Vol. 2, no. 5/6 – 2005

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

Peru: World's 1st giant field and with a world-class tourist attraction

Canadian oil sands: The world's largest single hydrocarbon resource

Sand injectites: Exploration targets in their own rights

GEO ExPro Vol. 2, No 5-6, 2005

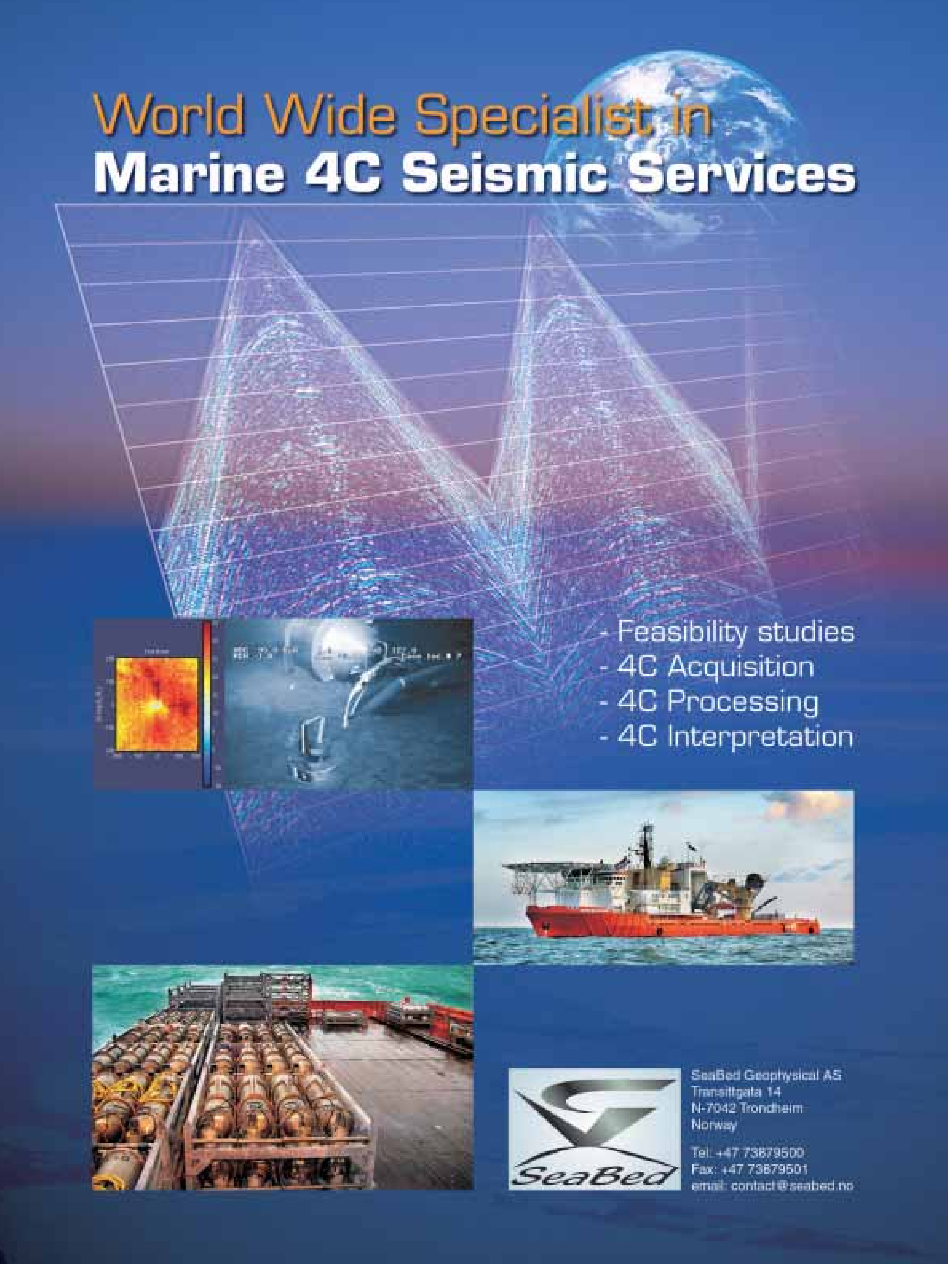
Terje Eidesmo

Svein Ellingsrud

Seabed logging

The oil companies now have a tool that serves to reduce the risk when exploring for oil and gas in offshore sedimentary basins. The next major step, the inventors say, is to make the technology work also in reservoir monitoring. Don't be surprised if the prophecy turns out to be true, because these guys are very stubborn and make up a very good team that has proven itself worthy.

GEOLOGY GEOPHYSICS RESERVOIR ENGINEERING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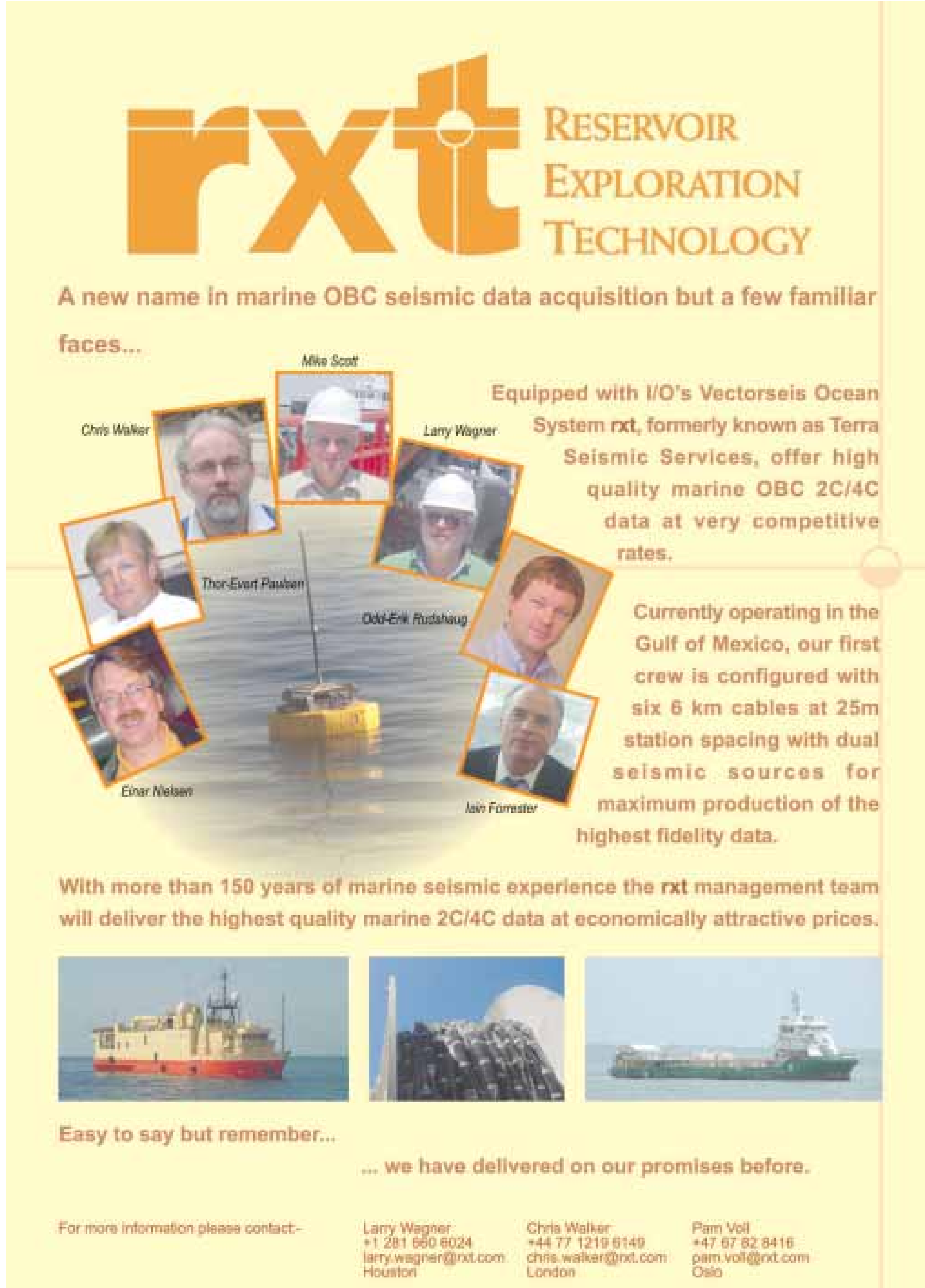
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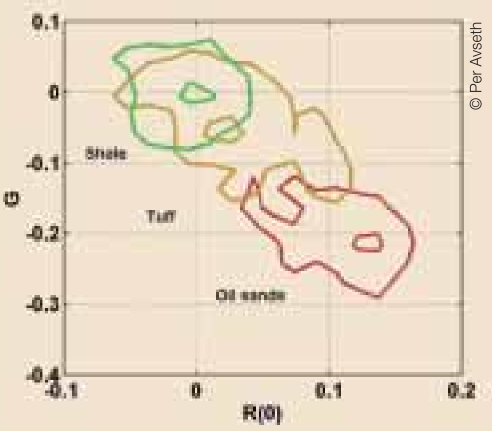

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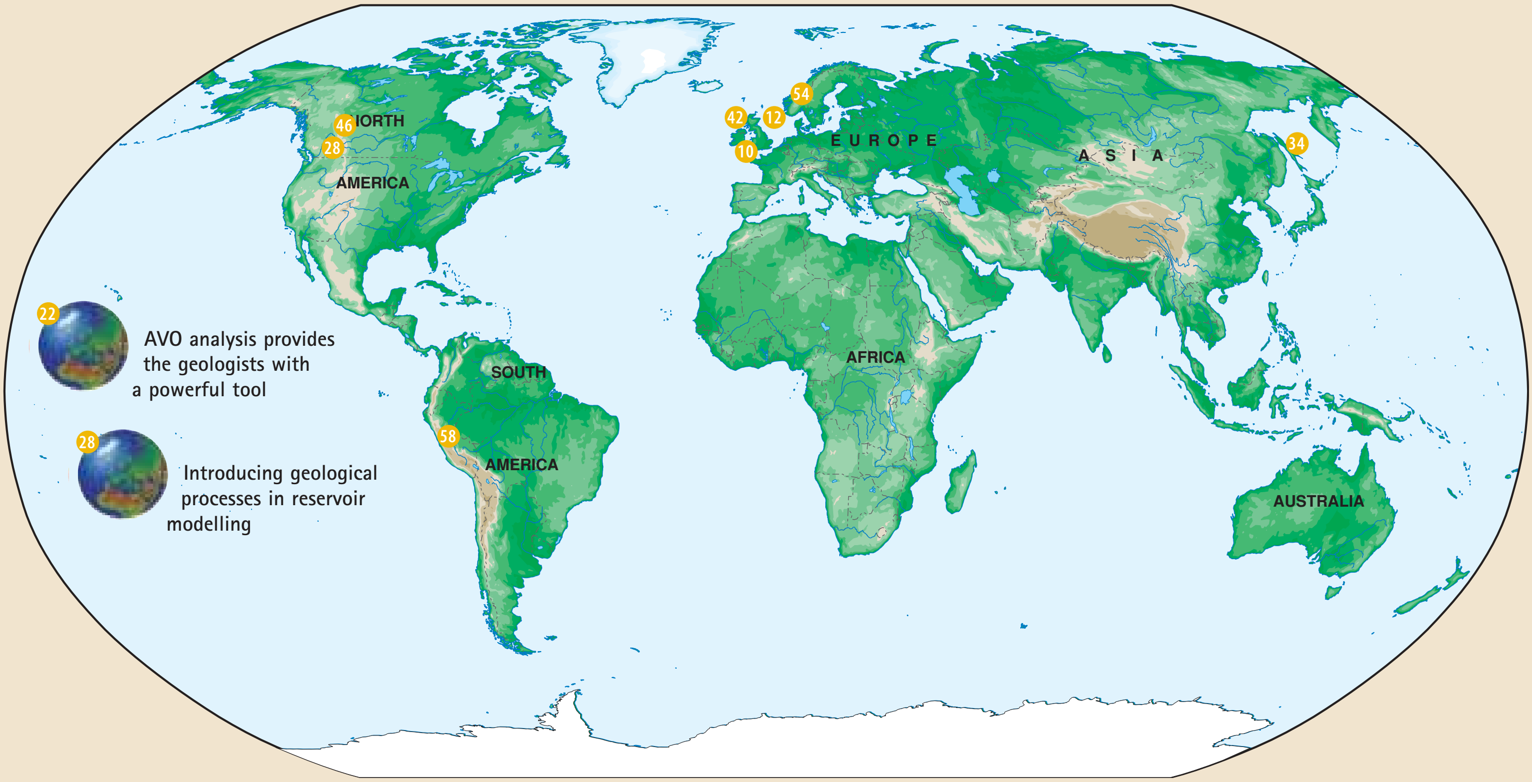
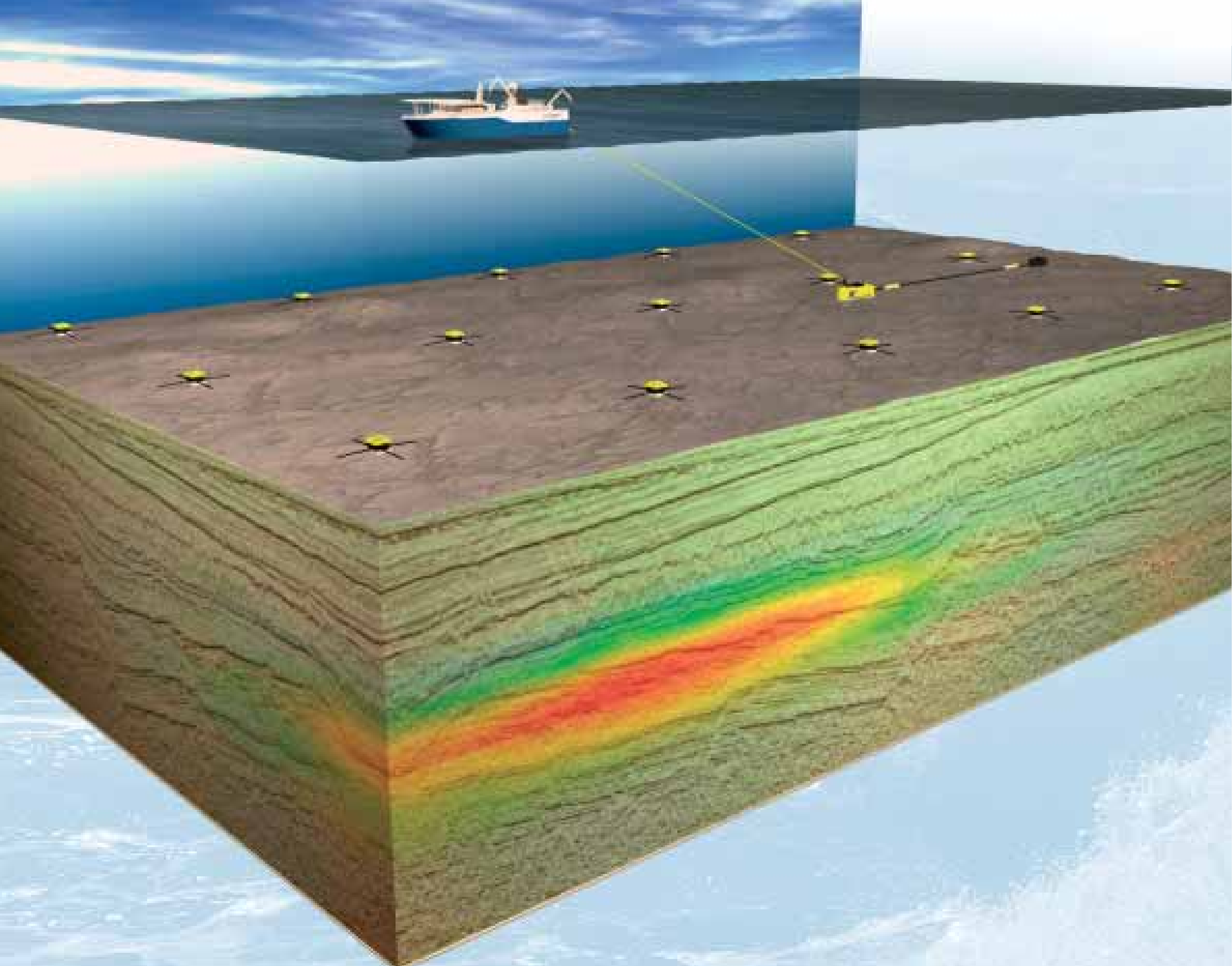
AVO analysis provides the geologists with a powerful tool that give information about pore fluids, lithologies and reservoir pressures. However, caution is encouraged, as AVO signatures can easily be misinterpreted without a proper feasibility study.





Understanding the subsurface

GEO ExPro can – with the current edition – celebrate the conclusion of two volumes. And, thanks to an overwhelming response from readers and advertisers, we are happy to announce that we have found good reason to continue with the third volume next year.

The first two years in operation have shown that there is a need for a "coffee-table" magazine that does not primarily have a scientific objective. Instead, we are aim to make petroleum geoscience available in a different format without compromising the scientific content.

GEO ExPro targets geologists, geophysicists and reservoir engineers, but most of all we intend to reach readers that are interested in the entire workflow starting out with initial exploration and ending up with tail end production. We strongly believe that petroleum geoscientists will benefit from familiarizing themselves with a broad aspect of themes.

Petroleum exploration and production benefit from quantum leaps in technology and corresponding advances in the geoscience disciplines. Geologists, geophysicists and reservoir engineers, all preoccupied with trying to understand the subsurface. With the common goal of finding and producing more oil and gas they are faced with an overwhelming flow of knowledge and data.

As a consequence, GEO ExPro is a response to the increasing demand for a magazine that makes it easier for the professionals to get an understanding of how our business is conducted. Similarly, the petroleum industry is becoming more international and involving more countries. This also justifies the creation of a new interdisciplinary magazine that covers new advancements and concepts within geoscience and technology related to exploration and exploitation of hydrocarbons.

This edition of the magazine illustrates the concept very well. Geographically, we have examples from the Sea of Okhotsk, Russia, in the Far East, to Alberta, Canada, in the "far west". Technologically, we are covering a broad range of subjects from exploration to reservoir engineering.

Halfdan Carstens
Editor in Chief

Photo: Halfdan Carstens

Canadian oil sands

The Canadian oil sands represent an enormous resource. Shallow oil sands deposits can be mined in open-pit surface mines, while deeper in situ deposits require other recovery methods. The production of synthetic crude from oil sands is, however, with present day technology, only economically viable with synthetic crude prices in the USD 25-30 range. The oil sands industry is also heavily reliant upon water and natural gas, which is necessary in both the extraction of bitumen from oil sands and the upgrading of bitumen to synthetic oil.

The problem is that removing the crude oil is technologically difficult, may be unfriendly to the environment and is expensive. Nevertheless, the oil sands have contributed to the recent boom in Canada's oil production.

Oil sands contain deposits of bitumen, a heavy, viscous oil. Lighter hydrocarbons must be added to the bitumen to allow it to flow. The bitumen is processed into "synthetic crude", and in general it takes about 1.16 barrels of bitumen to make 1 barrel of synthetic crude.

The oil sand deposits were originally giant oil reservoirs, but following the Laramide orogeny some 30-60 million years ago, the oil percolated to the surface upon which the lighter components evaporated and microbes eat the remaining hydrocarbons. The deposits are primarily located in sandstones of Early Cretaceous age.

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Writers needed

GEO ExPro targets geologist, geophysicists and reservoir engineers that are concerned with the subsurface. The aim of the publication is to present articles that explain geoscience and technology in a simple and readable manner to a wide range of professionals within the oil industry.

We are now looking for skilled writers who have a working knowledge of the petroleum upstream industry. A background in geoscience and/or technology is preferable, and experience in writing a necessity.

If you are interested, please contact, either:

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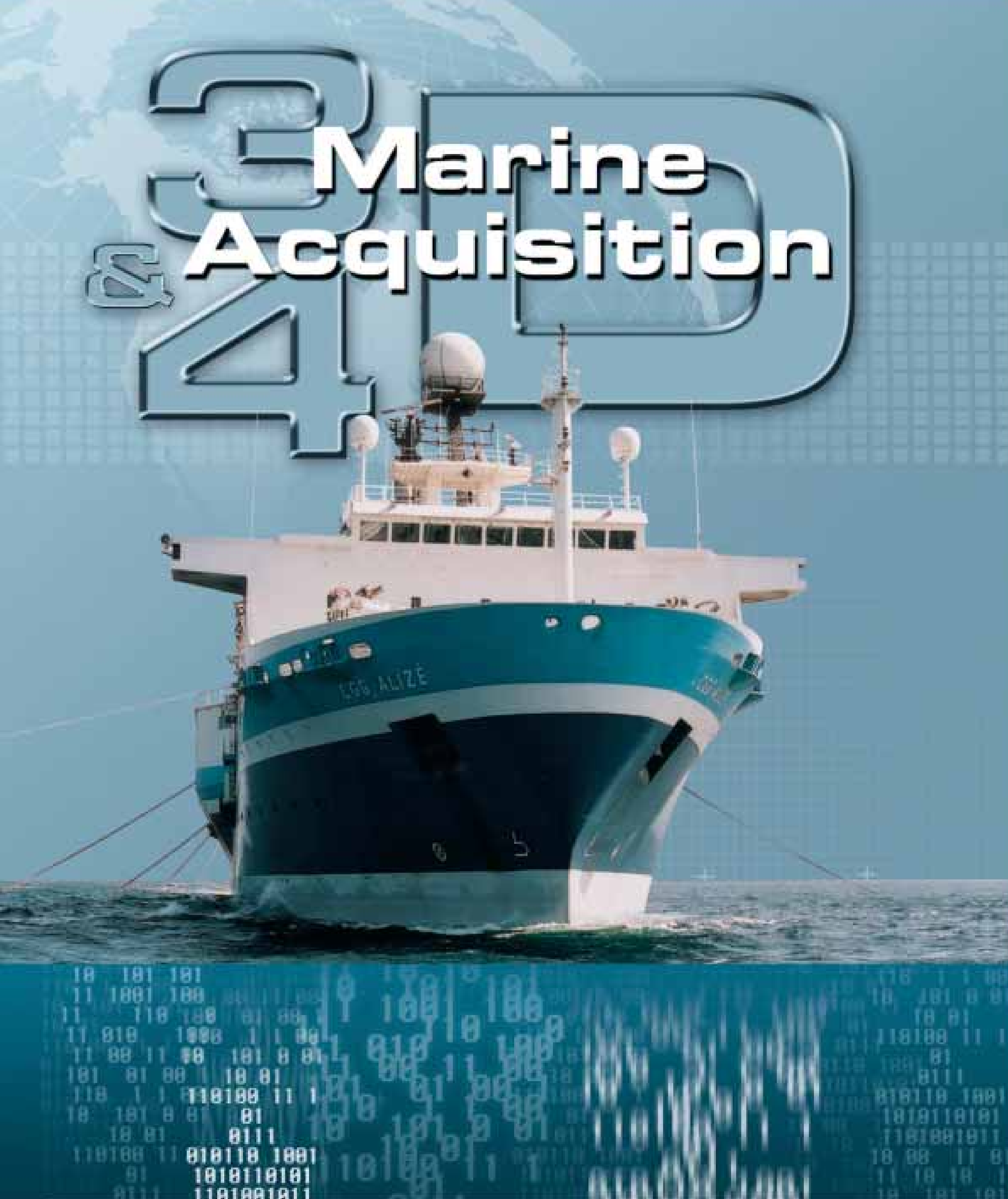
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GEO Ex Pro 2006

No. 1
- North American Prospects Expo (NAPE) in Houston, 2 - 3 February
- APPEX in London, 6-9 March

No. 2
- AAPG 2006 Annual Convention in Houston, 9-12 April

No. 3
- EAGE 68th Conference & Exhibition in Vienna, 12 – 15 June

No. 4/5
- SPE Annual Meeting in San Antonio, 24-27 September
- SEG 76th Annual Meeting in New Orleans, 1-6 October

No. 6
- Petex in London, 21 - 23 November

Second Rosneft-BP discovery offshore Sakhalin

CJSC "Elvary Neftegas" (Rosneft-BP joint venture) has announced the successful completion of drilling and testing of its second exploratory well in the Kaigansky - Vasuykansky exploration licence. The offshore licence block, covering over 6,000 square kilometres, lies in the south of the Sakhalin-5 acreage, north-east of Sakhalin Island. The Udachnaya well was drilled to a total depth of 2,705 meters and encountered hydrocarbons in three zones. A restricted test programme was conducted on a single zone which flowed at a rate of 1,900 barrels of oil per day.

This second discovery in the block was made on the Udachnaya structure located about 40 kilometers offshore, in water depths of some 100 metres.

