GEO ExPro
GEOSCIENCE & TECHNOLOGY EXPLAINED
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Egypt:
Geological beauties

ExPROFILE

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Gulf of Mexico:
Huge Potential Still Waiting

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GEOLOGY GEOPHYSICS RESERVOIR ENGINEERING

GEO ExPro
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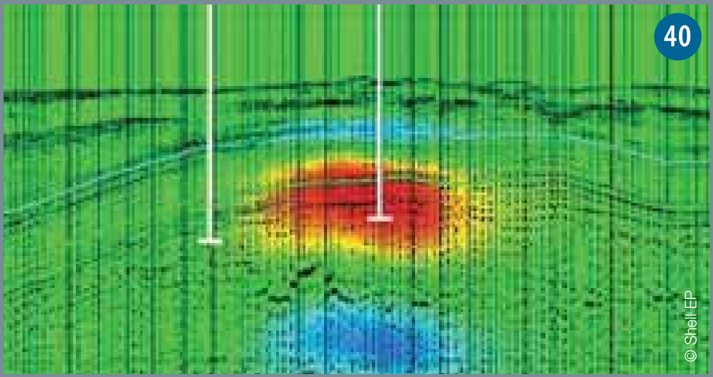
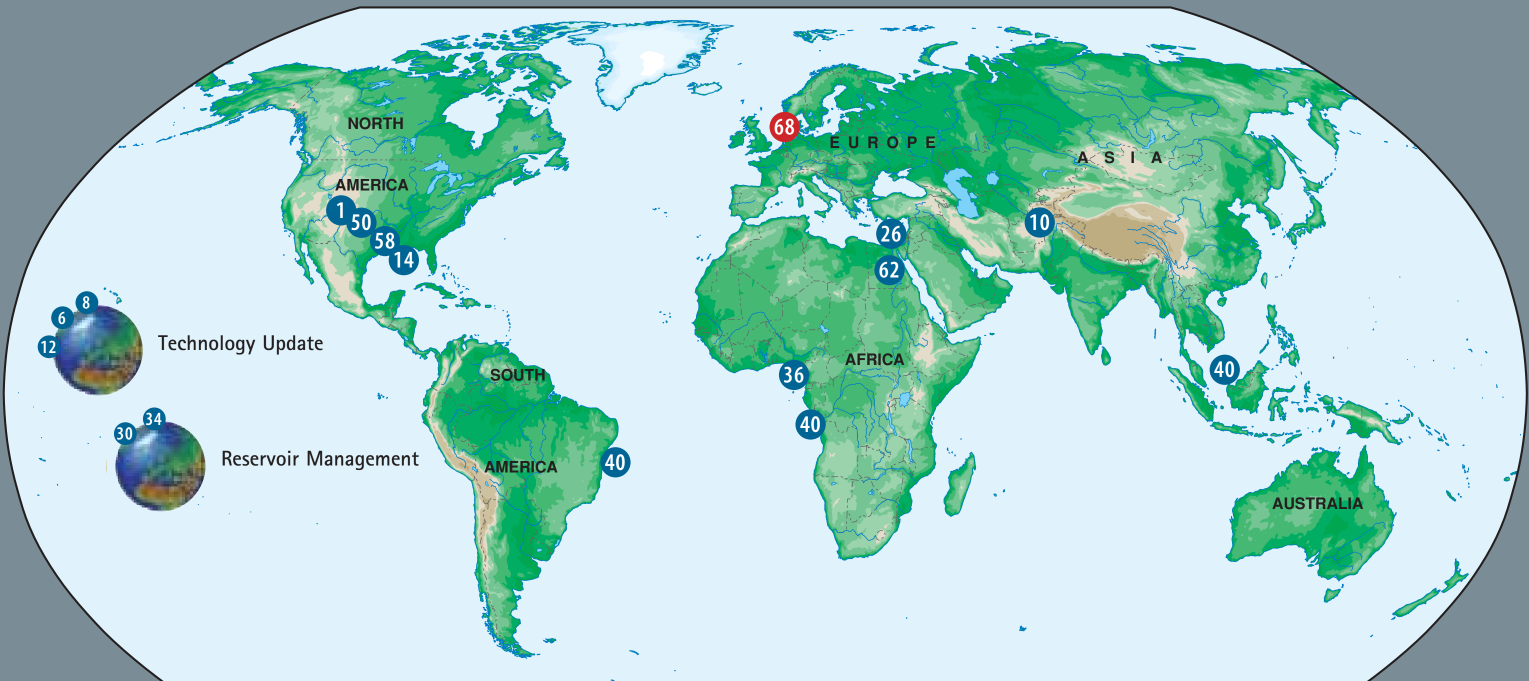
Coloumns

Features



Finding hydrocarbons
Through a series of surveys carried out in sedimentary basins worldwide, Shell has demonstrated that the use of low frequency electromagnetic signals emitted from a source above the sea floor can identify whether or not a potential reservoir contain hydrocarbons prior to drilling wells.

Exciting basin
The Gulf of Mexico is a mature oil and gas basin. However, the area remains prospective and exciting, as new plays have continued to extend the hydrocarbon prospectivity beyond the original boundaries, to deep and ultradeep waters, frequently through the development of innovative technology in both exploration and drilling.



More than enough – but expensive!

With a thousand barrels of oil being spent every second[1)], the equivalent of 86 million bopd , and with a 25 year forecast saying that this number will increase to 1,500 bopd, explorationists are left with a huge challenge; in the Gulf of Mexico (page 14-24), the Rocky Mountains (page 50-56), the Niger Delta (page 36-39) and elsewhere.

Having said that, we need to be aware that the world's oil resources go a lot further than light sweet crude (e.g. "North Sea Brent", "West Texas Intermediate") which is the prime petroleum product of today. There are a number of other sources for liquid oil – heavy oil, oil shales (GEO ExPro, No. 3, 2004) and oil sands (GEO ExPro No. 4/5, 2005) – that to a large extent have already been found. Similarly, there are huge amounts of gas stranded in *unconventional* reservoirs, such as gas hydrates (GEO ExPro No. 2, 2005), tight gas sands, gas shales and coal bed methane.

These abundant (!) resources have long awaited higher oil prices before being developed.

The price of energy has now reached a level at which unconventional oil and gas reservoirs are rapidly being developed. This is clearly demonstrated in the Canadian oil sands where oil production has reached approximately one million barrels per day, and by 2020, production will grow to four million barrels per day. The ultimate volume of bitumen in place is reckoned to be 1.6 trillion (10^{12}) barrels or 250 times the volume of oil that can be recovered from Prudhoe Bay.


Photo: Halfdan Carstens

The Canadian oil sands make a significant contribution to world oil production – and to global warming.

Recoverable, conventional oil resources are estimated to 3 billion barrels worldwide. Additional unconventional resources (extra heavy oil, oil sands, oil shales) bring these recoverable resources to 4-5 trillion barrels (ExxonMobil Energy Outlook 2004). Of this, approximately 1 trillion barrels have been produced since oil was first discovered.

The good news is therefore that we will have plenty of access to (expensive) oil and gas in the foreseeable future.

The bad news is that the CO_2-level in the atmosphere is bound to increase until these vast resources have all been burned.

Have a warm day!

Halfdan Carstens
Editor in Chief

1) Peter Tertzakian; The Coming Oil Break Point and the Challenges Facing an Energy Dependent World, McGraw-Hill 2006

Photo: Halfdan Carstens

More to be found

The 2003 discovery of the Covenant Field, some 200 km from the nearest significant production, could open up a billion-barrel oil province in the central Utah fold-and-thrust belt. Prior to the discovery, the complex geology of the thrustbelt had frustrated explorationists for over 50 years, with 115 wells drilled without a discovery.

The size of the discovery and the ultimate potential of the trend are still subject to much speculation. Nevertheless, this discovery – made possible only by persistent work through several years – certainly proves that we are in need of geologists with knowledge and experience, as well as imagination. Once again we have been taught that to find more oil and gas we rely heavily on people with in-depth knowledge gained through a long career.

In this edition, Rasoul Sorkhabi and Greg Nash, both with the Energy Geoscience Institute in Salt Lake City, Utah, explain the complex geology of the Utah fold-and-thrust belt trend. In our next edition we will discuss the discovery itself in some more detail.


Photo: Halfdan Carstens

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Moving forward - fast


Photo: Halfdan Carstens

"Acceptance of the e-Core technology by Statoil is a quantum leap forward," says Ivar Erdal, Managing Director of Numerical Rocks. Based on samples from cuttings, sidewall cores and cores, it is now possible to get digital analyses of key reservoir parameters, thus saving both time and money for the impatient oil companies.

It is well known that core analyses are done in the laboratory using sophisticated equipment.. And this was certainly the truth until new technology based on thin section analyses and computer modelling was introduced last year, making it possible to get the same analytical data based on a single thin section.

