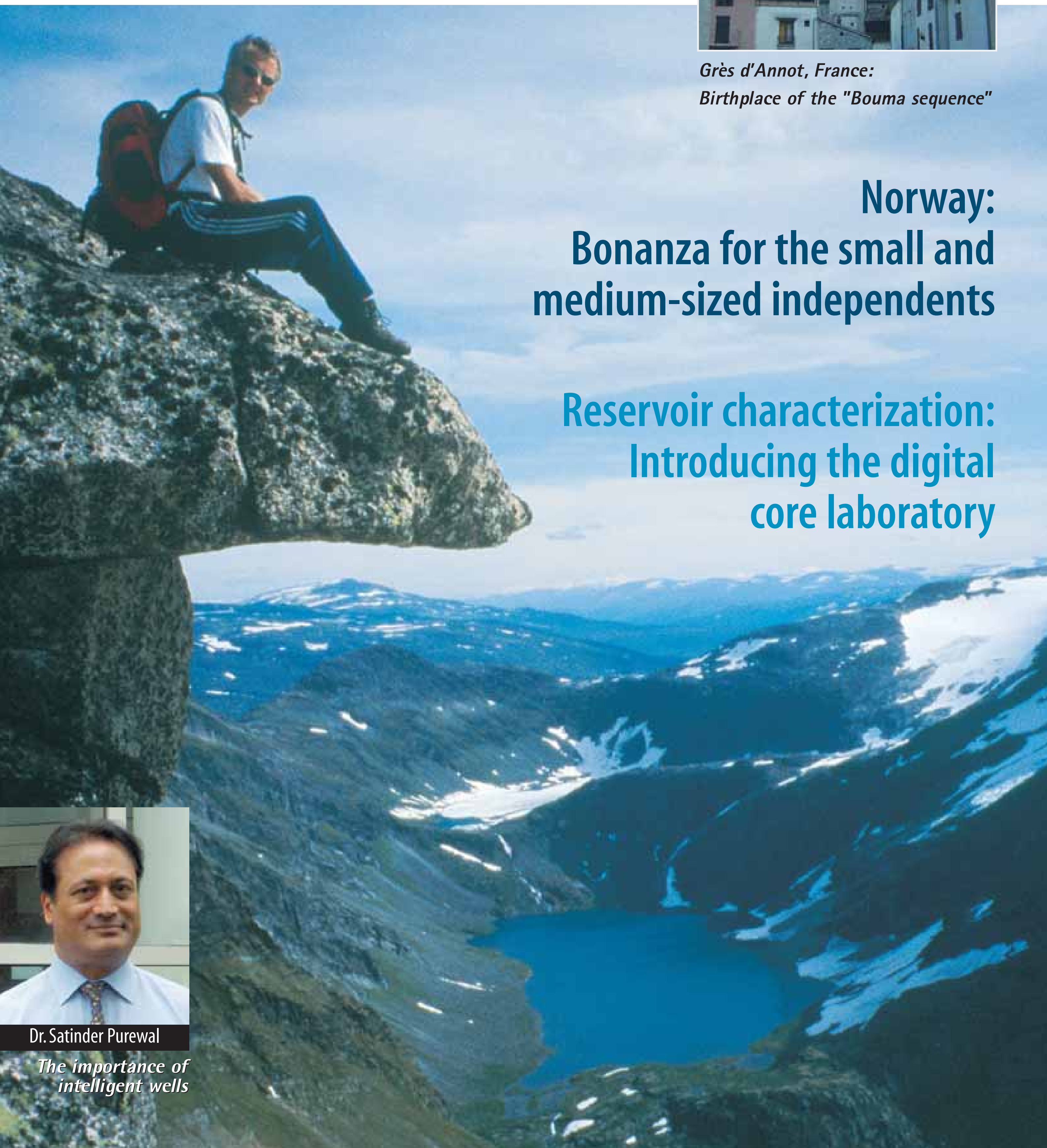
Vol. 2, no. 4 – 2005

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

Grès d'Annot, France:
Birthplace of the "Bouma sequence"

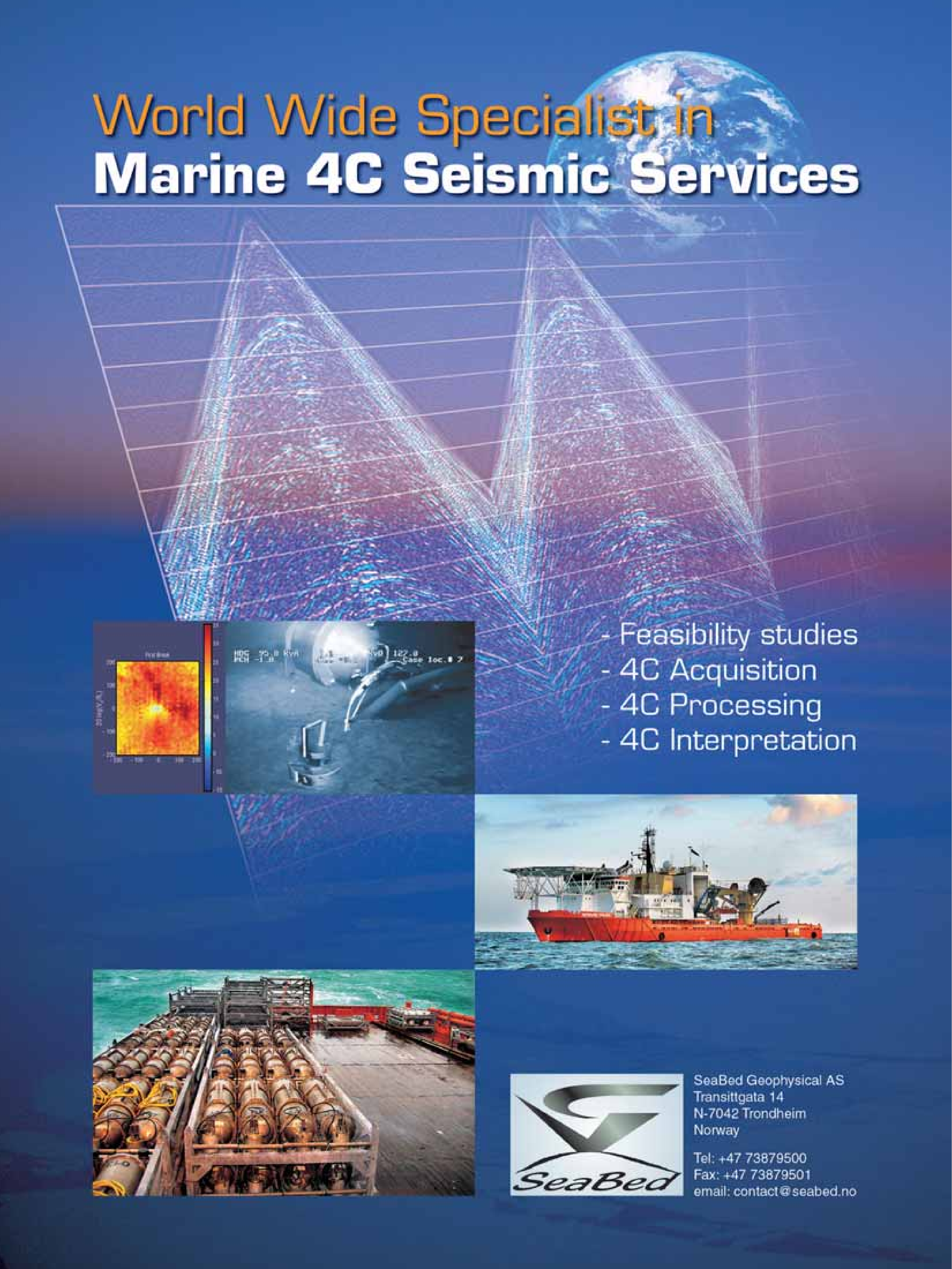


Norway: Bonanza for the small and medium-sized independents

Reservoir characterization: Introducing the digital core laboratory

Dr. Satinder Purewal

The importance of intelligent wells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GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

September 2005, Vol. 2 No. 4

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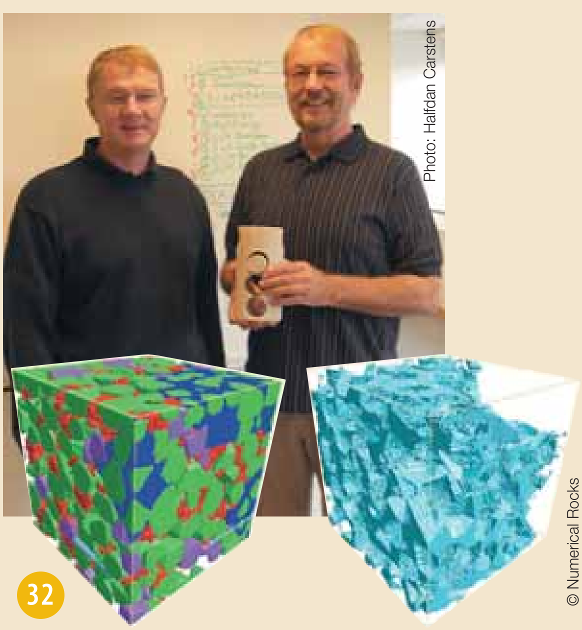
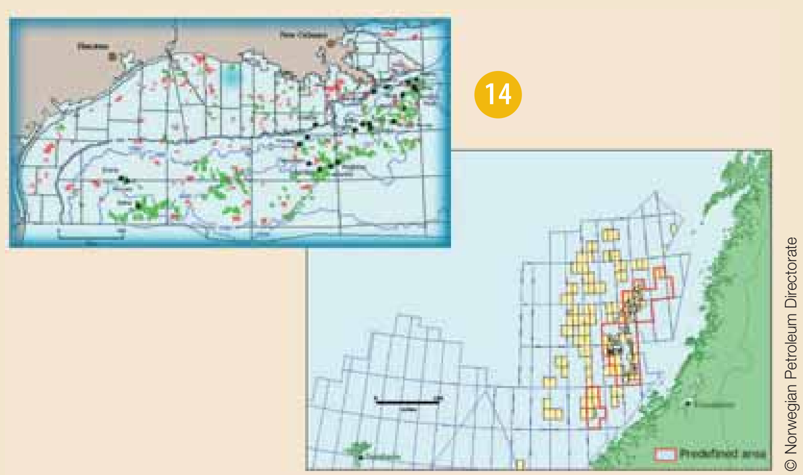
Coloumns

Features

Exploration in the Norwegian sector of the North Sea is now experiencing a dramatic change. Several of the majors and supermajors downscale their operations and focus on frontier geological provinces in Norway and elsewhere, thereby leaving the mature basins to the small and medium-sized independents. This is largely a result of an initiative from the Ministry of Energy and Petroleum a few years ago. The Norwegian Petroleum Directorate is now actively marketing opportunities in mature as well as frontier geological provinces all over the continental shelf under the slogan "Why Norway?" (www.npd.no)

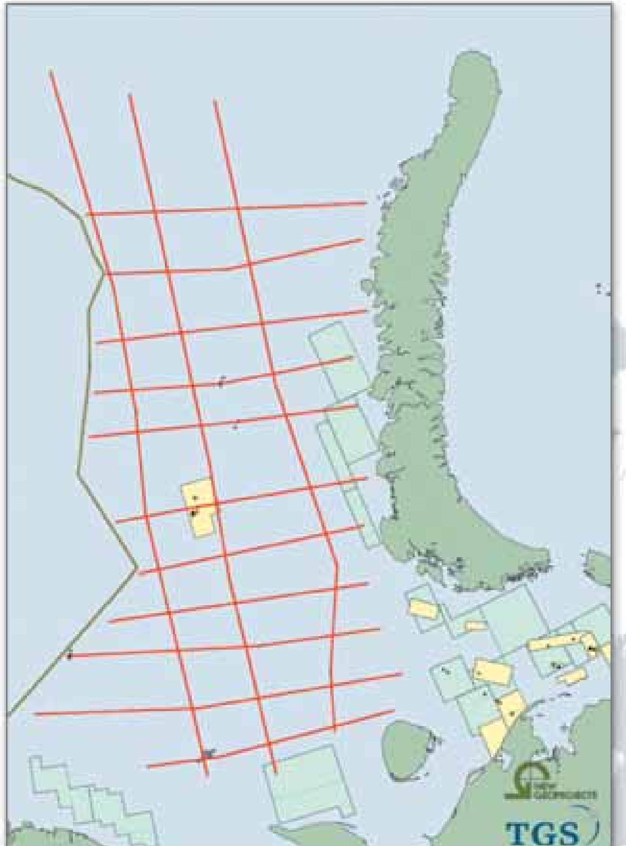


The grain/cement matrix and the complementary pore space of a North Sea reservoir as modelled by a new company that is now introducing the "digital core laboratory" as a supplement to conventional core analyses made in the laboratoryin. Pål-Eric Øren (left) and Stig Bakke has invented the new technology based on several years of dedicated research.

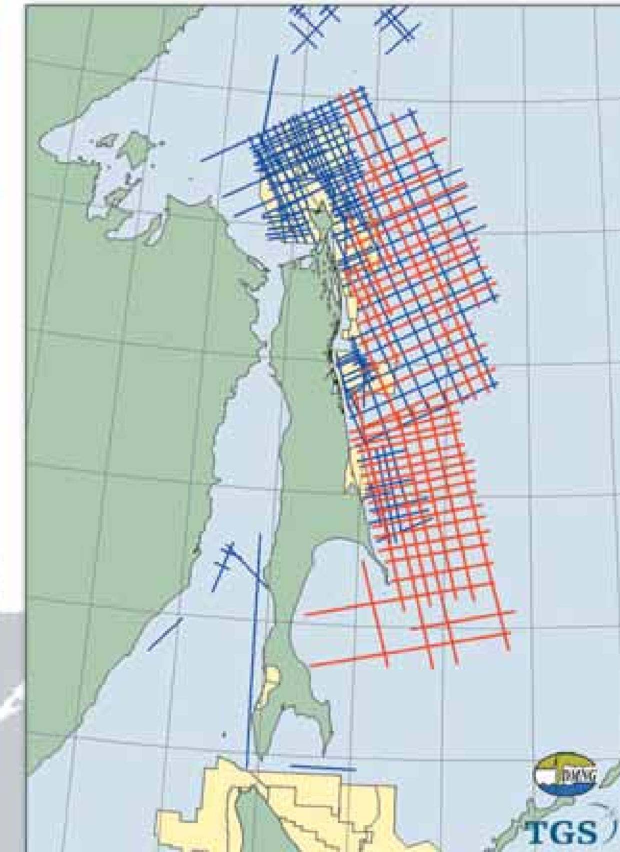


One of the arguments used by Norwegian authorities to attract newcomers is that the Norwegian shelf has a larger aerial extent than Gulf of Mexico. However, while more than 400 wells have been drilled in water depth deeper than 600 meter in the Gulf of Mexico, only 13 wells have been drilled beyond the 600 meter isobath in the Norwegian Sea, one of three areas where petroleum exploration and production is ongoing.

RUSSIA - NEW MC-2D ACQUISITION



TGS, with Russian partners, offers new multi-client 2D seismic data in Barents Sea and Sea of Okhotsk. Available by the end of 2005.



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Seismic Well Log Integrated Products TGS Imaging

TGS-NOPEC Geophysical Company

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Exploration in the mature basins

The Slochteren-1 well was spudded on May 25th 1959 and discovered the supergiant Groningen gas field in aeolian sandstones of Permian age.

Groningen gas field lies both on- and offshore the north coast of The Netherlands. The original gas reserves were probably more than 100 Tcf (2800 billion m^3 or 18 billion barrels of oil equivalents). This was then one of the largest known gas fields in the world outside the Soviet Union, and it is still the largest hydrocarbon field discovered in the North Sea Basin.

With 40 Tcf of gas remaining in the reservoir, Groningen remains to be a giant that is expected to be a key producer for another 25 years and a smaller-scale producer for 25 years after that.

The discovery well Slochteren-1 ranks as one of the real highlights of the oil and gas industry. Like the 1901 Spindletop well in Texas, Slochteren-1 opened up a major oil and gas province. The rush for hydrocarbons beneath the waters of the North Sea started. And it soon turned out that the continental shelf that belonged to the UK, the Netherlands, Denmark, Germany and Norway was a major petroleum province with a number of giant oil and gas fields. And, as is true for Groningen, this petroleum province is to be reckoned with in the next 50 years, and even beyond that, even if the production is already dwindling.

While the oil and gas is flowing as before, albeit in smaller quantities, a dramatic change has occurred as some of the basins have matured. The majors and the supermajors have to some extent been replaced by small and medium-sized companies that are able to establish a satisfactory rate of return on small fields and remaining reserves in large fields. As a result, the number of oil companies active in the North Sea has increased substantially (see separate story on page 14).

And that is good news for the North Sea. More oil and gas will ultimately be produced because of the newcomers.

© Millennium Atlas Company Limited

Play fairway mapping, as demonstrated in the Millennium Atlas, is essential when exploring for the remaining resources in the North Sea. See also article starting on page 26.

Halfdan Carstens
Editor in Chief

© Bjørn Helge Nygård, World Heritage Convention, Norwegian Nomination

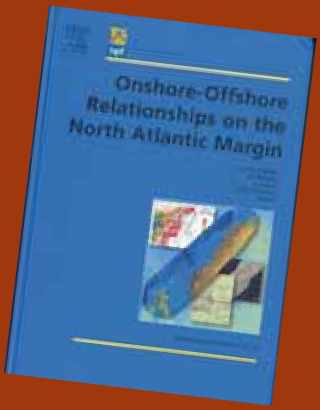
Onshore-offshore relationships

This year, the west Norwegian fjord landscape was inscribed in the UNESCO World Heritage List. The two fjords included represent a magnificent example of a classic fjord landscape with unique geology that has a long history to tell from the Precambrian all the way up to our time through the Palaeozoic, Mesozoic and Cenozoic. Only some few kilometres outside the two fjords we find the hydrocarbon-rich North Sea sedimentary basin.

The interrelationship between the offshore and the onshore geological evolution was the subject of a petroleum conference in 2002 - "Onshore-Offshore Relationships on the North Atlantic Margin" - hosted by the Norwegian Petroleum Society (NPF) and the Geological Society of Norway (NGF).

The proceedings from this conference are now published. Out of 69 abstracts, 15 have resulted in papers for this volume that is the 12th in a series from the Norwegian Petroleum Society. Altogether these articles comprise a comprehensive review of how onshore geological events are related to the offshore geological evolution that has produced a number of spectacular oil and gas fields.

The recent discovery of gas in Pliocene glacial sediments (see separate story on page 24) is another example that demonstrates this.



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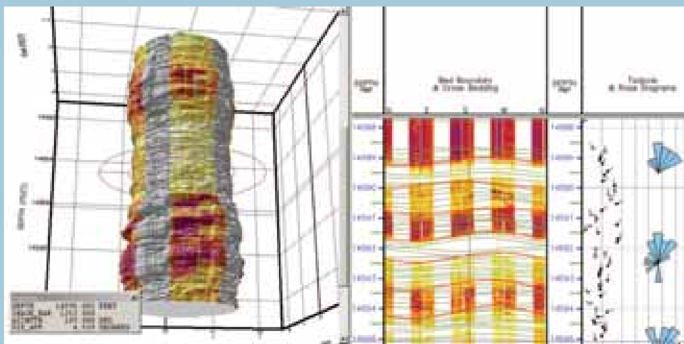
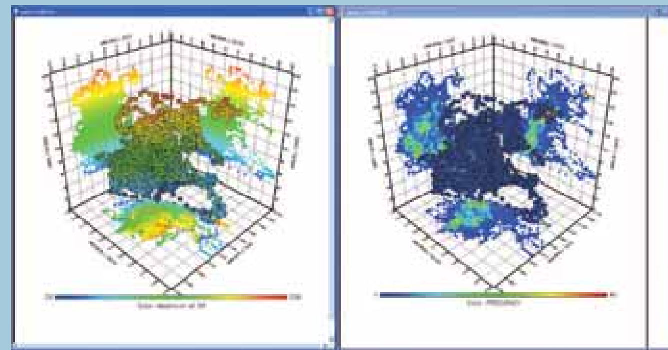
"The fast lane to formation evaluation"



Full 3D borehole viewer in the Geomage module.



Interactive 3D crossplotting in Geolog

Paradigm has announced the release of Geolog 6.6, the latest version of its software package for log management, correlation, geosteering and petrophysics.

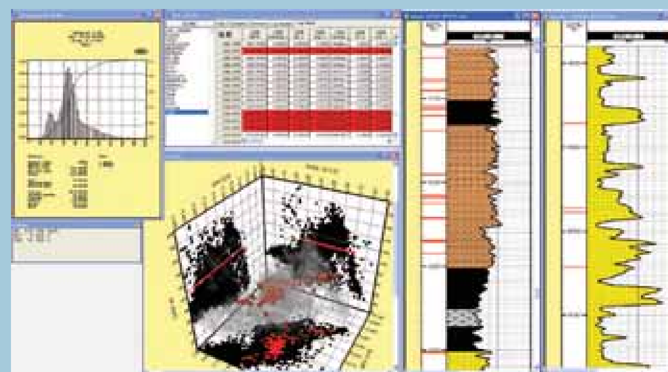
Following the increased use of the Windows operating system in the petroleum industry, Geolog 6.6 now supports three operating systems - Windows, Linux, and UNIX - with full interoperability on all three platforms.

"The interactive petrophysical tools offered in Geolog 6.6 provide a better understanding of the petrophysical properties of the reservoir, and add to the product's ease of use. Through Geolog's interprocess communication, when a change is made in one window, the effect of that change is immediately seen on the rest of the data. This enables the geoscientist to achieve reliable results quickly and efficiently," says Richard Pelling, Geolog Product Manager.

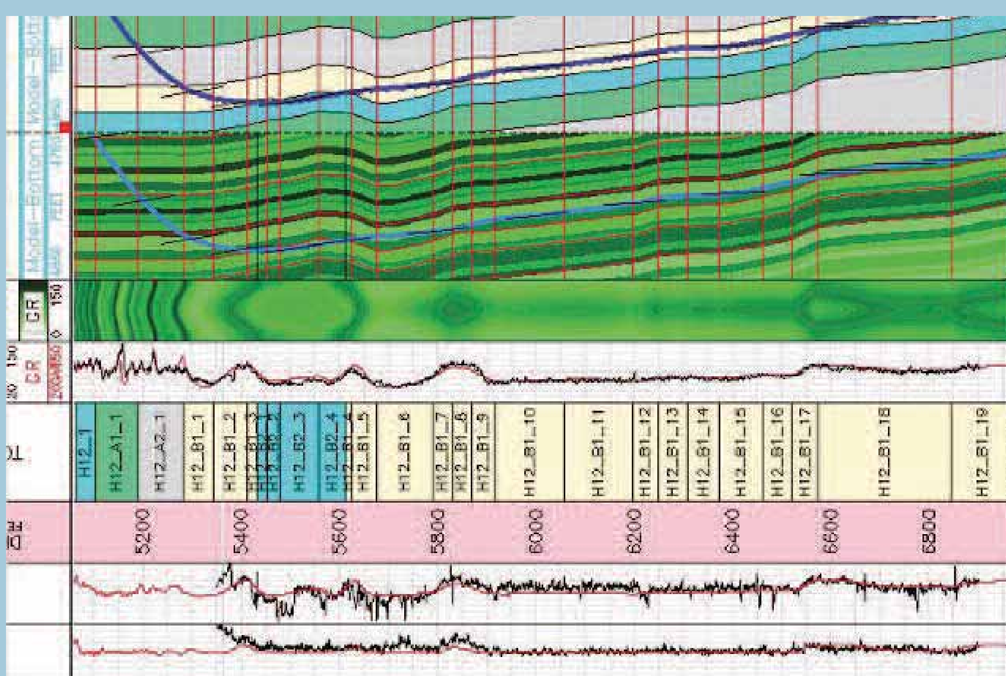
One of the leading modules in Geolog is the Facimage solution for electrofacies analysis, log prediction and core data modeling. Based on technologies licensed from Total, Facimage is a powerful automatic facies classification tool for formation evaluation.