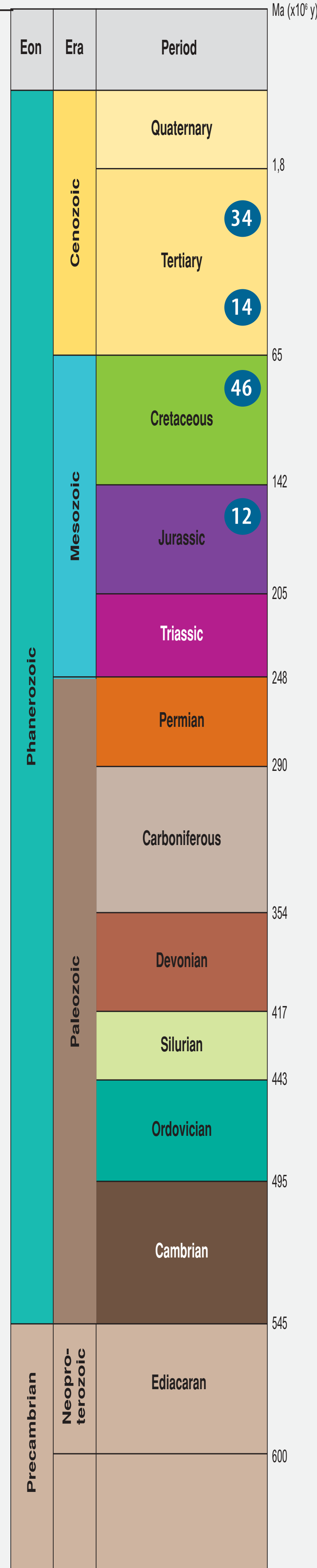
The first well in the Kaigansky-Vasuykansky exploration licence was drilled in 2004 on the Pela Lache structure some 15 kilometres to the east. It encountered significant volumes of oil and gas in a number of high-quality sandstone reservoirs.

Elvary Neftegas plans to continue exploratory drilling in 2006.

At the same time TGS-NOPEC and partners have initiated a new seismic program in the Sea of Okhotsk near Sakhalin Island. TGS and partner Dalmorneftegeofizika ("DMNG") will acquire 8,000 kilometres of multi-client 2D seismic data. The new program will infill the companies' pre-existing seismic grid in the region and extend the program into the Sakhalin 6 area for the first time.

See also related story starting on page 34.

GEOLOGIC TIME



Software boosts recovery

Two new computer programmes which could help to improve recovery from oil and gas fields have been developed by Statoil and Canada's Geomodeling Technology Corp. The software is now to be commercialised.

Offtech Invest, the group's wholly-owned investment company administered by the industrial development (I&K) unit, has injected some NOK 20 million in Geomodeling. This funding is intended to back commercialisation of the SBED and SBEDStudio software, which is used to create detailed fine-scale models of oil reservoirs. The programmes also permit more accurate calculation of the quantity of oil, water and gas in the structure, and of the way these substances flow in the rock.

Through its research and technology entity, Statoil has been helping to develop software in cooperation with Geomodeling for almost a decade. This work has been pursued over the past five years through a joint industry project, providing research funds and leading-edge expertise in partnership with eight other oil companies.

"A special feature of the software is that models are built with the aid of sedimentology," says adviser Trygve Lægreid in Offtech Invest. "We've been using SBED both on the Norwegian continental shelf and internationally. "The detailed models contribute to improved oil recovery and provide better estimates of how much oil and gas can be produced from new discoveries."

The programmes are used in both exploration and production, and estimates from Statoil's own operations teams show that they can help to boost revenues by hundreds of millions of kroner.

"Our investment through Offtech Invest forms part of our overall commitment to securing technology for improved recovery," says Mr Lægreid.

See also related story on page 28.

Extensive interest

At the deadline for application to the Awards in Predefined Areas (APA) 2005, the Ministry of Petroleum and Energy in Norway received application from 29 companies. The Ministry aims to award new production licenses in APA 2005 in December 2005.

"The extensive interest in mature areas of the Norwegian continental shelf continues (GEO ExPro No. 4, 2005). This year almost twice as many companies have applied compared to two years ago. It is encouraging to see that many of the newly established companies on the NCS have submitted applications in APA 2005. At the same time it is still a substantial interest for mature acreage on the NCS from the larger and established companies on the NCS," says Thorhild Widvey, Norwegian Minister of Petroleum and Energy.

Photo: Halfdan Carstens

On top of the anticline

The Kimmeridge Bay oil field, protected by fences, is probably the oldest continually producing well in the UK. The well was drilled and put on production in 1959. Today it produces less than 80 barrels of oil per day that is stored in tanks on site and collected twice a week by a tanker.

Ammonites flourish in the Jurassic rocks of Britain. They make excellent guide fossils for stratigraphy because they evolved rapidly so that each ammonite species has a relatively short life span. The ammonites became extinct at the end of the Cretaceous, at roughly the same time as the dinosaurs disappeared.

Kimmeridge with its characteristic stone buildings just above Kimmeridge Bay.

The producing well of the Kimmeridge Bay oil field is located directly on top of an anticline and thus represents a textbook example of a structural trap filled with hydrocarbons. The anticline is easily seen by following the highlighted limestone marker. Note also the fault at the far side of the crest and the Upper Cretaceous cliffs made up of chalk seen in the distance.

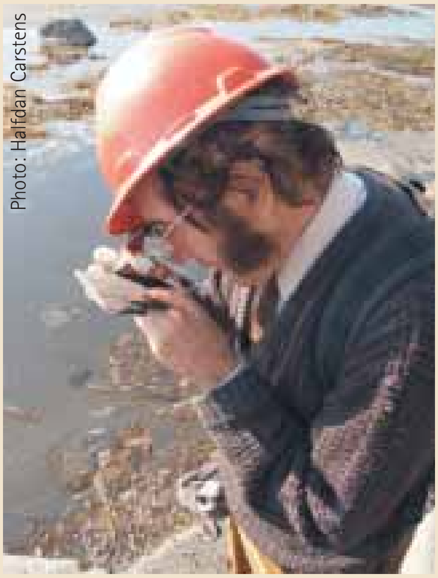
Kimmeridge Bay

The South Dorset cliffs along England's southeast coast are of international geological importance. The cliffs expose a complete section through the Upper Jurassic and the Cretaceous and include fossil-bearing rocks that have shaped our understanding of evolution. The Kimmeridge Bay is famous for its fossil reptiles and ammonites.

The shale beds in this bay are the type rock for the Kimmeridge clay formation of the Upper Jurassic and are the major source rock for the hydrocarbons of the North Sea.

The reservoir of the Kimmeridge Bay oil field, which has produced more than 3 million barrels, is sourced from Lower Jurassic shales. Nearby is the Wytch Farm oil field, with reported recoverable reserves of 460 million barrels, making it the largest onshore field in Northern Europe.

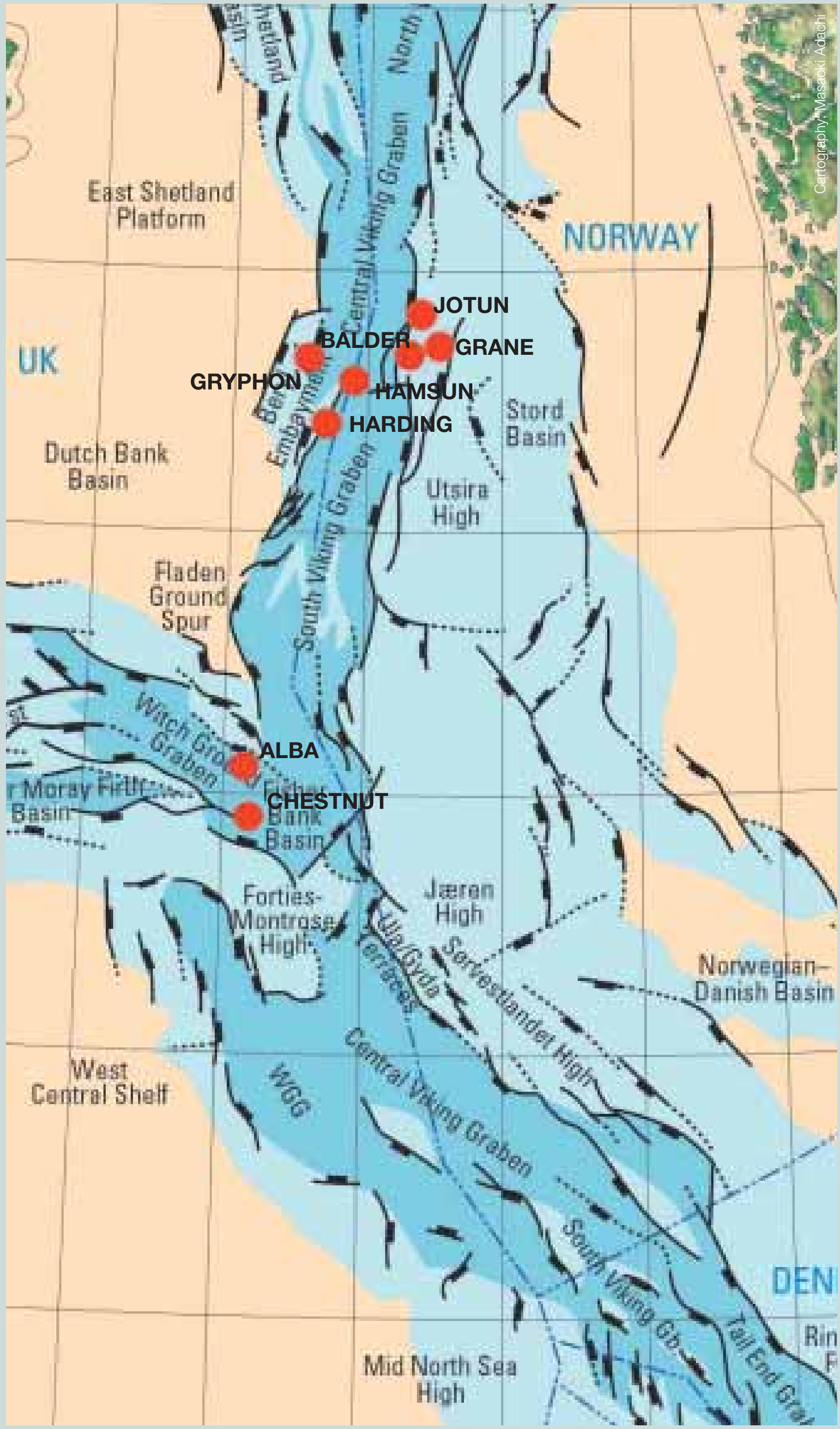
Photo: Halfdan Carstens



Dr. Ian West, who has got intimate knowledge of England's south coast by working the area throughout his entire carrier, has made the geology of the Kimmeridge Bay and the Wessex Coast, southern England, available to the whole world through his comprehensive website www.soton.ac.uk/~imw/kim.htm

Sand intrusions reveal increased reserves

Sand injections through the Miocene Monterey Mudstones near Santa Cruz, California, are studied as part of a research programme supported by the oil industry to increase their understanding of these reservoirs. In outcrop, sand injectites are easily identified where they intrude finer grained strata and crosscut bedding. Also, when dykes cut through depositional units, they may be distinguished by the absence of depositional sedimentary structures and different grain packing. As part of an ongoing research programme field work was carried out in California this summer with the purpose of acquiring outcrop data for integration into seismic and reservoir models. Here we see the Yellowbank Creek sand intrusion complex immediately southeast of Davenport, California. Margins are dashed lines. Note the irregular (scalloped) discordant geometry of the roof and the discordant lateral margins. The sands are fine- to medium grained, stained by iron oxides and are not tar-saturated. Dolomite cement (grey) is abundant.



Oil fields of the North Sea with extensive remobilisation features in Paleogene strata include Alba (UK), Balder (Norway), Chestnut (UK), Grane (Norway), Gryphon (UK), Hamsun (Norway), Harding (UK), and Jotun (Norway). Sand injectites are thus recognised as important modifiers of reservoir geometry in many deep-water clastic systems. In particular they are found in the Paleocene and Eocene, Lower Cretaceous and Upper Jurassic of the North Sea and along the Atlantic margins of both UK and Norway. In several cases the reserves have been upgraded because of their recognition. Similar features associated with turbidites are also recognised offshore Angola and Nigeria in Tertiary strata. Their common occurrence suggests that they may also be present in other clastic provinces, such as the petroleum provinces offshore Brazil and in the Gulf of Mexico. Although best known in deep-water clastic systems injectites may be present in eolian dunes and deltaic facies as well.

Highly permeable sand bodies injected into low permeability shales may provide additional reserves to existing discoveries and fields if properly recognized. Such sandstones, a product of postdepositional remobilisation, may also constitute exploration targets in their own right when thick and laterally continuous. Improved understanding and detection of sand injectites has – in fact – led to a recent discovery.

Halfdan Carstens

"Sand injectites comprise dykes, sills and other more irregular features that form intrusive traps within otherwise impermeable shales," says Andrew Hurst, professor of production geoscience at the University of Aberdeen in Scotland, who is now heavily involved in research on these intriguing sand bodies that have been overlooked by the petroleum industry for such a long time.

"Sand injectites may combine with more conventional traps or occur in isolation. The reservoirs typically crosscut depositional stratigraphy and frequently form pay zones above horizons conventionally interpreted as top reservoir. This is why we need to pay more attention to them," Hurst explains enthusiastically. And he knows what he is talking about, having been involved as a consultant in a highly unusual exploration campaign in the Viking Graben of the Northern North Sea.

"Recognition and evaluation of sand injectites can be vital for the appraisal and production of sandstone reservoirs affected by remobilisation and injection."

"A world first"!

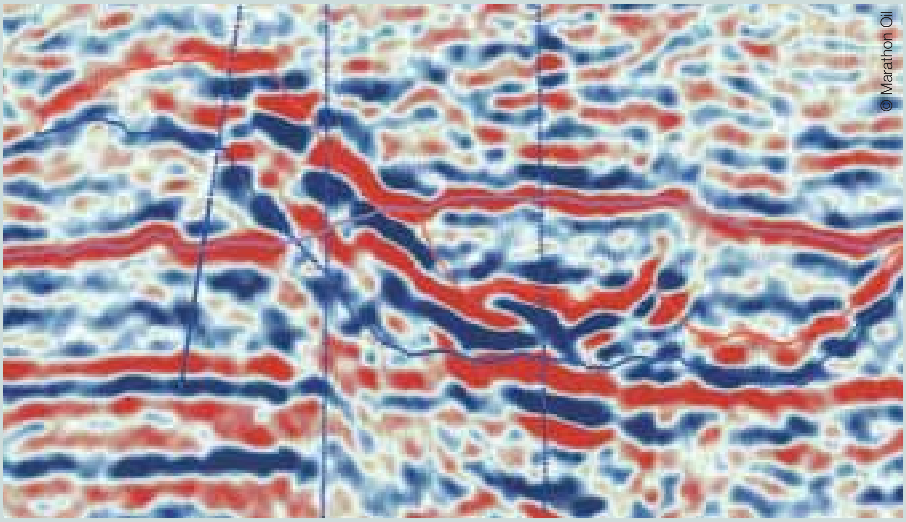
"Large volumes of sand may be injected from depositional sand bodies. Calculations on North Sea data indicate that the pore volumes of such sand bodies may be several hundred million barrels. They thus represent a significant potential to proven reserves and may even constitute separate exploration targets in many petroleum basins. However, evaluation of reservoir quality is complicated by the unusual geometry as well as variable thickness, net/gross ratios and cementation. The lack

Andrew Hurst has put his hand on a near vertical dyke complex saturated with tar (black) that thickens up eventually spreading laterally on a palaeo-seafloor. The complex is within the siliceous mudstones of the Santa Cruz Mudstone Formation (Late Miocene) of the Monterey Formation in the Red, White & Blue Beach near Santa Cruz, California. Above his head the mudstone is extensively brecciated with a fine-to-medium sand matrix. To the right we see a complex swarm of high-angle dykes cut through the mudstones. Oil migrated into the sands after injection probably as low-gravity crude (Monterey source rocks generate 25 °API crude). The injection occurred during deposition of the Santa Cruz Mudstone in several phases separated by periods (100's of years) without extrusion.

Dip section view of a sand injectite complex in Escapardos Canyon (Panoche Hills, CA). Orange arrow points to the deepwater clastic sandstones otherwise all sandstones are injected, a ca. 2 m thick composite sill (green arrows), diverse high-angle dikes and inclined sills (blue arrows) - all part of the Paleocene Moreno Formation.

of previous exploration of intrusive traps also hampers evaluation," Hurst says.

The dedicated geologist, with a long story to tell from more than ten years in Statoil and even more years as a professor, is now heading a research programme that focuses on acquisition of outcrop data and integration of those data into seismic and reservoir models. This work takes him to several places around the world where injectites can be studied in detail. The Miocene Monterey Mudstones near Santa Cruz, California provide good examples of sand injectites, which are easy to access, well exposed, and part of an active petroleum system. Here, dykes, sills and more diverse intrusive features, mud-clast breccias and sea-floor extrusions of sand all occur along the coast and are useful seismic-scale and intra-reservoir scale analogues for subsurface interpretation.



This seismic line through the Hamsun discovery of the Viking Graben, North Sea, shows where Marathon drilled the very first exploration well into a sand injectite complex. The pink horizon is top Balder Formation (top Paleocene) representing top of the massive deep-water sandstones. The red and blue horizons are the top and the base of the main sandstone in the injectite complex, respectively. The injection complex can be seen, but it is not possible to interpret internal geometries associated with the injected sands using these data.

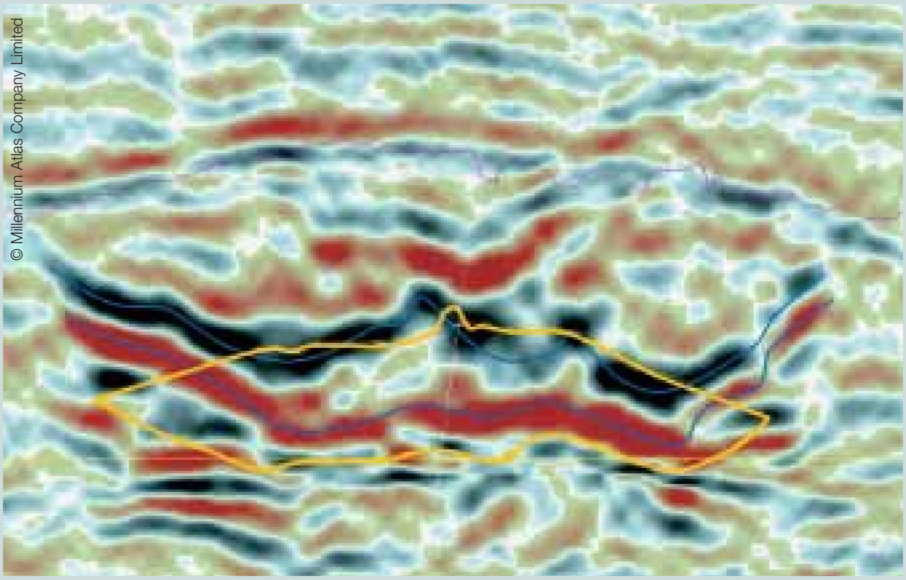
"Sand injectites often form highly permeable sand bodies within otherwise low permeability strata, which - when sufficiently large - form intrusive traps."

The ongoing research Andrew is involved in follows a two-year research programme that undertook subsurface examination of sand injectites and which was funded by an industry consortium. "The past programme encouraged pioneering exploration on the Norwegian continental shelf by Marathon who drilled the first deliberate exploration well into a sand injectite complex (Hamsun, 24/9-7, compare map). The well encountered an oil column that was greater than 100 m thick in sandstones," says Hurst.

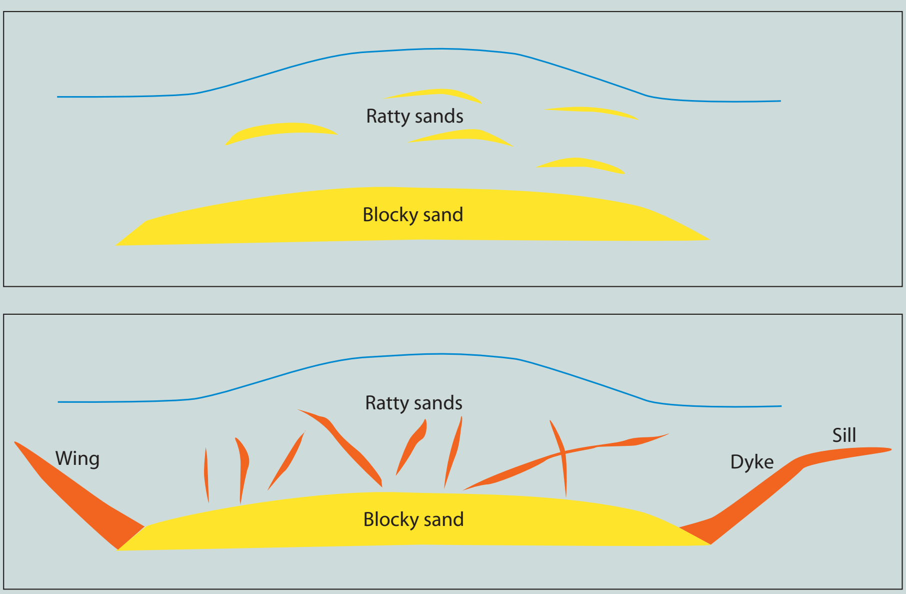
Bright seismic amplitude anomalies had previously been interpreted as a sandstone injection complex, but the prospect was considered too risky and not tested by the drillbit. Seismic modelling carried out by Marathon who acquired operatorship of the license in 2003 suggested that high porosity sandstones filled with oil caused the anomalies. One exploration well followed by three sidetracks proved high porosity sands and Darcy-range permeabilities.

"A significant oil discovery (in excess of

Vertical dyke reaching the palaeo-seafloor forming a 1-1.5 m thick extrusive sand unit. Low-angle lamination represents units deposited around seafloor vents from which sand escaped (as fountains of fluidised sand) - large burrows, including escape burrows, are common throughout - grades up into siliceous mudstones.



Interpretation of the Alba field before (yellow) and after (blue) a 4C seismic survey conducted in 1998. The yellow colour shows the old conventional seismic-data interpretation, while the blue colour shows shear-wave seismic data interpretation with injected sands cutting across mudstones.



Models of sand distribution and geometries vary depending on data quality and interpretation mind set. The upper model shows a structureless sand distribution confined to an erosional scour with "ratty" sands on gamma-ray logs interpreted as thin-bedded turbidites in the overburden shales. The lower model shows a massive sand distribution with no apparent confinement and mounding due to differential compaction. The "ratty" sands are interpreted as sand injectites in the overburden shales, whilst wing-like reflections at the edges of the sand are interpreted as low-angle sand dykes and sills/extrusions. Over the past decade, increased quality of core and 3D seismic data has changed the interpretation of many fields of the North Sea Paleogene from the upper to the lower model.

100 MMB oil) had been made by an exploration drilling campaign which specifically targeted a large-scale sandstone injection complex, and we now know that the seismic amplitudes are associated with porous, hydrocarbon-charged injectites," says Hurst who also acted as a consultant to Marathon during exploration and appraisal of the prospect.

"We believe this represents a world first," he adds.

Unknown to petroleum geologists

Andrew Hurst explains that sand injectites have been known as a geological phenomenon since the early days of earth science. The first description that he knows of, is found in the *Transactions of the Geological Society* in 1827. The legendary British geologist Roderick Murchison then published a paper that describes the Kintradwell dyke in the Kimmeridgian shales of the Helmsdale Boulder Beds of northern Scotland.

"Outcrop examples of sandstone intrusions were also described around a century ago by various workers in California where the tar contained in some of them was worked commercially. The tar was a particularly important resource during the rebuilding of the streets of San Francisco following the 1906 earthquake," Hurst explains.

Sand injectites have only recently been recognised in the subsurface. "Petroleum geologists and engineers have been unaware of their significance as reservoirs until the 1990's when it became evident that numerous Palaeogene reservoirs of the northern North Sea have been subject to large-scale remobilisation and injection of sands. Their full significance in petroleum systems is, however, the subject of further research."

"The reason can partly be ascribed to the fact that very few outcrop descriptions capture the same scale of features as identified in oil fields, even if they share many textural characteristics and geometries. Another reason is that their recognition in the subsurface is largely dependent on high quality 3D seismic, which have become abundant only the last 10 years or so," Hurst says.

One of the first detailed descriptions of sand injectites as a reservoir was made only some six years ago *(The Leading Edge, November 1999, p. 1306-1312)* by a team from Chevron and Schlumberger. Using ocean-bottom cables they acquired 3D shear-wave data over the Alba field in the

> *"Thanks to the improvement in the resolution and coverage of 3D seismic several deep-water clastic oilfields are now recognised as having substantial reserves in injectite facies."*

North Sea that led to the identification of large injected sand bodies at the margins of, and above, the main reservoir. In particular they noted "wing features" in the top sand reflector at the channel edges and occasionally over the central axis of the reservoir. Two wells were subsequently drilled based on the new knowledge. The first well encountered 150 m of oil-saturated sands within a post-reservoir shale section and produced up to 20.000 bopd. The second well showed that the wing in the western part of the field is 20 m thick. Both wells thus validated the presence of the wings.

These observations led the team to conclude that significant post-depositional deformation of the deep-water clastics had occurred. They hypothesized that reservoir sands had been remobilised and injected into the overlying shales. This work undoubtedly had a major influence on the economics of the Alba field development, if only because wells could now be drilled into sand-rich sections with far greater confidence.

Spectacular images

The dimensions of injected sandbodies range from millimetre to kilometre scale. In outcrop and boreholes, observations are based on a much smaller rock volume than seismic data, but they give a higher level of detail. Seismic data, on the other data, give the possibility to study intrusion complexes that are tens of metres thick.

"The best-known injectite reservoirs are in Tertiary strata associated with turbidite reservoirs. Sand injections, however, also occur in a variety of sedimentary environments and from other stratigraphic intervals," says Hurst. "It is therefore likely that we will see a large increase in descriptions of such facies and reservoirs as the criteria for their identification in cores become more robust and high-quality seismic help to define them in new locations."

