" it cannot, at which point the sound level is gradually increased until the animal indicates that it can hear it. By playing lots of different frequencies (pitches), it is possible to determine the



The scientific data collected in the composite audiogram shows that mysticetes have the most sensitive low-frequency hearing of all marine mammals, with an auditory bandwidth of 5 Hz to 22 kHz. They have good sensitivity from 20 Hz to 2 kHz. Their threshold minima are unknown, but speculated to be 60-80 dB re 1 µPa. The thresholds for odontocetes and pinnipeds are a composite of measured lowest thresholds for multiple species. Odontocetes have auditory bandwidth 100 Hz to 180 kHz. Pinnipeds listening in water have auditory bandwidth 75 Hz to 100 kHz. The vertical axis is relative intensity in underwater dB and the horizontal axis is the frequency of a sound on a logarithmic scale.
(modified from Office of Naval Research. 2001. Final Environmental Impact Statement for the North Pacific Acoustic Laboratory, May 2001.)

threshold point at which the animal can just barely hear for each frequency. In this way the scientists can determine what frequencies and sound levels are audible to different animals.

The ABR hearing measurement, which is also used to measure hearing in human babies just after they are born, is a way to study what a whale hears through the detection and recording of electrical impulses in the brain that occur in response to sound. It is harmlessly measured from the surface of the animal's skin with gold EEG sensors. The ABR test is powerful because it can be done rather quickly compared to behavioral hearing methods and because it can be performed with untrained or stranded animals.

The hearing functions of marine mammals are also studied by conducting anatomical examinations of dead animals. By examining the air-filled middle ear and fluid-filled inner ear, scientists have been able to estimate the range of frequencies that an animal may be able to hear. Much of our knowledge of mysticete (baleen whales) hearing has come from these anatomical studies.

AUDITORY CAPABILITIES

Odontocetes, like bats, are excellent echolocators, capable of producing, perceiving, and analyzing ultrasonic frequencies. In general, odontocetes have a hearing bandwidth of 100 Hz to 180 kHz, with the most sensitive hearing in the high-frequency range of 10 kHz to 65 kHz where their hearing threshold is 45 to 55 dB re 1 µPa. In the low frequencies below 1 kHz where airgun sound is concentrated, toothed whales have a very high hearing threshold of 80 to 130 dB re 1 µPa (see *GEO ExPro* Vol.7, No. 4 for an explanation of this terminology).

There is, however, considerable variability within and among species. Sperm whales, beaked whales and dolphins are said to sense sound from 75-100 Hz if loud enough. Dolphins are renowned for their acute hearing sensitivity, especially in the frequency range 5 to 50 kHz. Several species have hearing thresholds between 30 and 50 dB re 1 µPa in this frequency range. The killer whale has a sound pressure level threshold of 26 dB re 1 µPa @ 15 kHz.

Mysticetes have a very different hearing capability compared to toothed whales. Due to their immense size, these mammals cannot be kept in captivity for study like toothed whales. Little information exists on their hearing and further information is unlikely to be obtained in the near future. In the limited studies done, baleen whales reacted primarily to sounds at low frequencies in the 20 Hz to 500 Hz range. While this is their most sensitive hearing range, the hearing bandwidth for baleen whales is believed to range from 5 Hz to above 20 kHz.

In order to provide predictions, models based on anatomical data indicate that the functional hearing range for mysticetes commonly extends to 20 Hz, with several species expected to hear well into infrasonic frequencies. The upper functional range for most mysticetes has been predicted to extend to 20-30 kHz.

Pinnipeds have a similar hearing bandwidth to toothed whales, 75 Hz to 100 kHz, but their most sensitive hearing is at middle frequencies of 1 kHz to 30 kHz where their hearing threshold is 60 to 80 dB. In the low frequencies below 1 kHz where airgun signal is concentrated, hair seals have a high hearing threshold of 80 to 100 dB.

Man-made sound underwater can cover a wide range of frequencies and levels of sound, and the way in which a given mammal reacts to the sound will depend on the frequency range it can hear, the level of sound and its spectrum. We will discuss that in a later issue of GEO ExPro.

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History Carved Out of the DECCAN TRAPS

Photo: Rasoul Sorkhabi

Ancient cave temples carved out of the Deccan basalts are some of the best places to view both the world-renowned Deccan Traps and the Indian mythology narrated on these rocks.

This statue of Shiva depicts four faces representing Mahadeva (the calm "great lord," central figure), Aghora (the frightful or destructive aspect of Shiva, on the left), Uma (the beautiful feminine aspect, on the right), and Nandin (the sacred bull as the mouth or doorkeeper of Shiva, not visible). This sculpture is in Cave No. 1 on Elephanta Island.