Geolog enables geologists and petrophysicists to work collaboratively to define the optimal reservoir model. The geologist can perform manual interpretation as well as automatic detection of bedding dip, classification of rock texture and identification of fractures. The automatic detection functionality, a commercialization of Total's Diamage technology, allows rapid, reliable processing of large data volumes and removes bias that might be introduced by the interpreter.

"Extending petrophysical analysis to the 3D environment gives geologists and petrophysicists a more comprehensive understanding of their reservoir. Features such as interactive histograms and a new 3D crossplot application bring Paradigm's leadership in high-end visualization to the desktop of the petrophysicist," says Pelling.



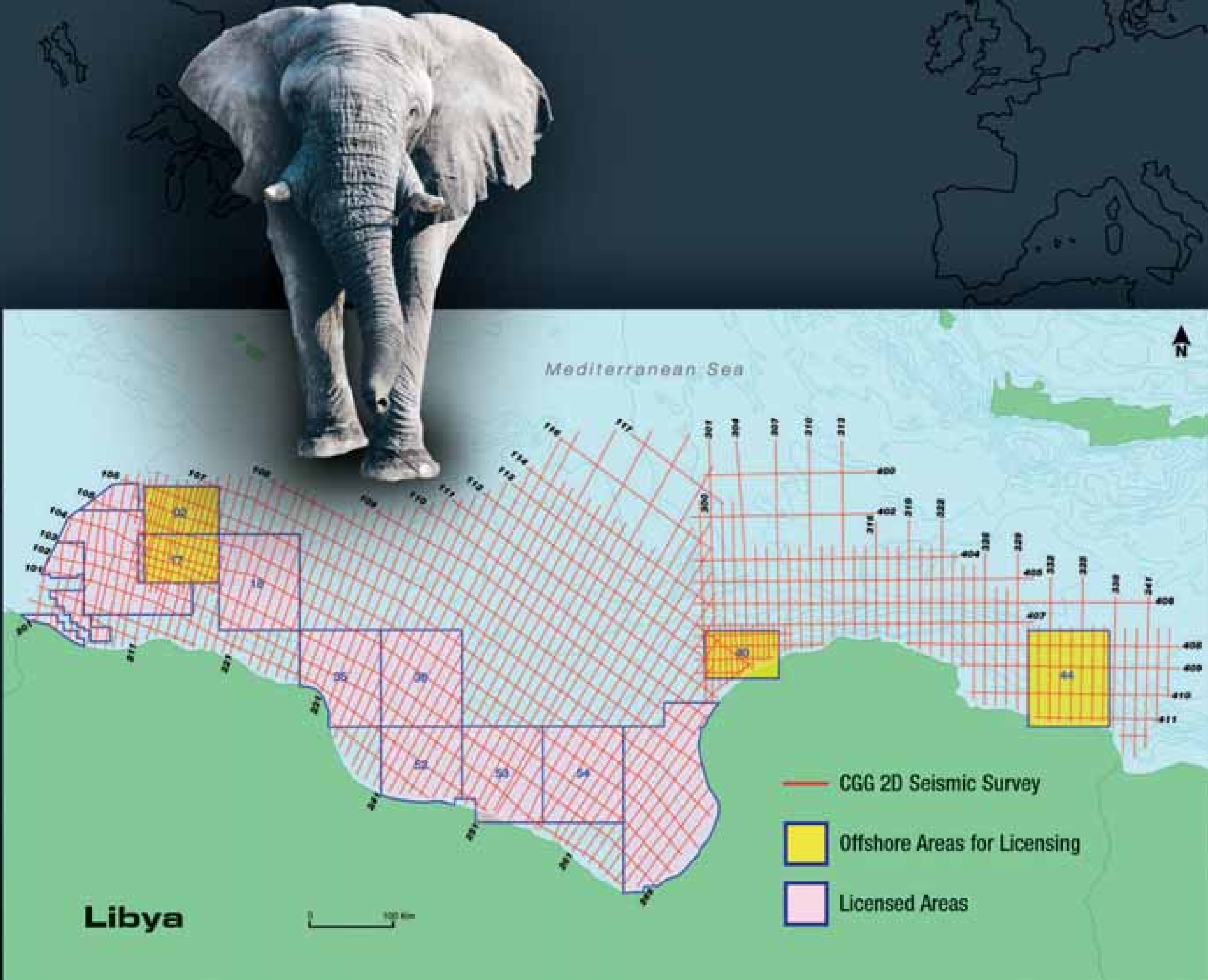
The Geolog workspace. Geolog is used for petrophysical analysis, well data management and geological interpretation.



This add-on module, developed in cooperation with Chevron Texaco, provides the petrophysicist with tools for modeling and interpreting petrophysical parameters in highly deviated wells.

Looking at **EPSA IV** **Libya Round 2?**

Look to **CGG.**



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LOOK TO CGG

Promoting innovative technology

Now is the time to learn more about how new ideas, novel concepts and innovative technology can assist geologists, geophysicists and reservoir engineers in improving their knowledge about the subsurface for the purpose of finding more oil and gas and increase production.

© Halfdan Carstens

May Britt Myhr in SINTEF Petroleum Research is member of the programme committee for the forthcoming conference Recent Advances in Petroleum Assessment – Implications for Value Creation to be held in Trondheim, Norway.

Recent advances in geology, geophysics and reservoir engineering have made a huge contribution to value creation in both exploration and production for oil and gas.

The young company **emgs** is an excellent example. In 2003 they won the "Best Exploration Solution Award" for SeaBed Logging at the World Oil Awards. Founded in February 2002, **emgs** developed a technique that employs marine electromagnetic measurements, which combined traditional seismic mapping with logging of resistivity to better rank prospects and enhance discovery rates.

"Companies like **emgs** prove that geoscientific research and development of new technology can make a difference to the oil and gas industry. The introduction of SeaBed Logging (GEO ExPro No.1, 2004) gives explorationists a new tool that potentially will reduce the number of dry wells, improve recovery and make new discoveries more efficiently," says May Britt Myhr in SINTEF Petroleum Research.

However, **emgs** is certainly not the only company that has presented new concepts and introduced innovative technology. There is a long list of individuals, research institutions, service companies and oil companies that has given valuable contributions along the entire value chain, and now is the time for them to share their experience on how these innovations have contributed to the understanding of the subsurface. During two days in October this will be the topic at the conference "Recent Advances in Petroleum Assessment."

"The scope of the conference is to present cases in which the new technology has shown how it contributes to our understanding of the subsurface, and ample time will be given to discussions between the speakers and the audience," says Myhr. "We have absolutely no intention of giving detailed accounts of the technology itself. We leave that to other arenas," she adds.

May Britt Myhr emphasizes that the conference is designed to attract those geoscientists that are actually interpreting the data. "This is a unique occasion to get first hand insight to a number of geological and geophysical tools that are now being used in both exploration and reservoir engineering," she says.

For information, programme and registration: www.geologi.no/recentadvances2005.

Recent Advances in Petroleum Assessment: Implications for Value Creation

Trondheim, October 19-20, 2005

For programme and registration: www.geologi.no/recentadvances2005

- Reconnaissance studies
- Imaging
- Basin modelling
- Risk assessment
- Electromagnetic surveying
- Real time reservoir modelling
- Special topics

Guest speakers: Knut Åm, Arild Bøe, Andrew Armour

"This is a unique opportunity where oil companies, service companies and research institutions will demonstrate how technological improvements increase our geological knowledge of the subsurface."

Terje Thorsnes, Geological Society of Norway, Secretary General

GEOLOGICAL SOCIETY OF NORWAY
1905-2005

"Patent belongs to Statoil"

Managing Director Terje Eidesmo in emgs is very pleased with the outcome of the patent entitlement hearing at the UK Patent Office that was announced in July. Together with his colleague Svein Ellingsrud, Technical Director of emgs, he is found to be the inventor of the technology they have named SeaBed Logging and which is now widely used in exploration. "In short, the judge says that University of Southampton has patented a technology that we have developed and explained to them in several meetings, something they should not have done," comments Eidesmo.

"I have found that Dr Ellingsrud and Dr Eidesmo should be named as inventors of the GB patent, that Professor Sinha and Dr MacGregor should *not* be named as inventors, and that the patent should belong to Statoil ASA, not the University of Southampton."

So he said, P. Hayward, Divisional Director acting for the Comptroller, in his conclusion following a patent entitlement hearing at the UK Patent Office published on 21 July (§115). And that was the end of Round 1 in a conflict between Statoil and the University of Southampton in which they are fighting over a patent on the SeaBed Logging technology (GEO ExPro No. 1, 2004).

In the background, two oil service companies are fighting for the right to use a brand new technology that has the potential for growing into a multibillion-dollar industry. emgs (Electromagnetic Geoservices) is a spin-off from Statoil, while OHM (Offshore Hydrocarbon Mapping) is a spin-off from the University of Southampton where Professor Martin Sinha and Dr. Lucy MacGregor have spent long days developing an electromagnetic source that Statoil made use of.

The ruling in July could also have been the end of the story, but the University of Southampton has appealed and a final decision is not expected before next fall. "If we loose in the high court, the worst thing that can happen to emgs is that we will continue to have a competitor. Our operations will not be affected, and we will be in a position with "business as usual"," says Eidesmo.

The Decision of The Patent Office outlined the conflict in the following way (§2): "To summarise the dispute in a nutshell, Statoil thought of a possible way of detecting oil reservoirs beneath the sea. To see if it worked, they needed to borrow a piece of kit that, at the time, only the University of Southampton had. Statoil and the University signed a contract which included clauses on confidentiality and ownership of intellectual property. The test went ahead and was successful. The University then filed a patent application. Statoil say the application was for their idea. The University say no, the application was not for anything inventive that Statoil had told them but for inventions they had come up with themselves."

In the following paragraphs the technology is outlined in detail, and the Director continues with a very detailed review of the historical events leading up to the time when The British patent application was filed on 7 December 2001 in the names of the University of Southampton and Dr MacGregor, with Professor Sinha named as inventor. (The ruling can be found at the emgs website: www.emgs.no)

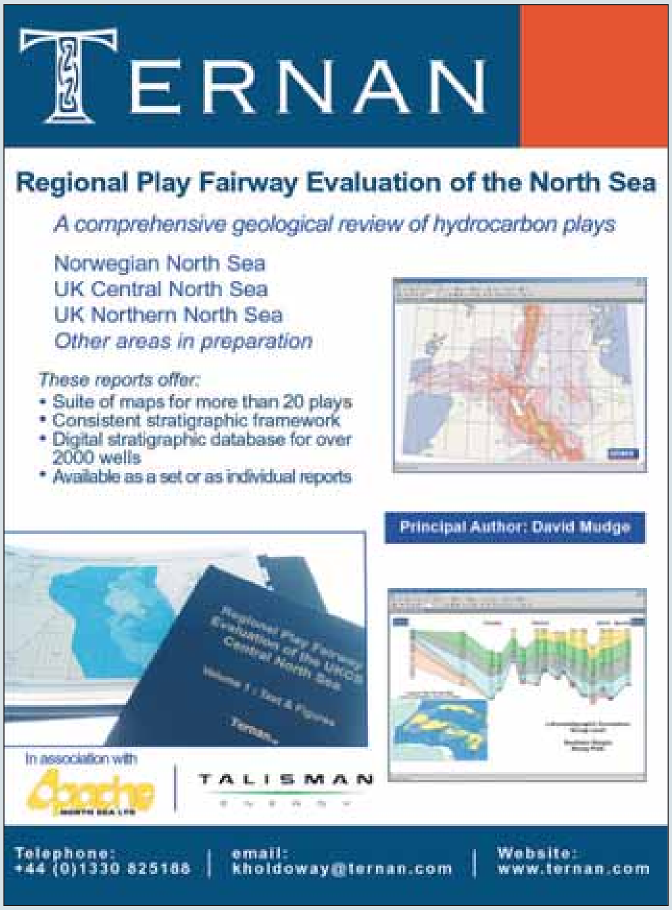
Statoil, on the other hand, meant that Svein Ellingsrud and Terje Eidesmo were the inventors. As a consequence, the patent and application should, they say, be in their name, not Southampton's, and that was the basis for taking the whole thing to the UK Patent Office.

"If the appeal court stays with the ruling, the patent will be transferred to Statoil and my colleague and myself will be named as the inventors," says Eidesmo.

The defendants in the entitlement hearing, now representing OHM, have on their webpage made known that they will appeal the ruling: "The University of Southampton, whose researchers have a long history of research and development in the controlled source electromagnetic imaging method, have announced today that they intend to exercise the rights of appeal against a decision they regard as wrong, and accordingly are actively preparing Grounds of Appeal."

They also stated that "OHM has been reviewing the effect of this ruling on its ongoing operations and has been advised that there is no immediate impact. The Company hopes that the appeal process will move forward promptly."

Millions of dollars are at stake for the British company.



Achieving indusry standard

Efficient software tools to explore alternative survey and vessel configurations for specific surveys are essential. PGS has through 15 years developed a tool that has become industry standard.

Modern 3D and 4D surveys represent significant investments for the operator. It is therefore essential to maximize the value from the resulting data. Critical decisions based on seismic data may depend on clarity of fault definitions, correct structural imaging as well as fluid characterization and drainage from 4D surveys – all dependent on the use of optimal data acquisition parameters. At the same time surveys need to be completed in the most cost efficient manner. Deciding on infill shooting during acquisition is an example.

New user requirements for extended flexibility and user efficiency have lead PGS to develop the **N2** next generation software for seismic modeling and survey planning. The **N2** software builds upon the geophysical modeling capabilities of Nucleus by integrating existing software capabilities with new hardware technology into a new and flexible application framework allowing the user to build automated modeling workflows. An important design feature of **N2** is the provision for individual customization of the user interface to meet the requirements of both the novice and the expert users.

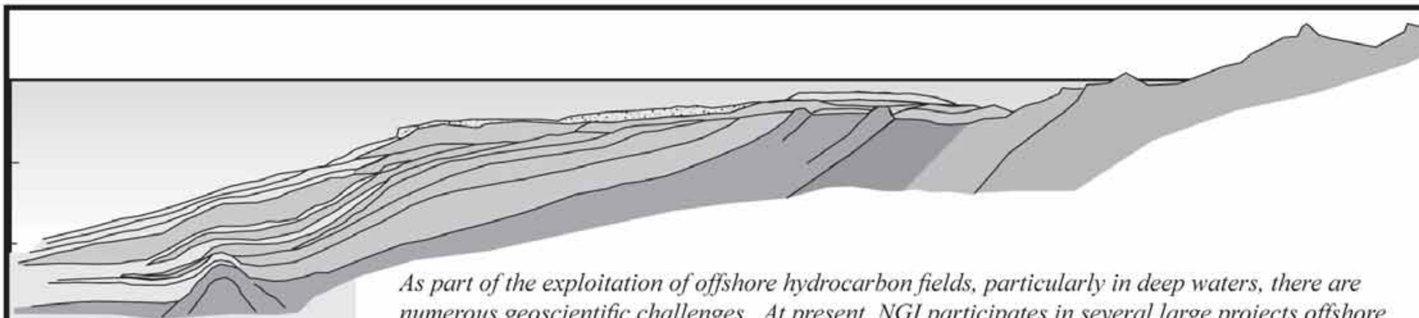
The first version of **N2** will be demonstrated at the SEG 75th annual meeting in Houston in November. New features of significance include amongst other things a powerful cross-plotting utility already used by PGS in an analysis of source-receiver azimuth differences from two 4D surveys for Shell.

Other new capabilities include an automated and optimized seismic modeling and processing flow using ray-tracing and pre-stack time migration, which can be used for making infill decisions based on geophysical criteria during acquisition. Several new modules are currently under development, including functionality for pre-survey multiple removal analysis.

Anders Jakobsen, project manager for Nucleus development in the PGS Research department, giving a preview of N2, the next generation version of the Nucleus survey design and modeling package at the EAGE exhibition in Madrid in June. Over a period of more than 15 years PGS has invested significant resources to develop Nucleus. "Today it is the most comprehensive system available on the market for marine survey planning," claims Jakobsen. Nucleus is used both internally by PGS, primarily by their geophysical support departments, and by oil companies as well as other service companies. "It has become an industry standard for marine survey planning," says Anders.

CALENDAR – SELECTED EVENTS

September			
11-14	AAPG International Conference and Exhibition www.aapg.org/paris	Paris, France	
25-29	18th World Petroleum Conference www.18wpc.com	Johannesburg, South Africa	
October			
9 - 12	SPE Annual Technical Conference and Exhibition 2005 www.spe.org	Dallas, USA	GEO ExPro No 4
18-19	Recent Advances in Petroleum Assessment, Geological Society of Norway www.geologi.no	Trondheim, Norway	GEO ExPro No 4
November			
6-11	SEG International Exposition and 75th Annual Meeting www.seg.org	Houston, USA	GEO ExPro No 5
15-16	Production Geoscience 2005 - Understanding and Modelling Geological Heterogeneity www.geologi.no	Stavanger, Norway	GEO ExPro No 5
21-23	International Petroleum Technology Conference www.iptcnet.org	Doha, Qatar	



As part of the exploitation of offshore hydrocarbon fields, particularly in deep waters, there are numerous geoscientific challenges. At present, NGI participates in several large projects offshore Norway as well as in many other parts of the world, such as offshore Asia, South America, Australia and in the Caspian Sea. Our need for expertise increases and we seek a new

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Tasks include:

- Consulting and research related to submarine slides, as well as other geohazards and geological problems
- Participation in offshore marine geological and geotechnical investigations
- Participation in projects where there is a need for marine geological and geophysical expertise

Required background / qualifications

- MSc or PhD within geology / geophysics
- Several years of experience are preferable. Recent PhD candidates with particularly relevant background will also be considered.

We offer

a competitive salary, good social benefits and an exciting working environment. NGI has a unique staff, representing about 15 different nationalities (25% of the staff are from countries other than Norway), and wide international involvement. The position provides good opportunities for professional and personal development, including NGI's educational fund for employees, providing the possibility for sabbatical leave. Project work abroad for shorter or longer periods of time may be required, also at NGI's subsidiary in Houston, Texas, USA.

For more information, contact

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- Kjell Hauge, Head of Personnel and Information NGI, Phone: +47 22 02 31 06, e-mail: kjh@ngi.no

Application with updated CV and transcript of records from relevant education should be sent as soon as possible to NGI, P.O. Box 3930 Ullevaal Stadion, N-0806 OSLO, NORWAY, and at the latest before 1st October 2005.

NGI (The Norwegian Geotechnical Institute) is a centre for research and development and advisory services within geotechnical engineering. NGI employs 160 persons. About 30% of the annual turnover comes from projects or clients outside Norway. NGI has expertise in soil and rock mechanics, foundation engineering, reservoir mechanics, offshore structures, embankments and dams, avalanches and slides, geoenvironmental engineering and instrumented surveillance of structures and constructions. NGI has modern offices and laboratory facilities in Oslo and a subsidiary in Houston, Texas, USA. In 2002 NGI was appointed Centre of Excellence by the Research Council of Norway, and is the leading partner of the International Centre for Geohazards (ICG). (NGI homepage: http://www.ngi.no).

NORGES GEOTEKNISKE INSTITUTT

NGI

NORWEGIAN GEOTECHNICAL INSTITUTE

Better Resource Utilization

"Research is absolutely necessary for continued value creation in the petroleum industry," said Torhild Widwey, Minister of Petroleum and Energy in Norway, when she opened the seminar on Better Resource Utilization (BRU). The Institute of petroleum and applied geophysics at the Norwegian University of Science and Technology (NTNU) hosted the seminar in the presence of industry leaders and academicians.

"This initiative in which the University is profiling their research and ask the industry for advice is very positive," she said.

The seminar given in August followed a tedious process in which key personnel from the institute had visited 49 oil companies, service companies, institutions, organisations as well as governmental agencies with the aim of discussing a research strategy within petroleum exploration and production. More specifically the team wanted feedback on how academic research can contribute to better resource utilization on the Norwegian shelf. This turned out to be a most valuable and successful task in which they got valuable insight, input as well as inspiration.

"The driving force behind the project was that NTNU felt the need to focus its resources in petroleum related activities," professor Jon Kleppe said in his introductory talk at the seminar.

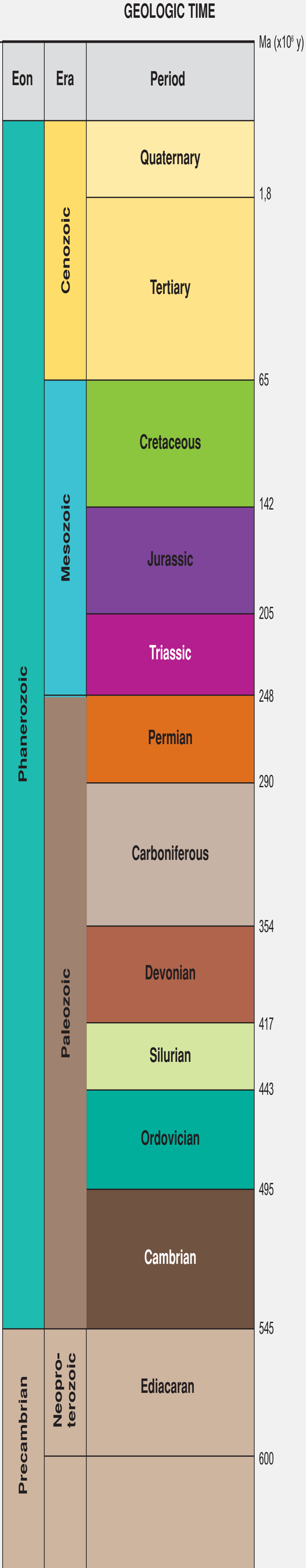
In line with this, the key objective with BRU Project has been to define the future technology and research areas that that should be given high priority at the university in order to solve the long-term challenges on the Norwegian continental shelf.

Professor Jon Kleppe and Torhild Widwey, Minister of Petroleum and Energy in Norway, at the BRU-seminar given at the Norwegian University of Science and Technology late this summer. Jon Kleppe has been instrumental in getting a new initiative going in which the University will focus their resources in petroleum research.

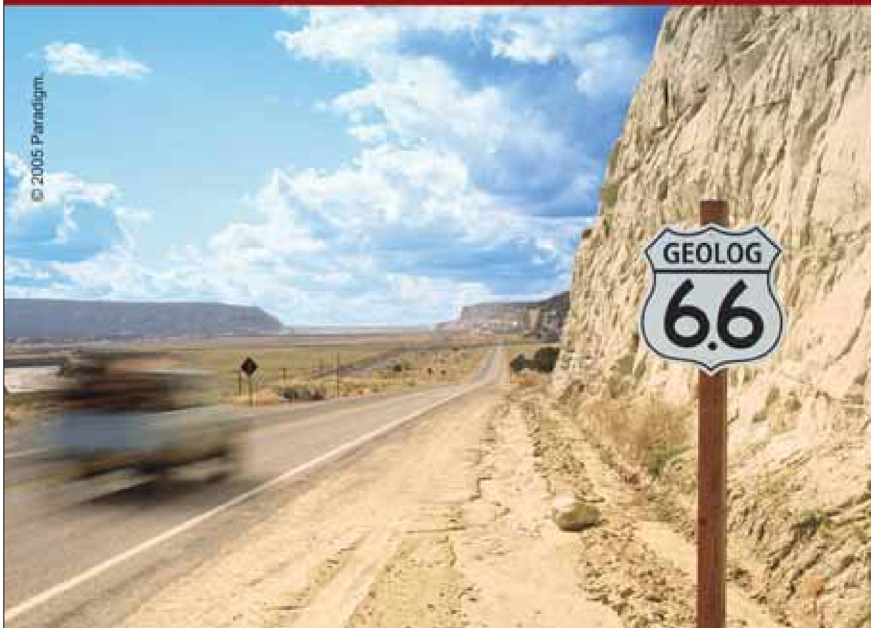
"The team got a clear message from the industry through this fact-finding mission," Kleppe said. "We need to concentrate on a few selected programmes, there is a need for step change technologies, integration and multidisciplinary tams are absolutely necessary, and - the students need to get a broad scientific background and be able to work in teams."