Last year, Numerical Rocks introduced the e-Core technology in which petrographical data from thin sections are used to model important reservoir parameters like relative permeability, formation factor, capillary pressure, resistivity index and residual saturations. All of these are crucial for doing a proper reservoir simulation with the purpose of planning optimal reservoir performance during production (GEO ExPro No 4, 2005).

This all sounds like science fiction, but the new methodology is now about to be approved by Statoil and will be used extensively by the company. "This is a breakthrough for Numerical Rocks," says Managing Director Ivar Erdal to GEO ExPro. "Up to now, Statoil has been using it as an R&D tool in selected projects only whereas now they plan to use it in their everyday operations."

"The e-Core technology is in the process of being introduced as an official tool in core analyses in Statoil," says Wibeke Thomas, advisor in Core Analysis in the company. "So far, we look upon this innovative technology as a supplement to laboratory measurements. We will continue to use the lab while at the same time we gather experience with the digital analyses. In particular, we need to calibrate results based on the e-Core technology with real values," she says.

"Another aspect is that we can do many more analyses in a short time once the "stone" has been built in the computer. Whilst measurements may take weeks and months, digital analyses take only minutes and hours. There is a huge potential for getting a lot more information from the well samples because of this."

Statoil has recently drilled a well in which only sidewall cores were taken in certain parts of the reservoir interval. "We have decided to use Numerical Rocks to analyse these zones based on thin sections from the sidewall cores. In addition, we will calibrate these analyses against laboratory measurements in intervals where cores have been taken. In this way we also get reliable data from parts of the reservoir where we were not able to retrieve core samples," says Wibeke Thomas.

Statoil is not, however, the only user of the e-Core technology. "We are doing R&D while at the same time commercializing the product. Our client list is therefore not very long yet, but we have succeeded in getting more customers in recent months. Because we have experience in building the reservoir rocks on the computer, some clients will prefer this to be done by Numerical Rocks. We offer both a software package to be installed by the clients and the possibility of doing all the work for them as a technical service, or a combination of these," Erdal explains, and refers to several successful tests and projects in which the digital analyses replicate the core analyses.

"One main argument for using this technology is to save time. While conventional core analyses may take weeks and months, we can do the same thing on the computer in a matter of days. This is, of course, an enormous advantage to the reservoir engineer who can start his modelling only a few weeks after the well samples have been made available," Erdal says. "We also have to remember that the laboratories have little or no capacity these days, meaning that there is a long time to wait to get data. Using e-Core technology and services from Numerical Rocks is therefore an attractive option for oil companies in need of fast and reliable reservoir data.

Numerical Rocks is now moving forward fast. "We have four major tasks; to build a market for the products, get more customers, continue to develop the technology and to build the organisation, which at the moment only consists of ten people," Ivar Erdal says.

"The Digital Core Laboratory" (GEO ExPro No. 4, 2005) is available on www.geoexpro.com [Reservoir Management].

ABBREVIATIONS

Numbers
(U.S. and scientific community)

M: thousand = 1 x 10^3
MM: million = 1 x 10^6
B: billion = 1 x 10^9
trillion = 1 x 10^{12}

Liquids
barrel = bbl = 159 litre
boe: barrels of oil equivalent
bopd: barrels (bbls) of oil per day
bcpd: bbls of condensate per day
bwpd: bbls of water per day

Gas
mmscfg: million ft^3 gas
mmscmg: million m^3 gas
tcfg: trillion cubic feet of gas

NGL
Natural gas liquids (NGL) include propane, butane, pentane, hexane and heptane, but not methane and ethane.

Reserves and resources
STOOIP:
Stock Tank Oil Originally in Place

Oilfield glossary:
www.glossary.oilfield.slb.com


Fault plane. In the eastern part of the Oslo Fjord we find a text-book example of a steep fault plane; crystalline basement rocks to the east are separated from downfaulted Paleozoic sediments of the Oslo Graben to the west.

Photo: Halfdan Carstens


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Low-impact Seismic

Low-impact seismic now offer the possibility to run seismic surveys in environmentally sensitive as well as hostile environments.

Doug Gibson, Vibtech CEO, is pleased with the fact that low impact, cable free seismic data acquisition is now a reality.

"Slainte!" says John Flavell Smith, co-founder of Vibtech, toasting in Scottish for successful testing of their new system on the island Islay, famed for its world class malt whisky, before the equipment *is* shipped to Texas for the first production trials with a major oil company.

With an increasing focus on protection of the environment there are many areas where seismic surveys are prohibited. "Low impact seismic operations" - using lightweight systems with correspondingly low personnel number crews - may enable some surveys to go ahead that otherwise would not have. Lightweight seismic systems are also the solution to hostile environments like dense jungles and for areas where security of crews *is* a critical issue and large conventional crews are exposed.

"We truly believe that Un*ite* *is* the answer to the explorationist's prayers, which have gone un-answered for too long," says Doug Gibson, Vibtech CEO.

Bill Park and John Flavell Smith founded Vibtech in 1996 with the belief that broadband cellular radio network would be able to handle massive data volumes acquired during a seismic survey. Both recognised the need to rid land and transition zone seismic systems of the messy and problematic cables and connectors, which are responsible for huge logistical, troubleshooting and HSE issues. Bill and John wanted the system to work in real time, but be cable free, handle an infinite number of channels, to be free of radio licensing restrictions and to overcome the interference and slow transmission rates that have historically plagued VHF-based radio frequency systems in the past.

The it System (Infinite Telemetry System) patented Cellular Seismic system was launched in 2003. It works by dividing the seismic spread up into a series of cells, with adjacent cells operating at different frequencies. "We use the same frequency band that microwave ovens operate in, so as long as we continue to heat our TV dinners in the microwave the band *is* unlikely to become licensed," comments John Flavell Smith.

The first system was sold to China Coal and used on a high density 3D survey in the Shandong Province southwest of Beijing in a mixed arable and urban area with homes, major roads and broad rivers throughout the prospect – an environment where it would have been very difficult to operate with a cable system.

BHP-Billiton operates an 800 channel it System in New South Wales, Australia under rigorous HSE regime in a highly environmentally sensitive area. The lightweight of the system enables it to be operated by a field party of only five personnel!

A detailed system design review of the it System was carried out in late 2004 and a new system was designed to harness the latest technology and to address user suggestions of features and benefits that they would like to see in the system. This resulted in the Un*ite* System, which was announced at the Houston SEG Convention in 2005. One of the improvements with the Un*ite* System *is* the elimination of the fibre-optic backhaul in the it System using a radio network. This means that the Un*ite* *is* a true cable less system altogether.

"We are all extremely encouraged by the results from these initial tests which have proved to the world that cable free seismic data acquisition *is* now a reality," concludes Doug Gibson.

Tore Karlsson

Cellular SeismicTM – Vibtech testing and performing production trials with Unite, their cable free seismic system, using mobile networking technology.

Marketing agreement

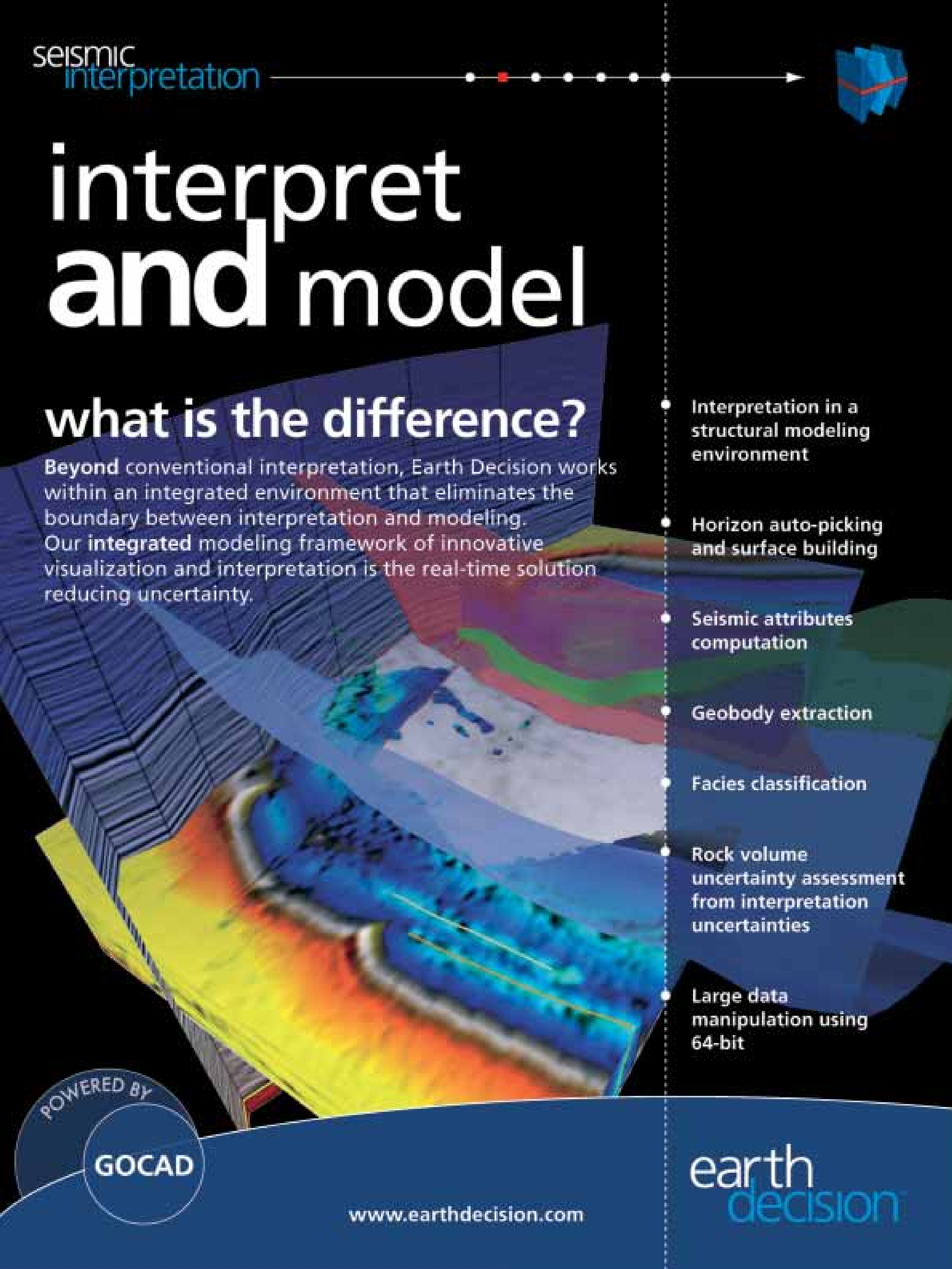
Global Geo Services (GGS) and Rock Solid Images have entered into a multi-year agreement under which Rock Solid Images will develop multi-well rock-physics and seismic model studies to be marketed by GGS in conjunction with their regional seismic programs.