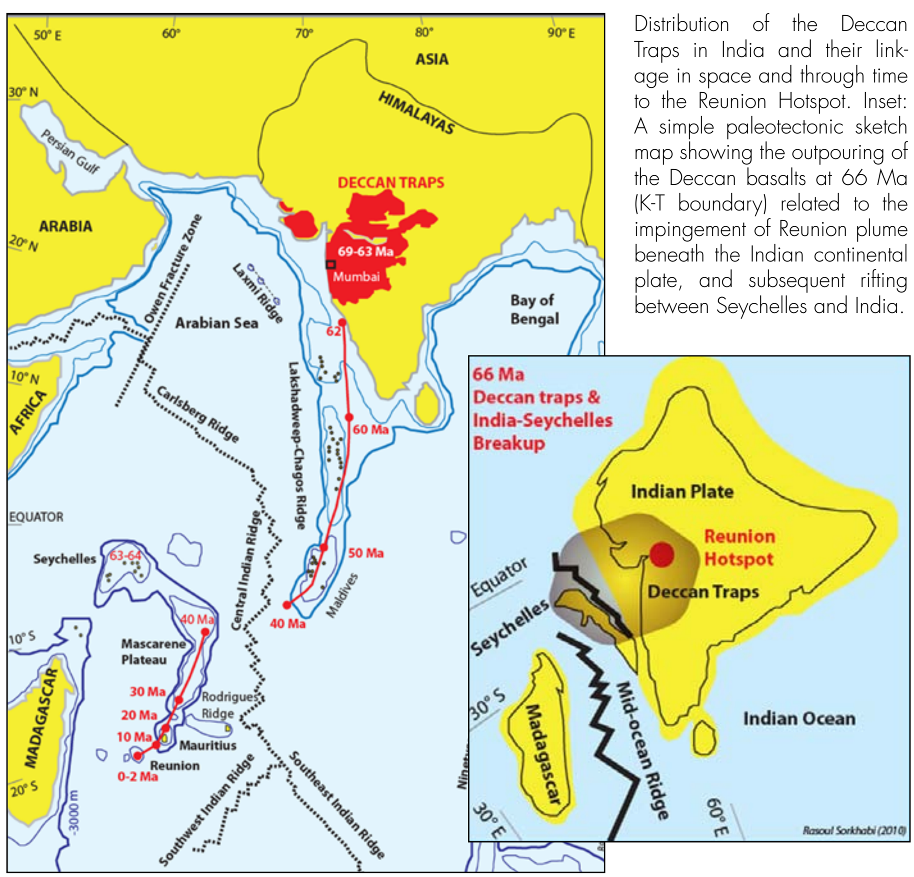
The Deccan Traps, one of the Earth's largest igneous provinces, cover over 500,000 km^2 of west-central India. Erupted about 66 million years during the extinction of the dinosaurs, these flood basalts, in cooperation with the sea, rains and rivers, have shaped the landscape of west-central India. Ancient cave temples have been carved out of the Deccan basalts in many places and the Elephanta Caves located on a small island offshore Mumbai (Bombay) is one such place.

FLOOD BASALTS IN CENTRAL INDIA

The triangular peninsula of India is largely a Precambrian shield, with a central flat area, the so-called Deccan Plateau, surrounded by the mountain ranges of the Eastern and Western Ghats. The name Deccan is derived from the Sanskrit word 'dâkshin', meaning "south." The west-central parts of the Indian peninsula are dominated by flood basalts which form a prominent terraced landscape; this form of flood basalt is called 'trap', after the Dutch-Swedish word 'trappa', meaning 'stairs'.

A large number of geochronological data have been reported from the Deccan Traps over the past four decades, and the data cluster between 69 and 63 Ma (corresponding to the magnetic polarity epochs of 31 Reverse and 28 Normal) suggests that the main phase of eruption was at 66.9 ±0.2 Ma, shortly before the Cretaceous-Tertiary (K-T) boundary at 65.5 ±0.2 Ma. This age range is also consistent with paleontological data from the interbedded sediments. Aside from terraces, the Deccan basalts also form numerous dikes, some of which represent the youngest phase of the volcanic activity. While some scientists support a several million year duration for this volcanic activity, others have argued that the eruption occurred within a million years at the K-T boundary.

The original extent of the Deccan Traps has been estimated as 1.5 million km^3, but the latter is highly imprecise as erosion on land and undersea subsidence on the western Indian margin have altered the rock volume accessible to us. The Deccan Traps are thickest on the Western Ghat Range (over 2,000 km thick) or in fault-bounded grabens in west-central India, but become thinner (less than 100 m) close to the margin of the trap province. Over 95% of these lavas are tholeiitic basalts



Distribution of the Deccan Traps in India and their linkage in space and through time to the Reunion Hotspot. Inset: A simple paleotectonic sketch map showing the outpouring of the Deccan basalts at 66 Ma (K-T boundary) related to the impingement of Reunion plume beneath the Indian continental plate, and subsequent rifting between Seychelles and India.

Image: Rasoul Sorkhabi

(tholeiite, named after Tholey, Germany is a type of basalt rich in silica). Mantle xenoliths in the Deccan Traps have been reported from a few places.