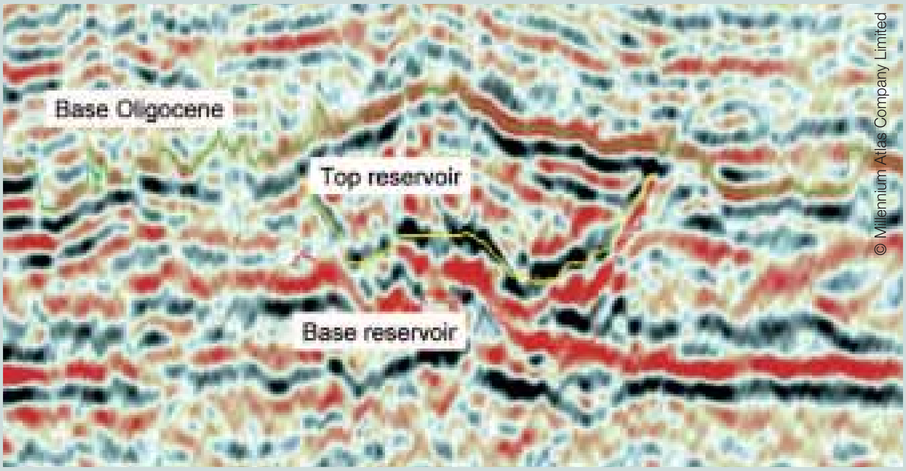
The sand injectites are similar in geometry to igneous intrusions, forming both laccoliths and dykes, and on the seismic data they have a distinctive appearance.

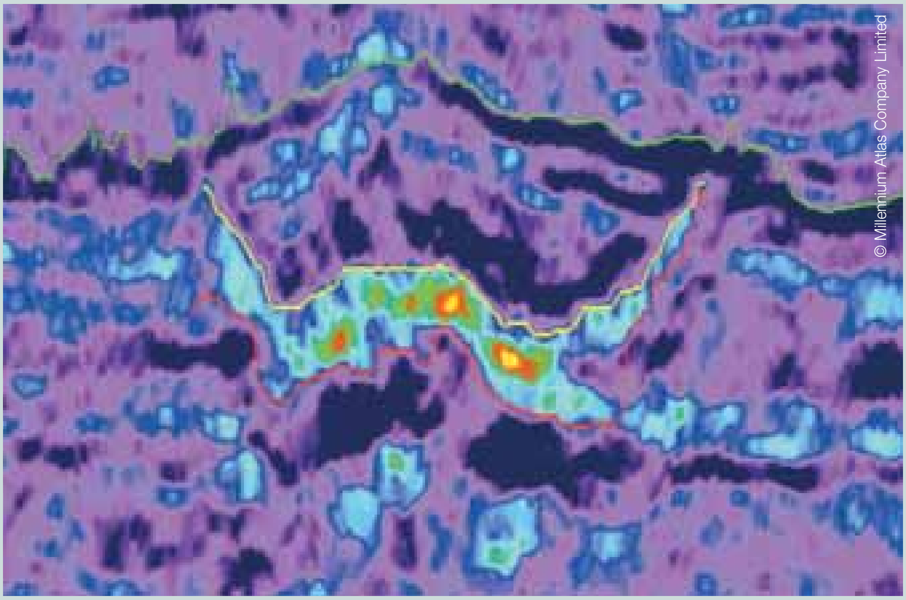
"Injectites that emanate from the edges of depositional sand bodies, sometimes referred to as "wings", are inclined (15-40°) sills that may be up to 25-30m thick and cross-cutting up to 200-250m of compacted strata. Laterally they may be extensive on a kilometre scale, and dykes may turn into sills. Wing-like reflections have been documented from a number of isolated sandstone accumulations in the northern North Sea. Palaeo-seafloor extrusions may also have occurred," explains Hurst (compare photo page 17).

The other seismic-scale feature related to sandstone intrusion comprises V-shaped (2D) or conical (3D) anomalies that do not appear to be in connection with underlying sandbodies. In the northern North Sea this seismic signature is very common in the Lower Eocene, and wells penetrating them have had tens of metres thick sandstones. The seismic anomalies are thus interpreted to be sandstone intrusions fed by blow-out pipes originating from massive sandstones below. These intrusions are in the order of 100-300m height and 500-1500m in diameter, with flank dips around 15-45°.

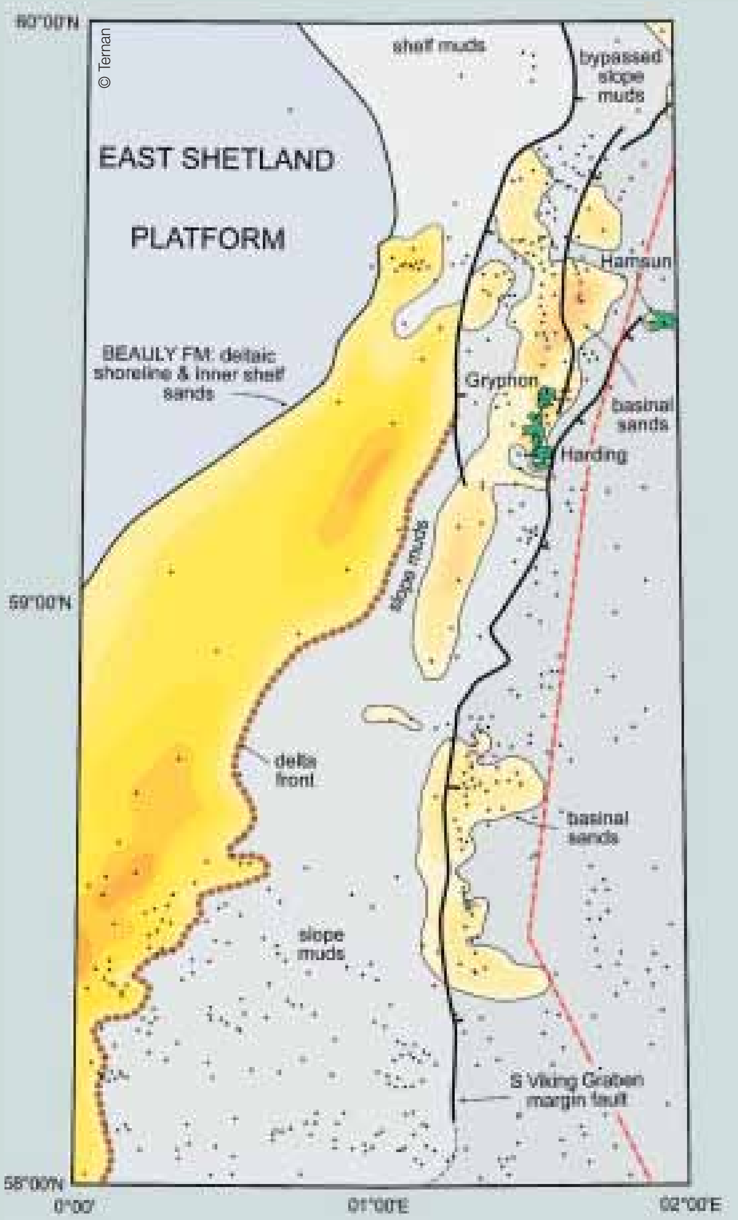
"Shales into which sand has intruded have an irregular pattern on seismic images. We interpret this to reflect the irregular thickness distribution of the sand injectites rather than folding or slumping of the shales. Cores taken within these shales and above turbidite reservoirs show the presence of thin-bedded, "ratty" sandstones as

"The initial failure to recognise sand injections has caused major problems in the evaluation and development of several North Sea fields."





Multi-component seismic data show reservoir sands injected into higher levels in the Alba field in the UK sector of the North Sea. Oil-filled sandstones lying above the main reservoir are now known to be injected and remobilised sands from the main reservoir body.



Lower Eocene Balder Play Reservoir Distribution. Many of the basinal sandstone occurrences (Odin Sandstone Member) are now interpreted to be injectites sourced from underlying Palaeocene sandstones. This map is relevant for the Gryphon, Harding and Hamsun Fields, which are all shown on the map. Map from Ternan´s Regional Play Fairway Evaluation of the North Sea.

identified by the gamma-ray logs. We believe they represent sandstones intrusions rather than thin turbidites. Without cores, these sandstone units can sometimes be identified using dipmeter and image logs due to their discordant nature and cross-cutting relations with the encasing shales."

Difficult to detect

"Seismic resolution of injected sands with sill or dyke geometry is possible, providing the sand bodies are sufficiently thick to give a tuning response or discrete reflections from top and base of the body. We believe that sand injectites of the order of 10m thickness are normally resolved in many North Sea reservoirs of Tertiary age, even if intrusions thicker than a meter or so they can occasionally be detected by high quality seismic data," Hurst says.

"The limit of detection is strongly dependent on acoustic impedance contrast between sand and the adjacent fine-grained strata. Vertical to steeply dipping features can only be imaged directly under special geological circumstances. Estimation of their presence, size and distribution is therefore problematic. Mapping of sand injectites from seismic data provides a minimal estimate of the number and volume present. Based on observations in boreholes we have good reason to believe that their numbers are underestimated when applying only seismic."

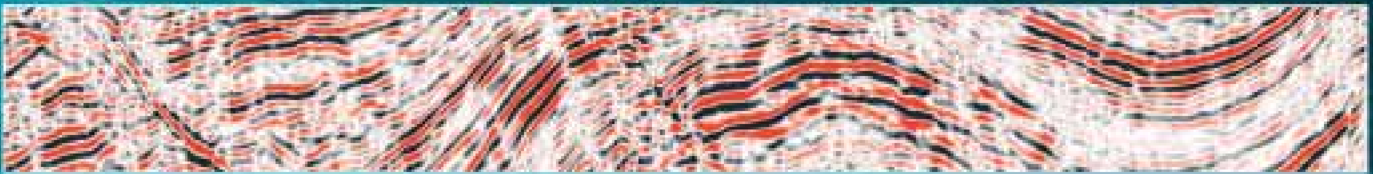
Geologists interpreting seismic data of turbidite reservoirs may also encounter difficulties. As large-scale sand intrusions and associated withdrawal of sand from the source sandbody will modify the original geometry of the reservoir, interpretation of the top reservoir horizon will be complicated. It does not correspond to a stratigraphic surface, rather it jumps from "highs" to "lows" along the line and may cause difficulties when trying to find optimal location of production wells.

Changing mind-set

"When large sand injections are present, such as in Alba, Balder, Harding and Gryphon fields, they constitute targets for development wells, and early recognition of sand intrusions is important for optimal development planning," says Hurst.

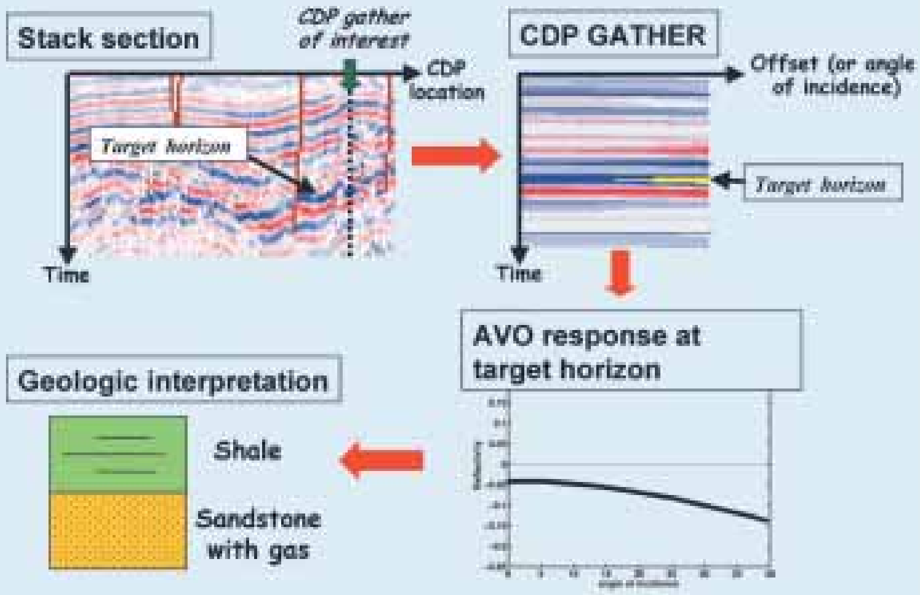
"Early recognition of sandstone intrusions is a key factor in maximising exploration and production success in the deepwater sandstones of the North Sea. Explorationists in particular should take care in including sand injectites in their interpretation mind-set, and this also applies to other geological provinces with deep-sea sediments such as the West African Atlantic Margin," concludes Andrew Hurst.

Professor Andrew Hurst at the University of Aberdeen, Scotland, has an industrial as well as academic carrier. His main research areas today comprise sand injectites, deep-water clastic systems, non-destructive analysis of porous media and mineral-chemical stratigraphy (the role of climatic change on clastic composition and supply).



AVO responses: The good, the bad and the evil

AVO analysis provides the geologists with a powerful tool that give information about pore fluids, lithologies and reservoir pressures. However, AVO signatures can easily be misinterpreted without a proper feasibility study.



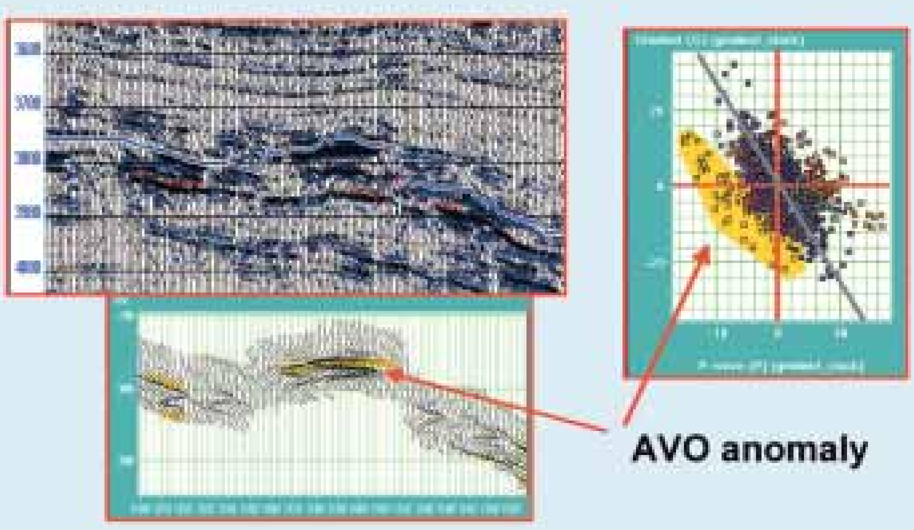
The basic principles of AVO analysis. The seismic stack section gives good information about stratigraphy and depositional geometries. However, important information about fluids and lithologies is hidden in the pre-stack seismic gathers. The AVO analysis seeks to extract this "hidden" information about rock and fluid properties.

Per Avseth, Norsk Hydro Research Center

More than 20 years ago, William Ostrander, winner of the Virgil Kauffman Gold Medal of the Society of Exploration Geophysicists, published a break-through paper in the scientific journal *Geophysics*. He showed that gas saturated sands capped by shales would cause an **a**mplitude **v**ariation with **o**ffset (AVO effect) in pre-stack seismic data. Shortly after, AVO technology became a commercial tool for the oil industry.

A revival

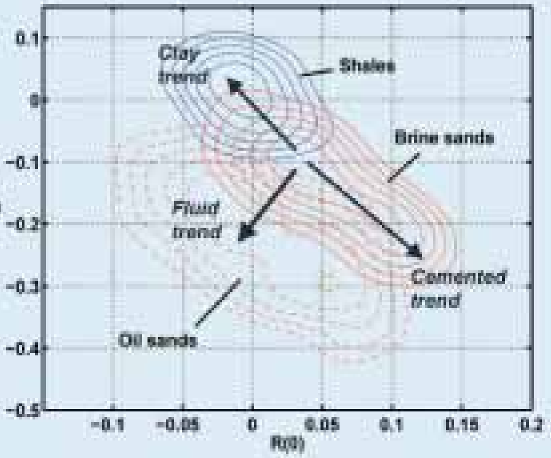
The AVO technique soon became very popular, as it was now possible to explain seismic amplitudes in terms of rock properties. The technique proved successful for hydrocarbon prediction in many areas of the world, but in other cases it failed. The technique suffered from ambiguities caused by lithological effects, tuning effects and overburden effects. It turned out that



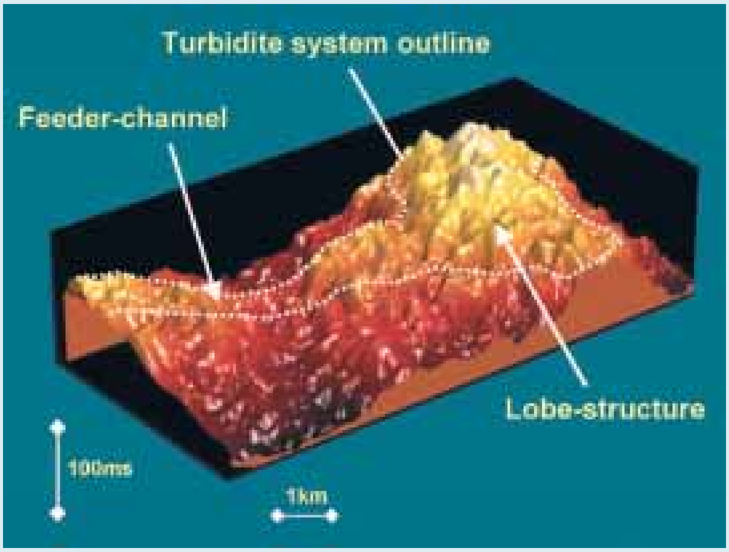
AVO crossplot analysis. The seismic section (top left) hides prestack information. By estimating AVO attributes from prestack seismic data it is possible to extract important information about hydrocarbons. The estimated AVO attributes are crossplotted against each other (right). By identifying the AVO anomaly off the background trend in the AVO crossplot (indicated by yellow colour in the right hand plot), one can investigate where this anomaly is located in the seismic cross section (lower left section). The anomaly is clearly confined to a structural high along this 2D section. This is a strong indication that the rocks are filled with of hydrocarbons.

even seismic processing and acquisition effects could cause false AVO anomalies. But in many of the failures, it was not the technique itself that failed, but incorrect use of the technique. Application of AVO analysis was therefore reduced.

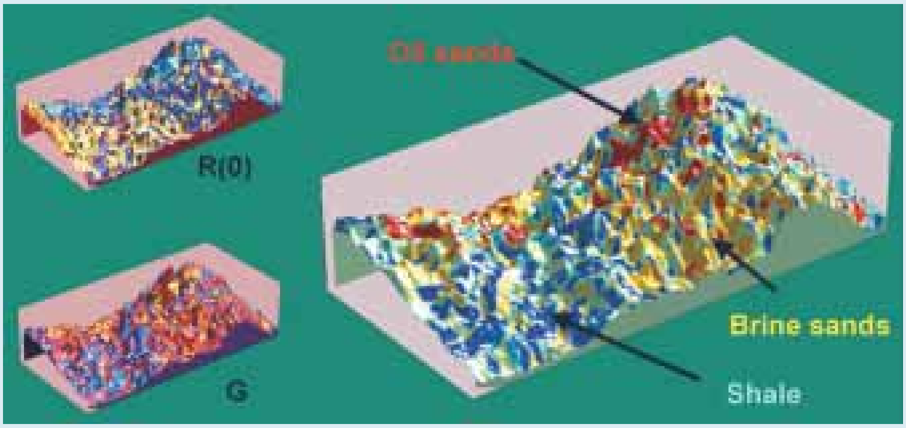
In the last decade we have observed a revival of the AVO technique. This is due to the improvement of 3D seismic technology, better pre-processing routines, more frequent shear-wave logging and improved understanding of rock physics properties, larger data capacity, more focus on cross-disciplinary aspects of AVO, and last but not at least, more awareness among the users of the potential pitfalls. The technique provides the seismic interpreter with information about pore fluids and lithologies, which complements the conventional interpretation of seismic facies, stratigraphy and geomorphology.



Example of AVO contour plots (R0 versus G) for different brine sands, oil sands and shales. The center contours represent the most probable location of the various facies and fluid types. Note the great overlaps and uncertainties between oil sands and brine sands.



Depth map to top reservoir of a North Sea turbidite system shows the outline of the submarine fan in the Glitne Field.



AVO attributes to the left (including R(0) and G) extracted from the top reservoir horizon and AVO classification results to the right. Note the prediction of oil sands in the structural highs of the turbidite system. Oil is produced from the lobe sands in the Glitne Field.

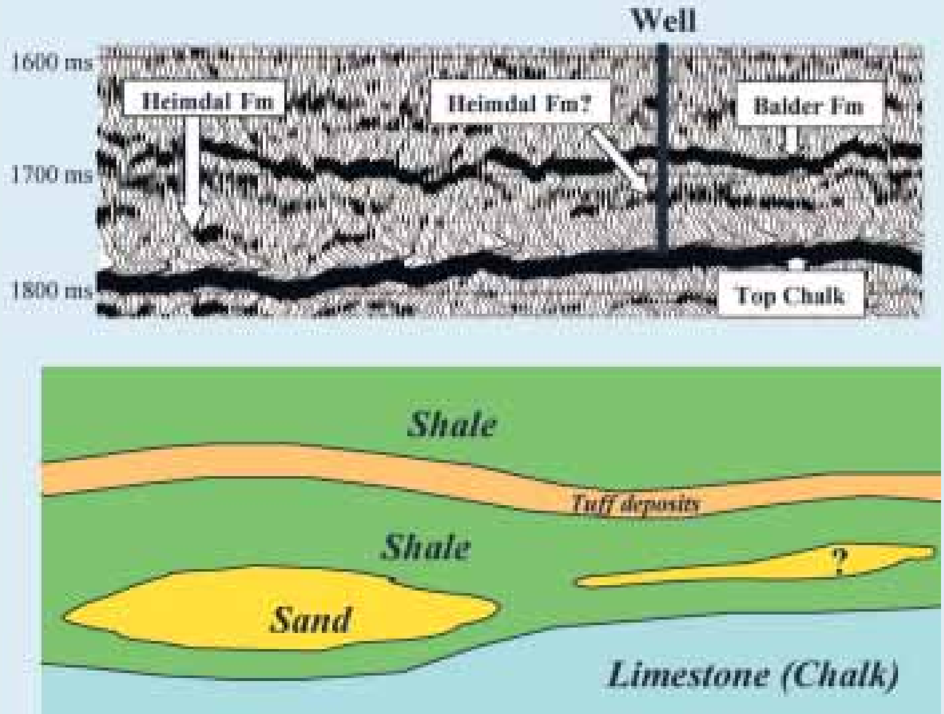
AVO analysis in a nutshell

The most common and practical way to do AVO analysis of seismic data is to make crossplots of the zero-offset reflectivity (R0) versus the AVO gradient (G). These attributes are estimated from pre-stack seismic gathers using simple least-square regressions.

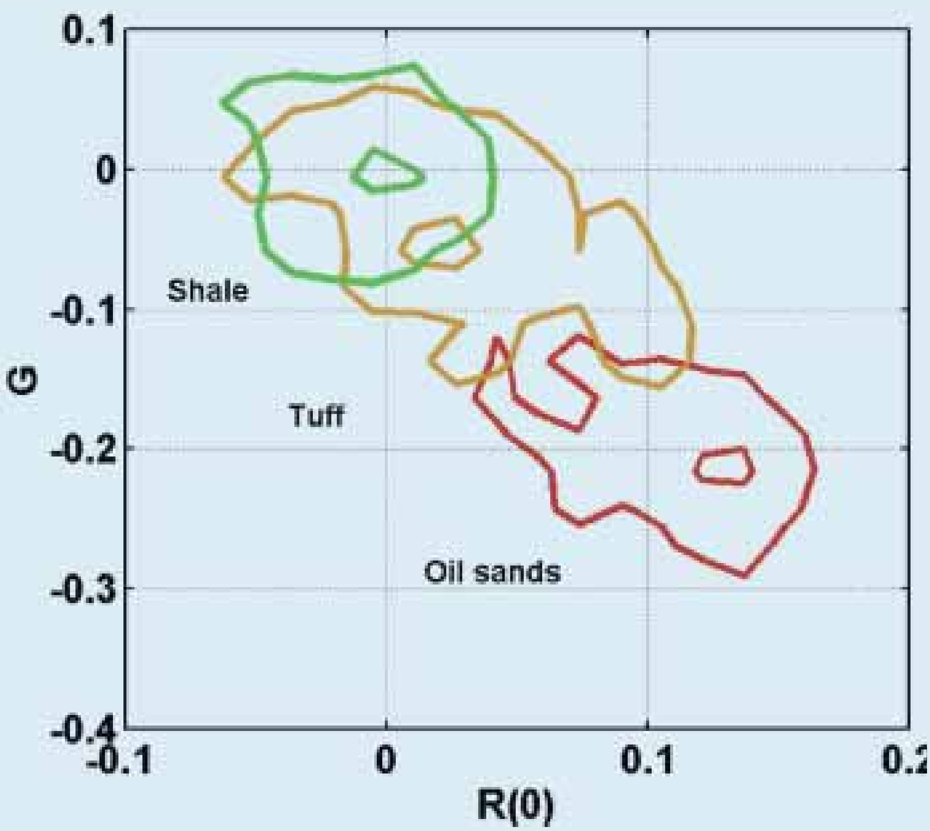
Brine-saturated sands interbedded with shales, situated within a limited depth range and at a particular locality, normally follow a well defined "background trend" in AVO crossplots. A common and recommended approach in qualitative AVO crossplot analysis is to recognize the "background" trend and then look for data points that deviate from this trend. The deviations from the background trend may be indicative of hydrocarbons, especially if these correspond to structural closures.