"The move from qualitative to quantitative seismic interpretation methods is fueling a rapid increase in demand for high quality well-based calibration data. By providing integrated seismic and well-data studies, our customers will benefit from a significant reduction in cycle time and improved risk assessment decisions," says Richard Cooper, President of Rock Solid Images.

"This agreement builds upon our existing successful relationship developed through marketing the East Timor/JPDA regional well and seismic study. A significant number of additional integrated programs are currently under development including West Florida, GOM and East Java, Indonesia." added Trond Christofferson, CEO of Global Geo Services.

GGS is a public company producing 2D and 3D non-exclusive seismic data on a worldwide basis. GGS also develops non-exclusive programs and provides seismic services at multiple centers around the world through its wholly owned subsidiary Spectrum Energy and Information Technology ltd.

Rock Solid Images provides solutions for seismic reservoir characterization, and specializes in the integration of surface seismic and borehole data to build seismic-scale models of reservoir properties such as porosity and fluid saturation.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18 times increase

A recent USGS assessment significantly increases Afghanistan's petroleum resource base. The country may, according to the study, have hydrocarbon resources close to 3.6 billion barrels of oil and 16 Tcf of gas.

Satellite image of northern Afghanistan showing the location of Afghan-Tajik Basin and Amu Darya Basin as well as four different petroleum systems assessed in the study.

The USGS and the Government of Afghanistan Ministry of Mines and Industry have completed the first-ever assessment of Afghanistan's undiscovered petroleum resources. They have determined that the resource base is significantly greater than previously understood. The assessment was conducted over the past two years, with funding provided by the U.S. Trade and Development Agency, writes USGS on their web-site (www.usgs.gov).

Although considerable exploration has previously occurred, the estimates increase the oil resources by 18 times and more than triple the natural gas resources, the study concludes.

The country currently imports most of its energy, including electricity. The petroleum resource assessment provides Afghanistan with information needed for conducting future lease sales and is likely to be of interest to oil and gas exploration companies.

Much of the petroleum resource potential of Afghanistan and all of the known crude oil and natural gas reserves are in northern Afghanistan, located in parts of two geologic basins – the Amu Darya Basin to the west and the Afghan-Tajik Basin to the east. Most of the undiscovered natural gas is in Upper Jurassic carbonate and reef reservoirs beneath an impermeable salt layer in the sparsely explored Amu Darya Basin. Most of the undiscovered crude oil is in Cretaceous to Paleogen carbonate rocks associated with thrust faulting and folding in the Afghan-Tajik Basin. The two basins encompass approximately 500,000 km^2 (equivalent to approximately 80 North Sea quadrants) in those portions that lie within Afghanistan.

The assessment follows the widely accepted, standard USGS methodology and protocol. It is based on the geologic elements of a total petroleum system including data from detailed studies of geochemistry, petroleum geology, geophysics and tectonics. Historical exploration and production analyses were also used to aid in the estimation of the number and sizes of undiscovered petroleum accumulations.

Results of the assessment can be found at: http://pubs.usgs.gov/fs/2006/3031/

Inventing a New Device for S-wave generation

VibroPile is a seismic source that generates S-waves that can be used in soft sediments where conventional shear wave sources have problems.

© GeoProbing Technology AS

Almost 1.5 million euros have been spent in development thus far, including a field test in France in 2003. For reservoir monitoring a typical configuration would have 25 installed piles with one moveable S-wave source. Each pile is approximately 0.6m in diameter and has a length of about 2m. The vibrator itself weighs around 1.5 tonnes. Total weight with the submerged power unit is 6 tonnes.

"VibroPile is a newly developed seismic technique that can give more detailed images of reservoirs using shear waves from a source placed in the seabed," explains Jon Tore Lieng, Managing Director of GeoProbing Technology AS.

While ordinary marine seismic surveys are usually conducted using airgun arrays towed on long cables behind a vessel, the VibroPile technology is based on an entirely different principle. VibroPile is placed *down* into the seabed itself. Here it vibrates horizontally, thereby generating shear waves (S-waves).

The idea came from Associate Professor Egil Tjåland at NTNU, Trondheim, Norway, back in 1997. Lieng, who was doing work on lateral excitation of piles at the time, thought it was a bright idea and was put in charge of the development. Funding from the Norwegian Research Council and several oil companies helped give it a quick start.

"S-waves have slower velocities and shorter wavelengths than P-waves of the same frequency. This means they produce higher resolution images. In addition, S-waves (together with P-waves) can determine important physical characteristics (lithology) and fluid content in reservoirs. Also, while P-waves are absorbed, S-waves penetrate gas-filled sediments, making it possible to study reservoirs under gas clouds, However, these waves are also useful for monitoring fracture development and in helping to optimise production in producing fields," says Lieng.

The VibroPile technology does not yet lend itself to traditional oil exploration, since it does not cover vast areas cost-effectively. While traditional seismic waves can provide relatively low-resolution images of vast areas, the S-waves instead provide high-resolution close-ups of smaller areas. In consequence, the technology is good for exploration in areas with existing infrastructure e.g. reservoir monitoring. However, VibroPile can also help in determining where that all-important first exploration well should be placed and minimize risk.

Photo: Halfdan Carstens

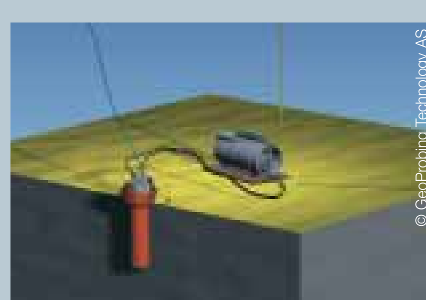
Jon Tore Lieng has other inventions to his credit. Now he is ready to supply the seismic industry with an S-wave generator in order to undertake better reservoir characterization.

S-waves alone have not previously been used for seismic analyses in connection with exploration and production of hydrocarbons offshore, because it has been difficult to generate waves that can propagate down into the substrata with sufficient strength. Lieng considers that VibroPile solves this problem. The system has already been tested in a decommissioned onshore oil field in France with excellent results.

Further development of this technology awaits an eager investor. Jon Tore Lieng needs additional funding to conduct offshore tests to demonstrate its capacity, strengthen the signal, do some redesign and make the source more user friendly.

"In short, we need more funding to prove that this is a tool that the oil industry can use with confidence," says Jon Tore Lieng. "A couple of million euros would do!".

VibroPile is forced into the seabed where it vibrates horizontally and generates S-waves. The instrument is now patented in several countries. There is no explosion, only a 10-120 Hz vibration, which generates a similar amount of energy as an airgun.