Most scientists believe that the Deccan Traps poured out as the Indian plate, on its northward journey after the Gondwana breakup, passed over the Reunion hotspot, a still active volcanic island located in the south-west Indian Ocean. Coeval with (or probably as a result of) this event, there was also a continental rift-drift between India and the Seychelles Islands. Indeed, flood basalts of similar age also occur on the Seychelles. (For Seychelles see the article "An Oil Prone Frontier Basin," *GEO ExPro*, Vol. 4, No. 3). The occurrence of petroleum reservoirs below the Deccan Traps remains unexplored.

Photo: Rasoul Sorkhabi

A view of two of the caves on Elephanta Island. The Deccan basalts are prominently seen in the photo.

CAVE TEMPLES IN DECCAN TRAPS

One can see exposures of the Deccan Traps in the Indian states of Gujarat, Madhya Pradesh, and Maharashtra in India, but vegetation, soil cover, and land development often mask these rocks. Cliffs of lavas on the Western Ghats and hill caves in Maharashtra perhaps provide the best outcrops to examine these formations. The hill caves are particularly important as many of these are also ancient Hindu or Buddhist temples, centuries old and portraying the Indian myths on rocks.

Some of the best known Deccan Trap caves are close to Mumbai (Bombay), including Ajanta (perhaps the oldest one dating back to 200 B.C.), Mandapesvara Caves, Kanheri Caves, Jogeshwari Caves, Mahakali Caves, and of course, the Elephanta Caves, which are our subject here.

Cave No. 1 or the Great Cave is the largest and most celebrated of all the Elephanta caves. This cave temple (restored in the 1970s) contains many statutes and sculptures of Lord Shiva and his life stories in Hindu mythology.

Photo: Rasoul Sorkhabi

ELEPHANTA ISLAND

The Elephanta Caves are located on Elephanta Island, offshore Mumbai, precisely 11 km north-west of Apollo Bunder near the Gateway of India, where numerous ferries take visitors to the island daily. The entire island, about 2.5 km long and 7 km in circumference, is made up of the Deccan basalts, covered with trees and bushes. Three villages on the island house a few thousand people engaged in farming, fishing, and tourism.

Through centuries, the island has come under the rule of various Indian dynasties. In 1534, the Portuguese occupied it. In 1661, when Charles II of England married Catherine of Braganza, daughter of King John IV of Portugal, Elephanta Island was given to the British royal court as a marriage dowry, thus beginning British control of the island until 1947, when India gained independence.

The native name for the island is "Gharapuri" – the "town of Ghari priests (those priests belonging to the Shudra or laborer and artisan class, and devoted to Lord Shiva). But the Portuguese called it Fontis (Elephanta) after a huge elephant statute that once stood on the island.

There are seven temple caves. The first five, on the western part of the island, are Hindu temples dedicated to Shiva, a deity which along with Brahma ('creator') and Vishnu ('preserver') forms the supreme Hindu pantheon. Shiva - literally the 'Auspicious One'- is often translated as the 'lord of destruction' but as one observes his various sculptures in Elephanta Caves he plays a far more varied role in Hindu mythology. The rock architecture of these Hindu caves has been dated between the 5th and 8th centuries.

The other two caves are Buddhist temples dating back to the 3rd century or even older and are not open to visitors. The Buddhist Stupa on the eastern part of the island is on the highest point of the island; it is called the Stupa Hill and is about 173m in elevation.

The Elephanta Caves were originally colour-painted but today only traces remain on the bare rock. Much damage has been done to the caves through centuries of weathering but also by the Portuguese soldiers who fired shots into the caves (to test the echo of their big guns), thus breaking some sculptures and pillars. In 1909, the Elephanta Caves came under the authority of the Archaeological Survey of India, and in 1987 UNESCO included it in the World Heritage list.

A trip to Mumbai is not complete without a visit to the amazing Elephanta Islands, where a portion of India's ancient history and mythology are preserved and displayed by the Deccan basalts – a fine sight, especially for geologists.

The stepped nature of the layered basalts of the Deccan Traps is clearly seen inland at Matheran, 90 km from Mumbai

RASOUL SORKHABI

Pennsylvania Crude Revisited

Photo: Michael Henderson, courtesy of Oil Region Alliance

Author Paul Adomites holding the book *Pennsylvania Crude* (119 pages with photographs by Ed Bernik).

Thanks to shale gas and Marcellus Shale, Pennsylvania (PA) is in the spotlight, at least in North America. But this state has a long and rich heritage of the petroleum industry. Long before oil from the Middle East, South America or even Texas and the Gulf of Mexico flooded the American markets it was the PA crude (famous for its light grade) that fueled America. Pennsylvania was the queen mother of the US oil industry in the second half of the nineteenth century; it was here, in Titusville in 1859 to be precise, that "Colonel" Edwin Drake drilled the first steam-engine propelled well to produce oil from underground, and its success triggered the oil industry as we know today (see "The Birth of the Modern Oil Industry,' *GEO ExPro*, Vol. 6, No. 3,; "Geomedia: Edwin Drake," *GEO ExPro*, Vol. 6, No. 1). But there is a lot more to the PA crude than the Drake well, and a new book offers a pictorial guide to this fascinating history.