"The four areas that future research will take place are exploration and production, drilling and subsea technology, integrated operations (e-Fields) and arctic technology." This is certainly compatible with the government's push to increase both exploration and the recovery factor while at the same time reducing cost along the entire value chain, as outlined by the Minister in her talk.

To make sure that the researchers are all updated as to global activities in their own field of experitse, the BRU Project also aims to establish a "global R&D scouting programme". This is meant to give an opportunity to utilize results and developments of activities performed internationally.



Geolog 6.6



Take the fast lane to Formation Evaluation

Geolog 6.6 combines the reliable infrastructure and customization flexibility of the industry's leading log management, well correlation and petrophysics software solution, with new and robust interactive applications. Geolog's middleware-based data management and cataloging system, multi-vendor interoperability and distributed data repositories, provide effective solutions for any enterprise computing environment. With support for native Windows, Linux and UNIX platforms, Geolog proves yet again why it's the petrophysicist's product of choice worldwide.

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November 6-11, 2005

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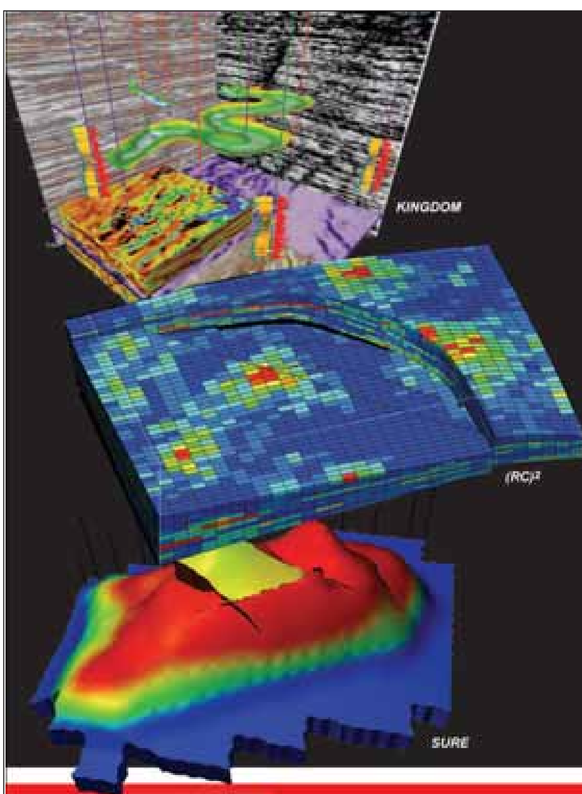

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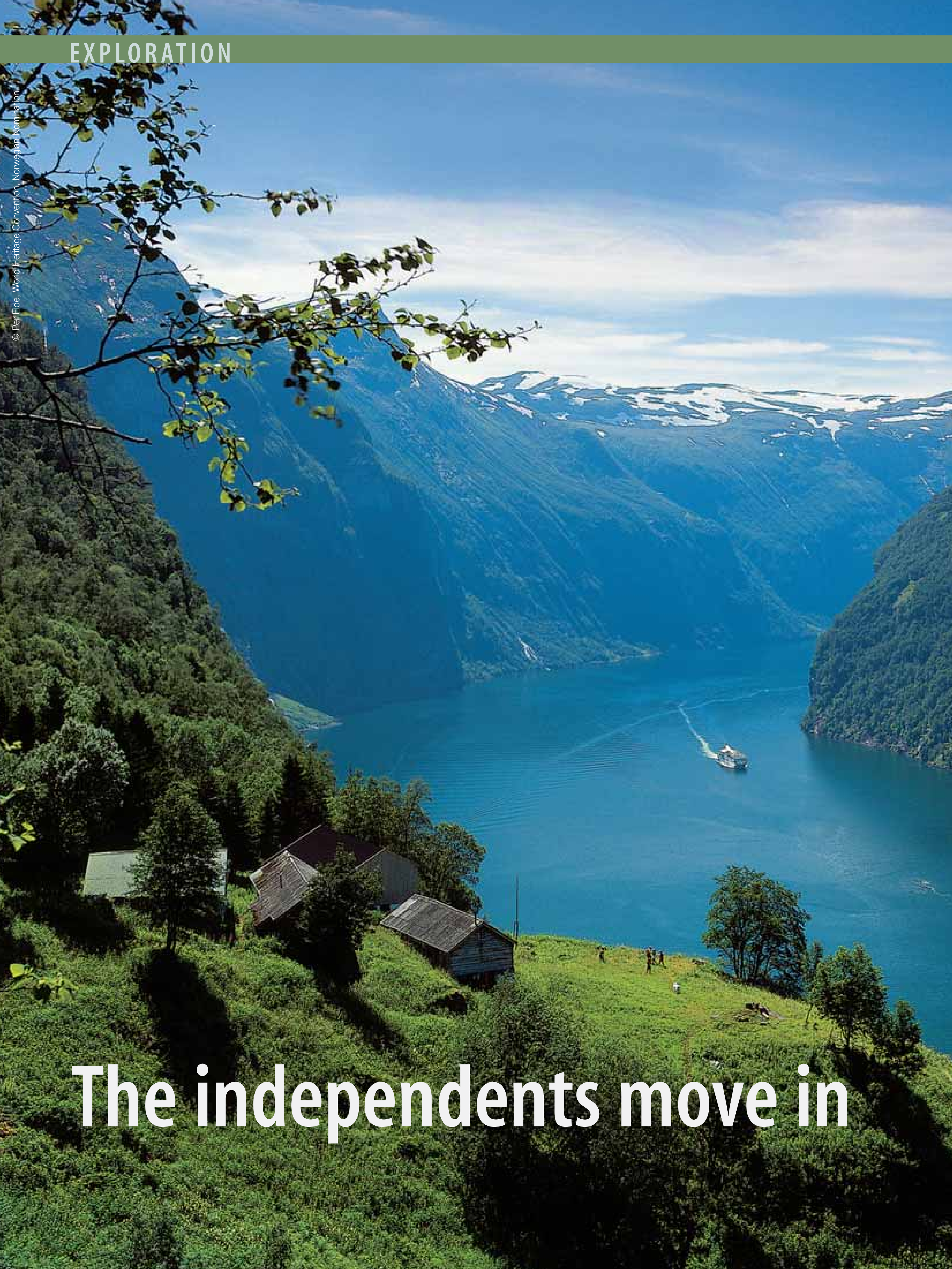

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The independents move in

Geological heritage

The west Norwegian fjord landscape, which stretches from Stavanger in the south to Åndalsnes in the north, was inscribed on the highly prestigious UNESCO World Heritage List on July 14.

Geirangerfjord and Nærøyfjord are among the world's longest and deepest and considered as archetypical fjord landscapes. They represent a magnificent example of the classic fjord landscape with unique geology, exceptional natural beauty and high aesthetic qualities, here exemplified by the Inner Geirangerfjord on a nice summer day. Their exceptional natural beauty is derived from their narrow and steep-sided crystalline rock walls that rise up to 1,400m from the Norwegian Sea and extend 500m below sea level. The sheer walls of the fjords have numerous waterfalls while free flowing rivers cross their deciduous and coniferous forests to glacial lakes, glaciers and rugged mountains. The landscape features a range of supporting natural phenomena, both terrestrial and marine, which includes submarine moraines and marine mammals.

On a worldwide basis only 102 geological sites are on the World Heritage List. This list does, however, include some of the most famous tourist attractions in the world, such as the Grand Canyon (GEO ExPro, No. 2, 2004), the Great Barrier Reef and Vredefort Dome in South Africa which is the earth's oldest astrobleme.

Due west of the Geirangerfjord and Nærøyfjord we find some of the largest oil and gas fields of the North Sea, and also some of the most prospective acreage for the abundant newcomers to the Norwegian sector. It has been shown that the crystalline rocks within the fjord landscape represent a source area for the sand in several of the prolific Jurassic and Tertiary reservoir horizons in the North Sea. There is therefore a close connection between the onshore geological evolution with weathered granites and gneisses and the offshore reservoir sandstones.

Acreage taken by new entrants to the Norwegian continental shelf has doubled many times in only a few years, and several independents have already succeeded in acquiring new licenses and boosting production in small fields. The explanation is high prospectivity, exploration incentives, cross-border cooperation and improved terms in combination with an active licensing policy.

Halfdan Carstens

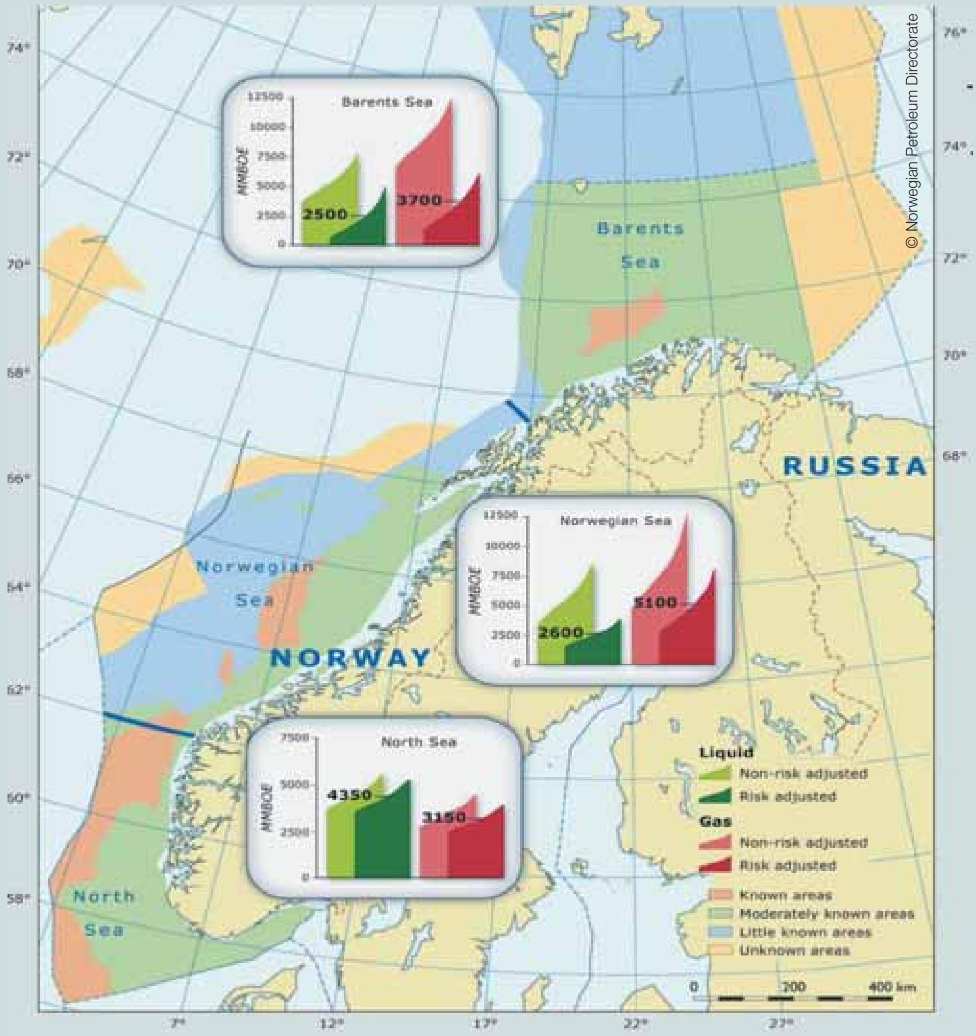
"We have to realize that most of the giant fields offshore Norway already have been discovered," says Bente Nyland, Director of the Norwegian Petroleum Directorate (NPD), thereby acknowledging that some of the geological provinces – not including the frontier areas of the Norwegians Sea and the Barents Sea – have reached a mature stage.

"We will still find fields with reserves of several hundred million barrels and we are actively exploring for fields with reserves less than 30 million barrels. The big ones are just a little more difficult to find nowadays," she adds.

The oil and gas potential of this huge continental shelf is certainly not exhausted. Rather, the new situation with a focus on *sub-giant* and *major* fields (for terminology: see page 50) opens a new area for exploration as the authorities, the service companies and the oil companies are now in the process of changing their strategy. This also means that some of the old players, including several of the majors as well as super-majors spend a larger portion of their big money elsewhere, while new players eager to pursue a new and different petroleum regime are entering the scene.

"It turns out that the Norwegian continental shelf now finds itself competing with other prospective basins to a greater extent than we have been used to. With reduced chances of finding giant fields, the supermajors find that their requirements for rate of return cannot be satisfied in Norway. The authorities therefore find it necessary to pass a message that the Norwegian shelf is attractive to most oil companies, regardless of size, and that all companies are welcome, says Nyland.

And the companies are interested: Last year the Ministry of Energy and Petroleum handed out 44 new awards to 20 companies and approximately 50 swaps or purchases were also approved.



The Norwegian continental shelf covers an area of 1.4 million square kilometres. For administrative purposes it is divided into three areas: The North Sea, The Norwegian Sea and The Barents Sea. The first exploratory well in the North Sea was drilled in 1966, almost 40 years ago, while the Norwegian Sea and the Barents Sea this year celebrates 25 years of activity. The three areas have their own unique exploration characteristics with respect to maturity, risk, fluids, water depth, infrastructure and environmental concerns.

Ranked as no. 8 by USGS

How much oil and gas that can eventually be found – in Norway and elsewhere – is a matter of constant debate with a number of experts involved. Some claim to predict with certainty ; others admit that their estimates are highly speculative.

As for the potential offshore Norway, both NPD and the United States Geological Survey (USGS) have made their educated guesses. NPD believes that the undiscovered recoverable resources amount to approximately 21 billion barrels (3.2 billion m^3) of oil equivalent, while USGS is far more optimistic with an estimate of 53 billion barrels (8.4 billion m^3) o.e. undiscovered resources.

According to the USGS, Norway ranks as

no. 8 in the world with respect to undiscovered petroleum resources (not reserves). USGS believes that Norway has 53 billion barrels of oil equivalents undiscovered. "USGS is very optimistic in their assessment, but we still consider their work as a very important reference," says Bente Nyland.

Such a view should inspire a lot more players to the Norwegian oil scene, as emphasized by Steven Hinchman, Senior Vice President of World Wide Production in Marathon, in a talk given in Houston in March as of this year. Marathon has itself been very successful in finding and developing the Alvheim field complex with 25.3 million Sm^3 (220 million barrels) and 5.7 billion Sm^3 (0.2 Tcf) of gas close to the Frigg and Heimdal gas fields. The oil is reservoired in up to 400m thick sandstones deposited as stacked deep marine fans on a Late Paleocene basin floor.

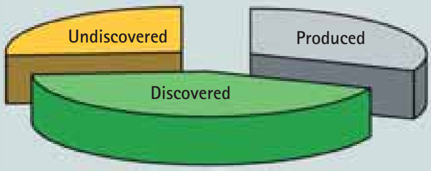
Incentives were needed

Following a programme acquired in 1962, the initial licensing round in 1965 and the first ever exploration well in 1966 offshore Norway (8/3-1 operated by Esso Norge), oil was first found in commercial quantities in 1969. The giant Ekofisk with huge amounts of oil in Upper Cretaceous and Lower Tertiary chalk came on stream in 1972, and since then Norway's oil production has increased steadily until it peaked in 2001 with more than 3.2 million barrels of oil per day. On the contrary, the gas production is now increasing steadily and is expected to continue to do so during the next 10-15 years.

"The largest resource growth happened during the early exploration phase, from 1973-1982 when more than 4 billion m^3 (25 billion barrels) oil equivalents discovered. During the next decade, the reserve growth decreased by 20% to slightly in excess of 3 billion m^3 (20 billion barrels), while the reduction during the next decade thereafter (1993-2002) was even more dramatic as only 1.2 billion m^3 (7,5 billion barrels) were discovered," explains Bente Nyland.

And that was the situation when the authorities just after the turn of the century decided that the oil companies needed incentives to explore for the small to medium sized fields in the mature basins. Changes made were modifications in the tax regime, in particular in the exploration phase, introduction of annual licensing rounds, acceptance of companies with a small organisation and reduced requirements as to technical documentation.

As a result, the interest for exploring in Norway has increased substantially the last few years, and there is an ever-increasing number of independent oil companies that have a strong desire to take part in the vacuum cleaning of the mature sedimentary basins. So far this year, 14 companies have applied for pre-qualification.



With 3400 mill m^3 (21.4 billion barrels) of oil equivalents yet to be discovered, according to the Norwegian Petroleum Directorate (www.npd.no), there is a huge interest to explore in mature as well as immature geological provinces offshore Norway.

Plenty acreage to explore

Talisman Energy, head-quartered in Calgary with a Norwegian subsidiary in Stavanger, was formed in 1992 when BP Canada was sold. The company today has activities in North America, South America, the Middle East and North Africa as well as Vietnam, Malaysia and Indonesia producing 460,000 barrels of oil per day.

Bente Nyland, Resource Director with the Norwegian Petroleum Directorate, emphasizes that increased exploration efforts, commercialisation of marginal fields and improvements in the recovery factor of producing fields are vital to the future of the Norwegian oil industry. In addition she is eager to admit that the terms may be tough in Norway, but Norwegian authorities do not discriminate by giving Norwegian companies better treatment.

In 2003 the company purchased BP's share of the Gyda field in the Central Graben and assumed operator responsibility. In 2005 Talisman took over the Varg field buying the PGS subsidiary Pertra. Talisman has also acquired additional acreage, also around the Gyda field, and is now operating 10 licenses and is partner in an additional 15. Talisman therefore exemplifies the new independent entrees to the Norwegian North Sea: They are skilled, they have cash and they are eager to invest in small to medium-sized prospects and fields in order to add value to their portfolio.

"Our strategy is to explore and develop mature areas. We want to make money by investing in the drill bit. This is why we now have a rig going continuously," Bård Johansen says, Managing Director of Talisman Energy in Norway.

To boost production, 130 improved recovery projects (IOR) are now under

"Why Norway?"

"Why Norway?" is a marketing campaign conducted by the Norwegian oil and gas ministry. The overall goal is to attract several more oil companies to explore and develop fields offshore Norway.

"We need to supplement the major oil companies with small to intermediate independents that have cash. This strategy has been successful in the UK where Department of Trade and Industry has played an active role," says Bente Nyland of NPD.

NPD is therefore often found giving their "show and tell" on conferences and meetings around the world.

© Norsk Hydro

The reservoir in the Troll field, Norway's largest oil producer, is within Upper Jurassic sandstones with sand particles derived with Precambrian crystalline rocks on the Norwegian mainland.

assessment by the authorities. Also, NPD informs that there are 60 discoveries, representing 742 million m^3 o.e. (4.7 billion barrels o.e.), that are not yet approved for development. No wonder then, that the oil-hungry independents are eager to take part in the ongoing bonanza where swaps and purchase of acreage and positions also are becoming more common.

"Exploration is now again in the focus. Not since the first licensing round in 1965 have more acreage been available for the industry," according to Nyland. "And more acreage will become available the next years in line with a predictable licensing system with frontier area awards every second year and mature area awards (APA; Awards in Predefined Areas) every year. "The companies can get acreage with a combination of awards, purchase and swaps," says Nyland. "A lot of discoveries are also made, and we can prove that exploration gives a profit, as opposed to the UK, where exploration efforts lately have not contributed."

"The terms are tough in Norway. We have to admit that. But it is also true that we are predictable, we have a very stable political regime and there are few surprises," Bente Nyland says.

The amount of available acreage has therefore been increased substantially

A new dimension in Norway

Founded in 1997, and introduced to Norway in 2001 by purchasing the assets of PetroCanada, including their share of Njord, Veslefrikk and Huldra, Paladin is one of the newcomers that have been qualified as both a licensee and an operator. With activity in eight countries, encompassing Australia, Indonesia, Gabon, Tunisia, Romania, UK, Denmark and Norway, reserves of 140 million barrels of oil and a daily production of 50,000 bopd (a seven fold increase in five years), this British independent is no longer a small company.

Their ambitions are not small either. The company's target is to produce 100,000 boepd from reserves of 250 million barrels of oil equivalent by 2008.

Focusing on materiality

"We are always looking for upside potential. Our primary consideration is the potential to add value. Maturity of the asset, geography or operatorship is not really a concern," said Helge Hammer, Asset and Commercial Manager of Paladin at a recent conference in Stavanger hosted by the Norwegian Petroleum Society.

"Our business strategy is based on materiality. Fields and prospects that are not material to the big companies may very well be material to smaller companies like us. This is a well-known strategy that many companies are pursuing in the Gulf of Mexico and in the UK. It is new to Norway, though. But this should not be a surprise. As a basin matures, fields get smaller and smaller, and the big guys don't bother to invest any more," says Tim Bushell, Managing Director of Paladin Resources in Norway. "Supermajors like BP, Shell and Total behave in Norway just as they do elsewhere; small fields and prospects are just not material for these companies when viewed in the global context of their portfolios," he adds.

Paladin's success - the share price on the London stock exchange has soared from 30 pence in 2000 to close to 300 pence

Photo: Halfdan Carstens

"The competition in Norway is increasing, partly because of our success, and most types of acreage that we want to acquire is already gone," says Tim Bushell of Paladin Resources.

today is a result of some carefully planned acquisitions and follow-up investments. For mature fields, the opportunity lies in increasing the production and the reserves, based on new investment. Helge Hammer is using the Montrose/Arbroath field in UK to exemplify the company's strategy. In 2003 59% equity was acquired from BP and Amerada Hess. "The operator did not want to invest. But we have embarked on a significant capital investment programme," he says. As a new operator we have undertaken a complete re-evaluation of the subsurface and in particular used seismic, integrated with production history to identify locations for new infill wells. We have already boosted production by a successful infill drilling campaign and also discovered and put on stream a small satellite field called Brechin.

Believes in 4D

The company's strategy of 'creating value through investment' has also been very well demonstrated in on the Norwegian Continental Shelf, with Paladin's involvement in Veslefrikk, Brage and Njord. These three fields had past their peak production sometime ago. Following Paladin's entry, the production decline has been arrested and new investment has now resulted in increased production in all three fields. Also, in each case fieldlife has been extended by several years. "We were able to do this by inspiring the operator to invest in the reservoir, says Bushell." Paladin is a great believer in the use of four dimensional (4D) seismic technology. We have been able to successfully integrate 4D seismic (which we have over all our fields) with production history, reservoir simulations and the geological model to develop an accurate predictive tool. We have used this on our Norwegian fields to locate undrained areas of the reservoir that can be targeted by new infill wells. Because of our work methods we often seem to be able to do this a lot faster than our operators. This has led to a healthy dialogue in the licence groups, when there have been discussions on new investment plans.

"We would like to operate mature fields in Norway, as we do in the UK, but at present the large companies seem reluctant to relinquish their control, even over some of their smaller and less material fields. For now we have to be content with trying to positively influence our various operators. The story of Veslefrikk, Brage and Njord clearly demonstrates that we are able to do this."

Paladin is now active in getting two dormant fields on stream, Blane and Enoch, both which lie within the UK/Norway corridor. "Discovered in the 1990's neither field was material to players on either side when discovered," Bushell explains. "Following the new framework treaty agreement between the UK and Norway, fields along the borderline have become a lot more attractive. We now have UK and Norwegian government approval for the development of both Blane and Enoch. Both fields are expected to come on stream in late 2006."

"With some 30 million barrels of oil recoverable and 30,000 bopd from Blane, this field is certainly material to Paladin," Bushell says.

Discovering "empty" fields

Another interesting opportunity arose for Paladin during the 18th licensing round. Statoil produced 18% out of in place resources estimated to 260 million barrels in the Yme field. Paladin believes that it maybe possible to recover a further 60 to 70 million barrels from Yme. "If we can find an economic way of doing so" says Bushell.