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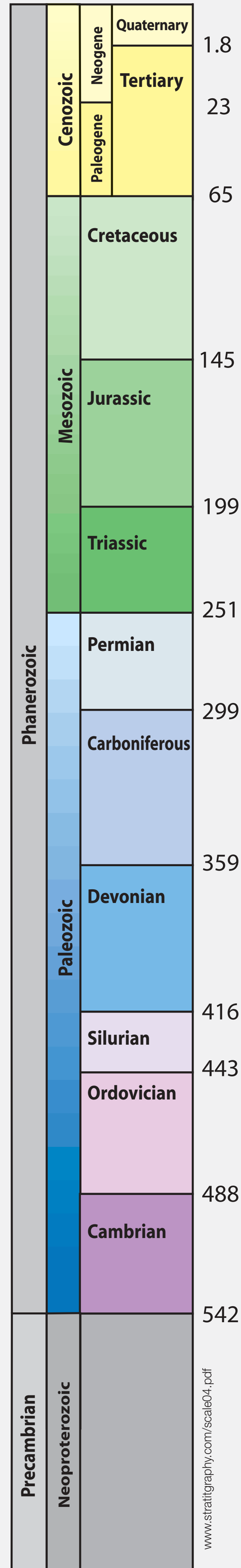
Geologic Time Scale

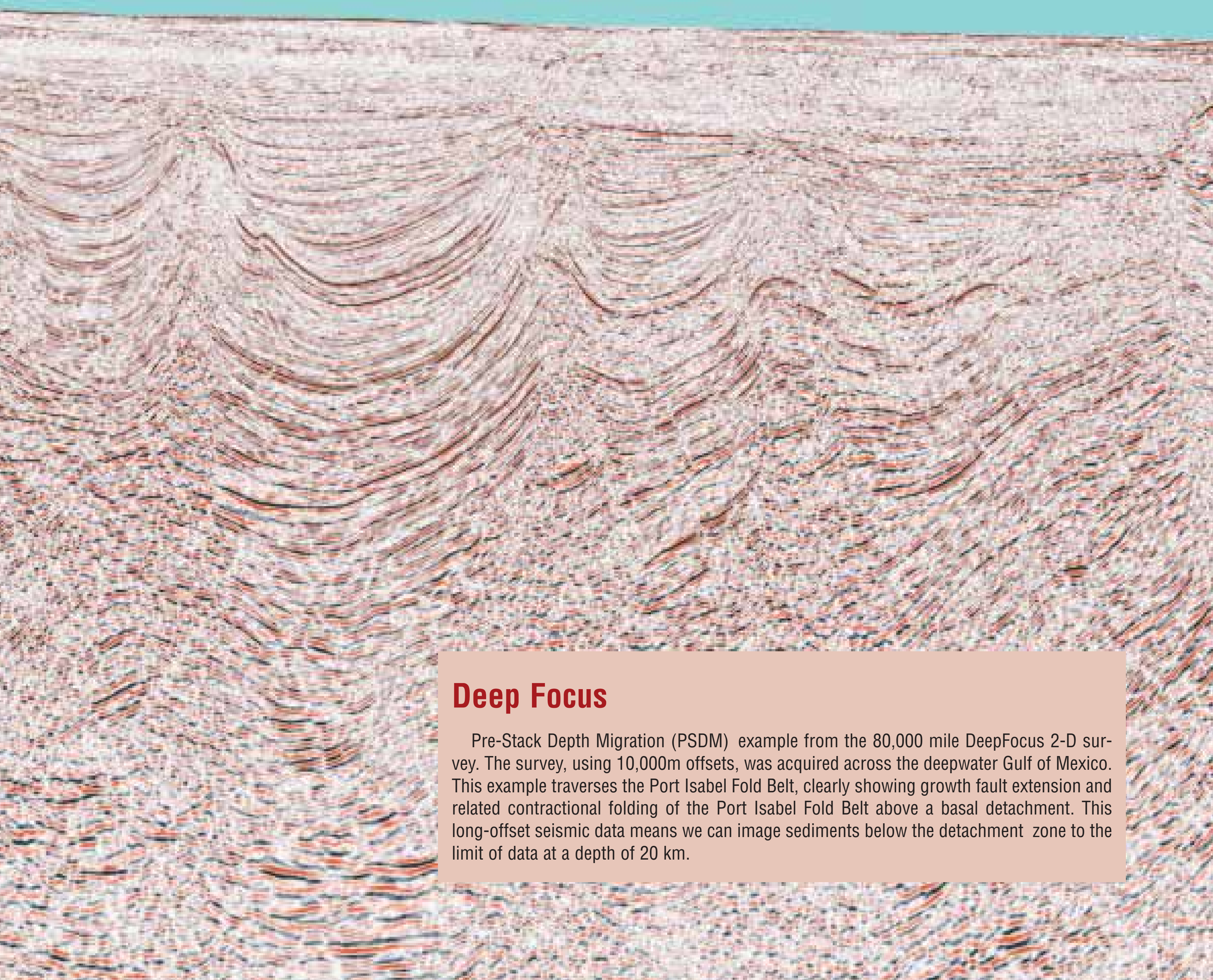


Huge Potential Still Waiting in the Gulf of Mexico

The first oil was extracted from the Gulf of Mexico back in 1938. Since then, 30 billion barrels of oil equivalent have been produced from the US Gulf, but the area is still thought to have huge remaining potential, particularly in the deep and ultra-deep waters.

The discovery of oil at Spindletop transformed Houston from a slow-paced frontier town to the metropolitan city it is today.

The Gulf of Mexico basin is a roughly circular structural basin, approximately 1,500 km in diameter, filled with up to 15 km of sediments ranging in age from Late Triassic to Holocene. About 20% of the Gulf lies in more than 3,000m of water, with the deepest part, the Sigsbee Deep, more than 4,000m deep.



Deep Focus

Pre-Stack Depth Migration (PSDM) example from the 80,000 mile DeepFocus 2-D survey. The survey, using 10,000m offsets, was acquired across the deepwater Gulf of Mexico. This example traverses the Port Isabel Fold Belt, clearly showing growth fault extension and related contractional folding of the Port Isabel Fold Belt above a basal detachment. This long-offset seismic data means we can image sediments below the detachment zone to the limit of data at a depth of 20 km.

Jane Whaley, Associate Editor, Europe

With 10 new oil and gas discoveries announced in 2005 in the deep water alone, the US Gulf of Mexico continues to play a very prominent role in the ongoing search for global hydrocarbon resources. Since offshore production began, more than 14.6 Bbo (2.3 Bm^3) and 164 Tcfg have been recovered from the US part of the Gulf of Mexico, and new plays are continually being tested and proved. According to the US Minerals Management Service (MMS), offshore operations in the Gulf account for a quarter of the U.S. domestic natural gas and one-eighth of the oil produced. Huge technological advances in drilling and production, innovative analytical methods and exciting new techniques for sub-salt imaging mean that interest in the area should continue for many years.

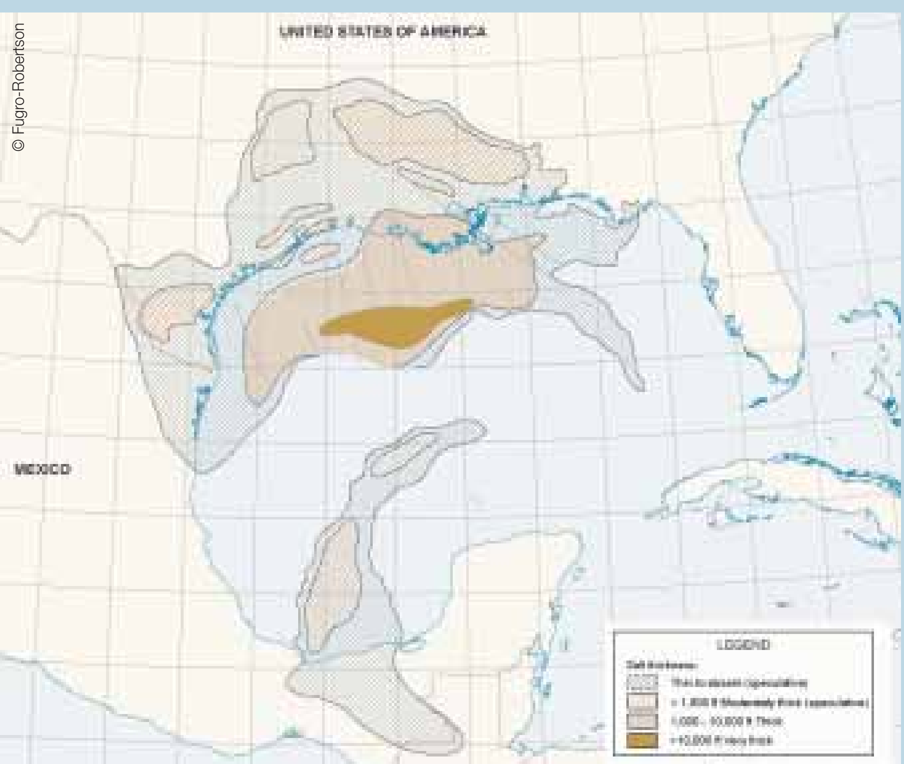
Understanding Tectonic History is Key

The Gulf of Mexico has been a stable tectonic area since the Late Jurassic, but the structures formed at that time are still important to the distribution of hydrocarbons in the area. The present Gulf of Mexico is a result of seafloor spreading which started with the break-up of Pangea in Late Triassic times. Rifting probably continued through Early and Middle Jurassic time with the formation of 'stretched' or 'transitional' continental crust throughout the central part of the basin.