A problem with interpretation of AVO crossplots is that a given point in the crossplot does not correspond to a unique combination of rock properties. Many combinations of rock properties will yield the same R0 and G. Moreover, due to natural variability in geologic and fluid parameters, one given geologic scenario may span a relatively large possible outcome area in the AVO crossplot, not just a discrete point. Hence, a hydrocarbon-like AVO response might occasionally result from a brine associated reflection, and hydrocarbon saturated sands might not always produce an anomalous AVO response.

One way to account for this uncertainty is to create probability cross-plots of various categories of lithology and pore fluid scenarios. These can be based on statistical analysis of well log data and/or rock physics models. Each category is plotted as "contour maps", almost like topography maps. Here, the "mountain tops" represent the most likely location of a given class. It is very important to be aware that the contours of different facies and fluids are overlapping each other. This implies that an observed set of R0 and G can represent



Seismic stack section (top) intersecting the Grane turbidite sands. A well was drilled targeting a potential satellite sand (right side top and bottom). However, the well encountered volcanic tuff at the target level. The volcanic tuff gave a similar seismic response as the oil sands of the Grane sands.



AVO probability contours of shale, tuff, and oil sands in the Grane area. This figure illustrates the potential pitfall of tuff in the assessment of seismic amplitudes. The tuff data are between shales and oil sands. Hence, a tuff data-point can easily be mistaken for an oil sand, if we ignore tuffs and only try to distinguish sands and shales.

more than one category. This is one reason why AVO analysis can give wrong results. In addition, these crossplots are often affected by noise in the seismic data.

As mentioned above, AVO analysis can sometimes be successful and other times not. Below, three different case examples are shown, each of which had different degree of success.

The Good

The *good* example is where we successfully predicted the presence of hydrocarbons. This case is from the Glitne Field in the North Sea. Oil is predicted in the lobe channels using using AVO probability cross-plots analysis and has been confirmed by drilling.

The Bad

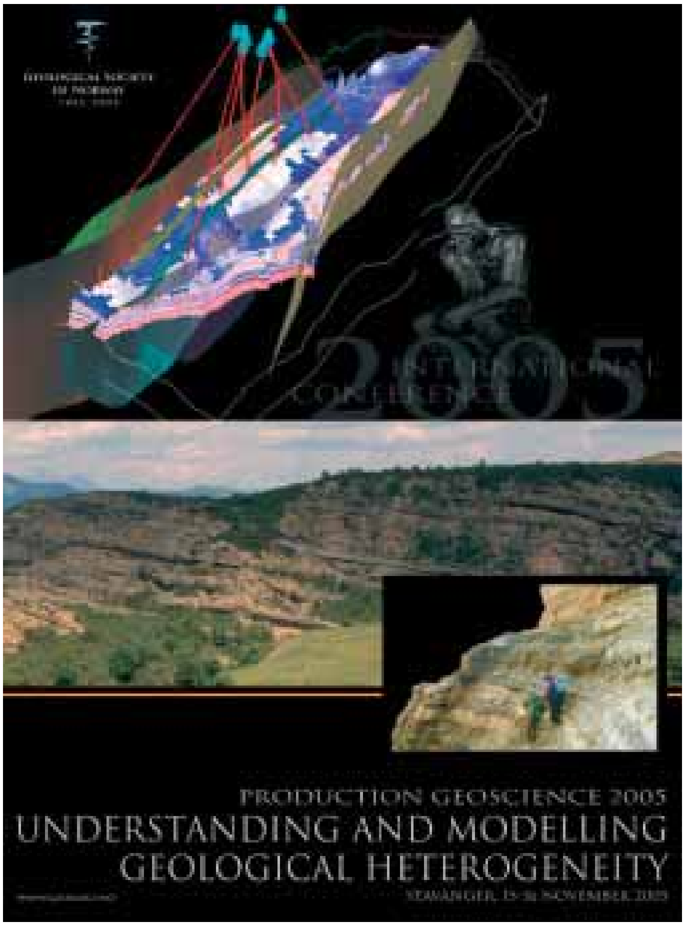
The *bad* AVO case is from the Grane area, also in the North Sea. In this case AVO analysis supported the presence of reservoir sands adjacent to the proven main reservoir body, but the model that was used neglected the presence of other lithologies than sands and shales. Post-drill analysis showed that the AVO method should be able to discriminate tuff from oil sands. Hence, it was not the methodology that failed. Insufficient information about the local geology was to blame.

The evil

One of the most notorious pitfalls of AVO analysis is related to low gas saturation. This leads us to the *evil* case, where the AVO technique was unable to discriminate residual gas from commercial amounts of oil.

It is well known that just a small amount of gas in the pore space of a rock can cause a dramatic decrease in the stiffness of the rock. Therefore, residual gas saturations can give similar seismic properties as commercial gas saturations. If we are dealing with light oil, there may also be similar ambiguities between residual gas and commercial oil, or even residual oil and commercial oil. This is one of the main pit-falls in AVO analysis, even when the data are perfect and the information of local geology is excellent.

A seismic AVO anomaly offshore West Africa was the basis for defining a hydrocarbon prospect. However, the target only contained residual gas. The probabalistic AVO classification predicted the correct lithofacies, but was not able to discriminate residual gas from commercial amounts of oil.



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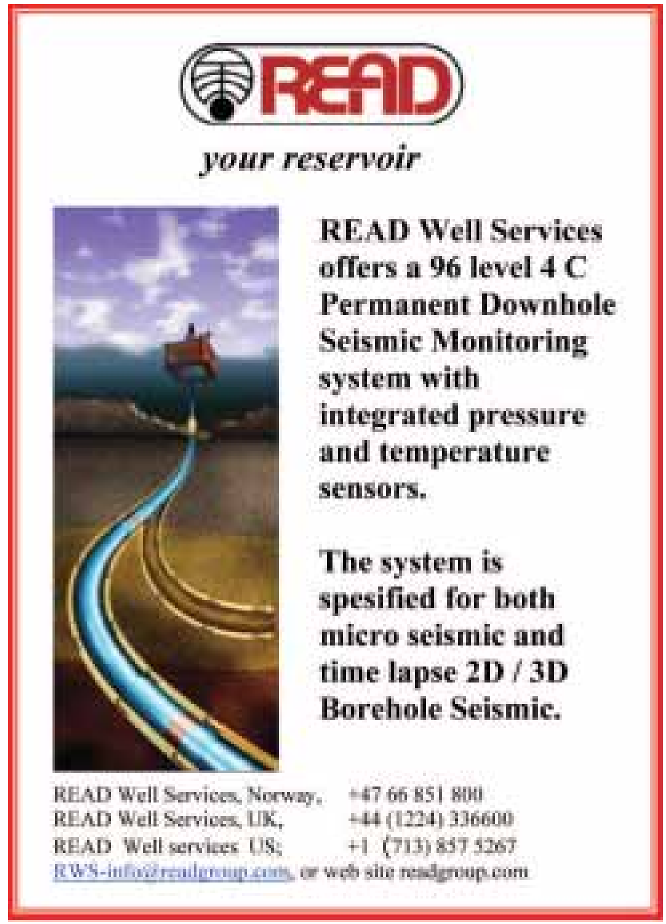

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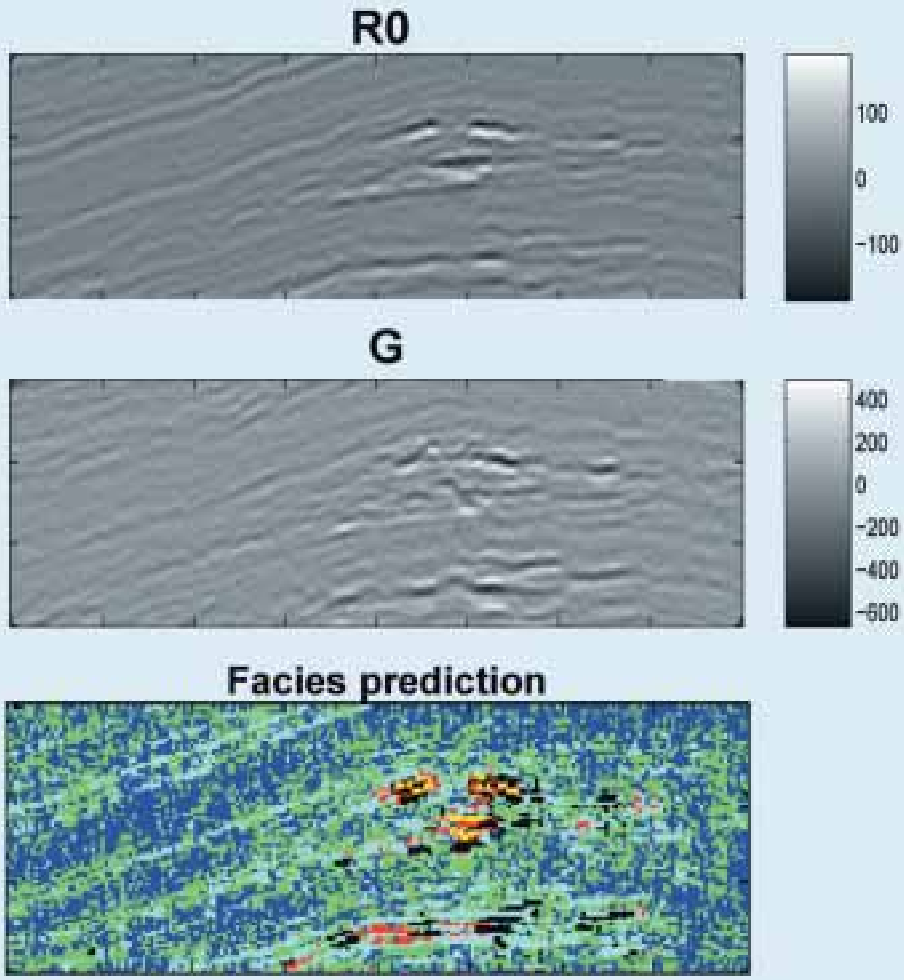

The upper two sections (R0 and G) show seismic anomalies from offshore West Africa. The anomalies were predicted to represent most likely oil and/or gas. The lower section shows AVO classification results (Blue=shale, green=heterolithics, cyan=brine sands, red=oil sands, yellow=gas sands, black=unclassified). The target zones were partially saturated with fizzy gas. In this case, the fizzy gas gave the same AVO response as commercial amounts of oil.

When is AVO useful?

Due to the many cases where AVO has been applied without success, the technique has received a bad reputation of not being a reliable tool. However, part of the AVO analysis is to find out if the technique is appropriate in the first place.

AVO will only work if the rock physics and fluid characteristics of the target reservoir are expected to give a good AVO response. This must be clarified before the AVO analysis of real data. Without a proper feasibility study, one can easily misinterpret AVO signatures in the real data. The feasibility study should be founded on a thorough understanding of local geology and petrophysical properties.

If we find that AVO analysis will work, and has the potential to detect hydrocarbons in the area of investigation, a new question arises: When should we do AVO analysis? Should it be done before, at the same time or after the conventional seismic interpretation and prospect evaluation?

During prospect evaluation it is common to do late-stage AVO analysis to strengthen the prospect, making it an ***AVO supported prospect***. Defining the prospects before doing AVO analysis means that potential prospects that would be detected only using AVO techniques can be missed. Fortunately, it is becoming more common for seismic interpreters to do interpretation on partial stacks.

Defining a prospect based predominantly on an AVO anomaly would create an AVO driven prospect. An ***AVO driven prospect*** needs a geological model that can explain the observed AVO anomaly. If the AVO work is done before there exists a thorough geologic interpretation in the area, it probably means that the geophysicist has made vague assumptions about the geologic input parameters in the first place. An AVO driven prospect can easily make the interpreter blind to pitfalls.

If AVO techniques are *integrated* with geologic interpretations of seismic data during prospect evaluation – ***geologically-controlled AVO analysis*** – it allows for more collaboration between the conventional seismic interpreter and the AVO analyst. The seismic interpreter can gain important input from the AVO analysis during the geometric interpretation, while the AVO analyst can get important input information to better constrain the rock physics models behind the AVO analysis.

Better cooperation

If we want to discover the increasingly more subtle oil fields in the future, a better interaction between conventional seismic interpreters and quantitative seismic interpreters must be established. This also means that the conventional seismic interpreter must become more knowledgeable in AVO analysis and other quantitative seismic techniques, whereas the rock physics and AVO analyst must become more knowledgeable in geologic aspects of seismic interpretation.

Acknowledgements

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Several of the figures in this article is taken from the book "Quantitative Seismic Interpretation" by Per Avseth, Tapan Mukerji and Gary Mavko, published by Cambridge University Press, 2005, see www.cambridge.org/0521816017 (see also GEO ExPro vol. 2, No. 2/3, page 66).

Introducing geological processes in reservoir models

Reservoir modelling and reservoir simulation are based on data collected at multiple scales with resolution ranging from sub-millimetre to tens of metres. New software using knowledge of the geological processes forming the reservoir rock now makes it possible to generate more accurate reservoir models, thereby improving prediction of both production profiles and reservoir volumes.

Cross bedding in the Mayaro Formation, Mayaro Beach, Trinidad.

Janice Liwanag

Improved oil and gas recovery is in the mind of almost everyone these days, and in order to get more hydrocarbons out of the reservoir it is of utmost importance to have realistic reservoir models. Following several years of industry sponsored research; a new reservoir modelling software is now bridging the gap between fine-scale and large-scale data.

Geomodeling, a Canadian company, has developed software with a focus on integrating multi-scale data into reservoir models. They do this by modelling the effects of fine-scale sedimentary bedding on large-scale reservoir permeability. The software, which has been named SBED, has contributed to improved prediction of both production profiles and reserve volumes in several fields in the North Sea as well as in the Norwegian Sea.

Backed by funding from major international petroleum companies, SBED is now making its way to the desktops of geoscientists interested in reducing the uncertainties in reservoir characterization.

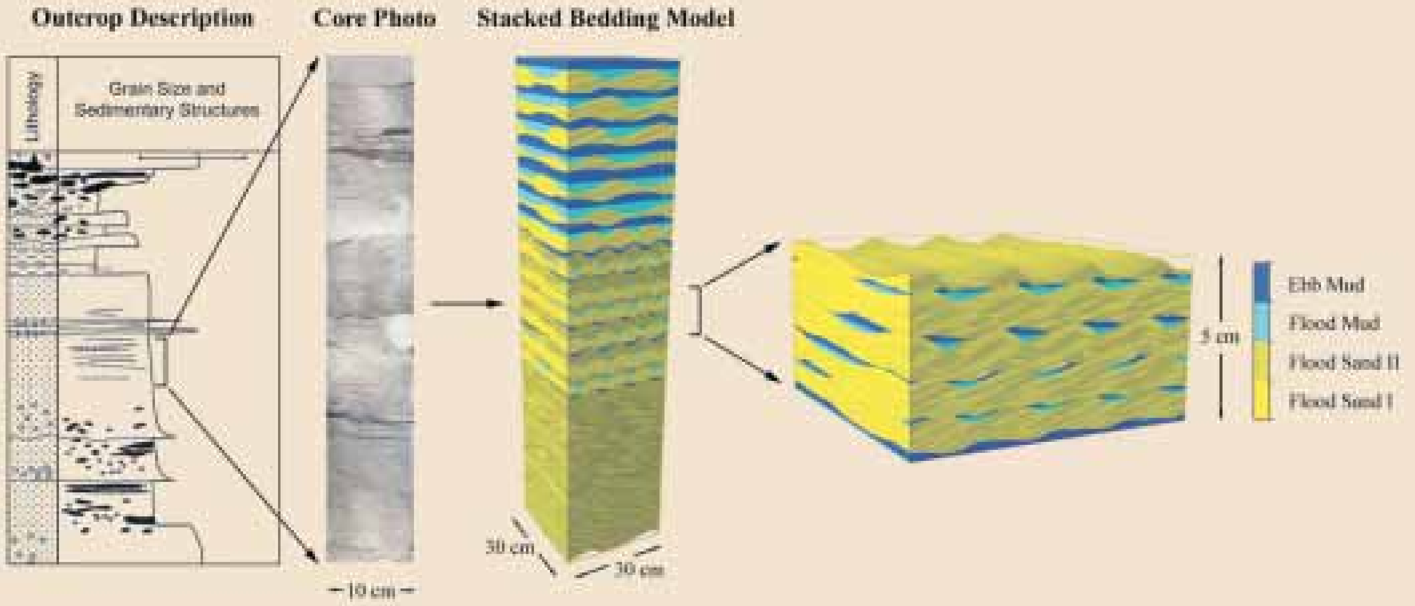
Missing scales

SBED addresses an ongoing challenge that reservoir asset teams face throughout the petroleum industry: Creating large-scale sub-surface models that honour input data describing reservoir properties at different spatial scales. These data include thin section data, core-plug measurements, well log results, seismic data and outcrop observations.

"Fluid flow is controlled by heterogeneity occurring at multiple scales - from sub-millimetre-scale pore spaces to metre-scale shale beds to sand bodies up to dozens of metres in size. All these elements can act as baffles or barriers to moving fluids," explains Renjun Wen, SBED's inventor and Geomodeling's founder and CEO. "This is why it is important to integrate multi-scale data," he adds.

"The more heterogeneous the field, the more complicated it is to calculate flow parameters such as vertical and horizontal permeability," he says. "To obtain more accurate permeability estimates and recovery factors, petroleum geoscientists need to consider the impact of multi-scale heterogeneity on fluid behaviour, even at the smallest scales."

Renjun Wen views reservoir data in terms of the scale at which it is collected: "Data from thin sections and core plugs are direct measurements of reservoir rocks and are the most quantitative information about reservoir. The resolution of these data is sub-millimetre to a few centimetres. Well log data reflect reservoir properties near the well bore and are important for deriving

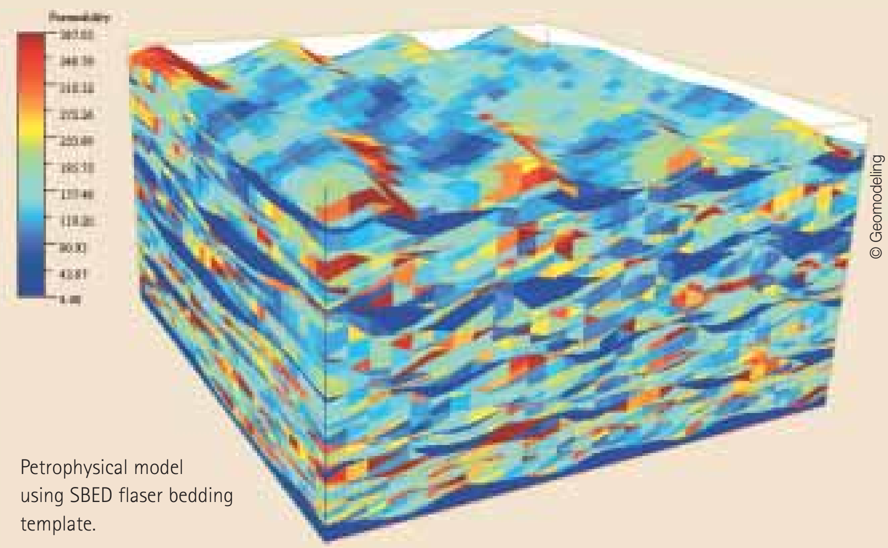


The SBED modelling method is based on core and outcrop data and generates 3D stacked bedding models. The block diagram shows a detail of tidal sediments with flaser bedding.

porosity and oil saturation. The resolution here is from decimetres to a few metres."

"Between core and well log data there is a 'missing scale', ranging from a few centimetres to one metre, at which we do not have rock measurements. Reservoir properties at this scale are mainly controlled by sedimentary bedding structures, even for rocks that have undergone diagenesis. Between well log and seismic data, there is another missing scale in measurement - from one to ten metres. Reservoir properties at this scale are largely controlled by internal stratification, such as cross bedding in fluvial reservoirs and thin-bed shales in deep water reservoirs."

"Reservoir models are largely conditioned by seismic data with resolution of about 15 to 30 metres," Wen says. "They don't include the bedding structures and internal stratification observed below seismic resolution."



Petrophysical model using SBED flaser bedding template.

Complementing existing tools

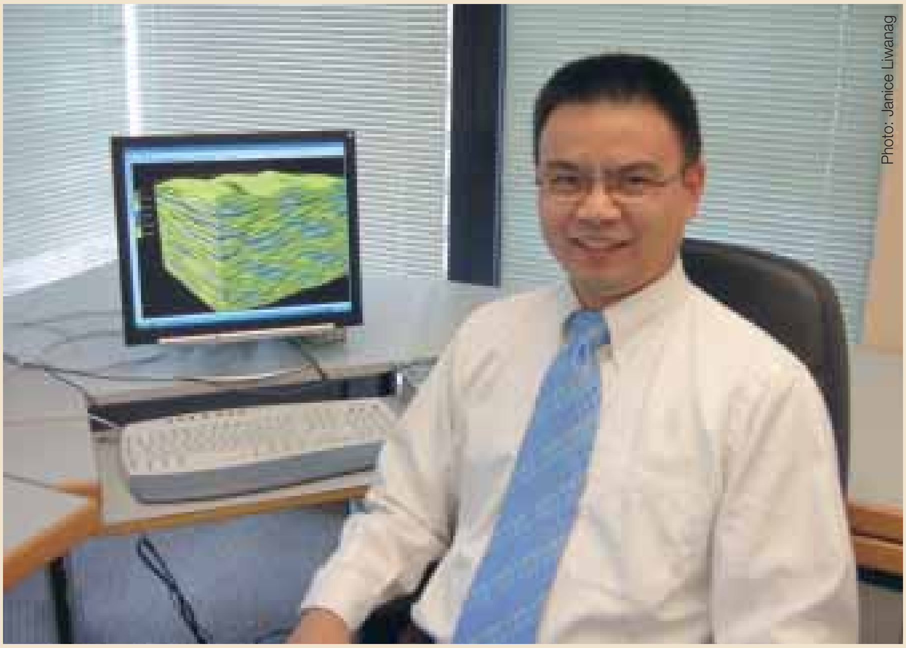
Upscaling is the process of mathematically extrapolating fine-scale reservoir data to coarser scales in order to populate reservoir grids cells up to dozens of metres in size. Conventional upscaling methods such as *arithmetic, geometric or harmonic averaging* do not consider the fact that the data is biased to a specific grid scale or to a sampling location. When the upscaled data is input to petrophysical simulations, the results incorporate the errors introduced by data bias and increase the uncertainties in reservoir predictions.

Wen summarises the advantage of the SBED modelling and upscaling method: "SBED generates geological models representing the scale at which the data was collected. The user populates these models with the corresponding data and then upscales the model - not just the data. The results reflect the reservoir properties at the corresponding scale and can be used to predict properties at scales for which we have no direct measurements."

Indeed, the SBED modelling and upscaling approach represents a paradigm shift in reservoir modelling. But as Wen points out: "SBED is not meant to *replace* existing reservoir modelling tools. It actually complements existing tools by providing detailed heterogeneity models, which can improve reservoir property modelling. In this way, it acts more as a plug-in tool for reducing reservoir uncertainty."

The SBED modelling method

The SBED modelling workflow starts with a conceptual interpretation of reservoir geology, based on core and outcrop observations. Equipped with a library of over 100 built-in geological templates, the user builds a 3D near-well-bore model. Depositional environments such as fluvial, shoreface or deep-water facies can be reproduced by



Renjun Wen, SBED's inventor and Geomodeling's founder and CEO.

stacking the bedding templates. The geometry of bedding, facies and boundary layers can be edited to match the observed geology.

Once the geological framework is established, the user populates the model with porosity and permeability measurements derived from core plugs and then conditions the model to well data. SBED petrophysical models are *upscaled* by numerical simulation methods. The upscaled models can then be exported to third party reservoir simulators. Based on multiple geological scenario simulations, asset teams can evaluate the range of oil and gas in place and quantify the associated uncertainties.

In addition to geological and petrophysical grids, SBED generates upscaled parameters, such oil saturation, porosity and relative permeability, for calculating recovery factors, sweep efficiency and reserves. The software also delivers template curves of facies-dependant kv/kh. This ratio of vertical to horizontal permeability is an important parameter for evaluating fluid flow, and is difficult to measure in thin-bed sediments.

The beginning

In 1987, Wen moved to Norway from his native China to pursue research interests in geostatistics and petroleum geology. As part of a post-doctorate project at the Norwegian University of Science and Technology in the early 1990's, Wen developed the core technology of SBED.

Wen explains how the SBED modelling method differs from traditional methods: "Using conventional object- or pixel-based modelling methods, one models geological bodies and layers by assigning objects or pixels with certain dimensions and petrophysical parameters. This is adequate for modelling large-scale, massive structures, but not for representing millimetre- to metre-scale heterogeneity."

"The algorithms used to generate SBED models don't just mimic bedding structures and internal stratification. They mimic the physical processes that created the bedding structures, such as bedform migration, erosion and deposition. We refer to this modelling approach as being 'process-oriented', because it captures the sedimentary processes - not just the preserved sediments. This is why the resulting models are geologically realistic."