The situation now is very different from when Statoil was the operator. The oil price was then less than 15 dollars per barrel, and there were a number of technical challenges in the development of the field, that were not apparent when the development pan was made. "Obviously we are now aware of those challenges and can incorporate solutions to these problems in our development plan. In addition, the price of oil has quadrupled since Yme was last in production, and this should help the project economy. Further work, including 3D seismic, is necessary to understanding the reservoir and we need to optimise drilling costs. We also plan to drill an exploration prospect nearby to Yme this autumn. If the well is successful, this will greatly enhance the potential for a re-development of Yme," says Bushell.

"We are technically and opportunity-driven. We will continue to look at a wide range of opportunities on the Norwegian Continental Shelf and continue in our quest to bring a new dimension to the Norwegian oil," concludes Tim Bushell.

during the last few years. However, to replace the dwindling resources with small discoveries require a lot of wells. The oil companies are thus concerned with getting a drilling rig that is compatible with the strict Norwegian regulatory system. The problem for several of the operators is that they have more acreage to explore than they have rigs to drill new holes on low-risk prospects.

Honouring quality

"In the future we need to find more oil and gas by intensifying our exploration efforts, we have to commercialize a full range of fields hitherto classified as marginal and – we need to improve the recovery factor in existing fields. Our explicit goal as stated in the 2005 Resource Report ("The petroleum resources on the Norwegian

Varg, now operated by Talisman, was brought back to life when Pertra (then a subsidiary of PGS) drilled an exploration well- based on a new seismic interpretation - that increased the reserves substantially. "To find new oil in small fields it will normally be necessary to drill exploration wells," says Erik Haugane.

Pre-qualification

"In connection with the wish to bring new, competent players to the Norwegian continental shelf, the Norwegian authorities have established a pre-qualification system for both licensees and operators.

This system has been set up to give the companies a means of assessing their own suitability for participating on the Norwegian continental shelf, before the companies invest resources in evaluating specific business opportunities. The system can also be used if the authorities deem it necessary to conduct a new review/re-qualification of a company that is currently a licensee/operator with a low activity level, but wants to increase its level of activity."

"The primary requirement for new players is that they must be able to provide an independent contribution to this value creation by means of their technical petroleum expertise. At the same time, it is important that new players possess HES competence.

Companies participating in the activity on the Norwegian shelf must possess a minimum level of competence within all relevant professional disciplines so that they are able to analyse, understand and follow up activities in the production licence. Operators and licensees must possess sufficient capacity and expertise to safeguard their obligations in relation to the requirements in the petroleum regulations."

As well as this minimum competence, the companies must also possess expertise within relevant professional disciplines so that they can contribute to value creation. New players are expected to do their own technical evaluations to challenge and complement the other participants in the production licenses."

"It is a precondition that the personnel in Norway possess technical competence in the following disciplines: geology/geophysics/reservoir technology/production technology/other relevant technology. The distribution of expertise among the various technical disciplines will depend on the phases of the production licence(s).

Experience to date shows that companies that have established themselves on the Norwegian shelf have built up an organisation consisting of at least 8-9 persons with technical and HSE expertise, in order to safeguard their obligations as a licensee in Norway." www.npd.no

Proven oil finders

Pertra, originally a subsidiary of PGS, became famous when more than doubling the initial reserves in the small Varg field in the Viking Graben. The field was scheduled to terminate production in 2002 when Norsk Hydro still was the operator and Pertra purchased Norsk Hydro's and Statoil's share of the license. The production profile left little doubt that the fields life expectancy could be extended a few months at most - to early 2003 - but only if the operating costs were reduced significantly.

"The sole hope of prolonging production after that rested on the ability to find more oil," says Erik Haugane, Managing Director of Pertra.

An in-depth geological study was therefore carried out focusing on the depositio-

"Pertra takes advantage of their geological expertise by focusing exploration efforts on geologically demanding play models such as the syn-rift Upper Jurassic depositional system. We are open-minded as to pursuing new ideas and cannot limit ourselves only to the existing play models," Tom Bugge, Pertra exploration manager, emphasizes.

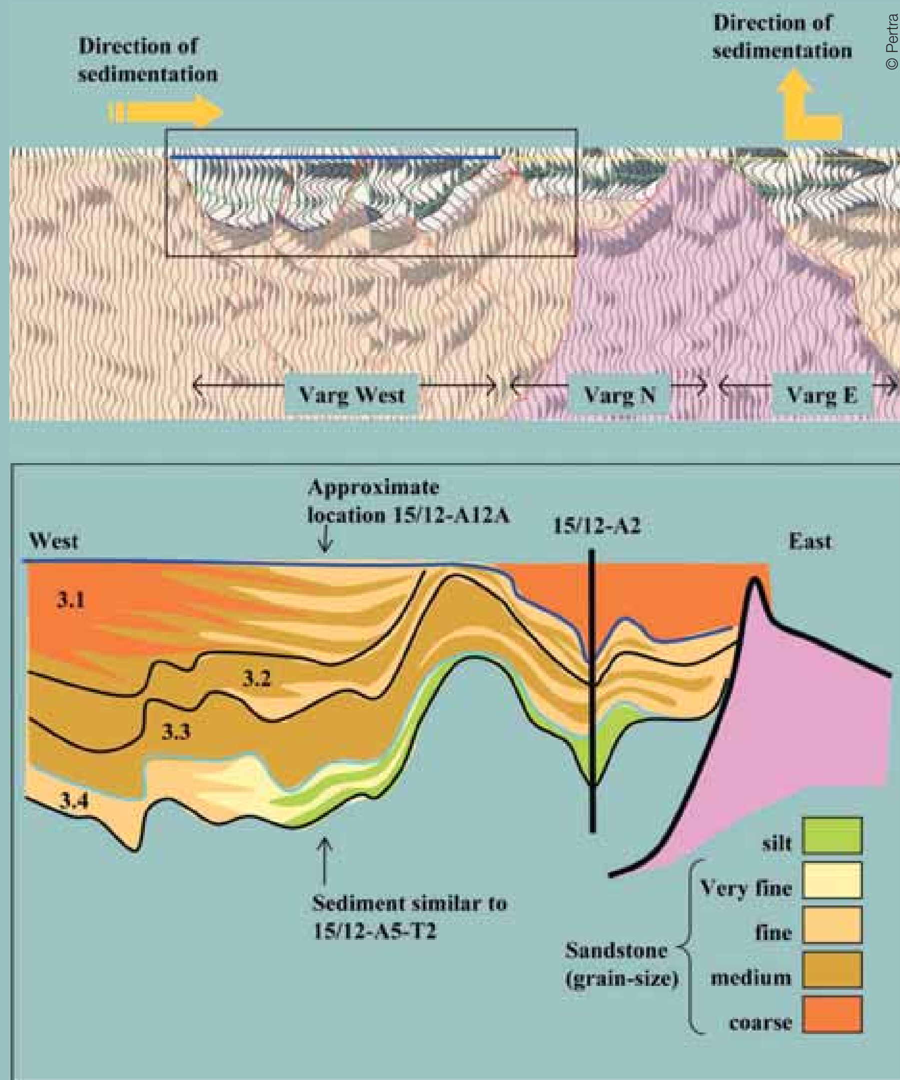
nal system thereby being able to predict reservoir architecture and reservoir properties. Says Chief Geologist Erling Heinz Siggerud: "Our new sedimentological understanding enabled us to predict the distribution of sand bodies. Based on this we decided to drill an unswept compartment of the field."

Investing in geologists

The well came in according to the prognosis, and following a new drilling campaign, which rested on the new geological model; reserves were increased with more than 50 million barrels. That is quite a lot for a field, which only a short time before was assumed to be exhausted. "The real value added by Pertra was our commitment to invest in seismic data as well as geological and engineering staff in order to improve our knowledge of a reservoir that was incompletely understood," says Erik Haugane.

"The lessons to be learned from Varg is that smaller fields have just as great a need for a solid reservoir understanding as do larger fields," Haugane adds. In 2004 he was awarded the prestigious prize "Oil man of the year" by the Society of Petroleum Engineers for being instrumental in putting Varg back to life.

Having outperformed Norsk Hydro, adding substantial value to a field that was close to being shut down in the tail-end phase, Varg and Pertra became an easy target for the oil hungry crowd of small independents. Canadian Talisman won the race and is now operator of the field with a 65% interest. Pertra, now with new owners, are left with 5% that is being used to get a new foothold on the Norwegian Continental Shelf.



Seismic line through Varg West and corresponding sedimentological model illustrating erosion to the west and thinning towards east. "The reservoir was interpreted to consist of a series of fan deltas and that has been subsequently been proven by the drilling of five wells," says Chief Geologist Erling Heintz Siggerud in Pertra. Discovering Varg West increased the reserves considerably in a field that was planned to be shut down.

Exploration and acquisition

Tom Bugge, exploration manager with long experience in the Norwegian oil industry, got the task of acquiring new positions and new acreage.

"Our strategy is split roughly 50/50 between doing exploration and acquisition," he explains. "The reason is that acreage available in the forthcoming licensing round is limited. Some of the best un-drilled prospects may in fact be left within licensed blocks."

This is why Pertra is actively looking at acreage held by other companies without having been offered for sale or trading. "The big companies may be too busy to pursue the small prospects, which are just not big enough for them to defend allocating personnel resources that are better spent on prospects with a – for them – much more attractive potential. For us, however, the same prospects may have significant value, and our way of doing a geological and engineering evaluation of such acreage may turn out to be favourable for both parties."

We are in a different position as we can prioritize projects that do not give sufficient rate of return for the majors. Also, our costs are lower and may turn an otherwise non-profitable field into a profitable venture."

"In Pertra, however, we focus on mature areas with middle or low risk where the petroleum system has been proven. With a size like ours we do not have the financial resources to explore in geological provinces with a high risk such as deep-water areas of the Norwegian Sea and the larger part of the Barents Sea," Tom Bugge says.

continental shelf 2005") is to increase the reserves by 800 million Sm^3 of oil, corresponding to five billion barrels, in the next ten years," says Nyland. "On top of that, there is a need to reduce costs in all phases of exploration and exploitation."

Bente Nyland is eager to get new oil companies to explore in mature as well as frontier areas, and she has a long list of good arguments in favour of her beautiful and oil-rich country. "In addition to a good resource base in both mature and frontier areas, we have a well developed infrastructure, we are close to the gas markets, we have a predictable regulatory framework, and – award of production licenses are based on the applicant's qualifications in petroleum related areas. There are no hidden costs or sign-on bonuses," she says.

Nyland is particularly eager to talk about the petroleum system that she thinks is world class. "One fourth of the recoverable resources, more than 20 billion barrels o.e. is yet to find, and the shelf comprises both mature and frontier areas where we are still making discoveries. New plays are still being developed and confirmed, all facilitated by easy access to geological and geophysical data."

"We want new companies to the Norwegian continental shelf that has the geological and technical expertise, backed up by financial muscle, to challenge the established players and contribute to value creation. We are especially interested in the independents that have a proven track record in other parts of the world," she adds.

Geologists with bright ideas for where to find new fields are certainly welcome to enter the scene.

Pre- or re-qualified companies on the Norwegian continental shelf

Aker Maritime
Altinex Oil
Amerada Hess*
Anadarko*
BG Group*
Centrica*
Chevron*
DNO*
DONG*
Endeavour
Enterprise*
Gaz de France*
Kerr McGee*
Lasmo*
Lundin*
Mærsk Olie og Gas*
Marathon*
Marubeni
Noble Energy*
Norske AEDC
OER Oil
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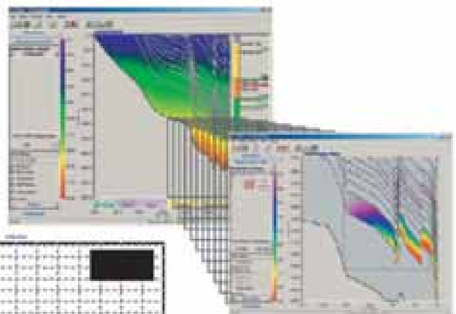

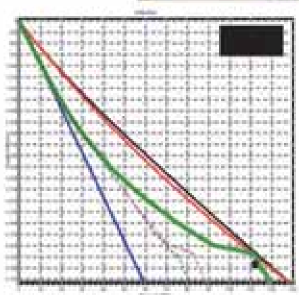

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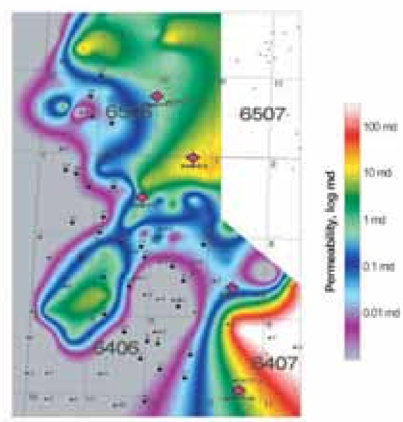

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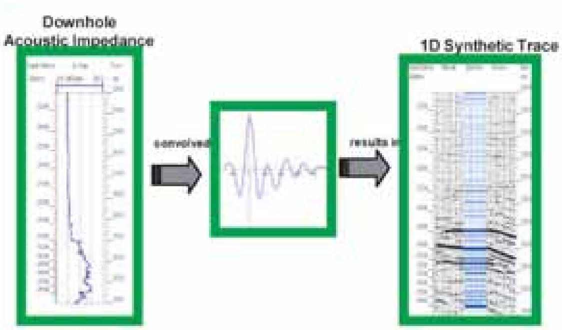

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Gas found in glacial, shallow sands

Hydro has announced a most remarkable gas discovery that the company just recently made in the North Sea. Possibly more than 30 billon m3 of gas has been discovered only 160 meters below seabed, and the reservoir consists of glacial sandstones capped by glacial moraines.

Halfdan Carstens

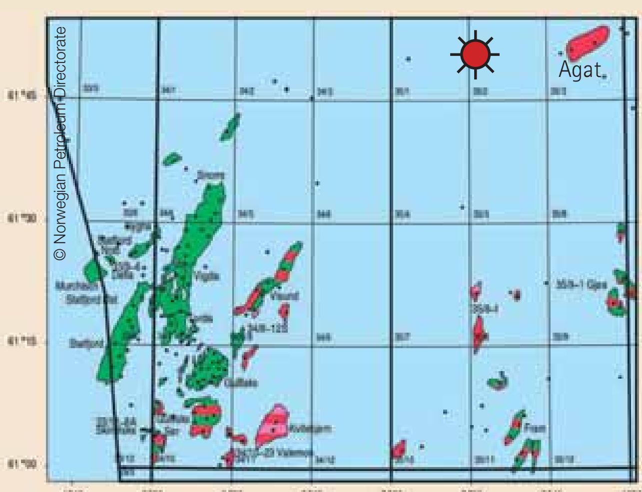
Hydro has made a large gas discovery in exploration well 35/2-1 in the northern part of the North Sea offshore Norway, and the operator already now says that the chances for a commercial development are good.

Unofficial press reports claim the recoverable reserves may amount to 30 billion m^3 (ca. 1 Tcf) or the equivalent of almost 200 million barrels of oil. Norsk Hydro does not to confirm this estimate, but the Minister of Energy and Petroleum, Torhild Widwey, did in fact use this figure when talking to the press. It is also known that the discovery covers a large area.

Relevant for the reserve estimate in this discovery is how much the gas is compressed compared to a reservoir at a deeper level with abnormal formation pressures. "If we assume that this young Pliocene reservoir has hydrostatic pressure, older reservoirs buried to several thousand metres will – given the same reservoir volume – have up to 10 times more gas in place," says Professor Jon Kleppe at the Department of Petroleum Engineering and Applied Geophysics, the Norwegian University of Science and Technology (NTNU), Trondheim. "A sizable discovery at such shallow depths with normal pressure thus requires a lot more area and volume than a deeper discovery," he adds.

This discovery on the Peon prospect is highly unusual in two different ways. Firstly, the reservoir is only 160 meter below the seabed. With a total depth of 687 meters and it is therefore the shallowest exploration well ever drilled in the Norwegian offshore sector. With water depth of 384 meters the sedimentary succession drilled was only 303 meter. Secondly, the reservoir consists of glacial sandstones deposited in the Pliocene while glacial moraines constitute cap rock. This discovery therefore adds another play model to the Northern North Sea fairway that very few – if anyone outside Norsk Hydro – have thought about.

"This discovery represents a new milestone in the exploration history of the North Sea," says Exploration Manager Tom Bugge in the small, independent oil company Pertra. For several years he was engaged in the IKU's Shallow Drilling Project and has thereby gained considerable knowledge about the upper layers of the continental shelf.



The discovery in the Peon prospect in the Sogn Graben is situated some 40 km west of the Agat field in block 35/-3 with gas reservoired in deeply buried Lower Cretaceous sandstones.

"The gas discovery is within sedimentary layers that have been mapped as representing potential drilling hazards because of shallow, gascharged sands," says Reidulv Bøe, Team Leader in the Norwegian Geological Survey for Marine Geology. "They have never been looked upon as potential reservoirs," he adds.

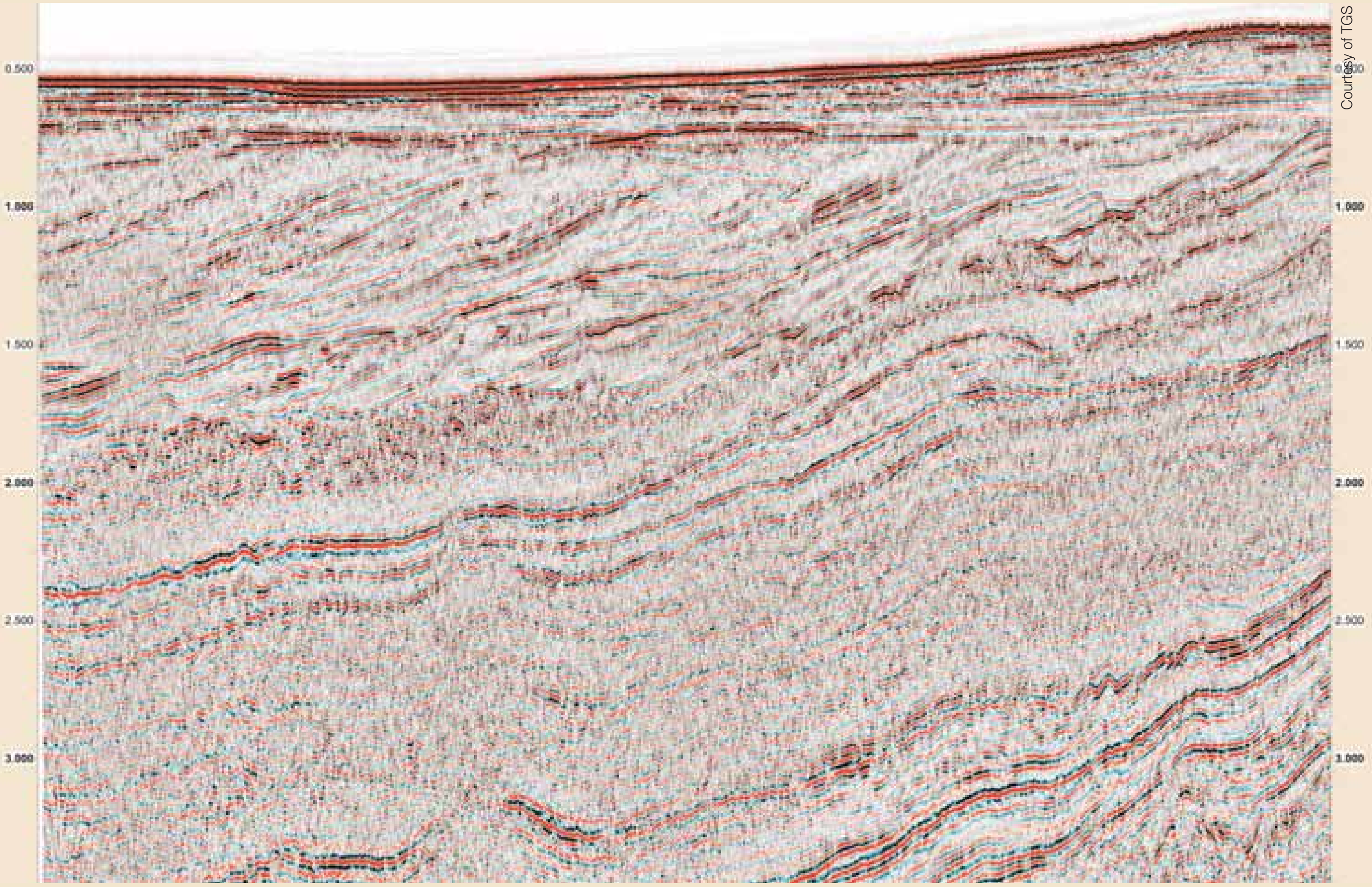
The prograding wedge of sediments below the unconformity seen on the seismic line is derived from the Norwegian mainland after the onset of the Pliocene/Pleistocene glacial period approximately 2.7 million years ago.

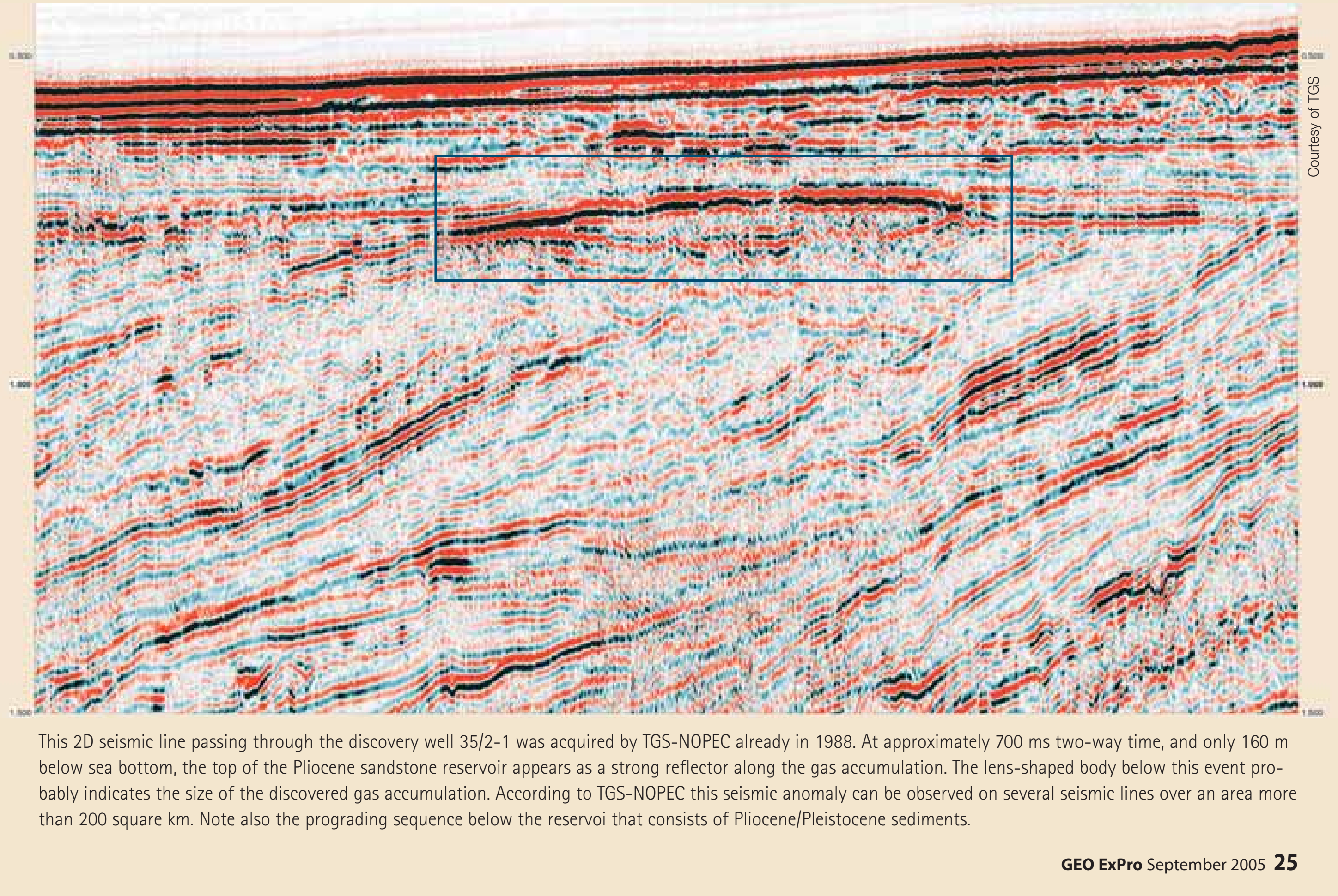
The pronounced unconformity represents an erosional surface formed by glaciers during one of the latest glacial advances and is probably less than 1 million years old. As has happened several times in the geological evolution of the North Sea, gneisses and granites in the Norwegian mountains were the source of the sediments," says Bøe.