According to Fugro-Robertson's recent report "Petroleum Systems Evaluation of the Gulf of Mexico: Implications from Plate Tectonic Modelling", analysing the distribution of oceanic and continental crust and their associated fault structures is crucial to understanding the hydrocarbon geology of the Gulf of Mexico. This analysis suggests that there was a sudden increase in attenuation of continental crust during the Middle Jurassic, followed by a more stable period in the Late Mid Jurassic. During this period there were a number of shallow marine incursions followed by minor uplift, causing the seas to dry out and widespread evaporite deposition to occur. Co-eval with this, oceanic crust development was occurring, as the Yucatan Peninsula rotated southwards and separated from the north American continent during the Late Jurassic to earliest Cretaceous (165 Ma to 143 Ma, compare Geological Time Scale, page 12).

The Florida platform to the east of the basin was characterised by aeolian sandstone deposition, up to 1,000m thick, until the Late Jurassic, with marine shales and turbidites being deposited further south and west in the basin. This platform became submerged at the end of the Jurassic, when movement of the Yucatan plate and the further opening of the basin resulted in deepening of marine waters and the deposition of a major source rock over much of the area, including the deposition of the organic rich Smackover Carbonate. In fact, most of the basin was rimmed during the Early Cretaceous by carbonate platforms, while the western flank underwent a compressive deformation episode in the late Cretaceous and early Tertiary.

Throughout the Cenozoic the area has been relatively stable, characterised by central subsidence. This is due in part to sediment loading, with the continental shelf in the Gulf of Mexico prograding seaward as a series of depocentres migrated eastward from the border with Mexico to the present Mississippi River area in the north-central Gulf. This thick Tertiary sequence provides the important overburden critical for maturation and supporting the mobilisation of hydrocarbons.



Gulf of Mexico salt distribution and thickness.

Deep Water

Traditionally, deep water is defined as those water depths greater than or equal to 1,000 ft or 330m and ultra-deep water as those water depths greater than or equal to 5,000 ft or 1,660m.

OCS

US Outer Continental Shelf, defined as the submerged lands, subsoil, and seabed, between the seaward extent of the State-s'jurisdiction and the seaward extent of Federal jurisdiction.

Salt Plays Crucial Role

Widespread evaporite deposits, up to 3,000m thick, form an important feature of hydrocarbon exploration in the region. They play a crucial role in the depositional and structural history of the northern Gulf of Mexico Basin, and to fully comprehend the development of petroleum systems across the whole area it is necessary to have an understanding of their distribution and movement. Traps are created and destroyed by salt movement, and hydrocarbon maturation and charge is hugely influenced by the local presence of salt. Furthermore, the deposition of reservoirs and seals and the development of mini-basins are controlled by salt movement at depth. (The word salt is used to mean any evaporite, including halite, anhydrite, gypsum and associated minerals.)

Salt tectonics, sedimentation and growth faulting are intimately related. The initial salt deposition infilled existing topography which had resulted from faulting and volcanics on the basement floor. The thickest salt developed where subsidence was highest during the syn-rift and post-rift phases of basin development.

Salt deposits are divided into autochthonous salt, which is found at the stratigraphic level at which it was deposited, and allochthonous salt, characterised by sheetlike salt bodies which have migrated above the original salt layer. The thickest autochthonous salt, possibly originally as much as 4,000m thick, is Middle Jurassic in age and does not appear to have been deposited uniformly across the basin, instead infilling the existing grabens whilst being thin to absent over adjacent horsts.

Two major evaporite belts can be recognised in the Gulf of Mexico. The first is the Louann Salt, found in the northern part of the Gulf and covering much of the coastal plain and offshore regions of northeastern Mexico, Texas, Louisiana, southern Arkansas, Mississippi, and Florida. The second area is the Southern Gulf of Mexico Campeche Salt Province, which runs along the west and northwest flank of the Yucatan Peninsula. These two areas were originally one, but are now separated by the salt-free Sigsbee Abyssal Plain, a deep, relatively structureless area underlain by oceanic crust, formed as the Yucatan pulled away.

Salt Movement Initiates Traps

Salt is much weaker and less dense at depth than other rock types. Essentially a viscous material, it moves and flows through the surrounding rock along lines of weakness towards the surface. Although

Hydrocarbon Exploration in the US Gulf of Mexico

The presence of oil and gas seeps off the west coast of America pushed the search for hydrocarbons offshore, with the first well being drilled off California in 1896. Onshore discoveries along the coast of the Gulf of Mexico later encouraged offshore exploration in this area, with initial drilling from low lying islands and then from wharfs specially built into the water. The first true offshore discovery in the Gulf was the Creole Field, near Cameron, Louisiana, drilled in 1938 in 4m of water.

Giant Discoveries

After the second World War, there were significant changes in the oil industry, with an end to government controls and a huge surge in public demand for oil and natural gas. This encouraged further exploration in the Gulf of Mexico, and in 1947 the first well drilled out of sight of land started producing 600 bopd 12 miles from the Louisiana coast. By the end of the 1940's exploration in the Gulf had increased dramatically.

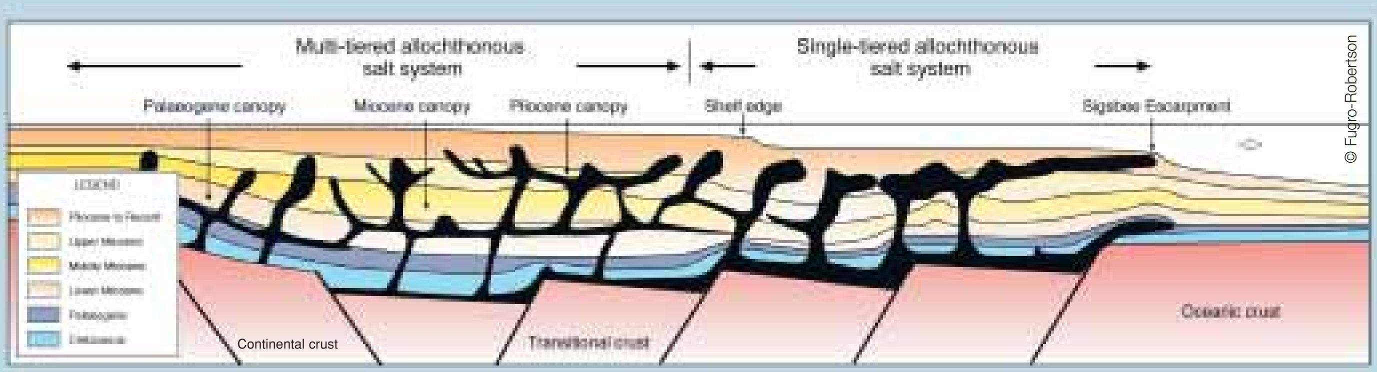
Exploration and production continued rapidly until, by the 1970's, more than 50% of the discoveries made in the Gulf Coast basins were offshore, with exploration moving further and further from the coast. This brought hydrocarbon exploration into progressively deeper water, pushing the limits of platform technology. By the 1980's exploratory drilling had reached water depths beyond 2,000m in the western part of the Gulf of Mexico, whilst also moving deeper below the seabed to investigate sub-salt reservoirs.

There was a slight lull in exploration in the Gulf of Mexico in the late 1980's and early 1990's, as the major oil companies began to look elsewhere, viewing the Gulf as a mature province with little remaining potential in shallow water. Gradually, however, huge advances in platform and drilling technology allowed oil companies to move further into the unexplored deeper water. At the same time, the development of exploration techniques such as 3D seismic helped locate commercial fields that were missed in earlier exploration efforts.