Written by freelancer Paul Adomites, in a plain style understandable to the general public and with fabulous photographs by Ed Bernik, **Pennsylvania Crude: Boomtowns and Oil Barons** (Forest Press, Bradford, PA, 2010, $39.95) is a coffee-table book whose publication was supported by several organizations in PA including the Oil Region Alliance. The book has six chapters: Seeps and Pits, Discovery, Boomtowns, From Mud to Market, A Second Book, and The Next Well.

The PA oil and gas accumulations are part of the larger Appalachian basin dating back to the Devonian shallow seas and deltas. Oil produced from seeps and springs was known to the Native Americans for centuries; they used it as medicine, lubricant, and as fuel for lighting. In 1627, a Franciscan father journeying this part of America mentioned in his letter about the region's "very good oil, which [the natives] call Atouranton." The European immigrants who settled in this region called it Seneca Oil (after the indigenous tribe). The modern oil industry developed along its seeps, and with it grew many boom towns - most of which later disappeared, although some survived, including Titusville. Aside from the Drake well, what put PA on the oil map was the discovery of Bradford field (the state's largest) in 1871. As we learn from this book, the credit for the first oil well (1859), refinery (by Samuel Kier in Pittsburg, 1853), pipelines (1866), and oil exchange market (Bradford, 1878) in the USA all go to PA. Even the word "wildcatter" comes from the Wildcat Hollow in Venango County, PA. By 1900, the state supplied more than half of the US oil consumption. While oil from Texas and California rapidly increased in the early 20th century, "water flooding" first used in the PA fields gave a new life to them.

Even today there are over 19,000 wells in PA producing about 7,000 barrels a day; most of these are stripper wells (the book's author has one in his backyard). The book also reports that about 14 million barrels of conventional oil (about 70% of the original proven oil) still lie underground in the PA field. In recent years, the state has increased its permits for oil and gas drilling, and thus, the PA crude story goes on.

One minor correction that the book perhaps needs is that the text often refers to "petroleum deposit." Strictly speaking, petroleum (unlike coal and gold) does not form as a deposit.

I read this book in one sitting on a weekend, learned from it, enjoyed its artistic natural photographs, and remembered my own sightseeing in and around Titusville. The book also comes with a DVD which presents a touristic documentary for driving in the classical oil counties of Venango, Crawford, Butler, Warren, and McKean in PA and the Allegany County in New York State. This is a very well produced publication in words, sight and sound.

AZERBAIJAN: Major Gas Discovery

Although it has not yet reached TD, the **Umid**-8 well, 40 km offshore and 75 km from the capital of Azerbaijan, Baku, has preliminary estimates of 6.8 Tcfg (192 Bcm), and 220 MMbc, making it the second largest discovery since the country's independence in 1991. This discovery was announced in late November, despite the fact that the final drilling target depth of 6,500m is unlikely to be reached before early in 2011. Umid's recoverable reserves are suggested to be ultimately as high as between 7 and 10.5 Tcfg (200 and 300 Bcmg) and 240 MMbc.

The field, which lies 50 km west-southwest of the giant Shah Deniz field in the Caspian Sea, was first investigated with geophysics in 1953, and nine wells were drilled between 1977 and 1992, but none were successful, probably because they did not go deep enough. Udin-8 was drilled by SOCAR, the Azerbaijan National Oil Company, the first it has drilled alone since 1995.

Azerbaijan, already a major oil exporter, (21st in the world table of producers, only marginally behind UK and Qatar, according to the BP Statistical Review), also has proven gas reserves of 70 Tcf (2 Tcm), with potential further reserves possibly twice as much again.

© BP plc

Umid is thought to be the largest discovery in Azerbaijan since Shah Deniz, one of the largest gas fields in the world, was found in 1999.

SIERRA LEONE: West African Discoveries Continue

The run of success in the West African Transform Margin continues, with the mid-November announcement that **Mercury**-1, on block SL-07B-10 about 65km off the coast of Sierra Leone and close to the border with Liberia, had found oil. This also continues Anadarko Petroleum Corp's series of African successes, with three gas discoveries off Mozambique in the last few months, as well as the Venus discovery in Sierra Leone, 60 km west-north-west of Mercury.

The deepwater Mercury well, drilled in 1,600m of water and reaching a total depth of 4,861m, was seeking a stratigraphic trap target in the Cretaceous. It found 40m net pay in two fan systems of that age, with light sweet crude of between 34 and 42° API. The well was preserved for future re-entry, testing or sidetracking to further delineate the reservoir's areal extent.