"We are exceptionally pleased with the drilling results on Peon. Large amounts of gas have been proven and we consider the possibility for a commercial development as good. We'll now evaluate data from the well and plan to test the find next year," said Lars Christian Alsvik, director of Hydro Oil & Energy's Exploration Norway business sector.

"The results of the exploration well combined with Hydro's large ownership share in the area (60% in block 35/2) are very positive. This is one of the most interesting finds made in the Norwegian offshore sector in recent years. It lies in a little explored area, it verifies a new exploration model and provides the basis for exciting projects and value creation for Hydro and other players in the Norwegian oil industry," said Alsvik.

Overnight, geologists with expertise in glacial geology have increased their market value substantially.





This 2D seismic line passing through the discovery well 35/2-1 was acquired by TGS-NOPEC already in 1988. At approximately 700 ms two-way time, and only 160 m below sea bottom, the top of the Pliocene sandstone reservoir appears as a strong reflector along the gas accumulation. The lens-shaped body below this event probably indicates the size of the discovered gas accumulation. According to TGS-NOPEC this seismic anomaly can be observed on several seismic lines over an area more than 200 square km. Note also the prograding sequence below the reservoi that consists of Pliocene/Pleistocene sediments.

Play fairway mapping - Key to successful exploration

Play fairway mapping is an excellent tool for screening and ranking acreage, whether for licensing round applications, asset acquisition or disposal. With increased exploration efforts, it is an effective way of reducing risk.

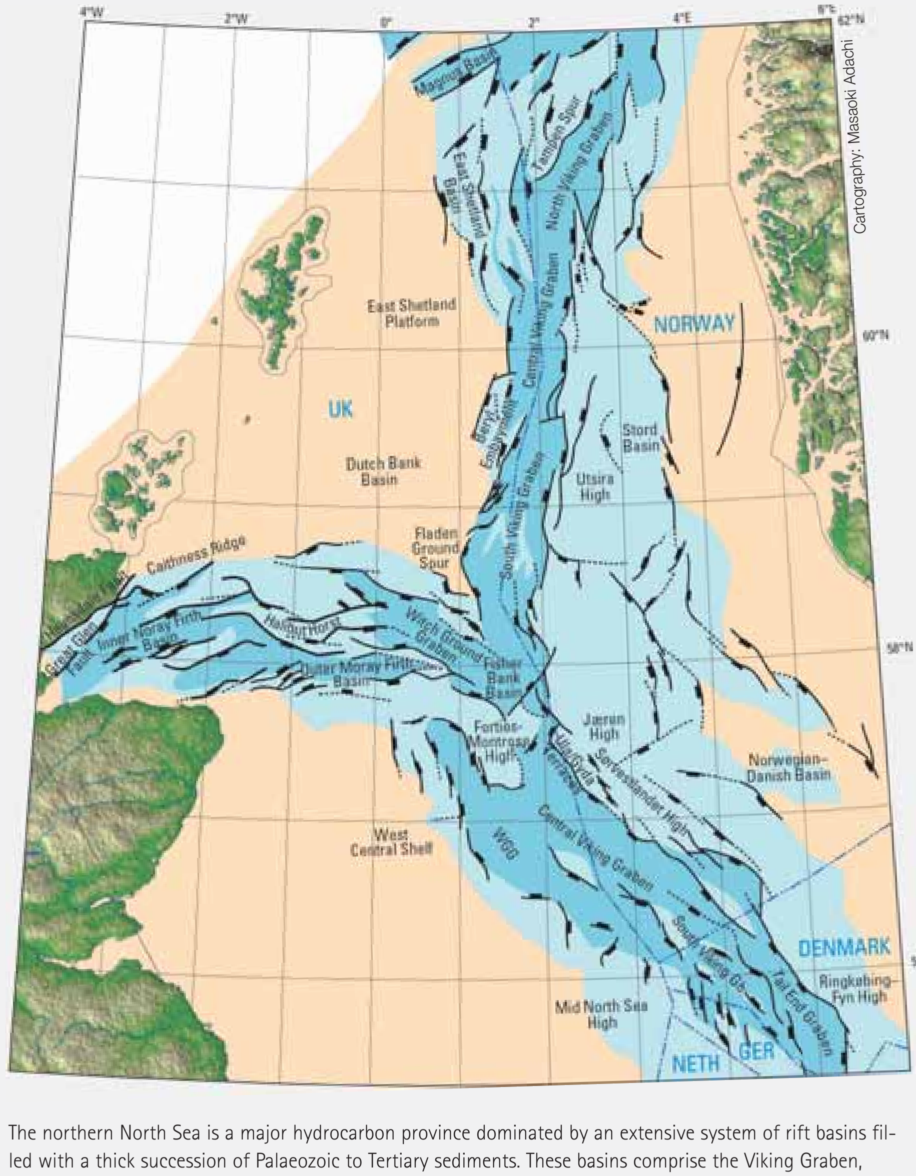
David Mudge and
Katrine Holdoway, Ternan

The decline in oil and gas production in the North Sea has initiated an intense debate on how to quantify the remaining "yet-to-find" resources in the region. It has also encouraged the Norwegian and UK governments to look at ways of making more acreage available through annual licensing rounds and releases of fallow and other previously licensed blocks.

Within a short space of time, these initiatives have led to a strong response from industry with re-licensing of much of the released open acreage. There has also been significant interest in the exploration of licensed acreage that has been only partially explored or not reviewed for a number of years, leading to an increase in company activity through farm-in, cross-assignment or takeover.

Historically, the UK/Norway median line has acted as a barrier to exploration with different stratigraphic terminologies being applied to rocks on either side, and seismic and geological maps terminating at the median line. Use of a stratigraphic framework spanning this political barrier enables North Sea plays to be mapped as continuous depositional systems, enhancing the value of the resulting interpretations and also allowing an uninterrupted view of prospectivity along the median line.

Detailed analysis of North Sea stratigraphy shows that non-marine, shelf, slope and basinal sediments are often represented within individual sequences. This combination of stratigraphic complexity and subtle structuring provides the ideal scenario for a long drawn-out tail of exploration activity as the more difficult plays are explored and understood, and new discoveries made.



The northern North Sea is a major hydrocarbon province dominated by an extensive system of rift basins filled with a thick succession of Palaeozoic to Tertiary sediments. These basins comprise the Viking Graben, Central Graben and Witch Ground Graben, which are bounded by stable platform areas with thinner sedimentary cover, and contain long-lived basement highs. A series of extensional tectonic episodes has created a large number of tilted Jurassic fault blocks and other structural traps within the basins and a widespread Upper Jurassic organic shale has provided a high-quality regional source rock. Cretaceous and Tertiary plays are associated with more subtle structural and stratigraphic trapping. Sandstones occur throughout the stratigraphic column, and chalk and limestone reservoirs are also present.

A two-part strategy

North Sea acreage availability and the recent strong oil price have stimulated exploration activity. However, oil companies, whether established North Sea explorers or new entrants, need to know where remaining prospectivity is located and how they can evaluate the risk associated with exploring this acreage. The most effective way to answer these questions and to assess the remaining hydrocarbon potential of North Sea acreage is to follow a two-part strategy: a first phase using play-based geological mapping to locate areas of regional prospectivity, and a second phase involving the evaluation of acreage within these fairways leading to the assessment of local prospectivity at the block and prospect scale.

In 2003 PGL, working with established and new-entrant North Sea operators recognised the need to do something different. Ternan was established with the primary purpose of undertaking regional studies using the play fairway technique with the objective of helping potential investors in the North Sea to get up to speed rapidly with the regional picture.

Play fairway mapping

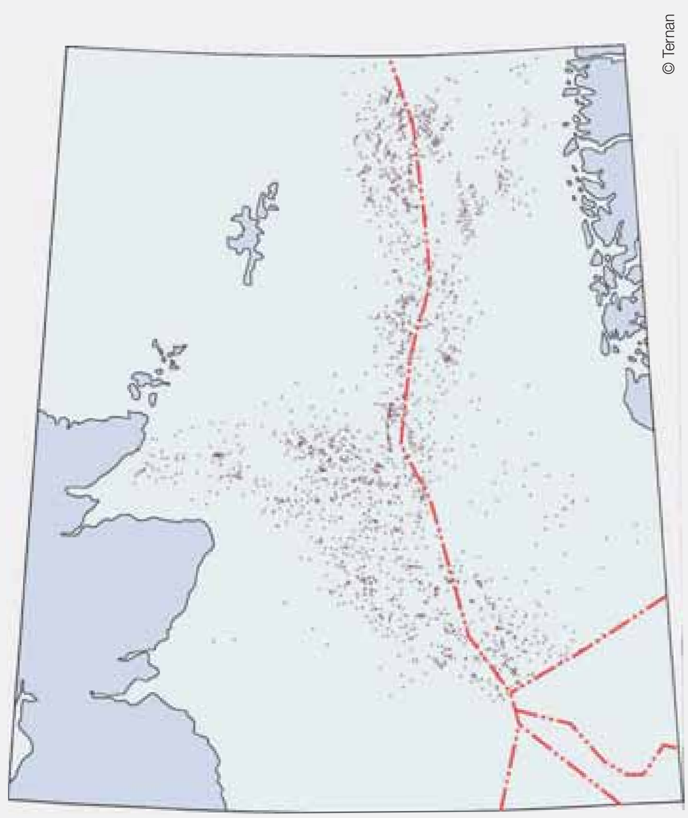
Play fairway mapping provides an effective means of defining remaining hydrocarbon potential in a mature basin such as the North Sea, which contains a large number of plays and has had a long history of exploration drilling. It also allows the prospectivity of individual blocks to be assessed anywhere in the basin. Play evaluation is based on rigorous stratigraphic analysis that provides a consistent framework for mapping regional reservoir, topseal and hydrocarbon charge. At least 20 plays can be mapped, using a database of more than 2000 UK and Norwegian wells.

Each of these plays contains at least one field with more than 100 million barrels of oil equivalent reserves (apart from Lower Palaeozoic, Carboniferous and post-Middle Eocene intervals). The plays are present in both the UK and Norwegian sectors and much of their remaining prospectivity lies within the Central Graben-Viking Graben system which straddles the UK/Norway median line.

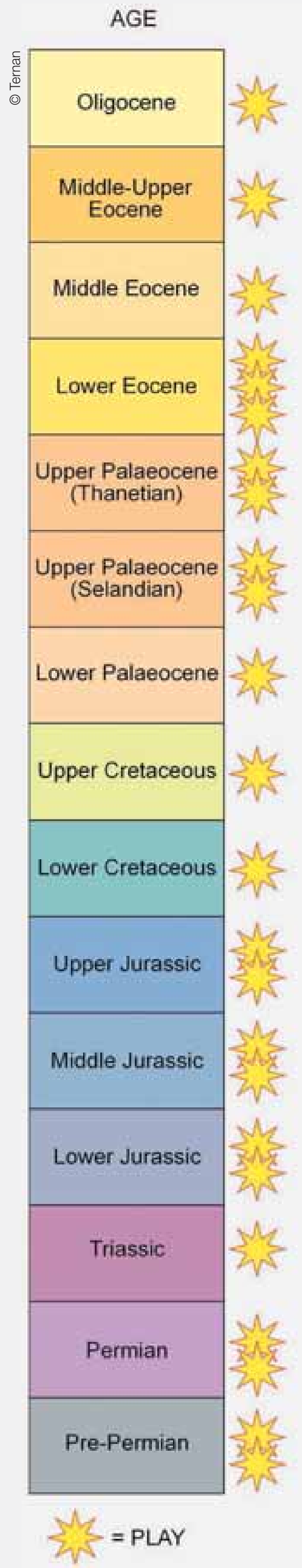
Play fairway mapping determines the geological controls and geographical extent of individual plays. A play can be defined as the combination of geological parameters that control the location of a

Regional evaluation identifies play fairways and helps to assess exploration risk associated with geological parameters such as reservoir, topseal and hydrocarbon charge. Detailed interpretation is then required to identify potentially drillable prospects, and local presence and effectiveness of reservoir and topseal.

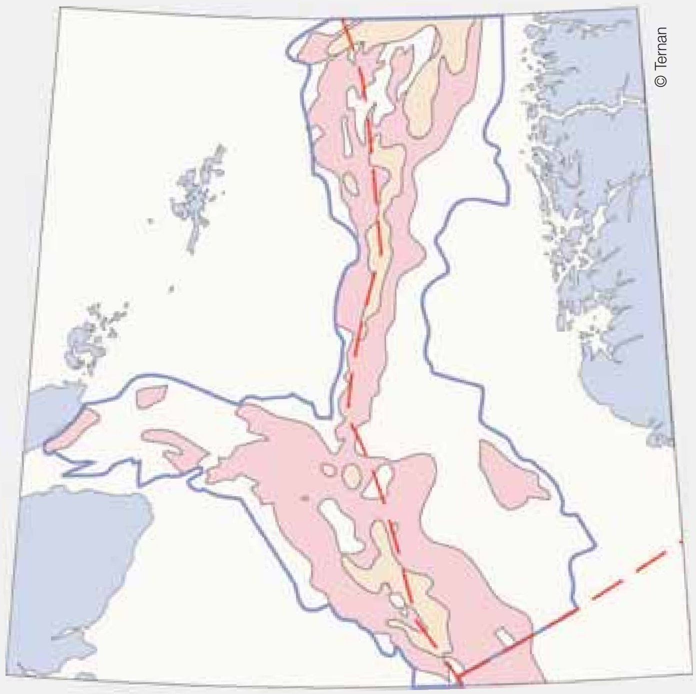
Ternan is named after the 5th Century Scottish saint who settled in Banchory, near Aberdeen. The company is a wholly owned subsidiary of PGL, a subsurface consultancy with broad North Sea expertise. PGL's ODM3™ software has played an essential role in creating the extensive digital well database that forms an integral part of the regional study output.



A database of over 2000 wells has been used to evaluate North Sea plays.



The North Sea differs from many other hydrocarbon provinces in having a wealth of plays throughout the stratigraphic column.



Integration of mapping over the median line improves understanding of plays and the hydrocarbon system overall.

hydrocarbon accumulation. Play fairway mapping relies on the identification of those components of a play that have a regional rather than local distribution. Distinguishing between local and regional geological parameters leads to a clearer understanding of the nature of these geological controls and so gives a more confident estimation of exploration risk at the prospect generation stage.

"A play can be defined as the combination of geological parameters that control the location of a hydrocarbon accumulation."

The regional parameters

In the North Sea, regional parameters are mapable over a number of quadrants or throughout the basin, whilst local parameters are defined at the block or prospect scale. The regional parameters for North Sea plays are reservoir, topseal and hydrocarbon charge. As reservoir is the most readily identifiable parameter, plays are usually named by reservoir. Hydrocarbon charge combines the presence of mature source rocks with the occurrence of a migration pathway into the reservoir. Local parameters that affect prospectivity at the block or prospect scale are trapping and local presence and effectiveness of reservoir and top seal. In the North Sea trapping is the most important local parameter that can be mapped and is the easiest to risk. Topseal or reservoir erosion on the crest of tilted fault blocks may also be a factor at this scale

The prospectivity of any play can be evaluated from its fairway map. This is constructed by overlaying the regional distributions of reservoir, topseal and hydrocarbon charge for that play. The area of maximum prospectivity, where these three parameters are all favourably combined, is defined as the play fairway. Outside the fairway, areas of increasing exploration risk can be mapped as the regional parameters become suspect or unfavourable. The map also allows the degree of confidence associated with this exploration risk to be estimated. Within the fairway - where the regional risk for the play is low or zero - available acreage can be targeted for prospects using seismic mapping and local well data. This play fairway methodology can be applied to any basin with potential hydrocarbon prospectivity.

Play fairway maps

A suite of regional maps has been produced for each North Sea play, with the aim of providing an integrated and consistent view of known and potential hydrocarbon prospectivity in the area to the north of the Mid North Sea High. Further, the stratigraphic interpretation of the wells

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Katrine Holdoway (kholdoway@ternan.com) is Managing Director of Ternan. She is a geologist with a long career in North Sea exploration, having worked for Mobil North Sea Limited in London for many years, latterly being responsible for co-ordinating licensing round evaluation and applications.

on which this mapping is based is captured in a digital database, facilitating interactive interrogation of the data and enabling updating. The technique is illustrated by using the suite of maps from the Palaeocene Heimdal/Balmoral sandstones play as an example.

In conclusion, play fairway mapping is an excellent tool for screening and ranking acreage, whether for licensing round applications, asset acquisition or disposal. It removes a significant amount of exploration risk before reaching the stage at which considerable investment of time and money is required for purchase of seismic data and detailed assessment of prospectivity leading to drilling decisions.

Integration of the 3 Ternan studies sponsored by Apache (UK Central North Sea and UK Northern North Sea) and Talisman (Norwegian North Sea) provides a comprehensive regional overview of the northern North Sea basins, and has advanced our collective understanding of important plays which straddle the under-explored median line corridor. The reports are available to the industry in general, with uptake coming from across the board - not only from new entrant companies but also from established North Sea players, from independents to super majors. With exploration firmly back on the agenda, many companies lack their own up-to-date regional work, essential to making the most of current opportunities in the UK and Norway.

A case study

Overlaying the regional distributions of reservoir, topseal and hydrocarbon charge produces play fairway maps.

David Mudge and
Katrine Holdoway, Ternan

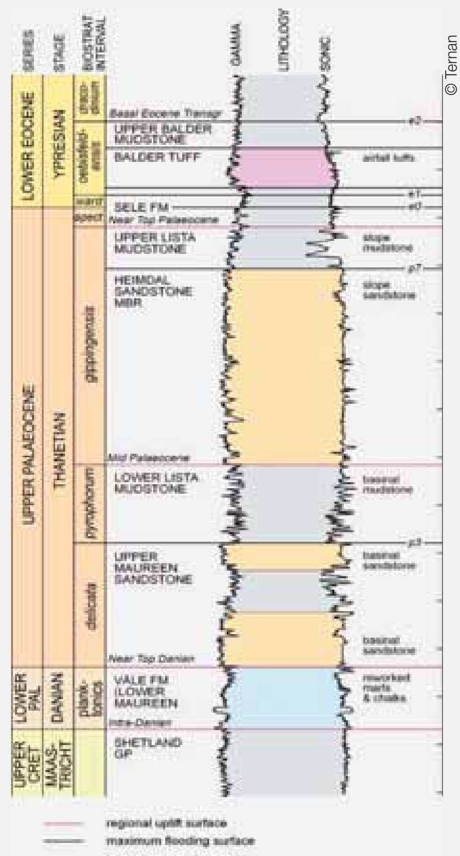
The Upper Palaeocene Balmoral/Heimdal sandstones provide a good example of how play fairway mapping can be used to evaluate remaining hydrocarbon prospectivity in the North Sea. Differing stratigraphic terminology for these widely distributed sandstones has led to the mapping of three separate plays: the Balmoral play in the UK Central Graben and Outer Moray Firth area, a Heimdal play in the Norwegian part of the South Viking Graben and a Heimdal play in the UK East Shetland Basin. However, biostratigraphic data and well correlation show that these sandstones were shed off the East Shetland and Forties platforms and laid down in slope and basinal slumps, submarine channels and fans during a single depositional event associated with thermal uplift and erosion of a Scotland-Shetland hinterland to the west.

Type well

A consistent stratigraphic framework is key to proving a solid foundation for Play Fairway mapping. Biostratigraphic data combined with wireline log correlation are used for stratigraphic interpretation, which is recorded in an extensive digital well database.

Reservoir distribution

The sandstones form excellent reservoirs up to 400 m in thickness, pinching out southwards into the Central Graben and eastwards onto structural highs. An incised east-west channel system is seen in the southern part of the Central Graben and sandstones of Heimdal age have also been drilled along the northern flank of the Ringkøbing-Fyn High. Evidence for active faulting is seen in the East Shetland Basin where over 800 m of sandstones have been drilled in the hanging wall of the platform margin fault.



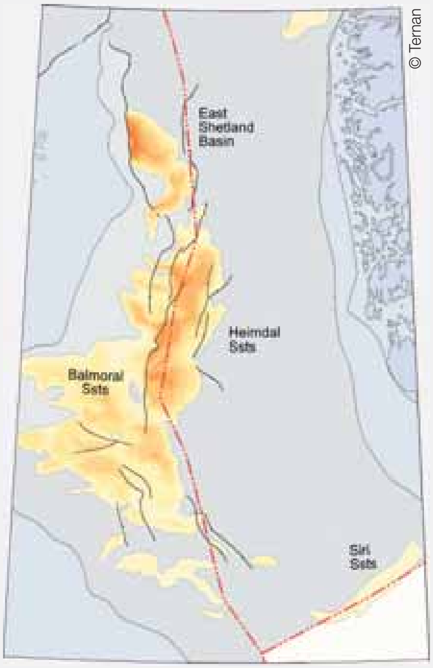
Type Well.

Topseal

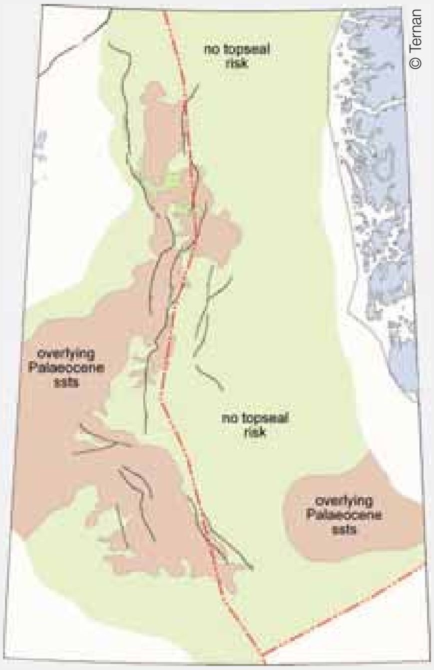
The presence of regional topseal is a critical risk for Palaeocene plays in the North Sea, as with very few exceptions hydrocarbons only occur in the highest reservoir interval in any well, implying that intra-formational mudstones are not reliable seals for light oil and gas. So viable topseal for the Balmoral/Heimdal play is limited to areas shown in green, outside the limits of overlying Forties, Sele and Balder sandstones (shown in brown).

Hydrocarbon charge and biodegradation

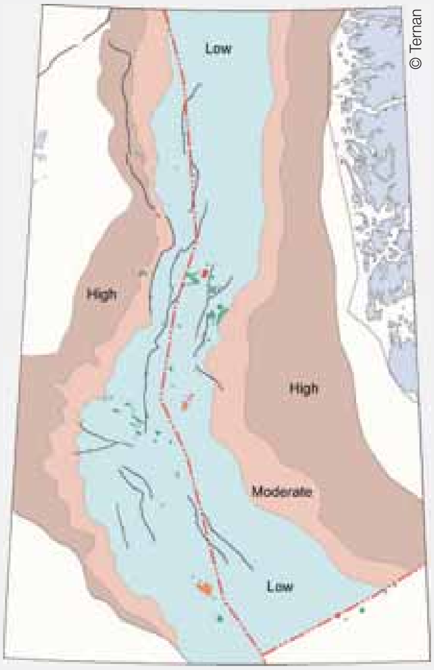
Mature Upper Jurassic source rocks are widely distributed beneath most of the



Reservoir Distribution.



Topseal.