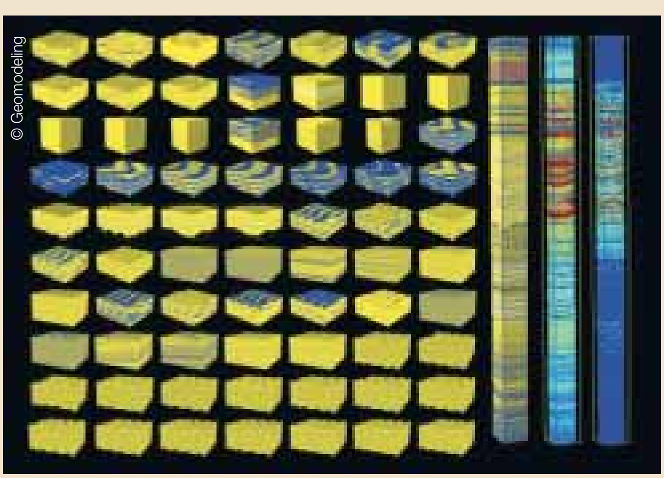
Based on his research, Wen was contracted by the Statoil Research Centre in Trondheim in 1996 to participate in an integrated reservoir characterisation study called the Remaining Reserves project. The aim was to explore solutions for improving oil recovery in the Norwegian sector of the North Sea fields, where shallow marine and fluvio-deltaic sandstone reservoirs hosted proven oil volumes. The reservoir asset teams knew that part of the solution was to include the effects of small-scale heterogeneity in full-field-scale reservoir models. However, available reservoir modelling technologies were unable to model the complex interlayering in the sandstone fields.

In two months, Wen developed software that could realistically model the cross bedding and parallel bedding structures observed in the deposits. These detailed models were subsequently used to calculate kv/kh for the reservoir units and helped to define strategies for optimal recovery.

New opportunities

After completing his contract in the Remaining Reserves project, Wen immigrated to Canada with his wife and two children. They settled in the booming oil and gas industry hub of Calgary, Alberta, where Wen saw great opportunities for taking his research to the business units of major petroleum companies. With savings earned from consulting projects in Norway, Wen registered Geomodeling and started his software development business from the basement of his home in late 1996.

In the summer of 1997, Wen was again contracted by Statoil, this time to participate in the 'Advanced Modelling of Heterogeneous Tidal Reservoirs' (AMHTR) project.



In a SBED digital rock library more than 100 bedding templates can be stacked to create near-well-bore geological models.

The project area was the oil and gas-condensate fields of the Halten Terrace, offshore Norway, where the reservoir intervals were tidal deposits of complexly interlayered mud and sand. Here, the recovery factors were typically below 30%, much lower than the over 60% recovery achieved in the fluvial and shallow-marine oil reservoirs in the North Sea. The difference was attributed to the complex fluid behaviour caused by fine-scale tidal bedding in the Halten Terrace.

The goals of the AMHTR project were 1) to develop models that realistically represented the tidally influenced deposits, and 2) to develop a method for accurately estimating porosity and effective permeability (k) of thin mud layers, especially kv/kh, for input to flow simulations. From his basement office, Wen designed tidal bedding models that mimicked sedimentary structures such as flaser and lenticular bedding.

Statoil successfully used these models to characterise the Halten Terrace fields and to estimate the effective properties of highly heterogeneous units. Based on detailed studies that included the use of kv/kh ratios calculated from SBED models, Statoil engineers re-designed water treatment facilities in the Tyrihans field, where production of light oil is planned to start in 2009. In the Heidrun field, reservoir optimisation studies showed that the estimated recovery potential achieved with small-scale modelling corresponds to millions of barrels of oil.

Innovation through partnerships

Following Wen's work in the AMHTR project, SBED technology was still largely considered as a research tool. Geomodeling's founder took SBED a step closer to commercialisation by following a simple philosophy: "The point of research and development is to find real-world solutions that can be used by your peers," says Wen, "And the best way to find the solutions is to build on the knowledge of your peers."

In 2000, Geomodeling established an SBED research and development consortium with industry partners BG International, ExxonMobil, Fortum (now ENI), Norsk Hydro, Shell, Statoil and Total. The aim of the project was to develop SBED as a commercial heterogeneity modelling and upscaling tool for sedimentary bedding structures. With the financial support and technical input of consortium members, SBED version 1 was delivered in 2002. It included modules for simulating parallel bedding, cross bedding, flaser/wavy/lenticular bedding, massive bedding, hummocky cross stratification, bioturbation and point bars.

Software development in SBED Phase II (2002-2004) focused on metre-scale heterogeneity modelling of internal stratification and bounding surfaces in the genetic units. The delivered product was SBEDStudio, which included three deep-water modules: channel-infill, channel-levee architecture and depositional lobes. These modules were developed in the context of full-field modelling, where seismic-derived horizon and attribute surfaces were used as conditional data.

Currently, the SBED JIP is in Phase III and now has eight industry partners: BHP Billiton, ConocoPhillips, ENI, ExxonMobil, Norsk Hydro, Shell, Statoil and Total. Phase III development focuses on three main areas: 1) integrating Phase I (SBED) and Phase II (SBEDStudio) products with other reservoir modelling software, 2) researching methods for conditioning data to bedding structure and infill architecture modules, and 3) developing more upscaling functions. Recent advancements in Phase III include the addition of multi-phase upscaling, which will be the first of its kind in the industry.

Plans for Phase IV include developing a multi-step upscaling workflow and creating more SBED templates (such as carbonates and delta environments). Geomodeling also plans to integrate SBED with third party reservoir interpretation software, such as Petrel, RMS, and GOCAD and to build links to other modelling tools, such as resistivity forward modelling and well test simulation technologies.

The next step

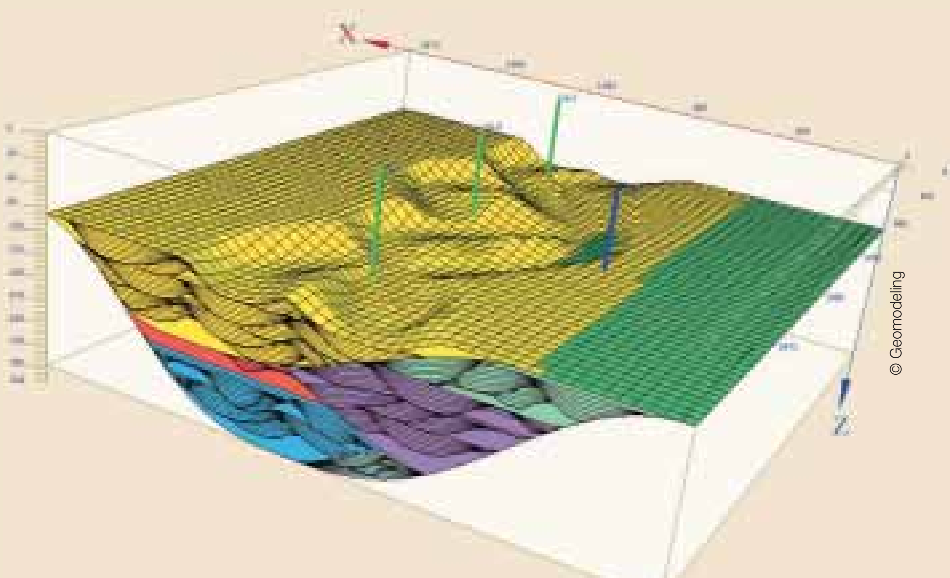
Geomodeling has evolved from a one-man operation into a corporation with over 60 employees in Canada, China, Mexico, Norway, United Kingdom and USA. In 2005 alone, the number of staff has increased by 30%. And the company continues to grow.

"The biggest challenge in managing a growing company is to keep innovating while we grow," Renjun smiles, knowing all too well about growing pains. "Many companies stop innovating or reach a plateau in product development when they decide to expand their markets. We aim to set the industrial standard and then continuously move that standard to the next level."

And Geomodeling is equipped for the challenge. A venture capital from Norwegian investor Offtech Invest AS will help to bring Geomodeling to the next level of innovation. The funds are being channelled to software development and international commercialisation of SBED.

"The quality of technology and talent offered by Geomodeling makes this investment attractive," said Trygve Lægreid, spokesperson for Offtech Invest AS. "The impact that multi-scale modelling in general, and Geomodeling's portfolio of products in particular, will make on the industry is going to be very significant."

While other software companies may have achieved success by thinking "large-scale", it is clear that Geomodeling has filled an industry niche by considering the fine details in between.



Reservoir heterogeneity model generated in SBEDStudio, showing internal stratification in a multi-channel depositional system.

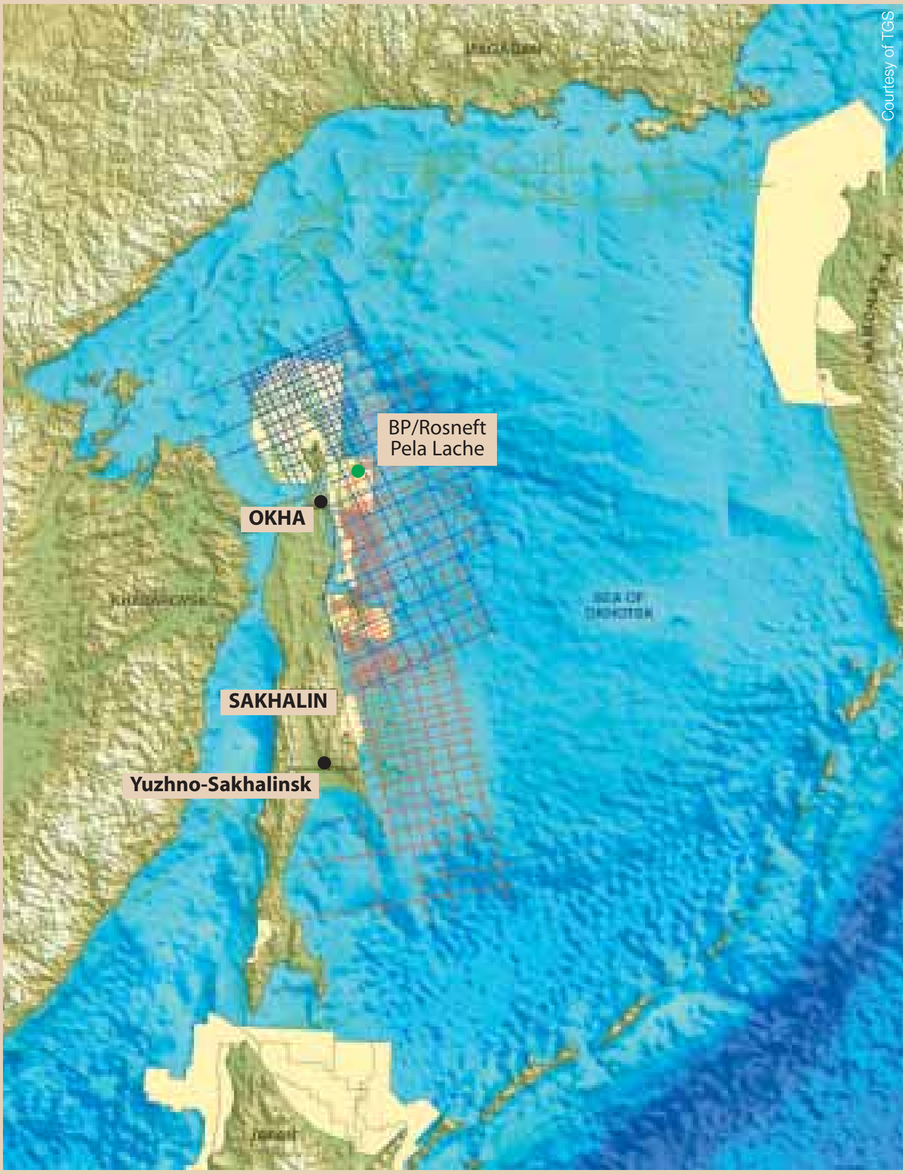
Multi-client seismic spurs interest

The Northeast Sakhalin Shelf, with several giant fields already discovered and put on production, is recognised as a world-class petroleum province. New seismic acquired in the rest of the Sea of Okhotsk indicate that there is more to be found.

Photo: Erling Frantzen

Courtesy of TGS

Dalmorneftegeofizica has acquired a huge seismic data base covering almost the entire Sea of Okhotsk. New, modern data is now made available through a cooperation with TGS Nopec.



The Sea of Okhotsk is named after Okhotsk, the first Russian settlement in the Far East. It is the northwest arm of the Pacific Ocean covering an area of 1,528,000 sq km, lying between the Kamchatka Peninsula on the east, the Kuril Islands on the southeast, the island of Hokkaido belonging to Japan to the far south, the island of Sakhalin along the west, and a long stretch of eastern Siberian coastline along the west and north. Most of the Sea of Okhotsk, except for the area around the Kuril Islands, is frozen during from November to June and has frequent heavy fogs. In the summer, the icebergs melt and the sea becomes navigable again. The sea is generally less than 1,500m deep; its deepest point, near the Kuriles, is 3,363 m. Fishing and crabbing are carried on off W Kamchatka peninsula. The DMNG/TGS Seismic acquired in 1998, 2004 and 2005 is shown in green, blue and red colours. Note also the location of Okha where oil seeps were found 125 years ago.

On the shelf of the Sea of Okhotsk, mainly off the coast of Sakhalin, the world's largest oil companies are actively exploring for and exploiting oil and gas resources together with several Russian companies. The region is highly productive and exceptionally important for fisheries.

Halfdan Carstens

Seismic line through the Lunskoye gas-condensate field offshore Sakhalin shows the gas cloud above the proven field and channel deposits immediately to the east, not imaged on older vintage seismic in the area.

Oil and gas have been produced in the North Sakhalin Basin since 1927 from a large number of small onshore fields. Offshore, giant discoveries have been made in the same basin, and this has spurred the interest for exploring in other sedimentary basins offshore Sakhalin. This interest is now reaching further out, to the rest of the Sea of Okhotsk as more seismic data is acquired and interpreted.

The Sea of Okhotsk thus represents another example where non-exclusive seismic data is a key tool to explore in a frontier area, the principle being that of dispersing cost and risk amongst several oil companies.

"The challenge in the case of Sea of Okhotsk lies with central and local Russian authorities. It is important that the terms permit and stimulate non-exclusive data acquisition: All parties will benefit. Russian seismic contractors will play an important role, and Russian authorities will experience higher interest and increased competition for exploration acreage," says Kjell Trommestad, Vice President and General Director Europe of TGS NOPEC.

First onshore – then offshore

Exploration on the Sakhalin Island dates back more than 100 years, to 1879, when a local hunter found oil lakes and numerous oil seeps near Okha on the northeast coast. This encouraged the first exploration drilling in the 1890's, but it was not until 1923 that the Sakhalin Trust struck oil and discovered the Okha field (compare map) that began producing four years later.

During the next 40 years eight new fields were discovered, and by the end of the 1950's all of the large anticlines mapped onshore had been tested to depths of 2.5 km. Deeper targets were thereafter drilled based on seismic data. By 1971, a total number of 35 onshore oil and gas fields had been discovered.

Offshore exploration began in earnest in 1968 with the drilling of a deviated onshore well into the offshore region. Modern activity was initiated during the first half of the 1970's, first through a co-operation between Soviet Union and Japanese companies, followed by a phase of activity by Russian companies alone, and eventually the entrance of international exploration companies came in the late 1980's and early 1990's.

Marine drilling did not begin until 1977. "From 1977 to 1989, 22 wells were drilled and a number of significant oil and gas discoveries were made offshore Sakhalin, including Odoptu (1977), Chaivo (1979), Lunskoye (1984), Piltun-Astokhskoye (1986) and Arkutun-Dagi (1989)," says Deputy Director Vladimir Kudelkin of Dalmorneftegeofizica Trust, which is headquartered in Yushno Sakhalin on the Sakhalin Island.

During the next few years, in the early 1990's, an aggressive exploration campaign followed both inside and outside the main fairway. A number of structures were drilled on the northeastern shelf, the southwestern shelf and the western shelf. The Aniva Bay and the Terpeniya Bay were also tested. "The five wells drilled were all dry. The main reason for this was that there were no reservoirs," says Kudelkin.

World-class province

"Exploration in the Sea of Okhotsk has to a large extent been limited to the areas

Photo: Halfdan Carstens

Vladimir Kudelkin is Deputy Director of Dalmorneftegeofizica Trust (DMNG) and has been involved in exploration in the Sea of Okhotsk for more than 20 years.

offshore Sakhalin. Offshore production started in 1999 and is taking place from the North Sakhalin Basin where prospectivity is related to a combination of excellent reservoir rocks, effective seals and simple structures," says Kudelkin.

"This has established offshore Sakhalin as a world-class hydrocarbon province. Accumulated reserves are in excess of 5.5 billion barrels of oil and 35 trillion ft^3 (6.3 billion barrels of o.e.) of gas. Dalmorneftegeofizica has estimated the oil and gas resources in place to be in excess of 90 billion barrels of oil equivalents. In comparison, total accumulated production on the UK continental shelf is in the order of 30 billion barrels of oil equivalents."

As offshore exploration has been very limited we expect that many major discoveries will be made in the future," Kudelkin adds.

Current investors in the area include major oil companies like BP, ChevronTexaco, ExxonMobil, Rosneft, Shell and TNK-BP.

Stepping out

"Despite the established prospectivity of the region, offshore exploration activity has so far been restricted to a narrow corridor east of the Sakhalin Island, where all of the above mentioned discoveries are located. The Pela Lache well drilled by Rosneft/BP in Sakhalin V in 2004 represents the first step outside the established fairway," says Trommestad.

In 1998, BP formed an Alliance with Rosneft to explore in Sakhalin via an exclusive bidding agreement (BP 49%, Rosneft 51%). In June 2002, Rosneft obtained the first exploration licence on behalf of the Alliance for the rights to explore Kaigansky–Vasukansky blocks in the south of the Sakhalin V area, which had no previous exploration history.

The first well in the block "encountered significant volumes of oil and gas in a number of high quality sandstone reservoirs," according to BP. It was drilled "farther north, farther offshore (49 kilometres), and in deeper water (114 metres) than any previous well offshore Sakhalin. This well marks the first drilling activity in the modern stage of Sakhalin oil and gas exploration."

"The results of Pela Lache -1 represent a positive first step towards opening a new area for exploration and subsequent development offshore northern Sakhalin," BP said. "This is a first confirmation of a prolific trend extending to the east and could lead to opening of new areas for exploration and subsequent development offshore north Sakhalin," says Trommestad who has seen the modern seismic data in the Sea of Okhotsk acquired by TGS NOPEC in cooperation with DMNG."

Excellent petroleum system

The Sea of Okhotsk is a large marginal sea located at a triple junction with the Eurasian Plate to the north, The Pacific Plate to the south and the North American Plate to the east. The larger part of the Sea of Okhotsk is occupied by the Okhotsk sub-plate, which suffered several rifting phases during Tertiary times: in Eocene-Oligocene, Middle Miocene and Pliocene.

The Kamchatka and Sakhalin orogenic systems were formed along collision boundaries of the Okhotsk sub-plate due to transpression regime.

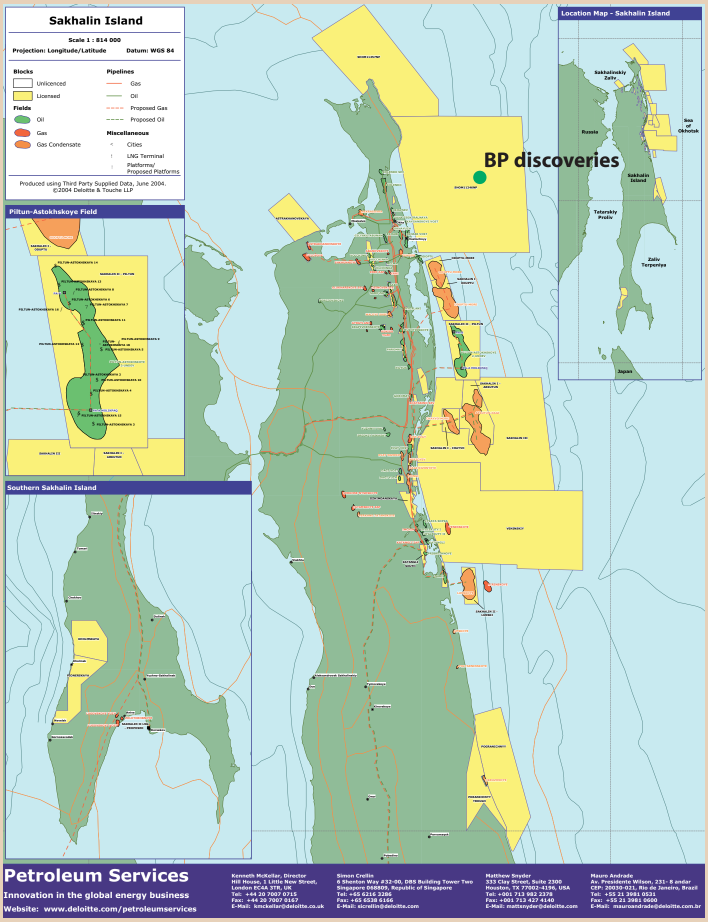
"More than twenty discrete petroleum basins are present in the Sea of Okhotsk, and the depocentres have several similarities. The region may therefore considered

DMNG and TGS NOPEC

Dalmorneftegeophizica (DMNG), a Russian seismic company based in Yuzhno-Sakhalinsk, and TGS-NOPEC Geophysical Company (TGS), a Norwegian/American company specialising in multi-client seismic have jointly carried out a number of multi-client seismic projects throughout the world for more than 10 years. During the last 6-7 years, the multi-client concept has also been successfully implemented in the Sea of Okhotsk in the Far East Russia. This activity has played a significant role in the exploration for oil and gas in this region.

Photo: Erling Frantzen

DMGG's premises in Yushno Sakhalin.



License areas offshore Sakhalin as of June 1, 2005. The recent discovery made by BP lies in Sakhalin V and represents a new play which give further incentives to extend exploration away from Sakhalin.

in terms of a relatively simple petroleum system," says Vladimir Kudelkin.

Kudelkin explains that there are two principal source rocks, both of which are Tertiary in age. It is the Palaeogene lacustrine and shallow marine shelf with kerogen type II and III that give both oil and gas and the Miocene marine shales with kerogen type II that give predominantly oil. The quantity of organic matter in the source rocks ranges from 0.6 to 4.2% and the geothermal gradient varies between 2.4 to 4.4 °C/100 metres. "The Golden Zone" (GEO ExPro no. 2, 2004), which supposedly contains 90% of the hydrocarbons in a sedimentary basin, should therefore be found approximately between 1500 and 5000 metres below the surface.

"The best reservoir rocks in the region are stacked deltaic sandstones deposited by the Neogene palaeo-Amur system since Early-Middle Miocene. Seismic data tells us that the delta extended much further north and east than Sakhalin in Eocene-Early Oligocene times. Individual sandstone beds vary in thickness from several tens of metres up to more than 100 metres. The sandstones have excellent reservoir characteristics with multidarcy permeabilities and porosities greater than 20 percent, "says Kudelkin. In the South Sakhalin area fractured Oligocene siliceous mudstones are potential reservoirs.

"In the Magadan and West Kamchatka areas distribution of potential reservoirs is little known but thick Palaeogene fluvial sandstones are probably the best potential reservoirs."

A variety of structural traps are present with Miocene-Pliocene wrench fault movements being most important.

"The small onshore fields occur within strongly faulted anticlines associated with Late Pliocene-Pleistocene inversion, says Kudelkin."

The principal play model in the region is hydrocarbons in reservoirs that are associated with the palaeo Amur delta system, sealed by shales and sourced from the Palaeogene.

Exclusive agreement

"Our current understanding of the regional geological setting in the Sea of Okhotsk is based on evaluations and interpretation of old seismic data with clear

The Sakhalin-1 project

The Sakhalin-1 project includes three offshore fields: Chayvo, Odoptu, and Arkutun Dagi. Exxon Neftegas Limited is the operator for the multinational Sakhalin-1 Consortium. Co-venturers include the Japanese consortium SODECO (30 percent); affiliates of Rosneft, the Russian state-owned oil company, RN-Astra (8.5 percent) and Sakhalinmorneftegas-Shelf (11.5 percent); and the Indian state-owned oil company ONGC Videsh Ltd. (20 percent).

Sakhalin-1 potential recoverable resources are 2.3 billion barrels oil and 17.1 trillion cubic feet of gas (485 billion m3 of gas). Sakhalin-1 will be one of the largest single foreign direct investments in Russia.