Venus was discovered in September 2009 and was the first evidence that the petroleum system responsible for the giant Jubilee field in Ghana could also be present in Sierra Leone, 1,000 km further west. It also found two Upper Cretaceous zones of reservoir quality sand in turbidite complexes.

Anadarko are operators of the block with 65%, partnered by Repsol Exploracion Sierra Leone with 25% and Tullow Sierra Leone with 10%. The company has interest in five deepwater blocks offshore Sierra Leone, where it has identified more than 17 prospects and leads on 3-D seismic on this acreage.

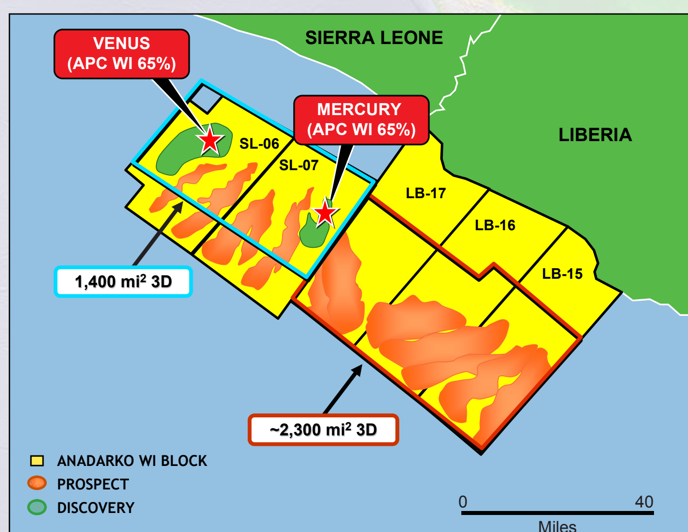
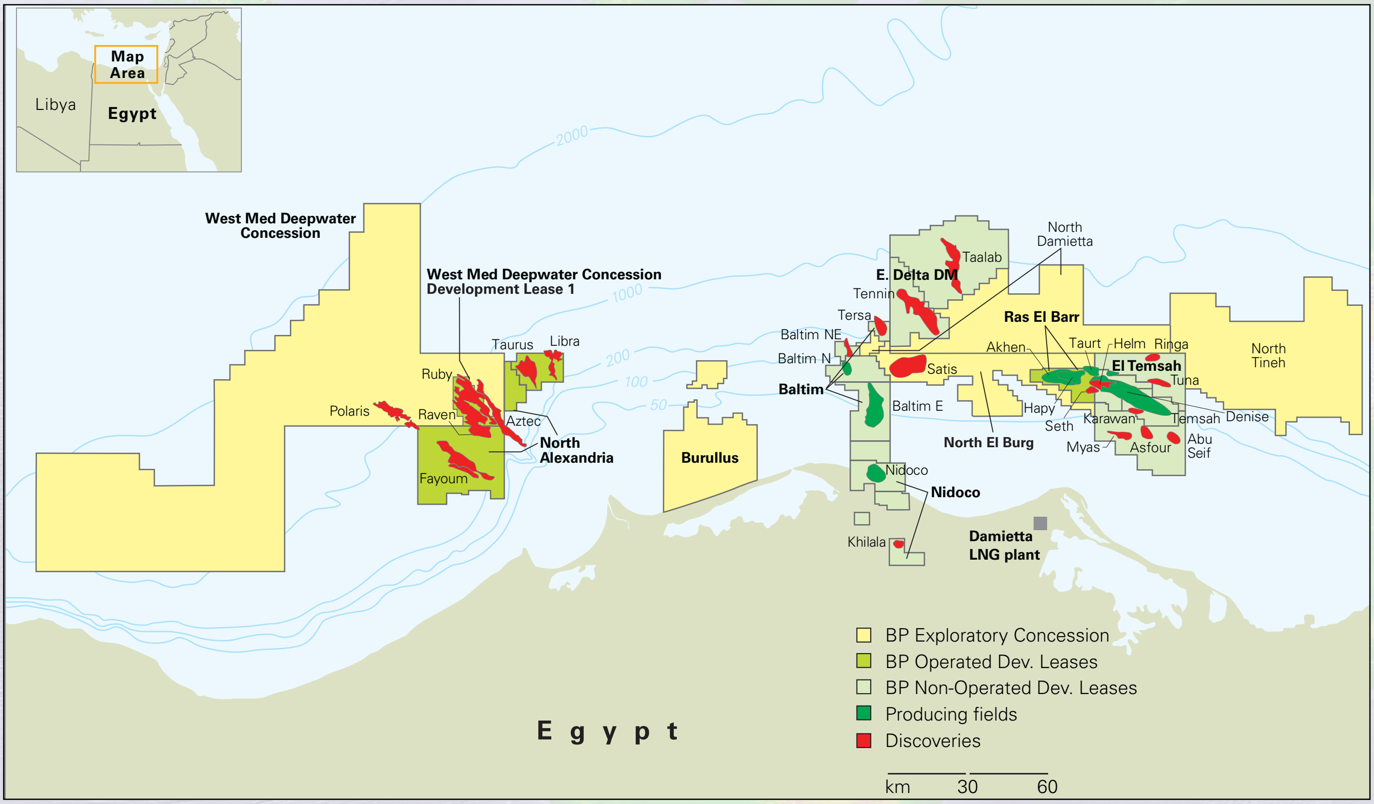


Image: Anadarko

Jane Whaley

EGYPT: Oligocene Deepwater Find



BP have made an important deepwater discovery offshore Egypt in West Mediterranean Deepwater Block B, about 80 km north-west of the port of Alexandria. Although results and reserves have yet to be announced, **Hodoa** has been described as a 'significant gas discovery' and additional appraisal is underway.