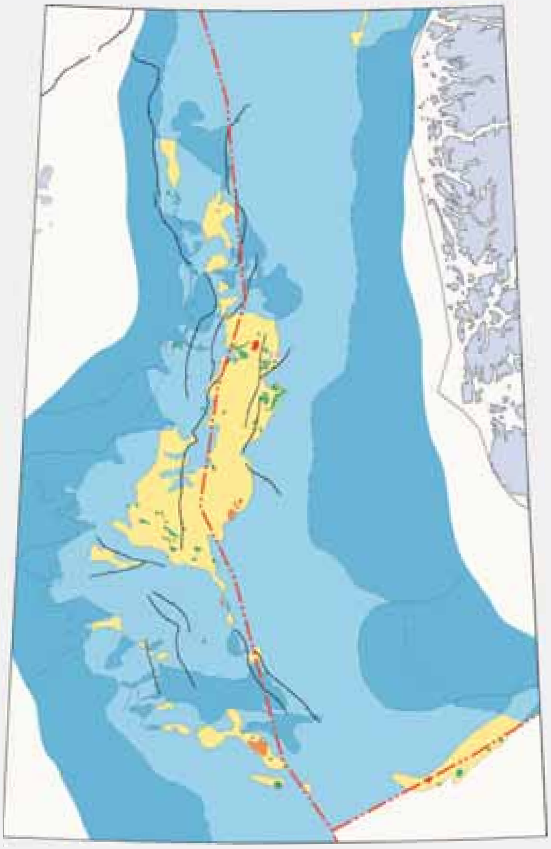


Hydrocarbon Charge and Biodegradation.

Palaeocene reservoir sandstones and sufficient hydrocarbons have been generated to fill any traps present. The presence of oil-bearing Heimdal sandstones in the Siri fairway along the Norway/Denmark median line demonstrates the potential for long-distance migration within the Palaeocene in the North Sea. The major charge risk is associated with biodegradation which is related to depth of burial. A straight-line relationship between oil gravity and depth shows that biodegradation risk is significant above depths of 1675 m (light brown) where gravities of about 20°API are encountered and becomes critical above 1200 m (dark brown) where oils of 14°API or less are predicted. Biodegradation is only a risk for the Heimdal-Balmoral play at shallow depths on the East Shetland Platform.

Play fairway

The Heimdal-Balmoral play fairway is produced by overlaying the regional distributions of reservoir, topseal and hydrocarbon charge. The area in yellow is the play fairway, where regional risk is low or zero. Areas of moderate to very high regional risk are shown in deepening shades of blue. By definition, oil and gas fields are concentrated in the play fairway, but a few hydrocarbon accumulations are found outside the fairway, e.g. in the Mariner and Emerald fields where an intra-formational mudstone provides local topseal.



Play Fairway.

A successful play

The main areas of the play fairway are highly prospective and productive in the South Viking Graben, on the Fladen Ground Spur and in the eastern part of the Moray Firth Basin. The success of the play can be related directly to the absence of younger Forties sandstones in these areas. The most significant Balmoral accumulations are simple anticlinal closures with an element of stratigraphic trapping that occur on the flanks of the Fladen Ground Spur.

In the South Viking Graben the Heimdal has proved to be the most successful Palaeocene play in the Norwegian sector, with hydrocarbon production in Sleipner East, Heimdal, Glitne and other fields. These fields are located along the margin of the Utsira High close to the eastern pinch-out line of the sandstones. Trapping is provided by drape or mounding with lateral shale-out providing stratigraphic closure in Jotun.

This stratigraphic play can be mapped southwards close to the UK/Norway median line. To the south and east of the main reservoir development, isolated channel sandstones contain hydrocarbons in the Joanne, Flyndre and Orion fields, and in the Siri field complex.

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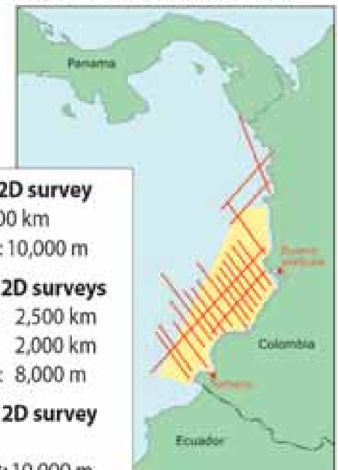

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The digital core laboratory

By getting a better understanding of the pore structure of the reservoir rock through detailed analyses of thin sections, a brand new methodology now makes it possible to predict petrophysical properties almost without using conventional core laboratory services. The ultimate goal is to improve reservoir simulation by offering a high number of inexpensive analyses of reservoir parameters in a minimum of time.

Photo: Halfdan Carstens

Halfdan Carstens

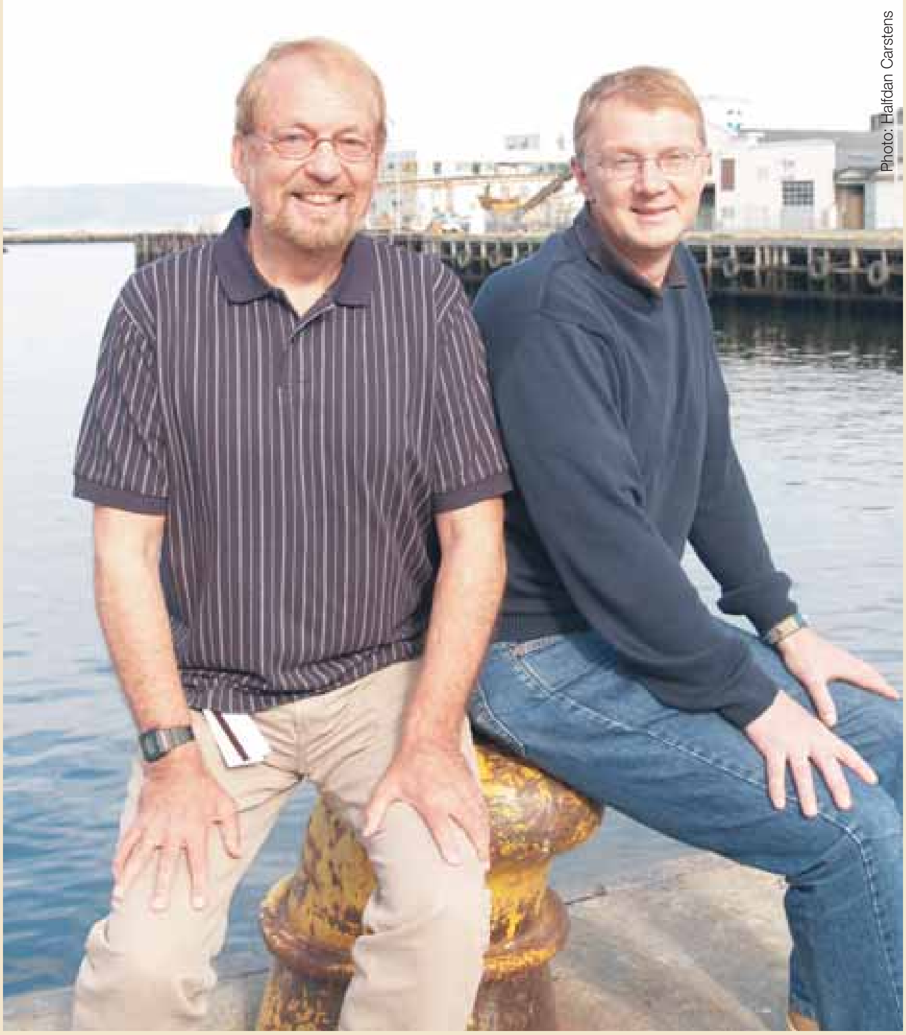
The new buzzword in reservoir characterisation is "e-Core technology". In short, it involves using petrographical data from thin sections to model important reservoir parameters like relative permeability, formation factor, capillary pressure, resistivity index and residual saturations, all crucial for doing a proper reservoir simulation for the purpose of planning optimal reservoir performance during production.

We are used to associating such parameters with measurements done in a conventional core laboratory equipped with sophisticated instruments and advanced analyses. And in all probability these labs will be part of our future for doing such measurements. However, the rapid increase in knowledge, technology and computer speed now makes it possible to supplement, and in some cases substitute, these with computer generated values. Numerical Rocks, founded only last year, has pioneered a technology for predicting the properties of reservoir rocks and is now ready to enter the market.

Statoil Innovation has been instrumental in getting Numerical Rocks to fly. "Spinning off this technology with two entrepreneurs and creating a dedicated company should ensure more focused and driven software development than keeping it in-house," explains Investment Manager Asle Hovda in Statoil Innovation. "Statoil Innovation is dedicated to commercialising the Statoil group's technology and expertise through new start-ups, and to invest in external innovative early stage technology companies. Numerical Rocks is the seventh investment by Statoil Innovation since the latter was created in 2001, and the second spin-off from in-house technology," Hovda says.

"At this stage we look at the new technology as a supplement to conventional core analysis. In the long run, however, our way of characterising the reservoir may replace some of the measurements because of both the cost- and time-aspect. Using inexpensive computers is certainly cheaper than expensive laboratory measurements, and the time we need to do calculations in the computer is only a fraction of what the laboratories need," says Ivar Erdal, Managing Director of Numerical Rocks.

Typical thin section displayed on Jurassic sandstone with ripples.



Stig Bakke (left) and Pål-Eric Øren have worked in tandem for many years in spite of widely different background and expertise. They believe that the technology they now master is a result of being part of a multidisciplinary team in the Statoil research lab, where chemistry, physics and mathematics is as important as geology, geophysics and petrophysics. They have now left Statoil for the purpose of continuing developing and marketing the software to the international oil industry. Statoil Innovation is a majority shareholder in the new company Numerical Rocks.

20-year lead-time

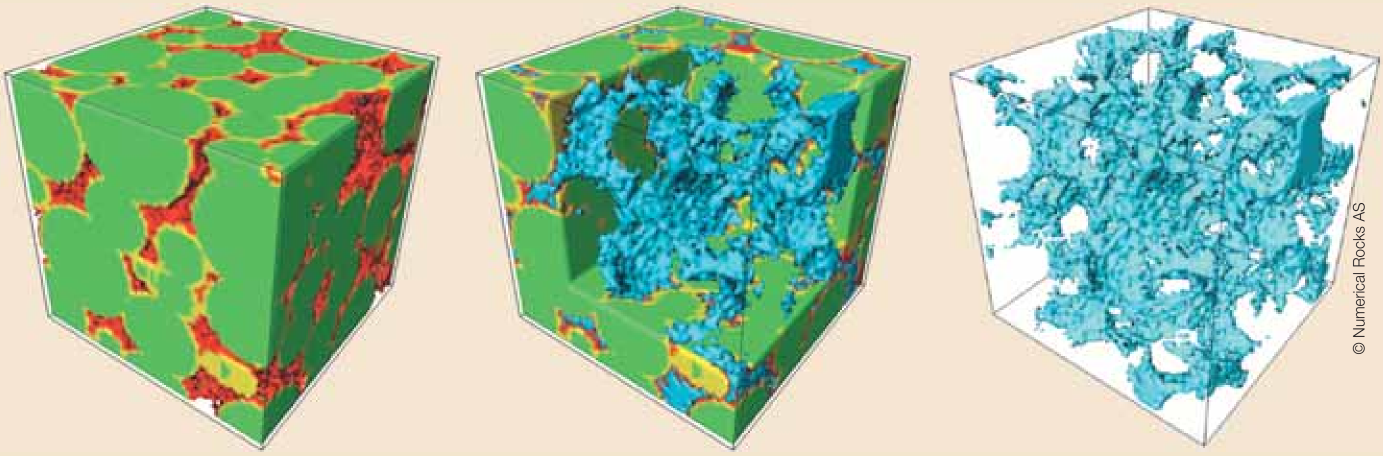
Numerical Rocks belongs to a crowd of new companies in the petroleum service industry that has been able to establish themselves because of a rapid increase in geoscientific knowledge, technological development and data power.

But even more important are professionals with the right ideas at the right time!

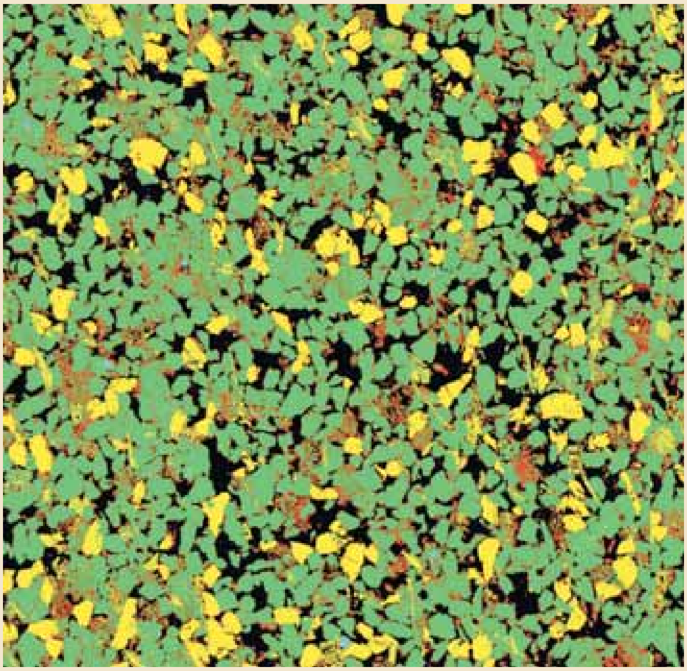
"Back in the mid 1980's we did some early thinking on how to characterise reservoir rock properties based only on thin sections. This was in line with current ideas that thin sections could be used to estimate permeability," says Håkon Rueslåtten who has now joined Numerical Rocks after a 19-year long career in Statoil.

"Preliminary results were encouraging, and a few years later the project was enforced by hiring a physicist who had specialized on fluid flow in porous media. The purpose was to use the rock properties in fluid flow analysis in order to improve reservoir simulation," Håkon says.

Pål-Eric Øren, with expertise in both chemical and physical engineering, had just finished his PhD in Sydney and was ready for new challenges outside the university system. "At that time we knew a lot about how fluids move within porous media and how one fluid (for example water) displaces another fluid (for example oil). However, we knew very little about what the



The pore space of reservoir rocks is highly chaotic, consisting of a spatial network of pores in which larger pores are connected via narrower pores (pore throats). The architecture and geometry of the pore network and its complementary grain matrix determine several macroscopic properties of the rock such as absolute permeability, relative permeability, capillary pressure, formation factor, and resistivity index.



Artificial coloured image of a thin section of a reservoir sandstone. The green and yellow grains are quartz and feldspar grains, clay coating and filling is red, heavy minerals are blue and the pore space is black

reservoir looked like, and we were for that reason not able to quantify the flow of fluids in the reservoir rocks. Not knowing the rocks pore structure was at that time – and still is – a significant limitation to the quality of reservoir simulation," Øren says. "

That may come as a surprise, considering that geologists have studied sedimentary rocks for centuries. "The fact is that we were not able to describe the geometry of the pores and how the pores connect with each other. Consequently we had no clue as to how we should make a model of the reservoir rock for fluid flow modelling," Øren explains.

Stig Bakke, a geologist who had spent thousands of hours looking into the microscope studying rocks in thin sections, and who had an interest in using computers in quantifying geological processes, also joined Statoil in the early 1990's. Stig's experience was very relevant for this project, and combining the expertise of the two proved to be the right thing.

"With information about minerals and pores from thin sections we tried to reconstruct the geological processes that formed the reservoir rock," Stig says. "Using our own algorithm, we built a 3D model with rounded grains, clay minerals and cement as well as pore space and connectivity."

And, they were successful. After a few years the small but efficient team had proved that it was possible to predict both the petrophysical properties and the flow properties of sedimentary rocks based only on thin sections, and their results were published in the SPE Journal (Vol. 2, 1997). Thin sections are easy and inexpensive to prepare, thereby making it possible to make a high number of analyses instead of analysing only a few samples in the core laboratory.

"We were now ready to try out the method on real rocks in a producing field," Øren says.

The e-Core technology

The essence of the new method is to build sandstone models that are analogues of actual sandstones by numerically modelling the results of the main sandstone-forming geological processes - sedimentation, compaction, and diagenesis. The input data for the modelling are obtained from analyses of thin section images of the actual sandstone.

"The microstructure of a porous medium as well as the physical characteristics of the solid and the confined fluids determine the macroscopic properties of a system. These include petrophysical and transport properties needed to characterise the reservoir. In principle, it should be possible to determine these properties from their microscopic origin," says Stig Bakke.

By "microscopic origin" Bakke is referring to thin section analysis, one of the basic geological tools used to describe rocks in detail in which a thin lamina of the rock is studied under the microscope. "Thin sections enable us to characterise the reservoir rock in terms of size and shape of the sand grains, clay particles present and to what extent the rock has been cemented after burial," says Bakke.

"Our first step is therefore to construct a numerical rock based on petrographic data. The input data include porosity, grain size distribution and mineralogy. This is done with our own software in which we fill up a cube with sand grains, clay and cement, and then remove all the solids leaving only the pore space. A 3D sandstone model and its complementary pore space is the output."

The next step is to generate representative numerical pore networks, upon which it is possible to calculate petrophysical data and simulate fluid flow directly from the numerical rock. These data include permeability, formation factor and capillary pressure. Other parameters like nuclear magnetic resonance and elastic moduli can also be estimated.

The generation of a network model makes it possible to carry out multiphase flow simulations and then to obtain macroscopic flow properties. These include relative permeability, capillary pressure, resistivity index and residual saturations.

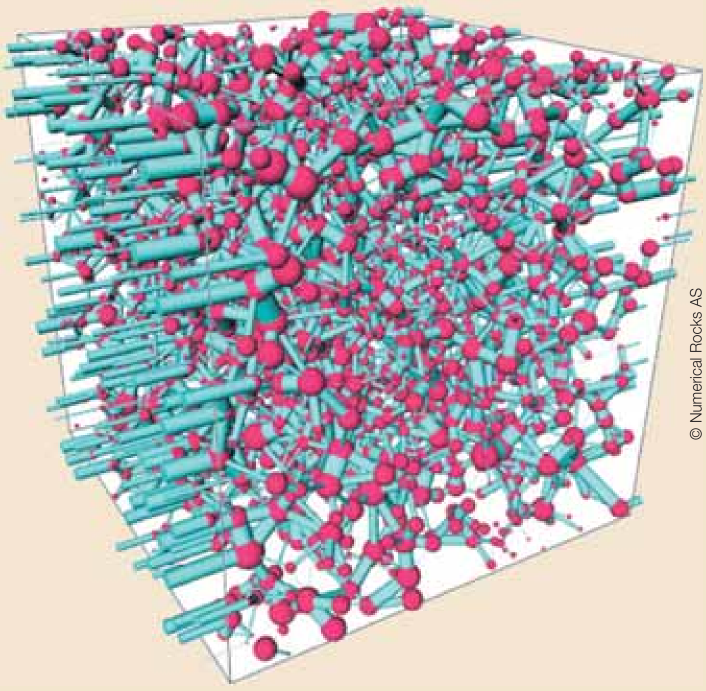
An animation of the process can be studied at www.numericalrocks.com.

The end result based on a single thin section is a series of parameters that normally require advanced laboratory analyses. "We can get all the rock parameters that we get from the lab, with only one exception: Wettability," says Bakke.

"The product is working," says Erdal. "But up to now specialists have been required

Photo: Halfdan Carstens

Håkon Rueslåtten was instrumental in developing the original idea of using thin sections in reservoir characterisation and has joined Numerical Rocks as Business Developoment Manager.



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A 3D sandstone model and the numerical network of a pore space with red nodes being spheres with radii equal to the inscribed radius of the pore body, while the light blue links are shown as tubes with radii equal to the inscribed radius of the pore throat.

to do the preparatory work on the real rocks and to run the software to get meaningful results from the numerical rocks. That is why three computer experts are engaged in developing software that is meant to be user-friendly, which is a prerequisite if you want to penetrate the market."

" Our vision is a new understanding of pore physics that enables the prediction of reservoir multiphase flow parameters."

Time is money

"There are a number of advantages in using the e-Core technology," says Erdal. "We all know that time is crucial when planning the development of a new field or when certain circumstances require a re-evaluation. While a conventional core analysis programme may take from 6 to 18 months, we can do this in a few days or weeks with the e-Core technology. That makes a difference."

"Another important advantage is that we only require a small chip of a rock to do the computations. A thin section of the reservoir rock is the only sample we need, and this we can get from cuttings, sidewall cores as well as conventional cores. It doesn't take much imagination to realise that both time and cost will allow for a high number of analyses that would have been prohibited with the traditional technology which includes coring operations and core analysis programs. Analyses can hence be made in numerous wells in which cores have never been cut," says Erdal.

"From an oil company perspective easy access is also good news because the database has the potential to increase multifold without increasing cost. Instead of scattered data points made from an incomplete core record, wells can now be analysed for reservoir parameters centimetre by centimetre."

However, he is eager to ad that the new technology by no means replaces conventional core analysis. Rather, it is a supplement that may increase the need and the market for reservoir characterisation. The long time required in the laboratory to get meaningful results may in fact have hampered more extensive use of such services.

New applications may also result because of the reduced cost. Håkon Rueslåtten, who is responsible for business development in Numerical Rocks, envisages a library of reservoir rocks with thin sections from each lamina, with associated simulation results that can provide important information in connection with for example exploration play models.

"The proof of the pudding is in the eating"

Numerical Rocks is now investing heavily in generating the necessary software to be able to offer their services with a streamlined product, and by next year they expect to approach customers who are eagerly waiting for a time- and cost-efficient tool that may ultimately give significant improvements in simulating fluid flow in the reservoir.

Before that, however, they also need to prove that the e-Core technology is more than theory. They need to show cases in which their new innovations have worked.

"The e-Core technology has been successfully tested and verified on both outcrop rocks and on different reservoir rocks, and reconstruction of the rock microstructure has been verified by quantitative comparisons with micro-CT images of the actual rock that give detailed 3D images," says Bakke.

"In the late 1990's we generated sedimentary rocks in the computer and predicted their properties on several Statoil operated fields in the North Sea and the Norwegian Sea, including Gullfaks, Statfjord, Veslefrikk, Kristin, Heidrun. We were asked to do more, but were constrained by the lack of time and resources. Without proper software we had to do everything ourselves. We were the only ones who could use the software and get meaningful results."

"It is still a bit early to conclude to what extent we can use the e-Core technology, but we have now gained considerable experience after testing the technology on fields in the Norwegian Sea," says Odd Steve Hustad, reservoir engineer with Statoil. "First of all, we can get the necessary data very quickly. But, we also generate a lot more information with this technology compared to doing measurements in the laboratory. The result is that we have a consistent and detailed database for early use in reservoir modelling, and that is very useful."

"The aspect of low cost is also very attractive," Hustad adds

Adding all this up, it is no surprise that the Statoil team wants to continue testing the technology. "The technology may turn out to be particularly useful for projects related to "increased oil recovery" that require a lot more detailed information, which can prove tedious to obtain through laboratory measurements," Hustad says.

The e-Core technology has been successfully tested on the Heidrun field.

Ivar Erdal accepted the position as Managing Director of a company based on digital core analysis after more than 15 years in a company that succeeds in conventional core analysis. So far Numerical Rocks have only seven employees, three of which are dedicated to making the new software user-friendly.

A nice ambition

Today, Numerical Rocks is modestly staffed, but it is easy to envisage that they are in the need of a large marketing and service delivery departments if their ambition is to conquer the entire petroleum world.

"We are not in a rush," comments Erdal. "We have to do this without going too fast. You therefore may have to wait a couple of years before you find an office of ours in Abu Dhabi or Houston."

Erdal has been in his new job as Managing Director a few weeks only. But he is no newcomer to the petroleum industry. His last position was General Manager of ResLab (Reservoir Laboratories) Norway who specialises in core analysis and who has gained a reputation for doing excellent work (GEO ExPro No 2-3, 2005). He is therefore well-positioned to predict how the new technology can add to value creation in the petroleum industry.

"Access to an increased database of reservoir parameters may ultimately result in a better understanding of the complex process by which oil and gas fields produces fluids, they being oil, gas or water. Also, more knowledge will assist the petroleum engineer in evaluating the effect of gas- or water-injection and other methods used to maximise recovery," Ivar Erdal says.