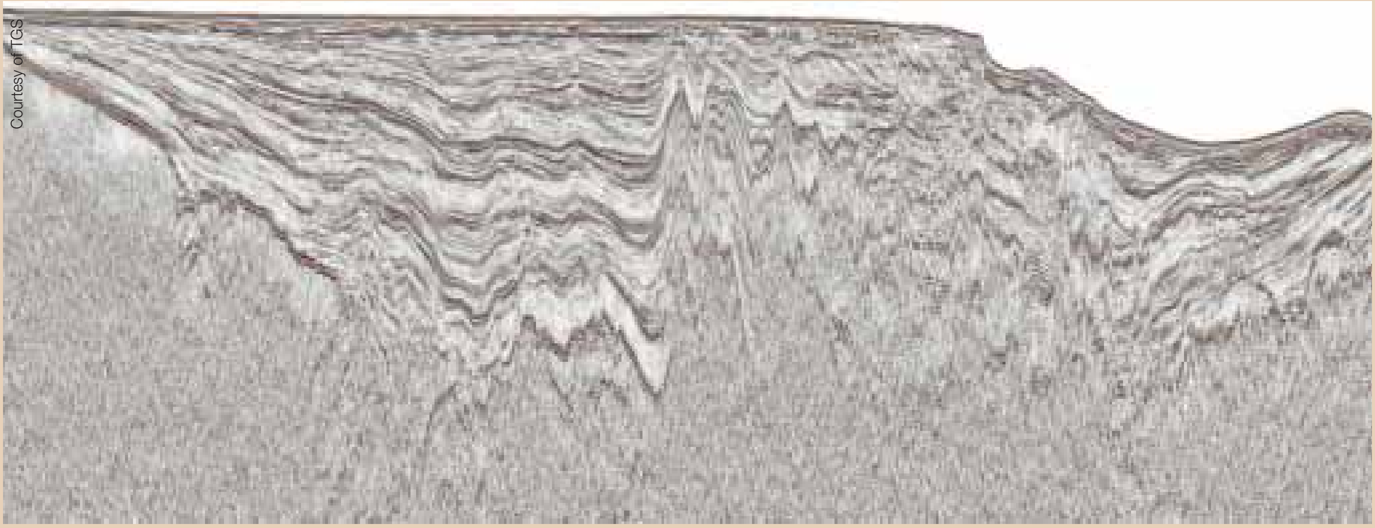
The Project will be executed in phases. The initial phase develops the Chayvo field with production start-up targeted for the fall of 2005. A dedicated oil pipeline and terminal facility at DeKastri on the Russian mainland will export crude oil to world markets beginning in 2006. The initial gas production will be sold in the Russian Far East domestic market. Export of the remaining gas reserves via pipeline will commence when a contract with a regional customer is secured. The Odoptu and Arkutun Dagi fields will be developed as subsequent phases.

The Chayvo field will be developed from both offshore and onshore facilities. The Chayvo Yastreb land rig is designed to drill extended reach wells to offshore targets from land based locations. In June 2003, a shore-based extended reach programme (ERD) to install wells under the seabed at distances exceeding 11 km to tap the northwestern flank of the main Chayvo oil zone was initiated. Six ERD wells have been drilled to-date from Yastreb.

Oil and gas will also be produced from an offshore platform. The 20-well concrete structure will serve as the offshore drilling and living quarters and will be used to develop the southwestern flank of the main Chayvo zone. Installation of Orlan at Chayvo is currently under way. The Orlan drilling rig will be operated on the platform year-round.

The Chayvo Onshore Processing Facility will produce at the rate of approximately 250,000 barrels of oil per day and 800 million cubic feet per day.

A 24-inch pipeline will be built from the Chayvo OPF to the DeKastri export terminal on the Russian mainland. The pipeline construction started in 2004 and is scheduled to be completed at the end of 2005.



Seismic line north of Sakhalin Island shows high quality image and good definitions of local Tertiary basins above basement north of Sakhalin Island. The structural high in the middle of the section is the northern prolongation of the island itself. East of the high lies the Derugin basin. No wells have been drilled yet in this area. The line is 250 km long.

limitations with respect to resolution and sequence definitions. Using modern, high quality seismic a new and better understanding of the area can be obtained. This will certainly benefit future exploration," says Trommestad.

With this background TGS NOPEC in 1998 entered into a 5-year exclusive, renewable agreement with DMNG. The purpose was to make plans, acquire, process and market new non-exclusive seismic 2D-surveys in Eastern Russia, limited in the extreme northeast by the Bering Straight and by Sea of Japan in the southwest. The agreement thus encompasses the Bering Sea as well as the Sea of Okhotsk. From now on new modern seismic data would be available to the industry.

The first programme under joint TGS/DMNG operation (9700 km) was designed to confirm some of the major untested structural trends that DMNG had mapped around Sakhalin Island and on the Magadan and Khabarovsk shelves.

A new era for data

Around Sakhalin Island the 1998 data represented a major improvement in resolution and definition of sequences and structural trends in many of the already established petroleum provinces. Pre-Tertiary sequences, specifically in Sakhalin 4 and 5 areas could now be defined, and undrilled inversion structures in Sakhalin 1, 2 and 3 stood out.

This 1998 programme has confirmed that Magadan geological province contains tilted fault-blocks, horsts, anticlinal structures and pinch out leads of world-class sizes. "The presence of these elements combined with a large number of Direct Hydrocarbon Indicators (DHI's) give reason for optimism in parts of Magadan offshore areas," says Trommestad.

On the Khabarovsk shelf the 1998 survey confirmed a heavily faulted structural trend where Tertiary deep grabens are thought to contain mature source rocks. More extensive acquisition is needed in this area in order to establish confidence in leads and prospects.

New and more data

The agreement between TGS and DMNG has been extended with another five years, and during the summer of 2004 a non-exclusive survey totalling 9,650 km (SA04) was acquired. The purpose was to get a denser grid in Sakhalin 4 (northwest of Sakhalin) and Sakhalin 5 (northeast of Sakhalin), but also to test the idea of Tertiary fan deposition into a huge area east of the Sakhalin, the Derugin Basin, in open areas not covered by seismic before.

Based on review of preliminary data (fig. 3) from the SA04 survey, it is clear that the objectives of the survey have been met. "The new data shows the presence of deep sedimentary basins not previously imaged. These basins could represent a different petroleum system than those we know about and have to be investigated further," says Trommestad.

Based on the results from the 2004 survey, a third survey was acquired this summer. This is partly an infill to the existing seismic grid, but also a test into Sakhalin 6 to the southeast also to date suffering from poor data quality. The geology in Sakhalin 6 is not fully understood, but gravity and magnetic indicate that huge basins could be present.

"Another significant step forward has been made with respect to data quality, and in combination with the extended coverage towards the deep-water areas of the Sea of Okhotsk, this year's survey will most likely image new structural elements and exploration models to be considered in the future seismic programmes. More data should therefore be acquired in the Khabarovsk, Magadan and West-Kamchatka areas," says Kjell Trommestad.

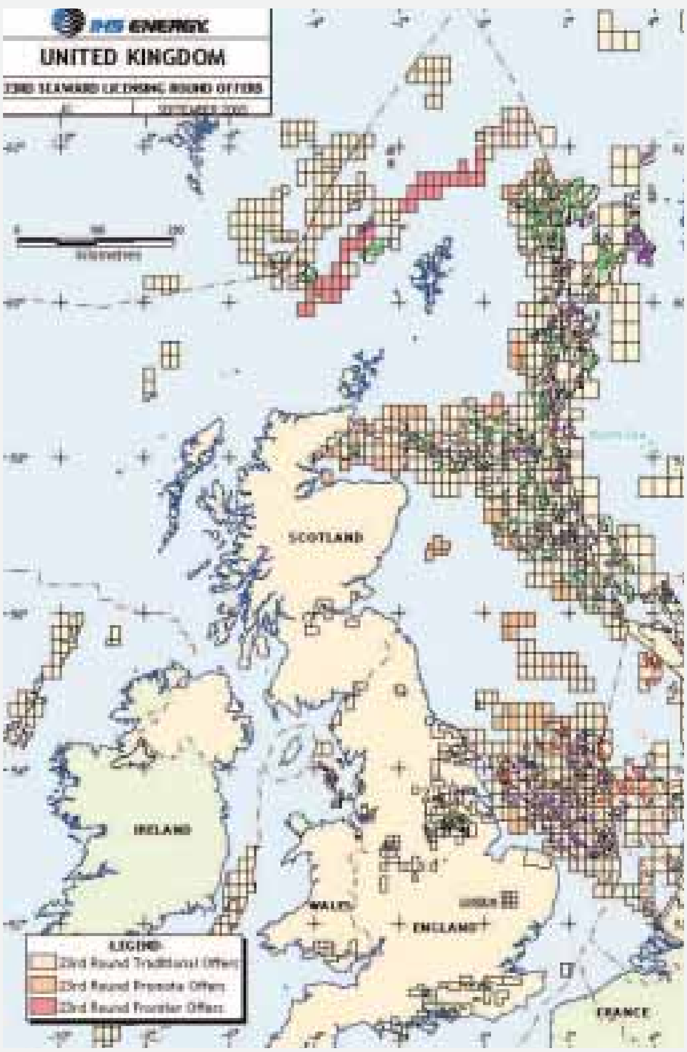
Industry focus

There is an increasing interest for Sea of Okhotsk among the international exploration companies. Several new players are working with the multi-client data as a part of their initial evaluations, with the aim to establish themselves as active investors and partners in the region. However, key factors will be the availability of exploration licenses/acreage and that the processes and terms related to this are predictable.

"Promoting" the North Sea

In the 23rd UKCS Oil and Gas Licensing Round, announced on 6th September 2005, a record number of oil and gas production licences are available. 152 licences have been offered to 99 companies, 24 of which will be new entrants to the North Sea. Has the introduction of new types of licences, in particular the 'Promote' licence, brought about this resurgence of interest in exploration in the UK Continental Shelf? We talk to two companies who have used this route to enter the North Sea.

Courtesy of HIS Energy



Blocks offered in the 23rd UKCS Oil and Gas Licensing Round.

Jane Whaley

Granby Oil and Gas is an example of a company which perceived the opportunity offered by this new initiative and used it as a stepping stone to build its business. Granby Enterprises Ltd was initially conceived by two ex-Enterprise geoscientists, Richard Moreton and Martin Whitehead. Back in 2002 they were starting out on their own, keen to be 'not just another set of day-rate consultants', but to create and develop a small oil company through equity growth.

Small cost and requirements

'We had always been interested in the North Sea', says Richard, Executive Director, 'but couldn't see a way in. It was dominated by the majors, who were sitting on acreage, and the basin was stagnating. The cost and requirements of the licence excluded the small guys with only ideas and enthusiasm to offer. The Promote initiative gave us the breakthrough we needed.'

He sums up the difference between the traditional and the Promote licence. 'A Promote application is far simpler. You don't have to bid large work programmes. Through DTI initiatives, such as DEAL, data accessibility has improved tremendously, giving you the information needed for a good technical application. The process itself is straightforward, as you don't need to satisfy the stringent checks required for a traditional licence. And, of course, it costs 10% of the traditional licence.'

In the 21st Round in 2003, which introduced the Promote licence, Granby identified a number of interesting blocks but eventually only bid for one. 'We had evolved a strategy for what we were interested in - shallow water; good charging mechanism, relatively low risk. We've moved on since then and, in retrospect, I wish we had applied for more!'

A year later Granby Enterprises Ltd had combined forces with Team Oil Ltd, also formed by former Enterprise colleagues. Granby was awarded 9 further blocks with Promote licences in the 22nd Round, having built up its financial background through strategic alliances with companies like Australian Elixir Petroleum. Simultaneous-

Photo: Jane Whaley

Richard Moreton, Executive Director of Granby Oil and Gas plc, attributes much of the successful growth of the company to the Promote initiative. 'It gave us the breakthrough we needed.'

ly, it had identified some interesting prospects on the original 21st Round block and was talking to companies interested in farming-in. Eventually it joined with Century Exploration and Elixir Petroleum and earlier this year drilled its first well on the block. This came in dry, but Richard was not downhearted, "Well, there's always a risk, but our investors see the value of our portfolio with multiple prospects in a variety of plays.'

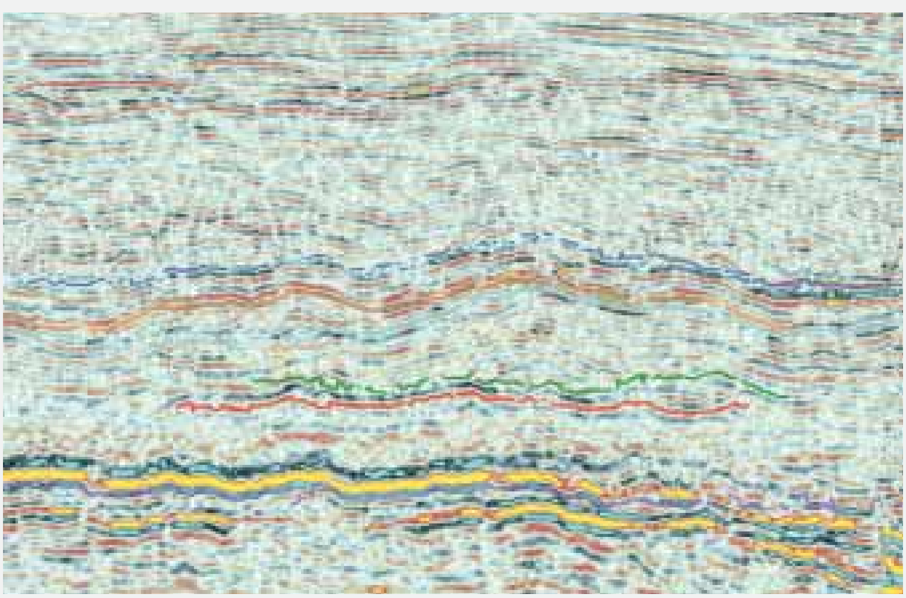
By 2005 the company had grown in size to a total of 10 technical and managerial staff, with premises in Central London. The combined entities of Granby Enterprises and Team Oil were successfully floated on the AIM in July this year as Granby Oil and Gas plc.

For the 23rd Round Granby looked at over 100 potential blocks, selected a number of them and was eventually awarded 12 blocks, 10 with Promote licences and 2 traditional exploration licences with 3D seismic commitments. Granby Oil and Gas also has an interest in the Galoc Field in the Philippines, slated for production in early 2007, and is currently seeking potential exploration and production opportunities both in the North Sea and overseas.

Richard Moreton attributes much of their growth to the Promote initiative, which gave Granby a much-needed entry into the market. 'Promote has been key to our business. Without it, growth would have been much slower – and the UK wouldn't have been our first port of call!'

Richard considers that the DTI can deem the Promote idea a great success, both for the industry and the country. 'It was a fantastic initiative - look at the number of companies, major and minor, international and home-grown, which are now in, or seriously looking at, the UKCS. The upsurge in this area is amazing and, while high oil prices have played their part, much of it is due to the publicity generated by the Promote initiative. This has had a major knock-on effect on the seismic and drilling rig busi-

© Iceni Oil and Gas



A Tertiary prospect on one of the blocks awarded to Granby Oil and Gas in the 22nd round, part of the multi-play portfolio the company has developed

Promote Licence

After more than 40 years of exploration and production, the UK Continental Shelf can be considered a mature area. By the end of the 20th century interest in the region appeared to be waning, with a number of major companies withdrawing, and it was realised that some innovative thinking was needed if the area was to be reinvigorated. Many North Sea experts felt that there were interesting plays left to be investigated, but the risk-averse mentality adopted by the majors meant that they were being ignored. The question was: how could smaller companies, with knowledge and expertise but not extensive funding, be encouraged into the area to chase their hypotheses?

After consultation with the industry, the UK Government introduced the concept of the Promote licence in 2002. The intention was to encourage small companies with geoscience expertise to bid for UKCS blocks and generate new prospects, in exchange for an exclusive interest in an eventual full production licence, giving them a strong awareness of the commercial value of their work.

It is a very cost effective way for a small company to enter the North Sea, since for the two years of Promote licence the charge is 10% of the traditional exploration licence fee. A Promote company is not obliged to fulfil the exacting entry checks required for the traditional licence while it works up potential prospects, primarily using existing data, without any commitment to undertake seismic or drilling at an early stage. After the initial 2 years, the company will either give up the acreage, sell it on, or commit to drilling activity, probably bringing in partners, having satisfied the DTI that it has the technical, environmental and financial capacity to drill.

From the start, there was considerable interest in the initiative. When the results of the 21st round were announced in 2003, there was an encouraging number of new entrants and start-up companies. Of the 88 new licences awarded, 53 were Promote, and there was a record 27 new entrants to the UKCS. In the 22nd Round, 58 Promote licences were awarded and for the 2005 round the number had risen to 76.

The 23rd Round marks the highest number of licences awarded since 1964. It would appear that the Promote initiative has indeed had a significant impact on the upsurge of interest in the North Sea.

ness and also on employment.'

Interestingly, however, he feels that the success of Promote could actually shorten the effective life of the initiative. 'The window of opportunity is closing. The increased attractiveness of the North Sea means that it is becoming more competitive, with much higher bids. Because a large area was on offer in this last round, there was still room for genuine "Promoters", but what will be available in the next round? How much opportunity will there be for the small guy with a good idea?'

The Promote initiative has been key to success for Granby Oil and Gas, allowing it to build through equity growth, as planned. Promote has reinvigorated interest in the North Sea, and endorsed the UK as a good place to be doing business. Richard does, however, have an interesting but as yet unanswered question: 'The Promote initiative has helped put the life back into the North Sea; will it actually result in finding more oil?'

A perfect opportunity

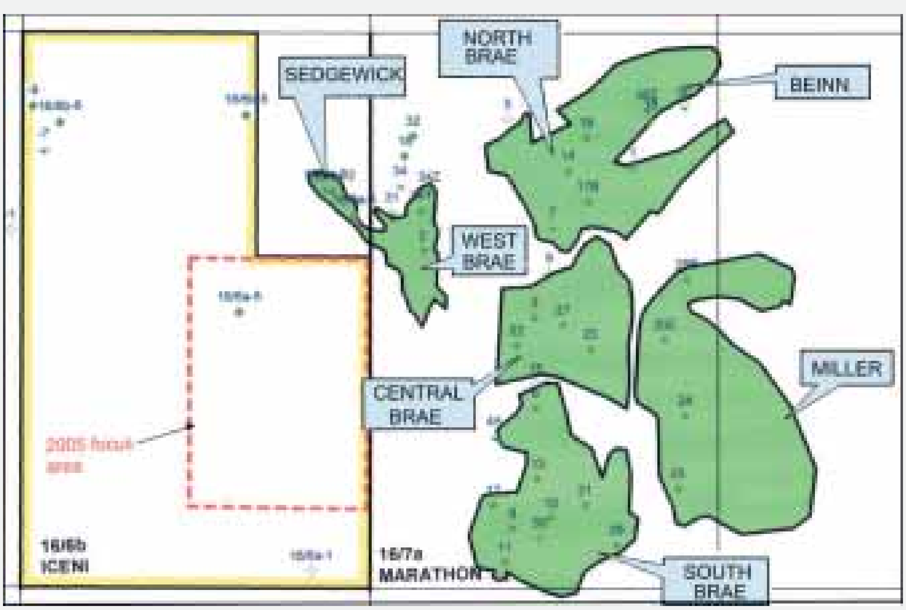
Between them, explorationists Ian Anderson and John Clure have more than 60 years of experience of the international oil industry, including much in the North Sea, working for a range of companies. When, as independent consultants, they learned about the DTI's Promote initiative in the North Sea they quickly realised that this was a perfect opportunity to build their own oil and gas business.

They formed Iceni Oil and Gas Ltd in January 2004 with the objective of participating in the UK Continental Shelf 22nd Round and taking advantage of the Promote terms. Iceni acquired 2 blocks from this round (16/6B and 3/16), with an initial work programme of seismic reprocessing in the first year and the option to 'drill or drop' after 2 years. The company is now working up 3D seismic on one of the blocks and is discussing farm-in opportunities with other companies.

In the 2005 23rd Licensing Round, Iceni were happy to be awarded two additional North Sea Promote blocks (14/15B and 15/11B). It is looking for new acreage, initially in the North Sea, but plans to expand further afield, probably to South East Asia, at a later date. Iceni is currently a private company but is considering going public in the near term and intends to participate in as much drilling as possible in order to maximise the chance of success.

The DTI's easy data access and many new initiatives to stimulate activity have definitely been a major factor in Iceni's plans. Senior Geologist Valerie Clure comments: 'Our experience of the Promote initiative has been very positive. The DTI are extremely helpful and obliging. They respond rapidly to phone calls and questions and help the licensee as much as possible. The Promote idea is brilliant and has proved very popular.'

Valerie notes how carefully the DTI look at all licensing applications, and are particularly interested in new ideas and play concepts. 'They are determined to make the programme work.'



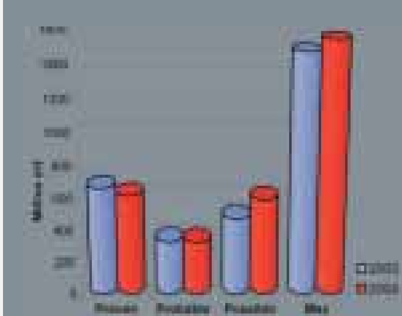
10 billion barrels left?

The UK Department of Trade and Industry has collect reserves data from each UKCS operator, including oil, liquids and liquefied products obtained from gas fields, gas-condensate fields and the associated gas in oil fields.

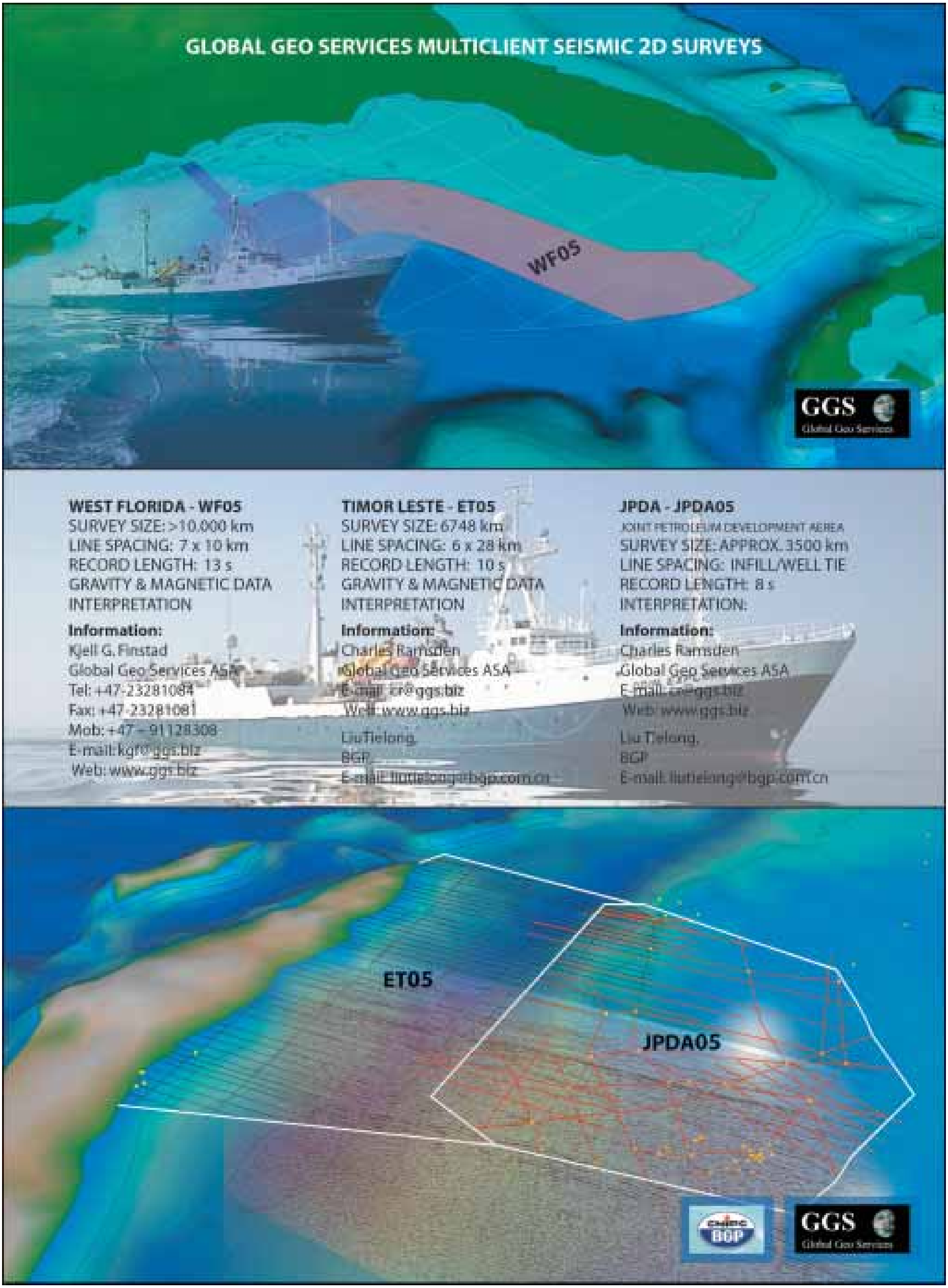
The calculation of total reserves is based on estimates of proven, probable and possible reserves. Proven reserves are those where available evidence suggests they are virtually certain; probable reserves are not proven but have a better than 50% chance of being produced; while possible reserves have a significant but less than 50% chance of being technically and commercially producible.

By the end of 2004 the UK total proven oil reserves were 620 million m^3 (3,9 billion barrels), while probable reserves were 330 million m^3 (2,1 billion barrels) and possible reserves were 596 million m^3 (3,7 billion barrels), giving a maximum remaining producible reserves of 1,547 million m^3 (9,7 billion barrels). Cumulative production to the end of 2004 was 3,500 million m^3 (22 billion barrels) of oil.

The chart shows proven remaining reserves at the end of 2004 standing 44 million m^3 (276 million barrels) less than at the end of 2003. Annual oil production in 2004 was 110 million m^3 (691 million barrels, or 1,89 million barrels of oil per day), leaving a proven reserves replacement of 66 million m3 (415 million barrels). The DTI suggest that this results from greater confidence in reserves estimates following technical and economic reassessments, meaning that reserves moved from probable to proven in a number of fields. At the same time, possible oil reserves have also increased.