The discovery well, WMDW-7, reached total depth at 6,350m in late November in water depths of 1,077m, and is exciting because it is the first Oligocene deepwater find in the area. BP has already made a number of discoveries in the thirteen offshore concessions it holds the Nile Delta. These include the Giza, Taurus, Libra, Fayoum and Ruby discoveries, all in the shallower Pliocene channel play, which lies above the widespread Messinian salt. In 2004 they also discovered the 4 Tcf (113 Bcm) Raven gas field in Pliocene reservoirs beneath the salt, but Hodoa is the first discovery in even older rocks. (see *GEO ExPro* Vol. 3, No. 4/5 and *GEO Expro* Vol. 5, No. 1 for further discussion of these discoveries)

BP, which operates and holds 80% of the West Mediterranean Deepwater concession, has been working in Egypt since 1950. RWE is the other partner on the block.

BP's new gas discovery lies about 15 km north of the Ruby field in the Nile Delta.

Photo: Anne Whaley-Sousou

Alexandria, 80km south-east of the latest offshore discovery, is full of archaeological treasures. Pompei's pillar is 27m high and is made out of a single piece of granite

What's Happening in the US Market?

Stephen Trammel is a Senior Product Manager for IHS in Houston, where he focuses on the Gulf of Mexico and on the increasingly important role unconventionals play in the world's oil and gas supply picture. Ahead of the major North American Prospects Expo (NAPE) in February 2011, he takes a quick look at what is interesting the domestic industry in the US.

What is 'hot' in the US domestic oil and gas industry at the moment?

The Bakken – Three Forks play in the Williston Basin has estimated recoverable oil of about 4 Bboe and the emerging Niobrara play in the DJ Basin could yield as much as 800,000 barrels per section over a 4,500 square mile (11655 km^2) area. Operators are producing oil from the Wolfcamp/Sprayberry, (aka Wolfberry) play in the Permian Basin along with production advances from the Bone Spring and Avalon Shales. Liquids rich gas plays like the Granite Wash in the Anadarko Basin and the Eagle Ford in south Texas continue to expand and add to the expansion of onshore oil production. With an oil to gas per Btu price differential of 3 to 1, it is no surprise industry is following the money. The Barnett oil window in north Texas and the wet gas in the Marcellus in the Appalachian Basin are other examples where the economics really work thanks to the liquid content of the production stream.

And what is not?

Average US gas prices in November have hovered around US $3.65, so U.S. gas plays without an associated liquids potential are struggling. This includes tight gas sand plays in the Rockies and shale gas plays around the country. Drilling in these gas plays is still occurring to protect leases and if the gas volumes are strong, but operators are slashing costs wherever possible. For instance, Ultra Petroleum, a key operator in the Pinedale Anticline of western Wyoming, has reduced drilling times by over 30% in recent months to keep the tight gas sand play viable.

What effects are still being felt from the Macondo disaster?

Hurricanes did not occur in the Gulf of Mexico after the spill which kept much of the spilled oil from piling up onshore. To date there has been no discernible effect on fish stocks and almost all the fisheries have now reopened. It is still early, and deep drifting oil plumes and other residual oil may still pose problems. The reorganized MMS, now called the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), is discussing delaying future lease sales until new safety rules are in place. Depending on the lease sale delays and the stringency of the new rules, some of the smaller independents, which currently hold about 66% of the Gulf's leases, could be pushed out of the area.

The NAPE (North American Prospects Expo) website claims to be 'the one industry event that everyone, no matter what the discipline, tries to attend'. Do you agree?

NAPE attracts 15,000 attendees to its winter meeting. With that level of attendance, it is an excellent marketplace for the buying, selling and trading of oil and gas prospects and producing properties via exhibit booths.

Does NAPE play an important role in deal making in the US and Canada?

I believe NAPE plays a very important role for deal making. While producing property offers are not a strong part of the exposition, new prospects draw the crowds. In one venue, you can see the latest plays, view prospects prior to a play even starting and get a great feel for future trends. It also is an outstanding networking event.

What purpose does the International Pavilion and Forum play at NAPE?