"We believe that the e-Core technology has the potential to optimise the production and by that improve the overall recovery."

That's a nice ambition for a company that is in the process of entering the market with a brand new product.

BLUEBACK RESERVOIR

Blueback Reservoir AS is a recently formed independent consultancy company providing high class services within the domain of geological 3D modelling. The company was started by a group of highly experienced people with a long history of both software development and consultancy services within geological 3D modelling. The company is based in Stavanger Norway, and operates on a global basis.

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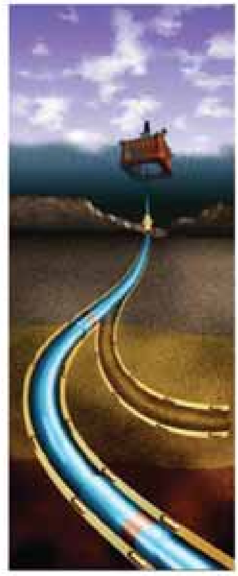

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19 October

INTRODUCTION
Welcome
Terje Thorsnes (Geological Society of Norway)

Knut Åm
Technological development; A key to successful petroleum assessment

Exploration

THEME 1 RECONNAISSANCE STUDIES
Chairman: Odleiv Olesen
Sedimentary geology; past, presence and future importance in hydrocarbon exploration and exploitation
Ole Martinsen (Norsk Hydro)
The "Golden Play" is within "the Golden Zone"
Per Arne Bjørkum (Statoil)
Plate tectonics and frontier exploration - new tools and methods
Trond Torsvik (Geological Survey of Norway)
Modern aeromagnetics challenge the established model for NE Atlantic opening
Odleiv Olesen et al. (Geological Survey of Norway)

THEME 2 IMAGING
Chairman: Ola Fjeld
Recent Advances in Seismic Imaging
David Hill (WesternGeco)
Advanced extraction of geological / geophysical information from seismic
Lars Sønneland (Schlumberger)
Visualization advances and the future
Eng Lim Goh (SGI)

THEME 3 BASIN MODELLING & RISK ASSESSMENT
Chairman: May Britt Myhr
Paleopressure evolution and cap rock seal efficiency
Cristina Daturi (ENI)
Quantification of uncertainties in pressure simulation
Ane E. Lothe (SINTEF)
From basins to reservoirs: Bridging the scale-gap in petroleum relevant geodynamic modelling
Yuri Podladchikov (PGP)
Risk Assessment: Principles and experiences
Kjell Øygard (SINTEF)
Enhancing Play Assessment Accuracy within the Halten Terrace Jurassic Petroleum System Using Discovery Process Modelling
Richard Sinding-Larsen (Norwegian University of Science and Technology)

Conference dinner

Dinner speech: Andrew Armour, Revus Energy

20 October

INTRODUCTION
Arild Bøe (University of Stavanger)
The end of the beginning ... - the future of the Norwegian Petroleum Industry

THEME 4 ELECTROMAGNETIC SURVEYING
Chairman: Ståle Johansen
SBL, a new tool for subsurface resistivity mapping
Ståle Johansen (emgs)
New technology challenges for exploration
Dirk Smit (Shell)

Reservoir management

THEME 5 4D/4C Seismic
Chairman: Egil Tjåland
Improved reservoir characterization based on 4C seismic data
Eivind Berg (Seabed Geophysical)
Reinterpretation of the Cantarell Complex with 4C Node Data
Marco Vázquez Garcia (Permex)
Valhall Life of Field Seismic - From Concept to Impact
Olav Inge Barkved, BP
Use of 4D and 4COBS in Statoil
Mark Thompson (Statoil)
History matching using 4D seismic and pressure data on the Norne field
Magne Lygren (Statoil)

THEME 6 REAL TIME RESERVOIR MODELLING
Chairman: Ola Fjeld
The Living ModelTM for Multi-Disciplinary Risk & Impact Analysis
Jim Brady (Schlumberger)
OPC/eOperations in Norsk Hydro
Trond Lilleng (Norsk Hydro)

THEME 7 SPECIAL TOPICS
Chairman: Ola Fjeld
Predictive Pore Scale Modelling
Pål-Eric Øren and Stig Bakke (Numerical Rocks AS)
Gravimetric reservoir monitoring
Ola Eiken (Statoil)
Reservoir uncertainty management: an integrated approach
Jon Inge Berg, Morten Fismen (Roxar)

21 October
Participants are invited to attend presentations from the following companies between 10.00 and 14.00:

* Sintef Petroleum Research, Institute for Petroleum Technology and Applied Geophysics (Sintef IKU)
* Geolgical Survey of Norway (NGU)
* Norwegian University of Science and Technology (NTNU)

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Towards the I-Field

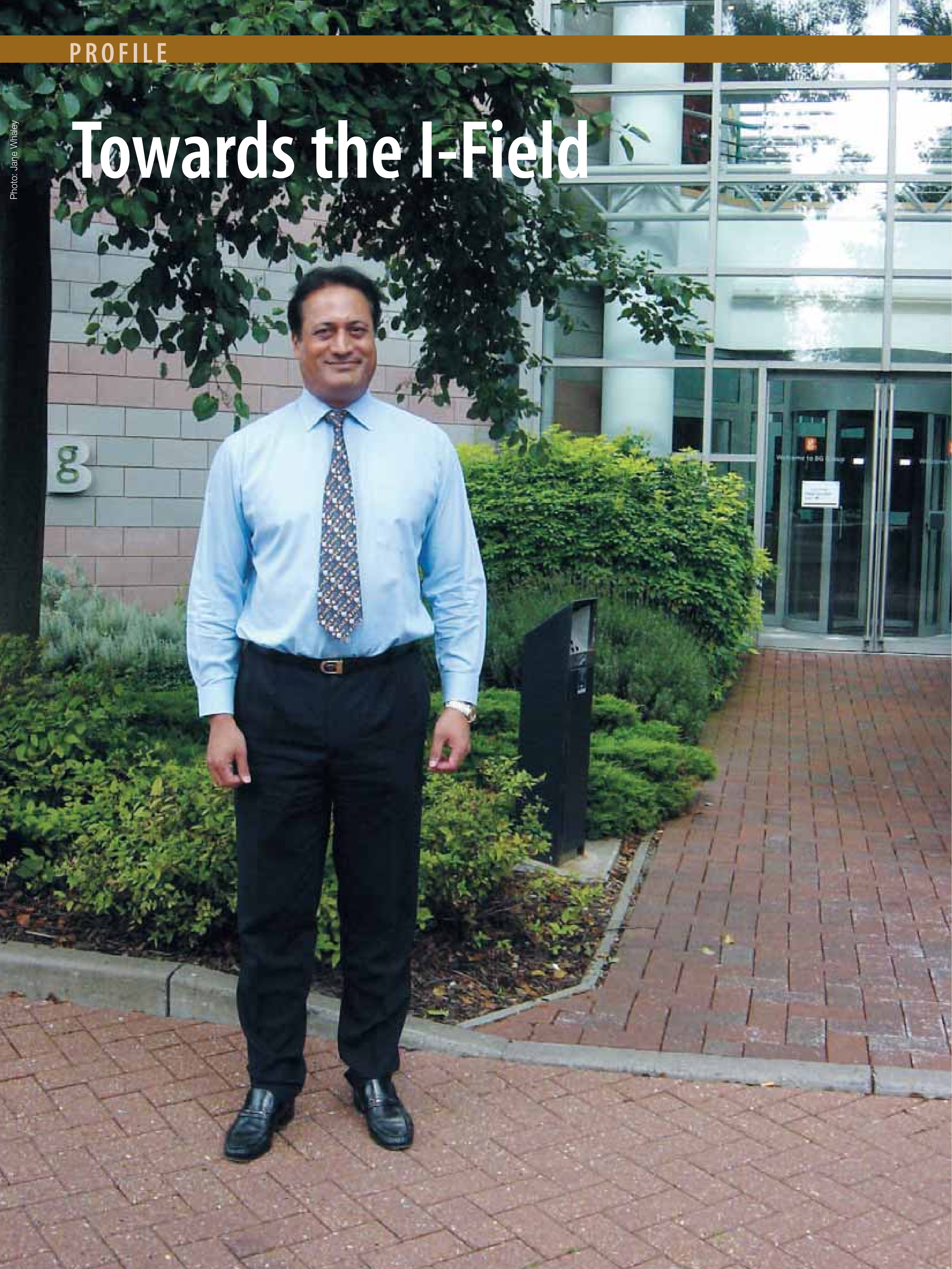


Photo: Jane Whaley

Reservoir engineers have a crucial role in oil companies, as they are involved in the entire value chain from initial exploration, though the discovery phase right through to first production.

Jane Whaley

"In essence, reservoir engineering is the optimisation of the economic recovery of hydrocarbons from the subsurface. The reservoir engineer takes the static geological and geophysical models and constructs a dynamic 'cellular reservoir simulation model' of grid blocks of subsurface strata," explains Dr. Satinder Purewal, Consultant Reservoir Engineer with BG Group in the UK.

Dr. Purewal has many years experience in reservoir engineering in various parts of the world. He is also the Chairman of the Distinguished Lecturer Committee of the Society of Petroleum Engineers and a Visiting Professor of Petroleum Engineering in Imperial College, London. He is therefore the ideal person to explain the development and importance of the discipline of reservoir engineering in the hydrocarbon exploration and production process.

"Reservoir performance is dependant on a range of variables in reservoir architecture, including variations in static and dynamic properties such as porosity, permeability, water saturation, and reservoir pressure. Reservoir engineers are concerned with the dynamic processes in the reservoir, creating dynamic reservoir simulation models to optimise production rates, the number and location of production and injection wells and production tubing sizes. It interfaces with the surface facilities to achieve optimum recovery from the reservoir" he says.

The fundamentals of reservoir engineering

"This summarises the fundamental difference between geological disciplines in hydrocarbon exploration, which are mostly concerned with the static condition, and those of reservoir engineering, which are concerned with dynamic situations."

"We also connect the subsurface to the surface, as the reservoir engineer is involved in optimising the design and construction of production facilities by predicting the plateau flow rates and the anticipated nature of the produced fluids. Data acquired from discovery and appraisal wells is crucial for developing the reservoir model and production profiles. Output from reservoir simulation models are input in financial software to determine economic viability of the project. Optimisation of the surface production facilities is an iterative process, involving an integrated team of engineers and economists.

Reservoir architecture is often very simplistic in the initial model of an oil discovery. Once appraisal wells have been drilled, reservoir extremities delineated and some dynamic well test information has been obtained, the model is then constrained by the larger data set, providing more confidence in it. After a couple of years of oil production you often see that the complexity of the reservoir architecture is much greater than initially expected. The reservoir engineer is involved from initial exploration, through the discovery phase and throughout the production phase of field life cycle. The key deliverables of the reservoir engineer are production profiles and reserves, the latter being fundamental in determining the value of the company."

Physics: A core science

Dr. Purewal did not initially anticipate a career in the oil industry. He studied Physics at Imperial College, and followed his BSc. with an MSc. in Applied Optics, concentrating on developments in laser technology. He then further broadened his scientific knowledge with a PhD. in Chemical Engineering, also at Imperial College, in which he studied theoretical modelling of light scattering. This somewhat eclectic mixture of sciences gave him, he feels, a very sound basis as a reservoir engineer!

"Physics is a core science, giving a fundamental grounding in the sciences that allows one to move into many other scientific or engineering disciplines. It also makes great use of modelling and simulations which are key elements in reservoir engineering." The Masters degree and Doctorate further broadened his skills and provided "most importantly, a different sort of thinking, particularly how to do research and where to find the information you need".

After completing his PhD, Satinder was offered research posts but decided it was time to travel and see more of the world. A position as a field engineer with Schlumberger offered the opportunity to achieve this ambition, and he spent three happy and informative years working both on and offshore, mostly in the Far East, during which time he designed and supervised well tests and helped develop business in Japan and the Far East. This was followed by a number of years as a reservoir engineer in the North Sea working on a wide range of projects with different companies and increasing levels of responsibility.

The urge to travel beckoned once more and in 1993 Dr. Purewal moved to Nigeria with Shell, where he led a number of large multicultural and cross-disciplinary teams and also became involved in training young Nigerian engineers. He found working in Nigeria fascinating and enjoyed a number of new experiences, although perhaps being held up at gunpoint and relieved of cash and valuables was an experience he could have done without!

Dr. Purewal has now been with BG Group for 5 years, during which time he has been involved in projects worldwide, from reservoir engineering for the Buzzard Field (GEO ExPro, No. 2-3, 2005) in the North Sea to simulation studies for projects as far afield as South America and the Far East. He was also recently heavily involved in the technical aspects of development of the Kashagan field in Kazakhstan, one of the largest oilfield projects in the world.

The need for field experience

Satinder has made a point of continuing his training and professional development and has undertaken many courses, including geological field trips. This, he feels, has made up for his lack of any formal geoscience training, and he thinks that one can learn much of what is needed "on the job", particularly by working in the field.

"I am always glad that I spent a number of years working on rigs. It allows me to fully understand all the issues involved in reservoir engineering, and the cultural and working environment around which decisions are made. It is sad to realise that nowadays some young reservoir engineers do not have the experience of working in the field, particularly those who go straight in to smaller oil companies which are not actively involved in drilling. They don't really have a feel for what goes on in operations and miss out on the very important practical nature of the job."

He also firmly believes that working in a variety of posts in different physical and cultural environments had a very positive effect on his professional life. As he puts it "I have created opportunities for myself in different countries and companies in order to keep learning and thereby develop my skills and knowledge as a reservoir engineer. More importantly, working in a variety of environments and with people from diverse backgrounds and cultures really helps one's ability to work in multicultural, cross-functional and multidisciplinary teams, particularly in a senior position. It helps you to get on with people and get the job done and done well."

Laptop simulations

Reservoir engineering is anything but a static discipline. As Dr. Purewal points out "classical reservoir engineering was undertaken with spreadsheets, or even just a pen and paper! Developments in reservoir analysis have moved apace, however, and complex simulations and well test analyses, as well as reservoir management, are now carried out by computer, using a huge variety of software."

"Reservoir simulation software has been around since the mid-eighties, when most of the majors had in-house simulation software, but it really took off in the nineties, when commercial software products came into vogue in a big way. Recent important developments include software products which can be used on a laptop, allowing the reservoir engineer amazing simulation portability."

"However, one of the most fundamentally important developments to come into the reservoir engineering domain in recent years is geostatistical modelling software, such as Gocad and IRAP/RMS, to name merely two products on the market. Multiple geological realisations, a direct result of increased computing power, has provided a tool for characterising uncertainty in a way which was not possible previously. The slow but increasing uptake of stochastic modelling is a sign that the industry is serious about risk reduction and narrowing the bandwidth of uncertainty."

Another important software product which has been introduced to the reservoir engineer recently is automatic history matching. This uses the dynamic reservoir simulation model to allow the matching of production history, which includes observed data such as fluid rates and pressures. This cuts down the time required to history match and to provide production forecasts, helping to reduce overall costs.

In addition, developments in other fields such as geophysics have had a significant effect on the work of the reservoir engineer. "In the early days of the North Sea, it was common to create a reservoir model based on 2D seismic. Nowadays, we have 3D, 4D and 4C data, giving us information on how the reservoir changes over time, the effect of production and injection on the gas/oil and oil/water contact, and a much greater idea of the compartmentalisation of the reservoir.

"I must have been doing something right"

Dr. Purewal is a strong supporter of the Society of Petroleum Engineers, which he has seen expand and develop considerably since he first joined it in 1983. He has been a member of the board of directors of the London Section for the last 5 years and was Chairman in 2002 – 2003, during which time he saw attendance increase considerably. London was awarded the President's award for Section Excellence during his Chairmanship, so, as he puts it "I must have been doing something right!"

He is a member of the SPE Distinguished Lecturer Committee (DLC), who select eminent speakers to make presentations on a huge range of petroleum related topics at the invitation of the SPE, often in conjunction with major conferences such as OTC and ATCE. Distinguished Lecturer candidates are nominated by their peers and the DLC reduce 70 or more nominations to about 30 lecturers, who are then invited by SPE local sections to make their presentations.

Dr. Purewal enjoys being part of this, as it gives him a wonderful opportunity to meet these eminent industry specialists, who now come from all over the world, as opposed to the situation a few years back, when the majority came from North America. He thinks that this is the way the SPE is evolving, with an increasing membership and active participation from outside North America. In fact, Dr. Purewal himself was recently elected Chairman of the DLC for 2005 to 2006; "a great honour, as I believe I am the first non-North American Chairman of the DLC."

Satinder still lives in South Kensington, near Imperial College, and enjoys keeping up his contacts with his old college. He is a Visiting Professor, working on the MSc. Course in Petroleum Engineering (GEO ExPro, No. 2-3, 2005). "Imperial College is excellent at the theoretical side of reservoir engineering, but I help by introducing students to the practical experience of the hydrocarbon industry. I assist them with their project work, and also lecture in field development planning, impressing on the students that reservoir engineering is a core discipline within petroleum engineering. I very much enjoy lecturing and working with the students."

The Intelligent Well System

Working with Imperial College and the DLC allows Dr. Purewal to keep abreast of the latest developments in his field. "Important advances in reservoir engineering have utilised new technology, with developments like multilateral wells allowing us to access reserves from several parts of the reservoir(s) with multiple bores connected via a single well bore to surface" he says. "We can also use new techniques like geosteering to reach targets in the reservoirs with an accuracy unimaginable few years ago, while new hydrocarbon sources such as tar sands require the reservoir engineer to work with totally different simulation and production processes."

However, the most important recent developments have been in software and, in particular, in the move towards 'intelligent wells'. An intelligent well system can monitor the well bore and reservoir characteristics in real time and analyse, adjust and optimise flow regimes. This automatic monitoring helps to reduce risk and optimise production while minimising the need for human intervention.

"For instance," explains Dr. Purewal, "the futuristic self-stimulating well can identify scale potential and ensure that the chemical stimulation is optimised. Many clastic reservoirs in the North Sea are generally of very high permeability with multiple zones with good sweep characteristics. However, mixing of injected water and in-situ water creates scaling tendencies which have to be managed in the production system from wells to production facilities. In the future well, the software may be able to automatically select the zones and wells for self-stimulation. This is still new technology and has a lot further to go."

"Ultimately," says Dr. Purewal, "the future lies in the 'i-field', the totally electronic, fully automated oilfield. Working towards this, it seems as though reservoir engineers are trying to evolve themselves out of a job!"

Young reservoir engineers need not worry: Dr. Purewal is sure that there will always be a need for human intervention "if only to turn the computer on!"

Stay informed:

Read about mining in the Athabasca oil sands
in the next issue of **GEO ExPro**.

"Canada's oil sands are the world's largest single hydrocarbon resource."

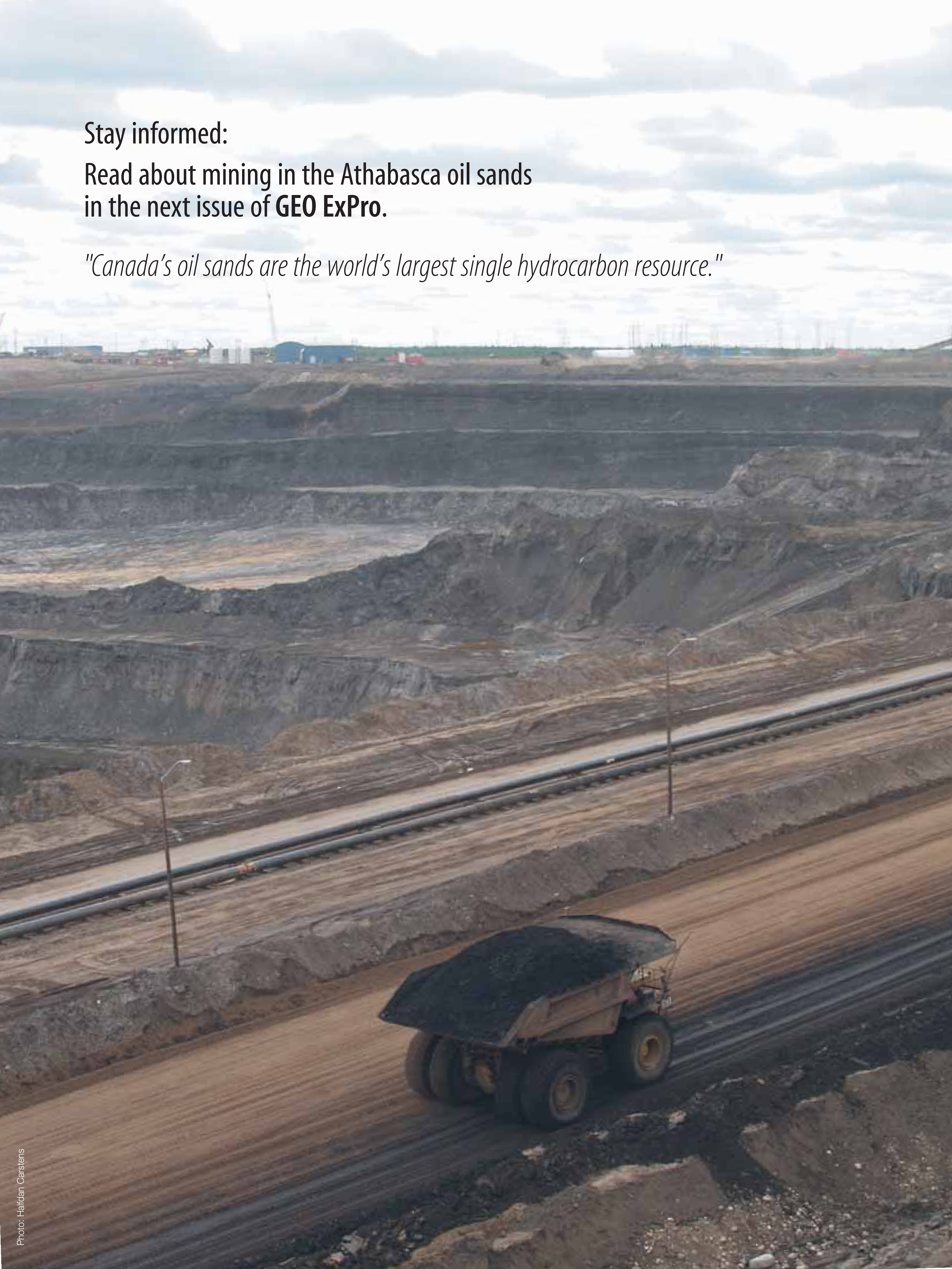


Photo: Halfdan Carstens

Building reservoir models in Provence

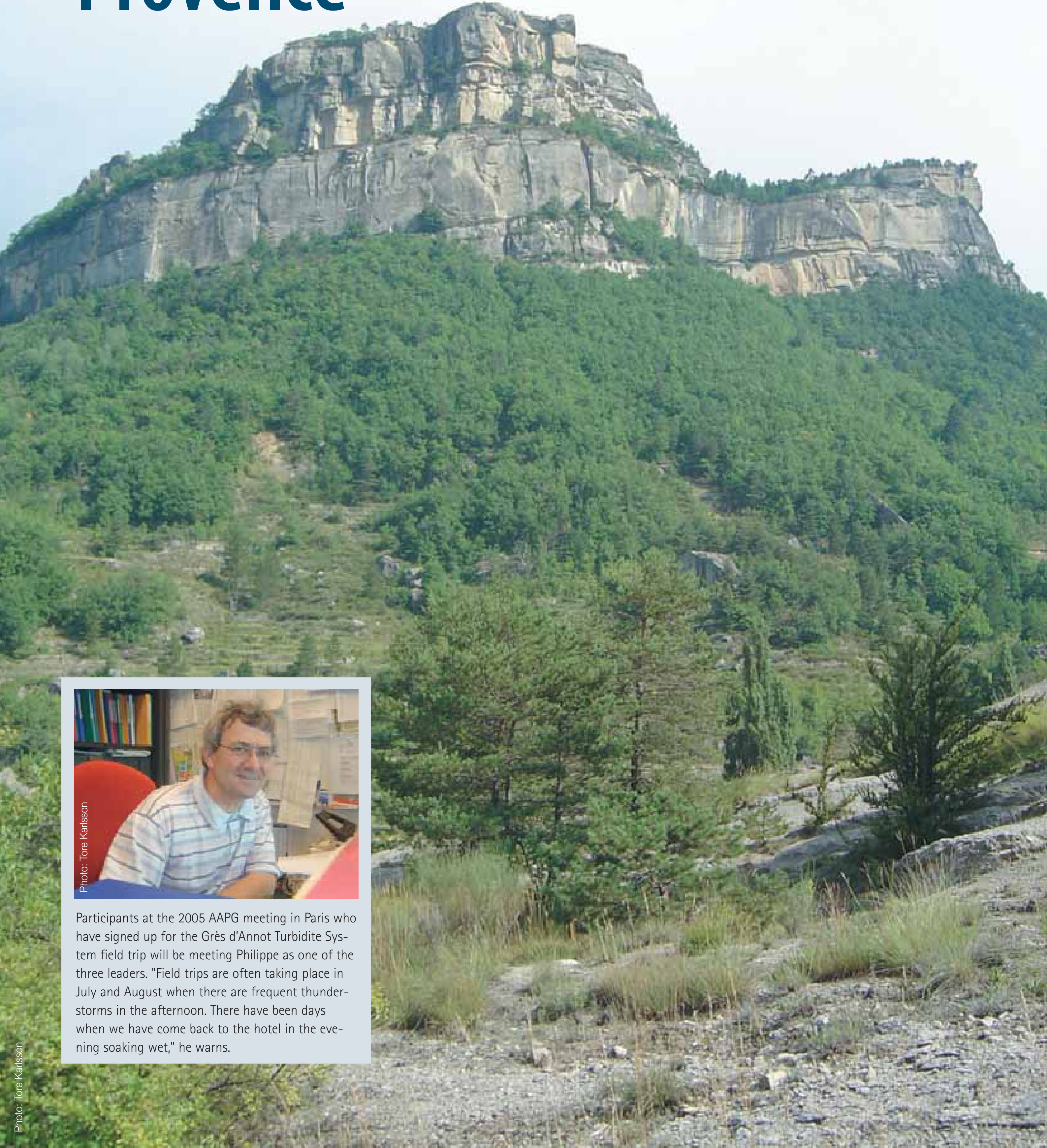


Photo: Tore Karlsson

Photo: Tore Karlsson

Participants at the 2005 AAPG meeting in Paris who have signed up for the Grès d'Annot Turbidite System field trip will be meeting Philippe as one of the three leaders. "Field trips are often taking place in July and August when there are frequent thunderstorms in the afternoon. There have been days when we have come back to the hotel in the evening soaking wet," he warns.