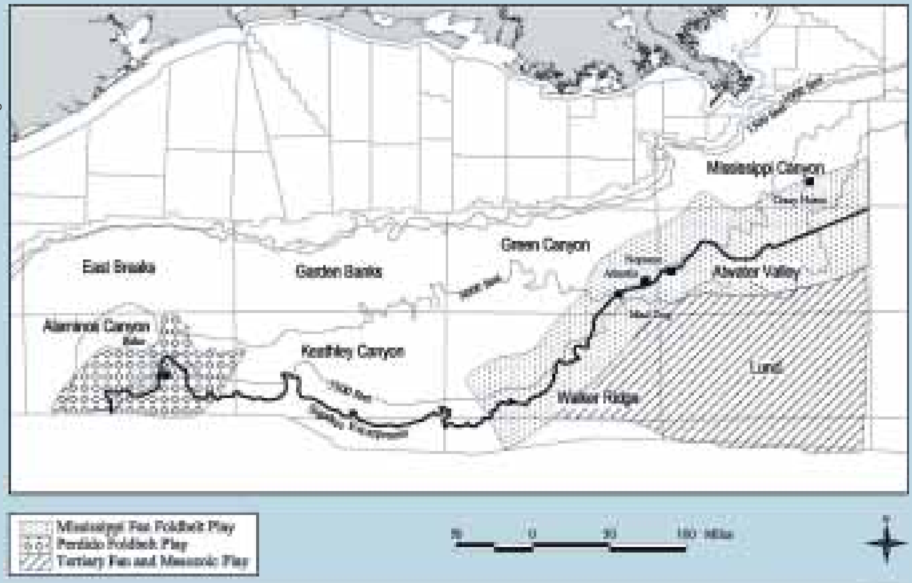
Deep Water Exploration Boom

By the late 1990's, a new era began in the US Gulf of Mexico OCS, with intense interest in the oil and natural gas potential of the deep and ultra-deep water areas. The OCS Deep Water Royalty Relief Act of 1995 provided incentives for operators to develop fields in water depths greater than 200m and had a significant impact on deep water activities. It led to a huge expansion in all phases of deep water activity. Oil production from deep water rose over 840% in the last decade, and deep water gas production increased about 1,600% during the same period. In December 2003, for the first time in history, a drilling rig explored for oil and gas in over 3,000m of water.

An exception to this rapid development of the offshore oil industry in the Gulf of Mexico is off the coast of Florida. In 1981 the State of Florida announced a moratorium on new drilling in State waters to protect the fragile environment and unique species of the Florida coastline. This moratorium expires in 2012 but there are already moves afoot within the US House of Representatives and Senate which could result in the lifting of the moratorium and allow drilling up to 100 miles (160 km) from the coast in an area that contains an estimated 5 Tcfg.



Summary diagram illustrating the relationship between multi-tiered canopies and single tiered canopies across the northern gulf of Mexico (after Mehlhop, 2004)



Caption: New deep and ultra-deep water plays in the Gulf of Mexico.

Oil industry transformed Houston

As you walk through Houston's hot, busy streets today, it is difficult to visualise this sprawling city as the swampy settlement it first was. Now the fourth largest city in the United States, with an urban population of over two million, it seems incredible that in 1900 Houston had a mere 45,000 inhabitants and was only the 85th largest city in the U.S. This startling development has been spearheaded throughout the last century by the oil industry.

The area now known as Houston began as a marshy, malarial swamp, only inhabited by a small number of Native Americans, and it remained so until the arrival of pirates at the beginning of the 19th century. These Caribbean buccaneers set up short-term settlements on Galveston Island, just south of present day Houston, and their legend lives on in Houston's folklore today.

Texas was under Mexican control until the 1830's, but when the growing number of settlers to the state became disillusioned with the Mexican government, a Texas resistance force was formed and war broke out with Mexico in 1836. After several defeats the Texans eventually emerged victorious and, soon afterwards, a settlement was formed along the Buffalo Bayou, named after the man who had lead Texas to victory, General Sam Houston. The settlement had been established by two brothers, John Kirby Allen and Augustus Chapman Allen, who had bought the land with the intention of making it 'a great centre of government and commerce'. The town soon became the capital of Texas, although it only remained so until 1839.

By 1870 the settlement of Houston had grown to be the third largest city in Texas. It had fast become an important transportation hub for both steamboats and railroads, but remained behind San Antonio and Galveston in size and influence until 1901, when oil was discovered at Spindletop, 90 km north-east of Houston.

Houston has always played a key role in the development of the petroleum industry, with the first geological department devoted to petroleum science being founded in Houston in 1897. However, it was this discovery at Spindletop, and later findings at Humble and Goose Creek in 1905 and 1906, that clearly marked Houston as a centre for the oil industry. Furthermore, it was a catalyst for a large influx of settlers to Houston from the US and beyond, which meant that by the 1930's Houston had become the largest city in Texas.

Further events, like the development of a new port in Houston and NASA choosing it as the site for the Manned Spacecraft Centre, meant that Houston maintained this rapid growth. Including the ever-expanding suburbs, the metropolitan area of Houston is now home to 5.2 million people. However, it is easy to see that it was only after the discovery of oil that Houston began the transformation from a slow-paced frontier town to the metropolitan city it is today.

there are cases where salt is locally exposed, most allochthonous salt has a thin, condensed overburden.

Tectonic structures due to salt movement are found in more than 60% of the present day slope area of the Gulf of Mexico. These can be very complex formations, including salt rollers and pillows, salt domes or diapirs, salt walls and tongues and turtle structures, with intricate interplay between the autochthonous and allochthonous evaporites and the surrounding rocks. This movement has a significant influence on the reservoir rocks, causing folding, detachment and faulting in the vicinity of the salt structure, thereby changing the rock properties and initiating a huge variety of hydrocarbon traps.

As well as being instrumental in altering the properties of reservoir rocks and in initiating trapping mechanisms, salt has a profound effect on the maturity of hydrocarbons, as it has a high thermal conductivity which retards the maturation of subsalt source rocks while accelerating that of supra-salt strata. The impermeable nature of salt also means that it forms a barrier to upward migration, creating a seal, although it can serve as pathway for hydrocarbons moving updip along its base.

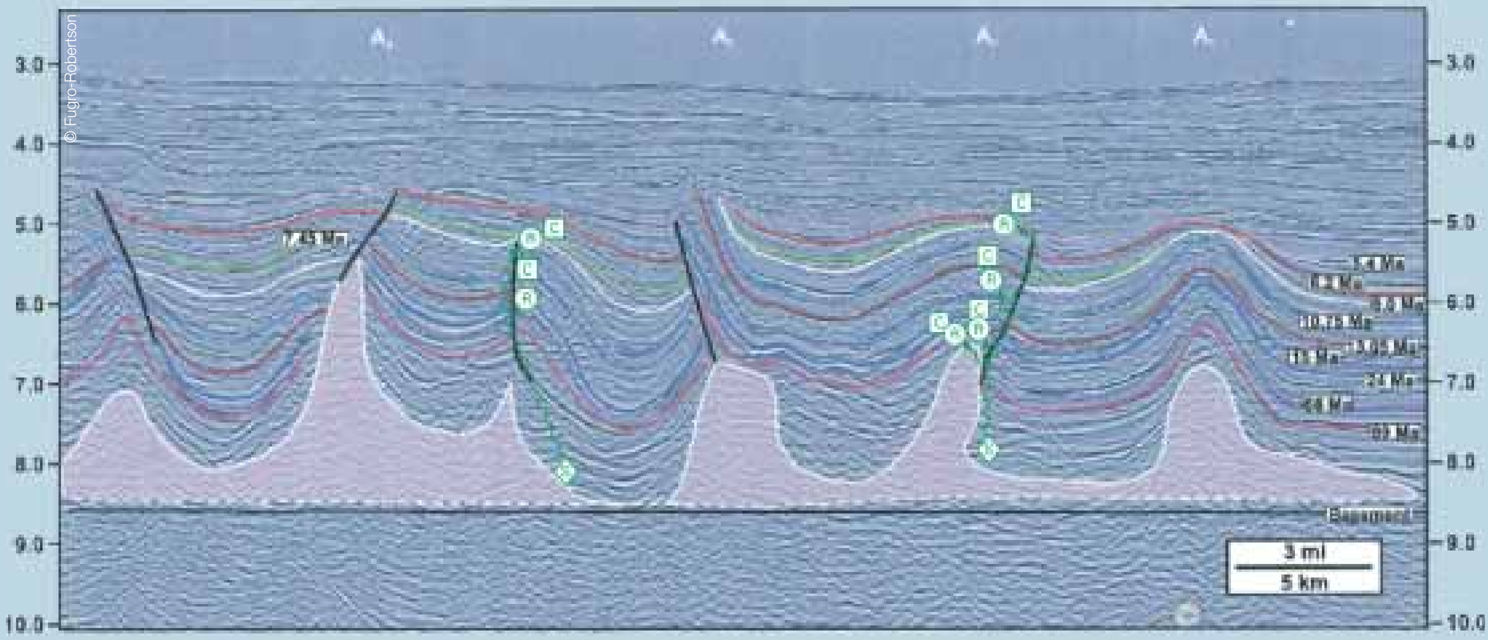
Well Established Petroleum Systems

After 70 years of exploration, the main producing plays and petroleum systems of the Gulf of Mexico are well known. Almost 99% of total proved reserves in the US Gulf are in Neogene (Miocene, Pliocene, Quaternary) reservoirs, and they are still thought to contain considerable potential.

Source rocks are relatively well understood, with the Late Jurassic (Oxfordian and Tithonian) fine-grained, organic-rich carbonates and shales providing the best regionally extensive sources within the Gulf, including the world famous Smackover Limestone. Cretaceous Albian and Turonian clastics and Eocene shales are also known sources.