Along with the global economic recovery, oil demand is increasing and global LNG markets are beginning to tighten. Oil and gas prices are strengthening. In spite of post-Macondo concerns, operators are planning to revive suspended offshore development projects both in the Gulf and elsewhere. Global discoveries continue to expand existing plays and to open new plays while unconventional gas and oil opportunities are being pursued throughout the world. The NAPE International Forum and Pavilion are designed to introduce successful E&P companies which are interested in going international to the opportunities and challenges that exist today. The forum provides education and promotion of international prospects. NAPE is really an exposition for international prospects and is not limited to North America. ■

The Barmer Basin of Rajasthan, India

Cairn India's successful development of the Barmer basin in north-west India has been one of the major oil industry events of the last two decades in that country, and has put both Cairn and Barmer in the spotlight.

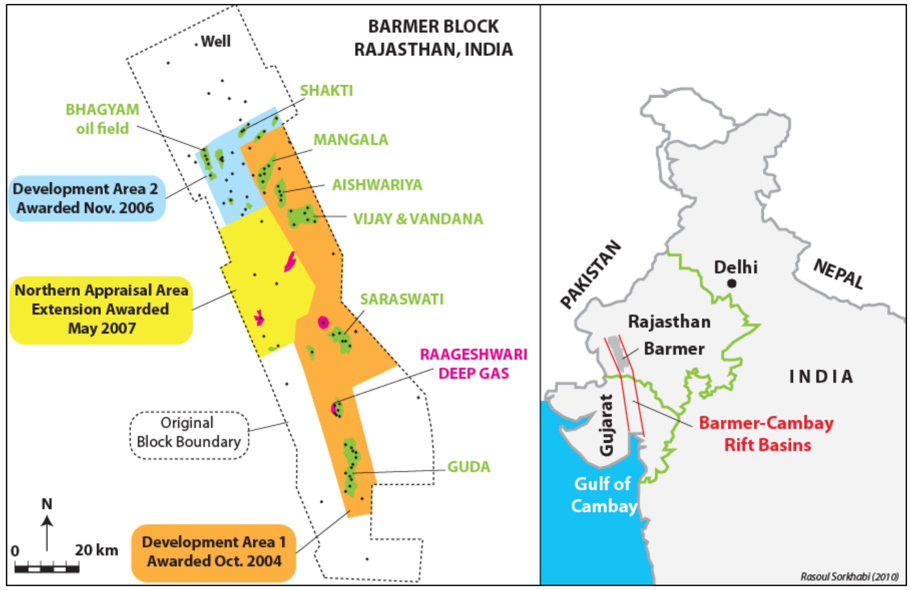
Cairn India's success in the Barmer basin, Rajasthan, is part of the story of India's opening to world market in the early 1990s, which increased competition among the oil players in the country to explore and discover new fields. The Edinburgh-based Cairn Energy entered India in 1996 through acquiring the Australian company Command Petroleum which had interest in the **Ravva** field, offshore eastern India.

In 1997, Cairn India (Cairn Energy's Indian arm) purchased the little explored fields in the Barmer block from Royal Dutch Shell, for $7 million. It then launched deep drilling and reflection seismology. **Guda-2**, drilled in 1999, proved an active hydrocarbon system and **Saraswati-1** in 2001 hit commercial volumes of oil from the Paleocene Fatehgarh sandstones. By 2004, oil from the same reservoir in the **Mangala, Bhagyam, Aishwariya** and **Shakti** fields credited the Barmer block as the largest onshore discovery in India since the mid-1980s. Meanwhile, Cairn India explored in the Gulf of Cambay and discovered the **Lakshmi** gas field in 2000, with production two years later.

Barmer is geologically the northern extension of the Cambay rift basin formed in the latest Cretaceous-Paleocene as India separated from the African margin, more specifically from the Seychelles fragment. This rifting event was coeval with the outpouring of Deccan flood basalts in western India and on Seychelles Islands.

Production of 240,000 bopd possible

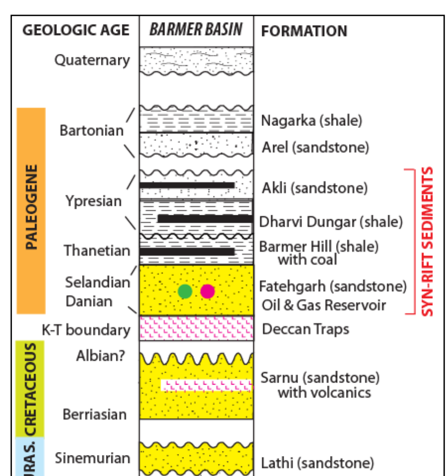
Production from Barmer began in 2009 with 20,000 bopd which in late 2010 reached 175,000 bopd (110,000 from the Mangala field, 40,000 from Bhagyam, and another 10,000 from Aishwariya). Cairn believes that with the expansion of the block's size, the production may go up to 240,000 bopd. Even at the present production rate this discovery has already increased India's crude output by 18% (to 647,000 bopd in late 2010). How much recoverable oil exists in Barmer? In March 2010, Cairn released its latest estimate as 6.5 Bbo, the previous estimate having been over 3.6 Bbo.