Reservoir engineers have a crucial role in oil companies, as they are involved in the entire value chain, from initial exploration to appraisal and development, right through to first production.

Tore Karlsson

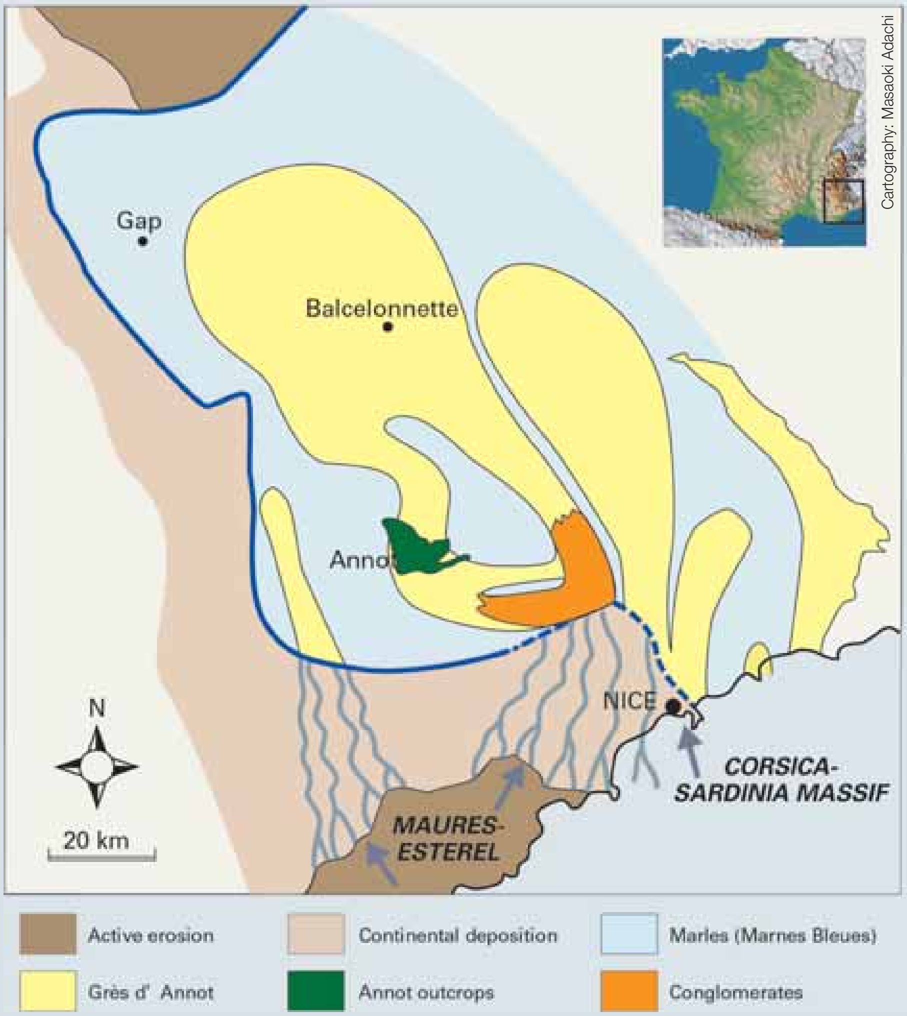
Perhaps you are visiting the French Riviera, but you are looking for a break from beaches and fancy restaurants? Well, here is a proposal for you that may satisfy your geological curiosity.

Within a couple of hours drive from Nice you can be at the heart of the fascinating outcrops of the famous Grès d'Annot turbidite formation. For more than 150 years this area in the southeast of France has attracted geologists from many countries and from academic as well as industrial spheres. If you like to stay overnight before going back to Cote d'Azur, *Les Gorges du Verdon*, unique in Europe and one of the greatest tourist attractions in Provence, is next door.

Benchmark example

The Grès d'Annot formation was deposited during late Eocene – early Oligocene times in the western alpine foreland basin in South East France. "The turbidites of this formation is considered a classic model for gravity deposits and show strong evidence of control by pre-existing bathymetric relief," says professor Philippe Joseph of the Institut Français du Pétrole (IFP) in Paris. Philippe Joseph has a PhD in sedimentology and has been a scientist with IFP since 1990. Joseph has been in charge of two industry consortiums, one on turbidites and one on stratigraphic modelling. The turbidite consortium was based on fieldwork in Grès d'Annot.

"The Grès d'Annot is a sand-rich turbiditic system, up to 1000 m thick, deposited in several parallel and tectonically controlled



The geological map of the Annot Basin, located at the southeastern tip of France, illustrates how sediments of the Grès d'Annot formation were transported from south to north. The clastic rocks are overlying marlstones of the Marnes Bleues Formation.

Building reservoir models

3D seismic is an essential tool for defining the overall geometry of deeply buried reservoirs. With limited resolution, however, it does not provide sufficient detail for understanding reservoir heterogeneity, critical for the prediction of fluid movement and reservoir modelling.

Studies of outcrop analogues have therefore become an additional tool providing a smaller scale 3D architecture of sand body geometry. Reservoir engineers can thereby optimize production and recovery by improved parameterisation and improved simulation.

Analogues like the one we find around Annot, a textbook example of deep-sea deposition, may assist reservoir engineers improve field performance in many parts of the world; such as offshore Brazil and West Africa, in the Gulf of Mexico, in the North Sea and along the North Atlantic Margin.

The Grès d'Annot formation lies at the cliff Les Scaffarels near the town of Annot, in the core of the present Annot syncline. The outcrops in the Annot area correspond to the proximal part of the Annot basin, which was fed from the Corsica-Sardinia and Maures Esterel massifs during Tertiary times. This proximal area is very sand-rich and characterized by the development of deep channels, filled by pebbly to coarse-grained high-density sandy turbidites. The plane of this photo is oriented perpendicular to the average current orientation and the channels.

The magnificent canyon Les *Gorges du Verdon* is located next to Annot and worth a visit when venturing out of Nice. The gigantic cliffs of calcareous rocks are the result of the erosion of the Verdon River. Never really discovered until the beginning of the last century, the Verdon Gorges have since fascinated innumerable visitors.

sub-basins. During Early Tertiary, the basin subsidence exceeded the sediment supply and the basin floor progressively deepened," explains Philippe who has been responsible for the organization of numerous field trips to the Annot area.

"Grès d’Annot is generally considered as a benchmark example of a sand-rich delta-fed turbidite system," says Philippe. "Sediments were primarily supplied from the Corsica-Sardinia continent to the south, which was at that time attached to the European plate. Grès d’Annot shows downstream evolution from massive coarse-grained erosive channels to tabular channelized or depositional lobes separated by thick heterolithic levels acting as major permeability barriers. The thickness of the series is very variable, from a few hundreds of meters on structural highs to more than one thousand meters in the deeper sub-basins."

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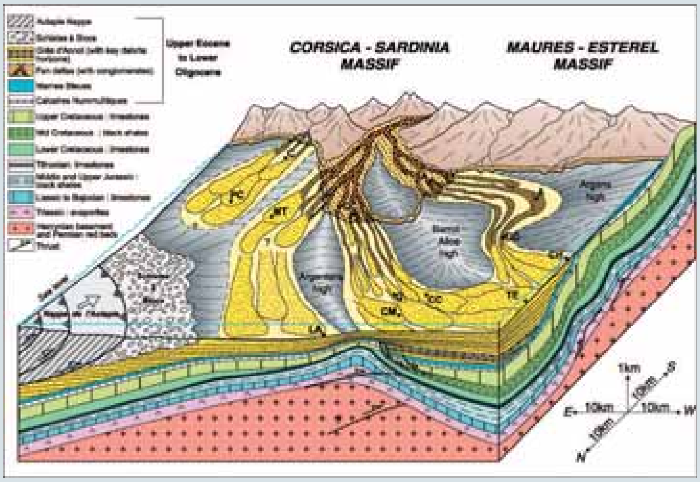
Schematic palaeogeography of the Grès d'Annot system in Early Oligocene times. © IFP; JOSEPH P. & LOMAS S.A. (eds) 2004. Deep-Water Sedimentation in the Alpine Basin of SE France: New perspectives on the Grès d'Annot and related systems. Geological Society, London, Special Publications, 221, 448 p.



Birthplace of the "Bouma sequence"

"Through the second half of the 20th century, research on Grès d’Annot took place in three phases," explains Philippe.

"Major advances were made in the understanding of sedimentology of deep marine deposits in the late 1950s and early 1960s with the progressive emergence of the turbidite concept. From that time onwards the Grès d’Annot outcrops were used as a training area in the field. In the 1960s the general structure of the system was mapped. In 1962 A.H. Bouma used the studies of the Peira Cava outcrops of Grès d’Annot as the basis for the definition of the well-known ‘Bouma Sequence’ for the description of turbidity currents. D.J. Stanley, who wrote his thesis at IFP in 1961, developed the first facies model for canyon and fan valley organization which was later intensively used as a standard analogue for deep-sea petroleum systems."

"This research was stimulated in the 1980s by the upsurge of intensive exploration on continental margins and the emergence of seismic stratigraphy. The high quality and large extent of the outcrops led university and research centre geologists to undertake extensive field survey in order to understand the large-scale organization of the system and to help seismic data interpretation in petroleum basins. These studies led Christian Ravenne and others to a reinterpretation of the standard radial fan model developed earlier and demonstrated that the sediments showed strong evidence of control by pre-existing bathymetric relief, with the existence of several parallel sub-basins acting as depocentres."

"A second renewal of interest in the Grès d'Annot occurred in the late 1990s with the development of detailed sedimentological studies of turbidite sandstone bodies by academic and petroleum company teams. The purpose was to improve the characterization of deep-water hydrocarbon reservoir analogues. At a late stage in field production it is realized that such reservoirs are more complex than expected. Early recognition of geometry and continuity of drainage is a key factor in order to optimize performance."


Photo: Tore Karlsson

Philippe Joseph explains the spectacular onlap of Grès d'Annot horizontal beds, pinching out abruptly against a pre-existing marlstone slope (Marnes Bleues formation) at Montagne de Chalufy.

Gateway to Brazil

"The Grès d'Annot has frequently been used as an analogue for sand-rich turbidite hydrocarbon fields where topographic control has played a key role in defining the reservoir bodies, such as in the North Sea and on the Brazilian margin," says Philippe.

In order to better characterize deep-water petroleum reservoirs along the Brazilian margin, IFP and Petrobras therefore undertook a very detailed study on some specific sites in 1995 and 1996.

"The purpose was to develop a better understanding of the architecture of these gravity deposits by reconstructing 3D reservoir models of their external geometry and of their internal facies distribution.

Annot has a history of more than 2000 years from when the Ligurian mountainous nomad people, les Verguniens, found refuge from invaders in caves in the Grès d'Annot carbonate rocks (for example La Chambre du Roi). Pope Gregoire VII mentions Annot as a relatively large mountain village in a bulletin in 1084. The near vertical Grès d'Annot cliffs around Annot are attracting climbers from all over Europe making the city a popular base for mountain climbing. www.annot.fr. *Courtesy of tourist office.*

Institut Français du Pétrole

L'Institut Français du Pétrole (IFP) is a scientific research and industrial development, training and information services centre active in the field of oil and natural gas, their applications and new energy and environmental technologies. With the need to respond to the growth in the energy demand, one of several priorities for IFP for the coming decades is renewing and increasing world oil and gas reserves. The research on Grès d'Annot is a part of this program.

www.ifp.fr

The interest generated by the first results led the two companies to let other oil companies in. A research consortium on 3D turbiditic reservoir models including BP-Amoco, TotalFinaElf, Enterprise Oil, Petrobras and Statoil resulted."

Studies of the Grès d'Annot formation allow the linking of the vertical evolution (facies sequence) with horizontal geometries in order to test new conceptual 3D models and predict the development of the reservoir between wells. For reservoir characterization purposes, kilometre-scale outcrop areas were studied in detail, resulting in bed-scale, 2D and 3D architecture descriptions.

Seven outcrop sites located in the different sub-basins were selected for detailed studies. For each location the vertical sections were measured with facies descriptions based on interpretation of flow transformation from debris-flow to turbidity currents. Direct measurements and mapping in the field enable the geometric characteristics of the reservoir bodies (size of channels, lobes, overbank deposits) and their internal permeability barriers (dimension of shale breaks, diagenetic concretions) to be quantified.

"These measurements allow the computation of geostatistical parameters that are characteristic of the internal facies distribution. Compiled in a database, these parameters may be used for the stochastic modelling of analogue deep-water reservoirs, where such quantitative parameters (and their uncertainty) are difficult to calibrate from scarce field data," concludes Philippe Joseph.

Turbidites

Turbidity currents represent one of the important mechanisms for transport of sediments from deltas and shallow water areas along the coast down the continental slope to the deep sea and abyssal plain.

Before systematic exploration of the oceans started, it was assumed that coarse-grained clastic sediments were deposited in shallow water areas near the coast and that the sediments became more and more fined grained away from the shoreline. When detailed mapping of the seabed started during and after the Second World War, it became clear that sand could be found down to several thousand meters of water depth.

The theory of turbidity currents was introduced in 1936 by Daly (R.A. Daly, Origin of submarine 'canyons' Am. J. Sci., 31, p. 401-420) and later refined by Kuenen and Migliorini in 1950. Kuenen had shown by model tank experiments that deposition from turbidity currents resulted in graded layers, called turbidites.

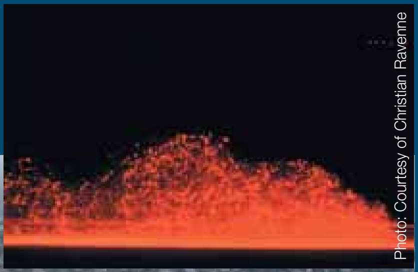
Turbidity currents are driven by the gravity effect on the density contrasts between material in suspension and the surrounding water. Turbidity currents are like underwater turbulent avalanches and can be triggered by storms and earthquakes, but can also continue from the flow in rivers if the river water is heavier than seawater.

As a simplification, a turbidity current can be considered as a sub sea river and the same hydrodynamic equations can by used to describe the fluid movement. An important difference is that friction induces turbulent mixing with surrounding seawater.

A turbidity current has four parts: the head, the neck, the body and the tail. Experiments show that the velocity in the head is lower than in the rest of the current. This means that sediments from the body of the current will be moved to the front before being turned back. Strong turbulence is generated at the neck of the current resulting in mixing with water and thinning of the turbidite.

The fine-grained fractions are found in the main body and the tail while the coarser grained fractions are found in the head. Sediments in the head will be deposited first, then from the body and finally from the tail of the current. The resulting deposit is a fining upward graded sequence.

Turbiditic currents and deposition represent an active field of research and it has now become clear that such systems are more complex than originally thought. Research includes fieldwork and measurements of current sedimentation processes as well as physical and numerical modelling.



Modern studies of turbidites include both fieldwork and tank experiments.

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How much oil?

Today, more than 80 million barrels of oil is produced daily. In 25 years, that number is expected to reach 120 million barrels. ExxonMobil has looked into the world's hydrocarbon resources and found that this increase in demand requires OPEC to add more than 1 million bopd every year after 2010.

According to the ExxonMobil Energy Outlook 2004 there is plenty of hydrocarbons left to meet the projected demand. The supermajor has looked at the liquids resource base, including *conventional* as well as *non-conventional* oil, the latter including extra heavy oil, oil sands and oil shales.

"The absolute level of conventional oil-in-place is not precisely knowable, but it is estimated to be between **6 and 8 trillion barrels**," writes ExxonMobil in their web-presentation. In comparison, USGS in their 2000 assessment estimated the total amount of future technically recoverable conventional oil, *outside the U.S.*, to be about **2.120 trillion barrels**". This concerns oil that has the potential to be added as reserves during the next 25 years (i.e. until 2030).

The non-conventional oils are more highly concentrated than conventional oil, with large deposits in Canada (oil sands), Venezuela (extra heavy oil), Russia (both) and the Caspian region (extra heavy oil). The non-conventional oil resources have, however, received much less attention than the conventional resources, largely because they are more expensive to produce and require new technology.

The estimates of non-conventional resources are very large. Exxon-Mobil says that the total resources of extra heavy oil and oil sands are over **four trillion barrels**. "With recovery in the 20-25% range, 800 billion to one trillion barrels may ultimately be produced – an amount equivalent to the total of all conventional oil produced to date," according to Exxon-Mobil.

BP has also published their view of the world's oil reserves which they believe are **1.2 trillion barrels** (BP Statistical Review of World Energy 2005). Included here is "official estimate of Canadian oilsands under active development". The reason for the discrepancy with the USGS number is that BP defines proven reserves as "generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions."

Given that we accept that there is enough oil to meet the predicted demand, the next question is if these resources can be made available within the next 25 years.

"The estimated call on OPEC increases slowly from about 28 million barrels a day to around 30 million barrels a day in 2010. During this time, growth in non-OPEC supplies satisfies most of the demand growth, leaving little room for OPEC growth.

After 2010, the call on OPEC increases quickly, requiring OPEC to add more than 1 million bopd of capacity every year. OPEC's resources are large enough to achieve this rate of expansion, and we expect that investments will be made in a timely manner," says ExxonMobil.

Photo: Halfdan Carstens

CONVERSION FACTORS

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

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

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

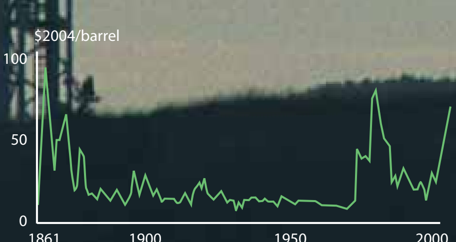
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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

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

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

Historic oil price



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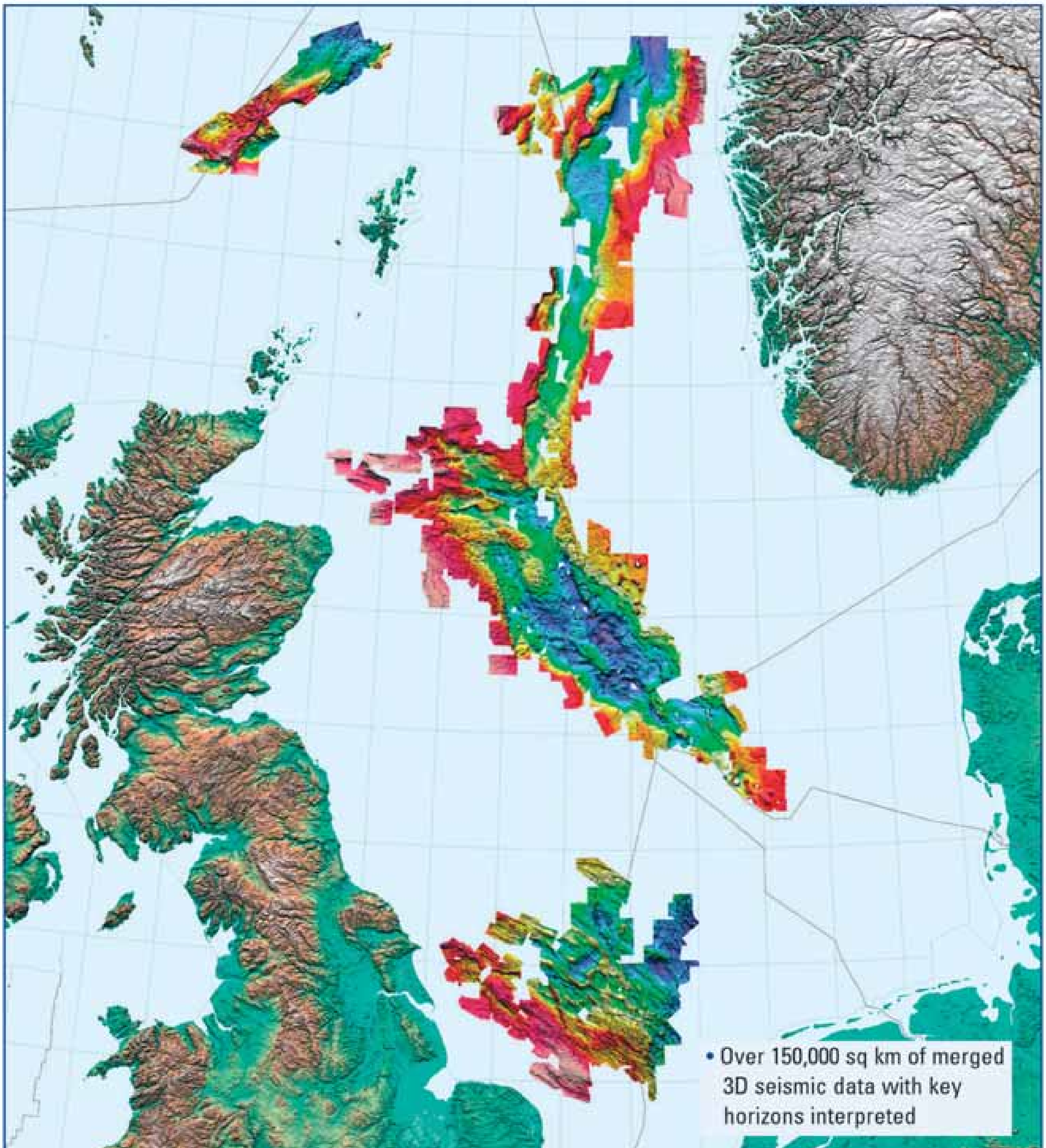

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