In the Gulf of Mexico many exciting plays have already been explored with the most prolific found to date resulting from Miocene-aged high frequency cycles of fluvial or incised valley fill, with deltaic to neritic and deep water submarine fans deposits. These are often associated with salt structures and deformation, both complicating and enhancing prospectivity. Explorationists originally drilled structural


Over
Q-Marine
Under



Miocene play in salt cored anticlines, East Gulf Coast Basin (after Morris et al 2004).

highs to explore these reservoirs in the early 1980s, but they are now seeking hydrocarbons trapped in ponded turbidite facies in the mini-basins which formed as the salt withdrew due to sediment loading.

Although the known shallow and shelf plays still prove exciting, much of the recent interest in the Gulf of Mexico has been generated by the move into deep and ultra-deep waters.

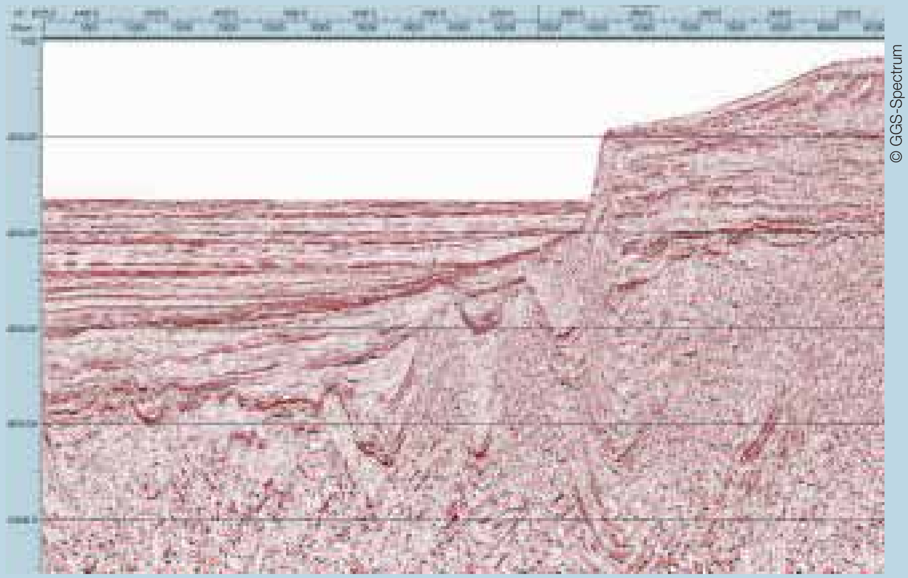
New Deep Water Plays

When the Gulf of Mexico was first explored, it was considered that deep water potential was limited by a lack of sediment supply over large areas into the deep water. Initial seismic analysis and the first deeper wells soon proved that this was not the case. Another early concern was the availability and maturity of source rocks, but modelling successfully demonstrated that probable source rocks, predominantly Cenomanian to Turonian in age, have entered the oil window throughout most of the deep and ultra-deep water province. Maturity modelling shows that most of the hydrocarbons in the vast Sigsbee salt sheet which culminates at the Sigsbee Escarpment are within the oil maturity window, while those found further south are more likely to be condensate.

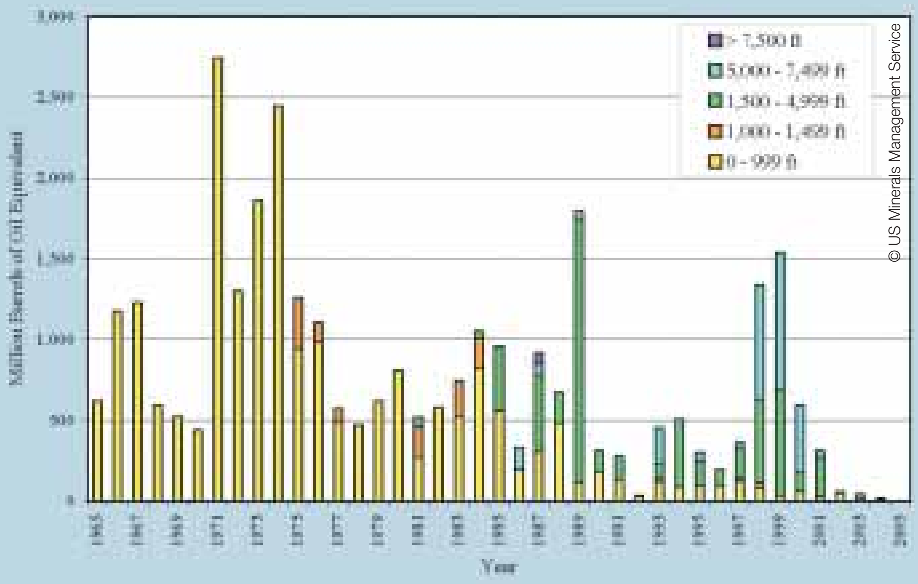
Production in the deep water has until now been centred on Miocene turbidite sands, deposited relatively recently from the Mississippi delta, with fields up to 500 MMboe being successfully produced. The Cascade discovery proved the existence of an older, Paleogene turbidite sand play more than 560 km down dip from the source deltas in south Texas. Reservoir potential in these well-developed channel sediments is thought to be excellent, with the hydrocarbons accumulating in stratigraphic traps.

Moving into deeper water from this play in the Eastern Gulf of Mexico, salt-cored thrust folds with middle and lower Miocene abyssal plain section draped across them have proved prospective. Two major discoveries in the Mississippi fan thrust and fold belt play, **Neptune** and **Mad Dog**, have recently begun producing and are thought to point the way to further finds in these sediments. A number of recent discoveries such as **Spiderman** and **San Jacinto**, are in water depths of more than 2,300m.

Foldbelts in ultra-deep water have been found to extend from the deep basin of the western part of the Gulf of Mexico up and under the Sigsbee salt sheet at the continental margin. These include large north-east to south-west trending compressional "box folds" and are characterised by large



Example of a Depth Section (PSDM) across the Florida Escarpment showing pre and post-salt plays in deep water and carbonate reef plays on the platform. Section width ~ 90 km. Vertical exaggeration ~ 5:1.



The movement towards exploration in deeper waters is shown clearly in this graph of annual reserve additions.

prospects, possibly containing reserves of over 1 billion boe each.

Cretaceous carbonates have proved very prolific in the Campeche Basin in Mexico, with fields reporting 100,000 bopd production from single wells. This play is speculated to extend northwards into the US Gulf, possibly as far as Florida, forming a very extensive but very deep target. The reservoirs include rudist and coral reef build-ups and slope carbonate deposits comprised of forereef debris rudstones and shelf-derived grainstones.

The very eastern part of the Gulf of Mexico area is one of the last remaining US petroleum frontier areas, very lightly explored due to the moratorium on exploration in Florida waters since the 1980's. According to a recent seismic survey offshore Florida obtained by GGS-Spectrum, significant volumes of hydrocarbons could be found here in a number of plays. Mesozoic plays include Cretaceous shelf reefs, inner platform reefs and carbonate apron fans, which are created at the foot of the Florida escarpment by the periodic failure of the upper carbonate slope, resulting in the shedding of large volumes of sediment to the basin. There are also deep water prospects associated with rifting and salt tectonics. Younger potential in the Eastern Gulf is represented by clastic plays of Oligocene to Miocene age such as basin floor fans and onlap/drape features.

Deep Water Potential

According to the MMS, the hydrocarbon potential of the deep and ultra-deep water in the Gulf of Mexico could be as high as 46 Bboe (MMS report 2006-022). Although the first deep water field did not start producing until the 1980's, by 1999 the volume of oil production from the deep water had overtaken that of the shelf, and this gap has been growing ever since.

Deep water Gulf of Mexico field discovery sizes have been several times larger than average shallow water field discoveries. The typical deep water field found over the last 10 years is 67 MMboe (proved and unproved reserves), compared to 5 MMboe for the average shallow water field. (The MMS considers hydrocarbon reserves as 'unproved' until it is confirmed that the field will go on production.) Deep water fields also tend to produce at significantly greater production rates, exceeding those of shallow-water wells by more than 1000%. These operations are very expensive, however, and require specialist technical exploration and production equipment, so large discoveries are needed to ensure exploration in the deeper water continues.

Emphasising the fact that exploration is moving ever deeper, there have been 22 discoveries in water depths over 7,000ft (2,134 m), during the last five years, with total announced reserves of 1.8 Bboe.

Recently, the US Government introduced measures to encourage the search for gas in deep water, to offset a decline in shallow water gas production since the mid 1990's. Although the deep water gas production increase has not been as dramatic as that of oil, these tax and financial incentives have resulted in a significant increase in exploration. Additionally, a deep shelf gas play has emerged, partly as a result of investigations into gas formation and porosity preservation in high-temperature and high-pressure reservoirs.