Over 25 oil and gas fields have been discovered in the Barmer basin, making it India's most prominent onshore discovery since the mid-1980s.
(modified after Paul Compton, *Petroleum Geoscience*, May, 2009)

Cairn Energy has a 62.37% stake in Cairn India. In August 2010, it was reported that the company wanted to sell 40 to 60% of its controlling stake in India to Vedanta Resources, a mining company managed by Anil Agarwal. The deal is worth between US $6.55-9.60 billion. The London-based Vedanta operates iron ore, zinc and copper mines in India, and the deal, if finalized, would open huge oil opportunities for this company (making it similar to BHP Billiton). Aside from eight fields in Barmer, Cairn India also owns interests in the Ravva field (offshore Krishna Godavari basin) and Block CB/OS-2 in the Gulf of Cambay. In Barmer, Cairn India has 70% stake while the remaining is owned by India's Oil and Natural Gas Corporation (ONGC).

The Cairn-Vedanta deal has been a matter of debates in recent months. ONGC and India's Petroleum Ministry have opined that Cairn should have sought their permissions. Cairn has argued that the transaction is a sale of its market shares rather than a new contractual assignment. Criticism has also targeted Vedanta Resources for its lack of experience in the oil sector and for alleged environmental misconduct in its mining operations (which Vedanta refutes). Nevertheless, Vedanta is negotiating with a syndicate of banks to raise loans for its purchase of Cairn's stake in India and several banks including the Royal Bank of Scotland, Standard Chartered, Barclays, JP Morgan, and Citigroup have responded positively. Both Cairn and Vedanta have stated that Cairn India's present management team under Rahul Dhir will be retained. Mr. Dhir, in turn, has suggested that the company retain its valuable name; to do so Cairn India needs to hold to at least 10% of the stake. It is expected that in early 2011, the Indian government will decide on the Cairn-Vedanta deal.



General stratigraphy of the Barmer basin. The sandstone reservoir Fatehgarh Formation (430m thick), although stratigraphically underlying the shale source rock Barmer Hill Formation (about 80m), is structurally higher in the oil fields because of normal faults in the rift basin.

The future of fossil fuels

For the fossil fuel industry, the future is bright, as there will be a great demand for their products. For the environment, however, the future may be grim, according to IEA.

"The age of cheap oil is over." That is the opinion of the International Energy Agency (IEA). Well founded, it would seem, as the forecast comes out of the 2010 edition of the World Energy Outlook (WEO) that was released in November.

The WEO 2010 looks at how the energy system will evolve in the next 25 years, taking into account the broad policy commitments that have already been announced by countries around the world to address climate change and growing energy insecurity. The outlook thus provides updated projections of energy demand, production, trade and investment, fuel by fuel and region by region, all the way up to 2035. Lots of numbers, lots of statistics - and lots of mind-boggling.

The most likely scenario (the "Current Policies Scenario") predicts that oil will be sold for US$ 130 per barrel in 2035, 25 years from now. As a comparison, 25 years ago, in early 1986, the price was down to US$ 10 per barrel for a brief period.

With a "New Policies Scenario", the price increase may be more modest, ending up at roughly US$ 115 per barrel in 2035. This is the first time IEA has done this particular exercise.

The WEO 2010 also states that China and other emerging economies will shape the global energy future. While the use of oil and coal is expected to decrease in OECD countries over the next 25 years, their use will increase both in China and the rest of the world, resulting in a net increase. And, while the energy growth in OECD countries is dominated by renewables, the energy growth in China stems largely from coal, oil and gas.

For those of you who believe in renewables, IEA is of the opinion that these are now entering the mainstream. But, IEA states, long-term support is needed to boost their competitiveness. Meaning, in my opinion, that renewables are still a long shot. This conclusion is substantiated by the IEA prediction that fossil fuels will increase three times over the increase in renewables.

Why is this so? Well, look at the number of passenger vehicles. As of 2010, the number is roughly 0.8 billion. In 2035 that number will have doubled to 1.6 billion, the largest increase being in non-OECD countries. China alone will increase the number of cars in the world by 350 million - that is what IEA predicts.

Whether you believe in climate change caused by CO_2 emissions, or not, it can easily be predicted that such an increase in number of cars and fossil fuels is not good for the environment.

This is a parabolic trough solar thermal electric power plant in California. According to IEA, the use of renewable energy will triple between 2008 and 2035, driven by the power sector, where their share in electricity supply rises from 19% in 2008 to 32% in 2035.

CONVERSION FACTORS

Crude oil
1 m^3 = 6.29 barrels
1 barrel = 0.159 m^3
1 tonne = 7,49 barrels

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

Energy
1000 m^3 gas = 1 m^3 o.e
1 tonne NGL = 1.9 m^3 o.e.

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

Supergiant field
Recoverable reserves > 5 billion barrels (800 million Sm^3) of oil equivalents

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

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

Historic oil price