UK cumulative production and ultimate recovery of oil have both grown over time while proven plus probable reserves have tended to decline since 1994 following a period of steady growth. However, the flattening of the curve shows that the rate of reserves decline has lessened since 2000 as the rate of oil production has declined.



GLOBAL GEO SERVICES MULTICLIENT SEISMIC 2D SURVEYS
WF05
GGS
Global Geo Services
WEST FLORIDA - WF05
SURVEY SIZE: >10.000 km
LINE SPACING: 7 x 10 km
RECORD LENGTH: 13 s
GRAVITY & MAGNETIC DATA
INTERPRETATION
Information:
Kjell G. Finstad
Global Geo Services ASA
Tel: +47-23281084
Fax: +47-23281081
Mob: +47 – 91128308
E-mail: kgf@ggs.biz
Web: www.ggs.biz
TIMOR LESTE - ET05
SURVEY SIZE: 6748 km
LINE SPACING: 6 x 28 km
RECORD LENGTH: 10 s
GRAVITY & MAGNETIC DATA
INTERPRETATION
Information:
Charles Ramsden
Global Geo Services ASA
E-mail: cr@ggs.biz
Web: www.ggs.biz
LiuTielong,
BGP
JPDA - JPDA05
JOINT PETROLEUM DEVELOPMENT AEREA
SURVEY SIZE: APPROX. 3500 km
LINE SPACING: INFILL/WELL TIE
RECORD LENGTH: 8 s
INTERPRETATION:
Information:
Charles Ramsden
Global Geo Services ASA
Web: www.ggs.biz
Liu Tielong,
BGP
E-mail: liutielong@bgp.com.cn
ET05
JPDA05
BGP
GGS
Global Geo Services

Barrels for the future

Canada's oil sands are the world's largest single hydrocarbon resource. The huge volumes of thick, sticky crude oil – bitumen – are now being exploited at an increased pace. Thanks to thriving oil prices and improved technology, production is bound to double and reach two million barrels per day in only a few years time.

Photo: Halfdan Carstens

The Athabasca oil sands surrounding Fort McMurray in the Canadian outback, some 400 km north of Edmonton, is the largest (40,000 km^2) and most accessible resource. It also contains the most bitumen, and perhaps as much as 20% can be strip-mined while *in situ* techniques are needed for the deep deposits. Additional deposits are found in the Cold Lake and the Peace River oil sands. The Cold Lake area (22,000 km^2) has Alberta's second largest resources of bitumen. Presently, some of these deposits are recovered using *in situ* technology. The Peace River area (8,000 km^2) is the smallest of the oil sands areas. Deep deposits are also here being recovered with *in situ* methods. Several oil sands leases produce significant quantities of coal, coal bed methane and natural gas.

Photographed on a late summer evening, the Athabasca River flows leisurely northwards and later joins the Mackenzie River and ends up in the Mackenzie Delta in the Arctic. Here, on the north side of the booming Fort McMurray, it cuts through the oil sands that are mined in several places further north by a number of oil companies. Water vapour emitted from extraction plants and "upgraders" in the Suncor operations along Highway 63 can be seen in the distance.

World Resources

Oil sands also occur in countries other than Canada, including the Former Soviet Union (FSU), the United States and Nigeria. Outside Canada, significant resources are only found in the FSU.

Halfdan Carstens

"Take the Abasand Drive, pass the school and park on the opposite side. Then follow the gravel road all the way down to the river. Here you can have a first-hand look at the oil sands." The instructions are given by one of the interpreters at the Oil Sands Discovery Centre in Fort McMurray. I am on my way to my first encounter with the famous oil sands. Huge deposits of sandstones filled with ultraheavy oil – bitumen – have been mined and produced for almost 40 years. The deposits are now gaining increased interest from all over the world, including U.S. policymakers eager for a source of oil in a politically stable part of the world.

Five hours drive north of Edmonton through endless stretches of cattle country, first; then desolate forests, rests Fort McMurray on a huge reservoir of bitumen. It is now generally accepted that the small boomtown of 50,000 inhabitants is in the centre of an area that has the largest resources of petroleum on Earth.

I do as I'm told. The road is muddy and quite slippery after the early morning rain, but with good shoes it is nonetheless an easy walk. The walls of the narrow valley are steep, as the moving water in the river down below has had an easy task of eroding these loosely consolidated sedimentary rocks. Small landslides are common. Much to my surprise, the road appears to be paved as I approach the river. Closer inspection, however, reveals that oil from the sandstones has flowed onto the road and made a natural paving during warm, sunny days.

The walk is definitely worth the effort. This is a unique chance to look right into the reservoir without seismic, without electric logs and not having to deal with drill cuttings and slim cores. Best of all, the rocks smell oil.

Oil sands – sandstones filled with bitumen – in a road-cut just above the Athabasca River. This is also the location of the now extinct Abasands Oils plant that was first opened in 1936. It operated on a regular basis by 1941 producing 2000 barrels a day. They drilled holed in the sandstones, inserted blasting powder and set it off. The loos sand was loaded onto trucks and hauled to the separation plant. A fire in 1945 completely destroyed the plant, and in 1946 the federal government abandoned the site. It took another 20 years before Great Canadian Oil Sands (now Suncor) launched a project to produce synthetic oil from oil sands.

The first attempts

The oil sands were known to the native people long before the White Man ventured west and northwards on their way towards the cold Arctic. They knew that if they mixed the bitumen with spruce gum they could use it to caulk the seams of their birchbark canoes. They may also have used bitumen for other purposes such as dressing wounds and waterproofing garments.

The first written account of the oil sands dates back to 1719 when a fur trader described a sample "that flowed out of the banks of the river," and by the late 18th century several European explorers were reporting of bitumen seeps along the Athabasca River. They didn't know it at that time, but they had in fact discovered what would much later turn out to be the world's largest petroleum resource.

Commercial interest in the bitumen deposits was triggered by scientists from the Geological Survey of Canada at the end of the 19th century. Their insights resulted in investigations funded by the Government, and in 1894 a well was drilled to see if the bitumen was seeping from a conventional reservoir below the sand. The conclusion was negative, and since then huge efforts have concentrated on mapping the extent of the oil sands and how to exploit the resource economically.

The first real attempt to recover oil from the sandstones was made in 1915 when an engineer wanted to use it for a road-paving experiment. Several paved roads in cities like Ottawa and Jasper resulted.

Only 20% of the oil sands can be strip-mined, the rest is lying too deep for this technology to work. Nevertheless, recoverable reserves amount to 65 billion barrels of oil, six times the recoverable volumes of Prudhoe Bay. If this had been conventional oil, the shallow deposits of the Athabasca oil sands would have ranked as the world's 3rd largest oil field.

Transportation of huge volumes of rocks turned out to be a costly affair, and hot water came into use as a means of separating bitumen from the mined sand. In 1925, a scientist with the Alberta Research Council successfully demonstrated a separation method using hot water and caustic soda. The same fundamental principle is still being used today in a process the industry calls "upgrading". Upgrading is the process that converts bitumen and heavy oil into a product with a density and viscosity similar to conventional light crude oil.

Gasoline, fuel oil and asphalt were first produced by Abasand Oils Ltd. in 1936. Again, hot water and solvents were used to extract the bitumen from the rocks. The plant burned down just as it was going to operate efficiently, but along with a similar mining-refining project elsewhere it was now proven that the technology could work. More than 200 years after the oil sands were first discovered, a technology had been invented that could extract bitumen from the sandstones.

The discovery of significant reserves of light crude in the late 1940s due south of Edmonton (GEO ExPro No. 2-3, 2005), however, halted further developments of any oil sands project for at least a decade. Instead, everybody wanted to invest in a resource that was much cheaper to produce and which did not require en elaborate process of "upgrading" before being sent to the refinery.

Towards a prospering industry

The modern era of extracting bitumen from oil sands began in 1967, almost 40 years ago, at a time when Fort McMurray was just a fur trading post and river port of 1,300 people far away from civilisation.

First on the scene was Great Canadian Oil Sands (GCOS), the forerunner of today's Suncor Energy Inc. Later, the Syncrude project, a consortium of oil companies, launched their project just as the oil crisis of the early 1970's shook the world. Syncrude nevertheless began producing upgraded crude oil in 1978.

Both operations were mining oil sands from deposits sitting close to the surface. Deposits below more than 75 metres of overburden require a different technology to get the bitumen out of the rock. This is called the in-situ method.

The story of in-situ bitumen development also began in the 1960's. Imperial Oil built a test plant to extract bitumen from the deeply buried Cold Lake deposits south of Fort McMurray. The technology involved injecting steam under high pressure into the oil sand formation, and pumping the bitumen to the surface as it became more inclined to flow. During the 1970's Shell developed a similar technology for producing bitumen from the Peace River oil sands deposit to the west of Fort McMurray.

Today, a licence map of the area around Fort McMurray shows a whole range of operators witnessing an industry eager to exploit the vast resources. Some 20 projects are either producing, from a few thousand barrels to more than 250,000 barrels a day, or are under way and plan to be producing in only a few years time. These are all mining extraction projects using huge shovels that load sand into equally big trucks.

Bitumen and oil sands

Bitumen is a thick, sticky form of crude oil with a specific gravity greater than 0,96 g/cm^3 and is a general name for solid and semisolid hydrocarbons. At 11°C it has the consistency of a hockey puck, at room temperature it is a tar-like substance that pours extremely slowly, and in order to flow into a well or through a pipeline it must be heated or diluted.

Bitumen stored in the Canadian Oil Sands started out as conventional, crude oil more than 1000 metres below the surface. Some fifty million years ago, however, huge volumes of conventional oil migrated upward until they reached and saturated large areas covered by sandstones close to the surface. Bacteria then feasted on the light hydrocarbons components and slowly turned the oil into bitumen. Bacteria always eat the simplest hydrocarbon first and convert them into carbon dioxide and water. The larger hydrocarbon molecules, as well as sulphur and metals, are left behind. As a result, there are more heavy hydrocarbons, sulphur and metals in bitumen than in conventional oil.

Upgrading is the process that changes bitumen into synthetic crude oil.

Heavy oil is a thick crude oil with a specific gravity greater than 0,90 g/cm^3. The term includes some oil that will flow, albeit slowly, but most heavy oil also requires heat or dilution to flow to a well or through a pipeline.

Oil sands are naturally occurring mixtures of bitumen, water, sand and clay. On the average a sample of oil sand will contain 12% bitumen by weight, but the bitumen content varies from 1% to 18%. More than 12% is considered rich, while less than 6% is poor. On average, it takes 2 tonnes of mined oil sand to produce one barrel of synthetic crude oil. The upgraded product is called "synthetic" because it is altered from its naturally occurring state by a chemical process. Synthetic crude oil is very similar to conventional oil. The synthetic oil leaves Fort McMurray by pipeline travelling 5 km/hr, and it takes 3 days to reach refineries in Edmonton.

Oil sands are water wet. Each grain of sand is covered by film of water, which is then surrounded by a slick of bitumen. The sands are bonded firmly together by grain-to-grain contact. The sand is composed primarily of quartz grains.

Oil sands are often referred to as "tar sand" because the bitumen resembles black, sticky tar. However, the term "tar sand" is incorrect as tar is a man-made substance formed through distillation of organic material.

Samples of the oil sands represent the ultimate experience for petroleum geologists as you can see both the reservoir and the oil it contains. In addition, you can smell the oil!

How much?

The amount of bitumen reservoired in mostly Cretaceous sandstones of the Western Canada Sedimentary Basin is colossal. Nowhere else on earth is the concentration of petroleum per square kilometre higher, and the Canadians themselves claim this is the world's largest petroleum resource.

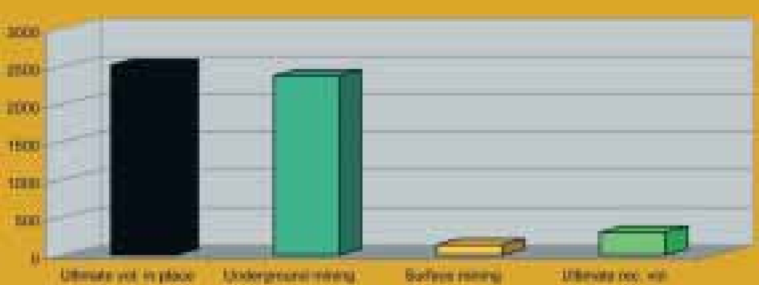
Canada's bitumen resources are situated almost entirely within the province of Alberta. Three deposits have been defined: the Peace River, Athabasca and Cold Lake Oil Sands Areas (compare map on page 47). These deposits collectively cover an area – 80,000 sq. km – comparable in size to Ireland or Scotland.

According to the Alberta Energy and Utilities Board (AEUB), the initial volume of bitumen in place is now reckoned to be 1.6 trillion (10^{12} barrels) barrels. The ultimate volume of bitumen in place, the volume expected to be found when all exploratory and development activity has ceased, is 2.5 trillion barrels. It is hard to grasp this number. It may help to know that you get this volume by multiplying the reserves of Prudhoe Bay (10 billion barrels recoverable) 250 times.

The larger part of the resources can only be accessed through underground mining because they are deeply buried. Only a small part is available for strip mining (compare diagram).

Of the ultimate in place volume of bitu men, approximately 315 billion barrels is estimated to be recoverable. Initial established reserves are 180 billion barrels. In comparison, the original reserves of Ghawar in Saudi Arabia, the world's largest oil field, was 80 billion barrels and the remaining reserves of Saudi Arabia is 263 billion barrels (BP Statistical Review of World Energy 2005).

Future estimates of reserves (recoverable bitumen) may increase, as the current numbers are based on a recovery factor of only 12 percent. There is a considerable potential for this percentage to increase as advances are made in recovery technology of deposits that are buried too deeply to be mined.



The upper diagram visualises how much oil that may be present in the Canadian oil sands altogether (black), how much of this that can be produced in situ (dark green), how much that can be mined (yellow), and how much oil that can be recovered (12 percent) taking into account current technology and economic conditions. The Alberta Energy and Utilities Board (AEUB) has estimated that some 315 billion barrels is ultimately recoverable. The lower diagram compares the potential oil sands reserves with numbers published this year by BP concerning remaining oil reserves (BP Statistical Review of World Energy).

Only about 10-15%, perhaps as much as 20%, of the Canadian oil sands can be mined. At more than 75 metres below the surface, a large part of the Athabasca resource is buried too deep for this technology. Instead, the in-situ method must be used. The same applies to the Cold Lake deposits that sit below 300-600 metres of overburden and the Peace River oil sands that are found 150-760 metres below the surface.

2 tonnes = 1 barrel

While conventional oil flows naturally or is pumped from the ground, bitumen from oil sands must be mined if close to the surface or recovered in-situ when buried more than about 70-80 metres.

The mining operation has gained worldwide fame because of the large-scale machinery being used. Through documentaries we have witnessed colossal shovels dig into the oil sand deposits and load their cargo into huge trucks that then transport it to crushers. Hot water is here added causing the fluids to dissolve from the rock fragments, and the slurry is then transported to the extraction plant through pipelines. At the extraction plant the bitumen is released from the slurry through the use of separators.

The sand is sent back to the mine site to fill in mined-out areas. Water from the extraction process containing sand and clay goes into settling ponds. The water is recycled back to the extraction plant for use in the separation process.

On the average, about two tonnes of oil sand have to be removed and processed to make one barrel of crude oil. Oil sand mining is thus very efficient with respect to the amount of bitumen recovered. The recovery rate is in general higher than 90 percent. In comparison, recovery rates in conventional reservoirs average 30 percent and very seldom exceed 50 percent.

Bitumen, behaving like a solid rather than a fluid, cannot be produced from wells unless it is heated or diluted. Injected steam is used for this purpose in most commercial in-situ operations. The heat softens, while the water vapour helps to

"GO BIG, OR GO HOME". In the late 1800's and early 1900's, when people first began mining oil sand, the operation was completely manual. Now, mining oil requires extremely large machines. To prepare for surface mining, the overburden, consisting of muskeg and glacial deposits, is first removed and saved to use in land reclamation. Suncor, Syncrude and Albian Sands are today using the same mining technology: Truck and shovel. The shovels move easily to select the richest oil sand and ignore low-grade ore. Open pit mining is done in benches or steps, as is evident in this photo. The benches are each approximately 12-15 metres high. Giant shovels dig the oil sand and place it into heavy hauler trucks that range in size from 240 ton to the largest with a 400-ton capacity. The latter can thus transport 400 tons of rock, equivalent to 200 barrels of oil when crushed and upgraded. The trucks dump the oil sand into crushers, which break up the big chunks of oil sand. From the crushers, warm water is added, and the slurry is then separated into bitumen, sand and water. The sand and water is pumped to holding ponds, while the bitumen is further awashed with a hydrocarbon solvent to prepare it for transport into the upgrading plant. Breaking the heavy bitumen into smaller molecules by adding hydrogen, heat and pressure and removing nitrogen and sulphur create synthetic crude oils. The main product of upgrading is thus synthesized crude oil that can later be refined like conventional oil into a range of consumer products.

Photo: Halfdan Carstens

Syncrude's massive oil production facility, the Mildred Lake operation just off Highway 63, is the largest single source of crude oil in Canada. In the background we see the main plant facilities for bitumen extraction and upgrading that is in the final stages of an $8 billion expansion. The strip-mining process scars vast acres of land that must be reclaimed and restored to what is called "equivalent land capabilities." In front, what appears to be a massive tidal flat with wet, light-brown sand, is an area that is currently being reclaimed, i.e. disturbed land is restored so that it is as productive as it was before it was mined. It will take 12 to 15 years to turn the site into rolling, grass-covered hills. Just south of Syncrude's plant (not seen is this photo) is the company's first mining site. It is now reclaimed and rolling hills of grass and trees support a herd of buffalo. The site includes also a pond used for mine tailings.

dilute and separate the bitumen from the sand grains. The pressure forced on the formations also forms cracks through which the bitumen can flow to the wells. The operation takes place in three stages: Stage 1 involves steam injection; Stage 2 means soaking the reservoir for several weeks, and in Stage 3 bitumen is flowing or being pumped through the same wells as the steam was injected. When the production rate declines after weeks or months, the cycle is repeated.

The production technology is continuously improving, steam-assisted gravity drainage (SAGD) being the latest development. Pairs of horizontal wells, one above the other, are drilled into a formation. Steam is injected into the upper well; the bitumen softens and drains into the lower well.

During in-situ operations between 25 and 75 percent of the bitumen in the reservoir can be recovered.

Ice that burns

The paved road out of Fort McMurray continues for about 65 km. On our way we pass a number of "oil fields", notably Syncrude's operations which can be overlooked from a viewing point, and with a SUV it is possible go on for another 40 km or so during summer. After that it is wilderness. All the way to the Arctic. Continuing on foot is no option. A five-hour flight north out of Edmonton will, however, take us to the next adventure. The Mackenzie Delta where enormous amounts of gas is stored in sandstones at several thousand metres depth.

In addition, the Arctic may contain vast amounts of gas in the form of gas hydrates (GEO ExPro No. 1, 2004, www.geoexpro.com). That gas is also, like bitumen in oil sands, stored in a solid state. Also similar to the oil sands, the hydrocarbons are found at shallow depth.

Unlike the oil sands, however, it may take decades before this resource can be produced economically.

Canada's hydrocarbon resources are plentiful. While the Alberta oil sands are now tapped at an increased rate, gas hydrates may be a huge resource in the future.

Photo: Halfdan Carstens

"We are both very stubborn"

Only some eight years after the idea stroke on a flight out of Houston, two innovative physicists can claim that seabed logging has been fully accepted by the conservative oil industry.

Halfdan Carstens

"We believe electromagnetic surveying eventually will rival the size of the seismic industry."

Not at all modest on behalf of the technology he has co-invented, Terje Eidesmo, president of emgs (Electromagnetic Geoservices AS), is looking into the future, something he has been doing together with his experienced management team and highly qualified board of directors. Their aim is to define a strategy for further growth in a market that seems to believe in both the company and the innovative technology it has introduced in an exceptionally expeditious manner.

"That may be the very limit," he admits. "But if we believe this technology will be useful not only in exploration, but also in reservoir monitoring, there is no reason we shouldn't see considerable growth in the years to come, not only for our company, but for the entire seabed logging industry."

Results match drilling

Less than four years ago, nobody had ever heard of seabed logging (SBL). Wireline logging, ok, but seabed logging, the concept was totally new to the oil industry when it was first introduced early 2002 (GEO 01/2002, GEO ExPro, no. 1, 2004).

Predictably, many geoscientists with solid background in geophysics and hydrocarbon exploration were sceptical, and so where the conservative oil industry at large. There were a good number of theoretical reasons why the technology should not work. But, to the great surprise of many self-acclaimed experts, a series of successful surveys have since then shown that it has a merit. In fact, several major oil companies already at this stage take exploration decisions based on SBL results and, in all instances to date, the results of SBL surveys have matched that of the actual drilling

Through more than 120 surveys, seabed logging has demonstrated its ability, and the methodology is on the lips of most explorationists dealing with offshore exploration. Customers include a long list of companies that is topped by supermajors like BP and Shell.

The geographical range of their operations is also impressive. Having been in regular operation only since late 2002, surveys have been carried out in the North Sea, the Norwegian Sea, the Barents Sea, the Mediterranean, offshore West Africa and Brazil and in the South China Sea. In other words, the company is already operating on a global scale.

The market demand has also grown in such a way that two ships are now in operation. "We are now in the process of evaluating if we need a third ship," says Terje. That should by itself take the wind out the sails of many sceptics.

The first attempt

Terje Eidesmo and Svein Ellingsrud, invented seabed logging. We all know that, but it is now also corroborated by the UK Patent Office in a hearing published on 21 July as of this year (GEO ExPro No. 4, 2005). Svein Ellingsrud is the other half of the invention team, and now serves as vice president for research and technology.

Both Terje and Svein have a profound background in physics with, first a Masters Degree, and then a PhD from the Norwegian University of Science and Technology in Trondheim, and, as it happened, their thesis had to do with electromagnetic waves. In the early 1990's they joined Statoil, Terje first, then Svein, as research scientists and soon became involved in petrophysics and well logging. Their first encounter with electromagnetic waves when working for Statoil was in a project concerning geosteering. The idea was to use electromagnetic waves to measure the distance to the oil-water contact.

"This was our very first attempt to use electromagnetic signals for long range detection. Up to then such tools had normally been used in wireline logging with penetration depths in the order of one meter or less," explains Svein.

"We were then faced with the same problem as we would meet later. We had to reduce the frequency of the signal to reduce attenuation, but that also meant that we would get lower resolution. In hindsight, what we learned in that project was very useful at a later stage, even if the project was not successful."

However, the geosteering project triggered other downhole monitoring ideas and projects. A conclusion was that with knowledge about the resistivity in a well, electromagnetic tools outside the casing could monitor approaching waterfronts. Several patents were applied, and later granted, and a downhole resistivity monitoring system (WMR, Water Monitoring Radar) was designed and built in cooperation with NGI and Roxar. Another monitoring radar project was run in cooperation with Kongsberg offshore and NASA in Houston.

Flying high

"We had been in a meeting in Houston and were on our way back to Norway. In the meeting we got to know about an electromagnetic source that was extremely powerful. While sipping a glass of wine or two during dinner, we probed the possibilities: If this source could be strong enough so electromagnetic signals could be used on a much larger scale? Was there any particular reason why we couldn't reduce the frequency even more so equipment on the seafloor could measure the subsurface resistivity? Why not use a large distance between the source and the receiver in a kind of scaled logging approach to "see" really deep? These were the crucial questions at that time.

"The thoughts we made on this flight triggered the whole idea about sea bed logging," explains Terje.

"This was in 1997, and it should take only a few years before the technology would prove its value," says Svein. Already in 2000 a SBL survey was carried out offshore Angola to demonstrate the technical viability of the method. Another survey in 2001, carried out offshore Norway, confirmed that they were on to something big.

The next year, emgs was established as an independent service company with Statoil as a majority shareholder. That was a

Svein Ellingsrud (left) and Terje Eidesmo, both with a PhD and a strong background in physics, have the word of the UK Patent Office that they are inventors of seabed logging, a technology that is now gaining worldwide acceptance in offshore exploration for oil and gas. In 2002 they founded emgs together with their employer Statoil, and in less than three years the company has done surveys in key hydrocarbon provinces around the world.

major turning point for the two scientists who left secure jobs with a sizable oil company, but also, it should turn out later, a decisive moment for the entire oil industry that has always been looking for a tool that can detect hydrocarbons before making a decision to drill.

SBL options

Several results have since then been published that serve to prove that the technology works. Most noteworthy is a story told by Statoil in their annual report for 2004. Seabed logging was instrumental in discovering a small field in the Norwegian Sea. Using SBL data, the company's belief in the prospect was strengthened and it was thus put high up on the priority list for drillable prospects. As a consequence, Statoil now uses SBL regularly in exploration.

Several other companies are now also using SBL for the purpose of screening and maturing prospects. In the last licensing round offshore Norway, work programs have been suggested in which positive results from SBL-surveys will be a prerequisite before a decision to drill is made. Seismic options are well known to the industry. SBL options are entirely new and certainly reflect that the oil industry has accepted this technology in a surprisingly short time.

"For us, this is major and important step forward," says Terje. "It is a good measure of the acceptance level we have reached. Seabed logging is now a tool that not only explorationists are using in preliminary analyses. The methodology has been lifted to the management level."

"In fact, we have learned that economists and managers without a geoscientific background have met the new situation with an open mind. They are also able to see the economic potential, while geophysicists believe they have other tools that can assist them in finding oil, making seabed logging unnecessary.

"The number of opponents is decreasing. They may still be able to halt single projects, but they are not in a position to stop a fast-moving train," says Terje. "Nevertheless, we certainly welcome critical comments because projects are better founded that way."

Stubborn and strategic

Terje and Svein have spent almost the entire working carrier together, or at least close by. They were not exactly student colleagues at the university, as Svein is Terje's senior by a couple of years, but they had the same professor and were both heavily involved with electromagnetic waves during their thesis work.

This background is possibly why they easily made good friends and had an exceptionally good working relationship when they had both ended up as research scientists in Statoil almost 15 years ago. They are different in many ways, but they have some things in common. Both are technical experts but have divided their tasks: Officially, Terje more took a managerial role and Svein the technical role, but in all practical aspects both have contributed.

"We are both very stubborn, a quality that has been very necessary when developing the technology and challenging a system which was dominated by scepticism," says Svein. "In addition, we have both diplomatic skills as well as the moving power that has been essential in the elaborate process it is to develop new ideas."

"A milestone was achieved in 2003 when the SBL technique was awarded the World Oil Award for "Best Exploration Solution"

"Even more important, we believe that we have been able to take advantage of our differences," adds Terje. "We have had an open mind as to the personal quality of the other. We both also understood soon that we had to build a team. Without the teamwork, including a glass of beer in an English pub as well as long evenings in the office, this thing would never have happened. It has definitely not been a "one-man job." As we fought conservative opinions several times we thought it would have been much easier to do something else."

"As we went along, we had to involve the sceptics, we had to avoid getting enemies that later could put a spoke in the wheel. It was necessary to be strategic," Terje emphasizes.

Having been able to convince Statoil that the company should stake on this project, the next phase was to get the industry to commit itself to use this technology. Also here they seem to succeed. One of the remaining obstacles is in fact that the oil companies now lack enough qualified staff to interpret the data.

"The next step is therefore to get the universities to introduce electromagnetic surveying as a separate class," says Terje.

The future

Having acclaimed fame in the exploration departments, the next step for emgs is to prove their worth in reservoir monitoring.

"Logging the reservoir with a resistivity tool will always be necessary. It gives the reservoir engineer the necessary knowledge of saturation and net/gross of a reservoir. The third parameter would be to know the areal extent of the hydrocarbons. And this we can get by using SBL," claims Svein. Different from Terje, who has chosen a management carrier in the new company, Svein is still heavily involved in developing and manufacturing the technology. For a long time he has been advocating SBL's future in reservoir monitoring.

"A survey carried out over the giant Troll gas field shows that SBL is well suited for reservoir delineation," Svein says.

"I thus firmly believe that we will soon be able to acquire 3D SBL surveys for the purpose of mapping the extent of an accumulation, not only proving or disproving the existence of hydrocarbons in the reservoir. The next step after that would be to do repeated surveys that can be used for monitoring the production."

"4D SBL will soon be a product," says Svein. "I wouldn't be surprised if we have the first repeated survey in five years."

"Our long term vision is that SBL should be equally important as seismic when exploring for and producing hydrocarbons," Terje says. "It is a long way to go, and for this to happen we need to invest heavily in technological development," he admits.

The future looks bright for emgs. Thanks to emgs, the future also looks bright for the oil exploration and production industry.

Peru – not just a tourist des

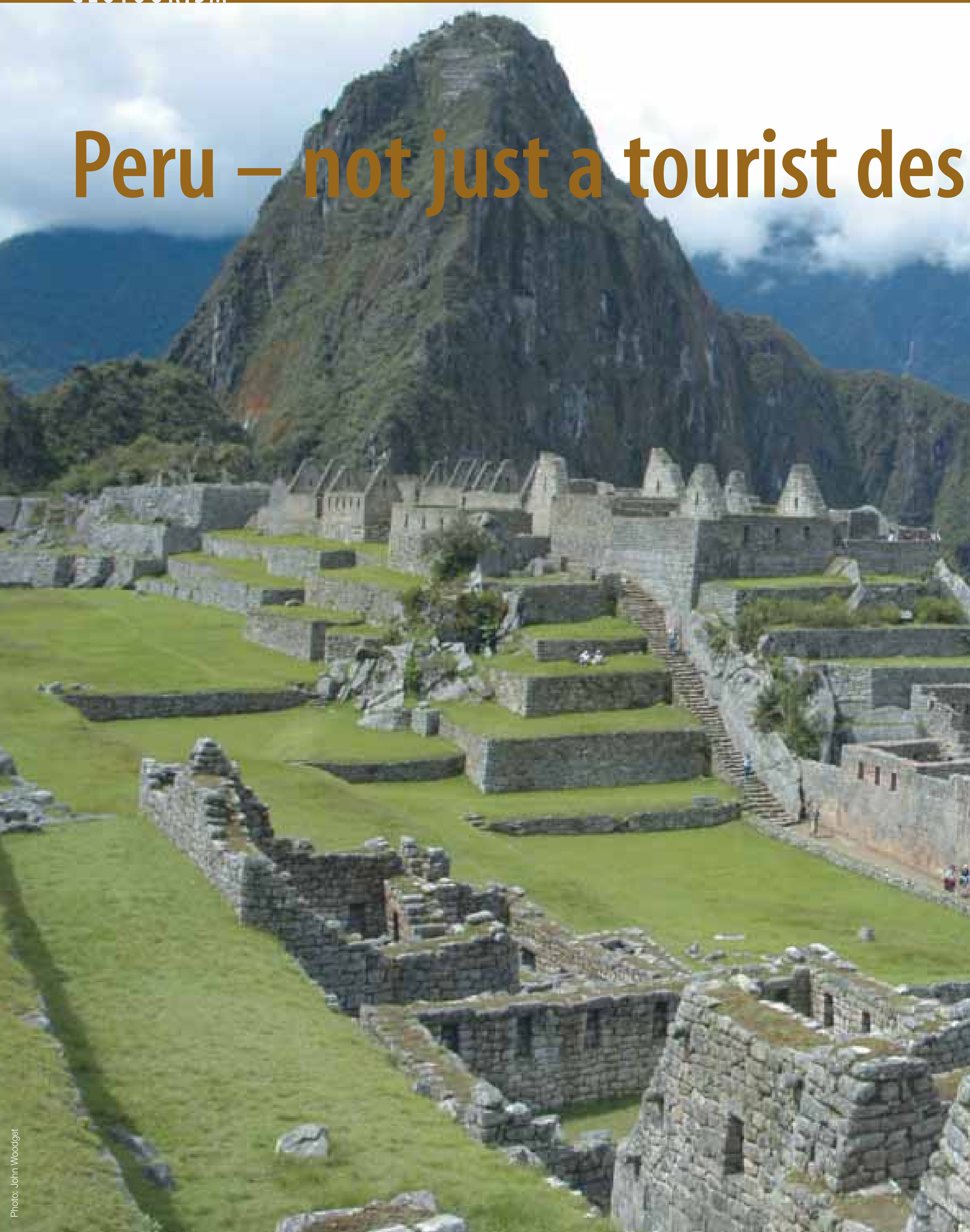


Photo: John Woodget

tination

Exploration and production in Peru are concentrated in four widely separated basins: The interior Marañon Basin in the northeast (900 MMbo produced to date), the largely offshore Talara Basin west of the Andes (1,400 MMbo produced), the Ucayali Basin east of the Andes (800 MMbo and 12.5 Tcfg proven reserves), and the newly emerging gas province of the Madre de Dios Basin (2.5 Tcfg probable reserves), also east of the Andes. All basins in Peru are considered to contain the main elements for a petroleum system and many frontier areas remain undrilled, so considerable potential remains in both the explored and unexplored basins.

Machu Picchu, often referred to as the lost city of the Incas, attracts historians and tourists alike. An astounding archaeological stone citadel, it stands 2,400 metres above sea level and is believed to be more than 600 years old. Many visitors choose to hike the Inca Trail, ancient Inca pathways leading to Machu Picchu, along which some of Peru's most dazzling scenery can be experienced. Note the location of Machu Picchu due south of two hydrocarbon bearing basins and within crystalline rocks (see map above).

After many years of civil unrest and terrorist activity Peru has now experienced relative economic and political stability for more than 15 years. A well-established hydrocarbon industry offering attractive terms has helped rebuild this beautiful country. However, faced with rising internal energy consumption, the country is trying to attract foreign companies to undertake exploration in new, possibly high-risk areas like the remote Madre de Dios Basin. Can Peru ever become self-sufficient in hydrocarbons again?

Jane Whaley

Hydrocarbons were known to exist in Peru for many centuries; indeed, it is thought that the conquistador Pizzaro caulked his ships with tar from seepages when he arrived in 1521.

Oil exploration began in the middle of the 19th century and the Zorritos Field, found in 1861 in north-west Peru, was the first discovery in South America. This was followed shortly afterwards by the finding of the first giant oilfield in the world (i.e. more than 500 million barrels in reserves), the La Brea-Parinas Field, discovered in the same area in 1869 in the Talara Basin. This field is still producing, having produced over a billion barrels of oil.

Oil was first exported in 1905, making Peru the first hydrocarbon exporter in South America. With such an impressive and innovative start, Peru could fairly have been expected to be in the forefront of exploration throughout the 20th century. It was, however, rapidly overtaken in importance by other South American countries such as Brazil and Venezuela, and for many years has been considered an 'also-ran' in the hydrocarbon industry. Is this purely the result of unfavourable geology, or have other factors been to blame? And, more importantly, can there an optimistic outlook for the future of the hydrocarbon industry in Peru?

Complex petroleum geology

Structural geology in Peru is dominated by the evolution of the Andes, as the east moving oceanic Nasca plate is subducted by the westward movement of the crustal South American plate. The main sedimentary basins are therefore found in the fore-arc coastal region and in the sub-Andean Foreland area.

The first discoveries were made in north-west Peru, where the Proto-Amazon delta flowed westwards into the Pacific, before the Andean uplift in the late Tertiary. This

Photo: John Woodget

A growing population and rapidly increasing demand for energy means that Peru is now a net importer of oil.

Machu Picchu

Almost everyone feels they must visit Machu Picchu at some time in their lives. Occupying a outstanding position overlooking the dramatic gorge of the Urubamba river, and protected by the impressive dome of Huayna Picchu, the Incan city is surrounded on all sides by magnificent ridges and snow capped peaks.

The overgrown site was found almost by accident in 1911 by American archaeologist, Hiram Bingham. Little is known about the city, which had possibly been abandoned before the Spanish arrived. It was obviously a very important royal or religious ceremonial town, boasting many large temples and palaces with the highest quality stonework and ornamentation.

This spectacular city is built on intrusive igneous rocks, mostly grey and white granites and batholithic granodiorite of Permo-Triassic or late Hercynian age. Quaternary and Recent glacial and erosional processes have broken much of the surface granite into major blocks, many of which are incorporated into the fabric of the city. All the buildings are made from this granite and the quarry which provided much of the stone lies within the city limits.

Rockslides have occurred in the past and the huge number of visitors to Machu Picchu each year, coupled with high rainfall and steep slopes, make the site very vulnerable. The Incas themselves stabilised the land with terraces and containment walls, but they had not anticipated that 500,000 people would visit their city annually. While measures have been introduced to control the numbers walking the Inca Trail, the majority of tourists travel to Machu Picchu by train, and the huge financial benefit to the whole country from these visitors makes any decision to limit numbers a difficult one. Let us hope that Incan engineering will allow visitors to enjoy the unique ambience of their fabulous city for many years to come.

The Ordovician San Jose Formation and the granite of the Machu Picchu Massif overlook a high flat plateau of Tertiary rocks.

area produced the majority of Peru's hydrocarbons for many years, but has now been overtaken by the vast Marañon Basin in the sub-Andean Foreland belt in the Amazon jungle in the north-east of the country, which now accounts for about 65% of total production.

Oil was discovered in the remote sub-Andean Ucayali Basin in 1931 and it remains one of the most prospective areas in Peru, with a large number of seismically identified undrilled prospects. It has multiple, mature source rocks, with large quantities of oil migrating through the system. Interest in this late Tertiary basin was enhanced by the discovery of the non-associated gas fields which make up the Camisea Project. Success in the Ucayali Basin sparked further exploration in the even more isolated Madre de Dios Basin, which is productive in Bolivia from a world class Devonian source rock. Promising indications were reported from the few wells which have been drilled, culminating in the 1999 discovery of the undeveloped Candamo Field.

There are a number of smaller, underexplored but possibly prospective Andean basins, mostly east of the Andes. Basin modelling will be key in these areas, allowing better understanding of their complex tectonic history, as well as elucidating hydrocarbon migration and hydrodynamics.

Roller-coaster economy

In the early 20th century the economy of Peru was strong, with a major export boom involving sugar, cotton, copper and oil. A strong ruling elite of local landowners and merchants held power, together with international companies, and there was little investment by the state. This situation came to an abrupt halt with the Great Depression in 1929, and the government then tried to intervene with economic measures such as price controls and import duties. Widespread poverty and general unrest led to military intervention, the introduction of measures to encourage exports and the development of a new elite. This roller-coaster cycle of political instability, state intervention and civil unrest continued through most of the 20th century and while the hydrocarbon industry had some successes, it meant that there was little enthusiasm for the country from the international oil community.

For many years exploration remained confined to the north-west coastal region, as the region east of the Andes was considered by most companies to be too inaccessible to be economically prospective. With the discovery of the Corrientes Field in the Marañon Basin in the 1970s, however, there was a rush to the Amazon tributary areas, and wildcats were drilled in new, even more isolated eastern areas such as the Madre de Dios Basin, east of Machu Picchu.

Exploration slowed in the 80s, despite the 1984 Shell discovery of the giant Camisea gas fields. It which took years to develop this complex, partly because the domestic market for gas was undeveloped at the time, but also due to political volatility and fierce opposition to Amazon rainforest development. Peru's state of political

Tourism in Peru

Peru could be regarded as one of the most perfect travel destinations in the world. A beautiful coastline, tropical jungle, the breathtaking Andes and some of the earth's most important historical sites make Peru a truly 'somethingfor everyone' travel destination.

Firmly established on the radar of the trend-setting young backpacker and a very popular trekking destination, Peru is fast becoming one of the highlights of South American travel. It has remained a safe place to visit since Alberto Fujimori was elected president in 1990 and tourism has responded accordingly. Between 1996 and 2000, Peru saw a 29% annual growth of tourist arrivals, with the total number of visitors in 2000 exceeding 1 million for the first time. This number is expected to dramatically increase over the next few years.

Machu Picchu, often referred to as the lost city of the Incas, attracts historians and tourists alike. An astounding archaeological stone citadel, it stands 2,400 metres above sea level and is believed to be more than 600 years old. Many visitors choose to hike the Inca Trail, ancient Inca pathways leading to Machu Picchu, along which some of Peru's most dazzling scenery can be experienced.

Other visitors to Peru come to be baffled by the mysterious Nasca lines, a collection of giant geoglyphs and lines depicting animals and birds that were etched into the desert rock in about 600A.D. They are almost half a kilometre in length and are virtually unrecognisable unless viewed from the air.

In addition to the historical and natural sites of Nasca and Machu Picchu, Peru has abundant attractions for the foreign traveller. Lima is a modern metropolis with art galleries, museums, theatres, superb shopping and a glittering nightlife and those looking for a more traditional holiday can visit the stunning northern beaches for some sun, sea and sand.

Many believe that Peru will be a leader in the trend for eco-tourism, with an emphasis on the importance on being a responsible traveller, encouraging the old mantra, 'take only photographs, leave only footprints'. Whatever the tourist trend happens to be, Peru is such a bountiful and awe-inspiring country that there will always be visitors.

The jungle covered granite massif rises into the clouds from the deeply incised Urubamba River, seen here from Machu Picchu.

turmoil and instability during these years slowed oil exploration and exploitation considerably.

After many years inactivity and decline the Peruvian oil industry entered a new phase in the 1990s when stability returned. In 1993 the government introduced new fiscal terms, privatised all state-owned upstream assets and created Perúpetro to promote private investment. Progress was still slow, so in 2003 the Peruvian government established a new royalties scheme with tax-exempt exports to encourage foreign investment. In addition the Peruvian government offers generous free access to data (see www.perugasoilexplor.com).

Looking to the future

These initiatives appear to have been successful in renewing interest in the industry, with a number of new entrants signing exploration and production contracts and an encouraging number of new discoveries throughout the country. It led to further exploration in the Amazon region and earlier this year two blocks were awarded in the Marañon Basin. Other license contract awards are pending in the country and there was a major new discovery, Buena Vista, in Block 39 in the Marañon Basin in June this year.

As exploration pushed into the Amazon jungle, environmental problems and issues involving the indigenous people became major concerns. The Madre de Dios Basin, for example, is considered to contain some of the most pristine rainforest remaining in the world, with many unique species and a subtly balanced ecosystem. The Peruvian Government has attempted to address these issues, providing services to advise oil companies on environmental concerns. Environmental issues inflate exploratoration economics and are of great significance when development projects are under consideration.

There has also been an upsurge of interest in the coastal area in the north-west. In addition to the existing producing fields in the Talara and Tumbes-Progreso Basins, there are plans by BPZ to develop the offshore Corvina gas field, discovered in 1982, along with commercialising other shut-in gas discoveries in the area.

The coastal basins south of Talara have had limited success until recently, but in June this year Peru announced the first oil discovery in the Sechura Basin, after 100 years of exploration history. It is the most southerly discovery offshore Peru, and has encouraged further exploration in the southern basins, including the Salaverry Basin, south of Sechura, and the Pisco Basin, south of Lima. These offshore basins are thought to have sedimentary sequences up to 4,000m thick and prospective structures have been identified on seismic, although it is possible that extensive local volcanism may have made potential source rocks overmature.

The outlook for gas

Political stability has also seen the long overdue development of the Camisea project, which took 20 years to come to fruition, but finally resulted in the construction of natural gas and NGL pipelines to Lima and a fractionation plant on the coast. Production started in August 2004, although current gas production is below the maximum capacity due to lack of demand and inadequate export facilities. About 350 MMcfg/d is reinjected because there is no commercial market for it at present.

The initiation of these pipelines should be a key factor in opening up the country east of the Andes and in commercialising gas. Peru is thought to have one of the largest total gas reserves in South America, but before the construction of the Camisea pipelines most gas finds were automatically considered non-commercial, due to the cost of developing infrastructure and the lack of a home market. This situation is changing, as domestic consumption of gas is rising rapidly and the Peruvian government has encouraged investment in gas-fired power plants and the construction of an LNG terminal.

An attractive proposition?

Peru has a long history of the exploitation of hydrocarbons and could be considered to be a mature oil country, past its peak. However, the discoveries made to date have been achieved with a relatively small exploratory effort, especially considering the complexity of the geology.

Proven remaining reserves of oil are 353 million barrels and gas reserves are 16Tcf. Oil production in Peru peaked at about 200,000 bopd in the early 1980s, and by 2004 had dropped to 94,120 bopd. However, with the Camisea project now online, the 2005 production rate is 112,000 bopd.

Peru is unlikely to ever be a low risk proposition, so the government needs to continue encouraging enough companies to participate in the sector to maintain and accelerate this reversal of the longstanding production decline curve. With a stable political and economic environment, together with favourable terms and the development of an infrastructure system for hydrocarbon distribution, refining and export, Peru can now be thought of as a far more attractive proposition. With its long history of hydrocarbon exploration and exploitation, could Peru finally be on course to realise its potential?

Acknowledgements

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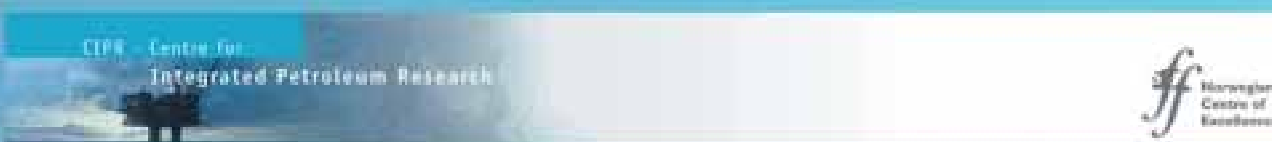
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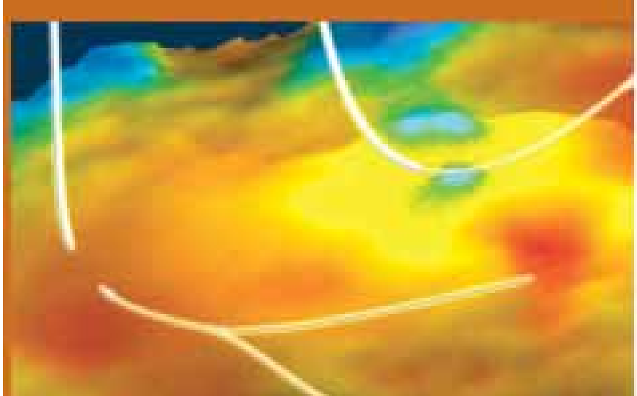


Cretaceous Park

Read about the Dinosaur Provincial Park in the next issue of **GEO ExPro**.

"In the Western Canadian Sedimentary Basin, within a unique geological setting caused by rivers eroding into soft sandstones creating a badland landscape, huge amounts of dinosaur fossils are found in Upper Cretaceous rocks that lie above oil and gas fields in deeper strata."

Photo: Halfdan Carstens

Where most of the oil is

Hugh amounts of oil sands in the Western Canadian Sedimentary Basin will in few years time strengthen Canada's position as one of the world's largest oil producers. This situation will also last for a long time as more oil can be recovered from the oil sands in the outback than from Saudi Arabia's deserts.

This edition's cover story (page 46-52) concerns the Canadian oil sands, which are said to be the world's largest single hydrocarbon resource. Oil in place is estimated to 400 billion m³ (2,5 trillion barrels), while recoverable reserves are in the range of 50 billion m³ (315 billion barrels). No other country in the world – not even Saudi Arabia – is known to have larger oil reserves than this.

Venezuela's Orinoco Belt also contains vast hydrocarbon resources, generally referred to as heavy and extra-heavy crude oil (specific gravity higher than 1.0 g/cm³). According to recent estimates the amount of oil in place may constitute 300 billion m³ (1.9 trillion barrels), ultimate recoverable reserves of 43.2 billion m³ (272 billion barrels) and proven reserves of 12.3 m³ (77.8 billion barrels).

The future seems bright for the Canadian oil sands. As oil prices soar, interest in these unconventional oil fields is steadily increasing and the competition for acreage is getting tougher day by day. Improved technology may also result in a higher recovery, thereby boosting reserves additionally.

CONVERSION FACTORS

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

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

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

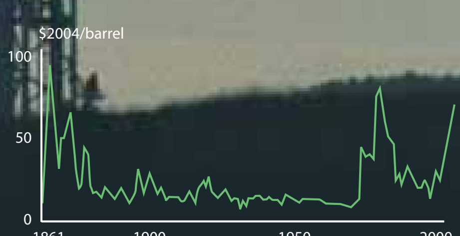
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

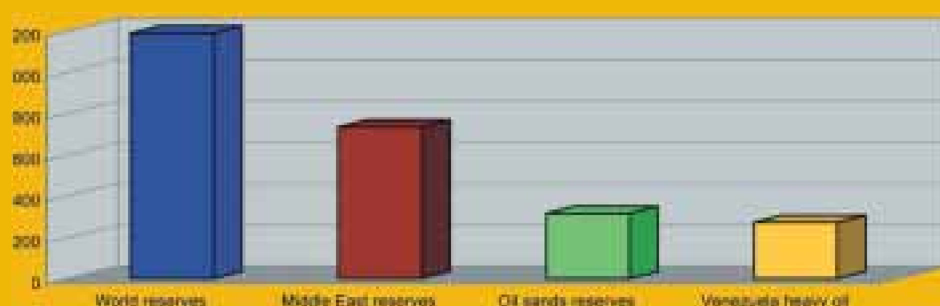
Supergiant field
Recoverable reserves > 5 billion barrels (800 million Sm³) of oil equivalents

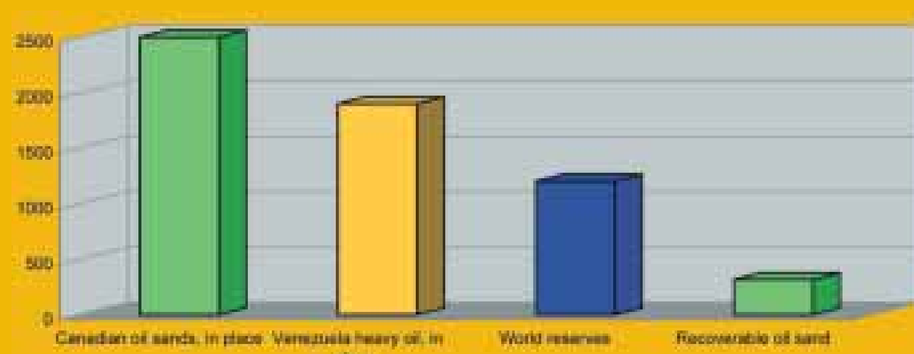
Giant field
Recoverable reserves > 500 million barrels (80 million Sm³) of oil equivalents

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

Historic oil price







The upper diagram illustrates the relationship between world oil reserves, Middle East oil reserves (both numbers from BP Statistical Review of World Energy), Canadian oil sands reserves and Venezuela heavy oil reserves. The lower diagram shows how much oil is in place in the Canadian oil sands and in the Venezuelan heavy oil compared to world oil reserves and oil sands reserves. The scale is in billion barrels of oil.