New Frontier Plays

New technologies have been instrumental in opening up another new frontier

Over 100 wells have now been drilled sub-salt, the largest of which to date is BP's **Thunder Horse** (previously Crazy Horse), discovered in 1999 and due to go into production in late 2006. The semi-submersible platform, lying in 1,900m of water, 190 km off the coast of Louisiana, is one of the largest and most complex deep water projects ever undertaken.

The Creole Field was the first true discovery in open waters in the Gulf of Mexico, drilled from a 30m drilling platform secured to a foundation of timber piles in 4m of water.

Mark Cowgill, Manager, Geology and Geophysics, Fugro-Robertson, and co-author of the recent study, considers the Gulf of Mexico very prospective, with new plays extending the hydrocarbon prospectivity of the area.

play in the Gulf of Mexico, the sub-salt reservoirs. For many years the extensive salt layer was considered 'economic basement' in the Gulf of Mexico, because the high seismic velocity of salt, contrasting with the relatively slow velocities of the adjacent clastics, meant that the evaporites acted as a barrier to seismic, making it difficult to image the underlying layers. Recent innovations in both seismic acquisition and processing, such as multi-azimuth seismic, mean that salt is no longer a barrier to exploration (see 'The Sub-Salt Imaging Challenge', this edition of GeoExpro.

Imaging through the salt opens up two areas for exploration. Much of the allochthonous salt is found in laterally extensive thin sheets, masking large areas which have been relatively untouched by salt tectonics. Imaging sub-salt means that it is possible to consider the potential beneath, for example, the huge Sigsbee salt sheet, to investigate whether the previously mentioned anticlinal 'box fold' structures continue under the salt into shallower waters. In other places the salt forms less extensive structures such as diapirs or tongues, trapping upwardly migrating hydrocarbons. These were previously hidden from conventional seismic and are only now being clearly imaged.

While new approaches to seismic acquisition and processing unlocked the potential of the deep water and sub-salt plays, different technological challenges have had to be met in order to drill and produce successfully from these. New research has lead to technologies such as slimhole drilling, which are necessary to explore and produce ultra-deep water reserves economically. Although expensive to research and develop, these technologies should ultimately help reduce the cost and time necessary to bring ultra-deep water hydrocarbons to the market.

Mature Basin - Good Potential

A long period of tectonic stability from the Late Jurassic to the present day has led to the development of excellent source and reservoir rocks. The thick Tertiary sediments form excellent reservoirs while maturing source rocks and initiating salt movement to create traps. These factors have combined together to create a widespread and prolific petroleum province.

The Gulf of Mexico might be considered a mature hydrocarbon basin, with proven reserves in the US Gulf of Mexico OCS estimated to be 18.75 Bbo and 176.8 Tcfg from 1,112 fields (as of December 31, 2002, the last year for which figures have been released from the MMS). The area remains prospective and exciting, however, as new plays have continued to extend the hydrocarbon prospectivity beyond the original boundaries, frequently through the development of innovative technology in both exploration and drilling.

As Fugro-Robertson's report points out, there are still huge undiscovered resources within the Gulf of Mexico Basin. The study considers that the Miocene and Pliocene clastic plays hold the greatest remaining potential in the US sector, with further possible potential from the Cretaceous and Lower Paleocene carbonates which are so prolific in the Mexican sector. With advances in technology to aid the exploitation of deeply buried reservoirs into increasingly deeper waters of the Gulf, there should be no limit to exploration within the Gulf of Mexico in the foreseeable future.

Annual offshore gas production from the US Gulf of Mexico peaked in 1997 and that of oil in 2002, but it is hoped that recent large discoveries in the deep water will reverse the trend.

Acknowledgements

Particular thanks to Carol Boorman, Mark Cowgill, Eva Ginal, Robert Mandley and Julie Thompson of Fugro-Robertson; Glyn Roberts, New Ventures Manager GGS-Spectrum; Sinéad Archer.

The Sub-Salt Imaging Challenge

Throughout the world, sub-salt imaging remains a major issue. Service and oil companies are striving to meet this challenge.

Steve McIntosh, Regional Sales and Marketing Director of Fairfield Industries.

James Keggin, Seismic Quality and Technology Manager for BP Egypt. James and Steve are among the many dedicated and innovative people who have seen that progress in wide and multi-azimuth seismic technology has resulted in impressive enhancement of sub-salt seismic imaging.

Jane Whaley

Like many major oil companies, BP has been investigating different ways of solving the sub-salt imaging predicament, particularly in the Nile Delta and the Gulf of Mexico. Working in conjunction with seismic companies, much of the research has concentrated on alternative ways of receiving the seismic returns, moving away from the linear architecture used in the traditional seismic survey.

Looking under the table

"Exploration in the offshore Nile Delta has concentrated on the prolific Pliocene channel play, which lies above the salt and gives us excellent images," explains James Keggin, Seismic Quality and Technology Manager for BP Egypt.

"However, beneath this there is a regionally extensive, thin layer of Late Miocene anhydrite, interbedded with other material, which sits about 3km below the seabed and effectively masks the deeper horizons from seismic investigation. Some of us think there is a prize down there, but trying to see through the salt is like trying to see through the textured glass of a bathroom window, as it distorts the acoustic returns and makes it difficult to get an accurate picture of the geology below."

Traditional 2D seismic uses a sound source and multiple sensors towed behind a seismic boat, recording signals reflected back from the subsurface, which, as James explains, "builds up an image in one direction like a single page from a book."

"Conventional 3D seismic extends this by combining many 2D images in the same way so that the pages of paper combine to make a cube. We are now broadening this idea by looking at the same part of the seafloor from many different angles or azimuths, with up to six conventional 3D surveys recorded in different directions in quick succession. These are then processed separately and the data is combined to give a much clearer and more accurate picture of our reservoirs."

"It's a bit like trying to see under a table. If you look at it from only one angle you cannot see the whole picture, so what we are doing is repeating the experiment from different angles," says James.

A world first

The concept of multi-azimuth seismic (MAZ) has been recognised for a long time, but although it has been done for many years on land using stationary receivers, it has only recently been considered to be economically feasible in a deep water marine setting.

"Only one vessel is required, and even if we survey an area six times, the economy of scale and shared mobilisation costs mean that it is not six times as expensive," explains James.

"Our first multi-azimuth survey, working with PGS, was an appraisal of the Raven Field, in the western Nile Delta," James says. "This was a world first and we have been delighted with the results. We had previously identified channel systems in the reservoir area, but we could not delineate them clearly enough to confidently place appraisal and development wells. Our six-fold multi-azimuth survey, undertaken in late 2004, has given us a far clearer image of the reservoir. Economically, the extra seismic costs are easily countered by the savings made through more informed and successful well placement."

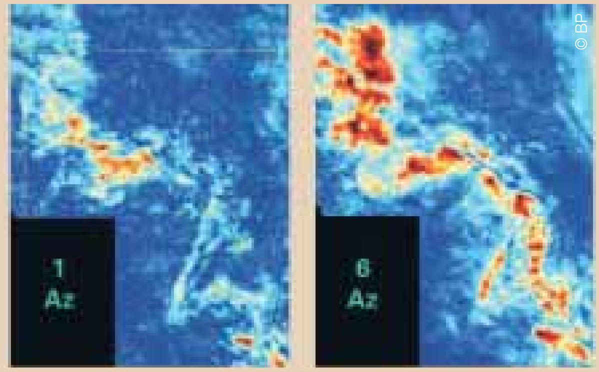
BP has been so satisfied with the results in the Raven Field that they have now commissioned a new 'Mega-MAZ' survey to look at further sub-salt exploration targets in the offshore Nile Delta. As James says, "We believe in the offshore sub-salt potential, so multi-azimuth surveying is a vital tool in our exploration efforts."

Wide Azimuth

While multi-azimuth seismic has proved successful in the Nile Delta, it is not necessarily the key to sub-salt imaging in the Gulf of Mexico. Here the challenges are different, as the mobile salt horizon results in variations in wavelength and thicker bodies, causing severe imaging problems below salt. Tim Summers, Sub-Salt Imaging Technology Director for BP, takes up the story.

"In the Gulf of Mexico we first tried several azimuths of seismic to visualise these large salt bodies. When that showed promise, we moved on to wide azimuth towed streamer seismic, or WATS, to maximise the number of azimuths in a single survey. This is a multi-vessel operation, using a streamer boat and dual source vessels offset laterally. Sources are fired sequentially and the sensors receive data from each in turn, giving us data from many different azimuths. This gains us a much clearer image of the salt bodies and what lies beneath it."

The first WATS survey was completed in early 2005 for BP by Veritas over the Mad Dog Field in the Gulf of Mexico. The early results proved successful and resulted in plans for further work over other BP operated fields in the deep water Gulf during the second half of 2006. Tim adds that "while the application of WATS were performed on appraisal and development projects, we fully anticipate extending the technique into exploration, applying it over large areas to reduce risk on the increasingly complex subsalt prospects'.

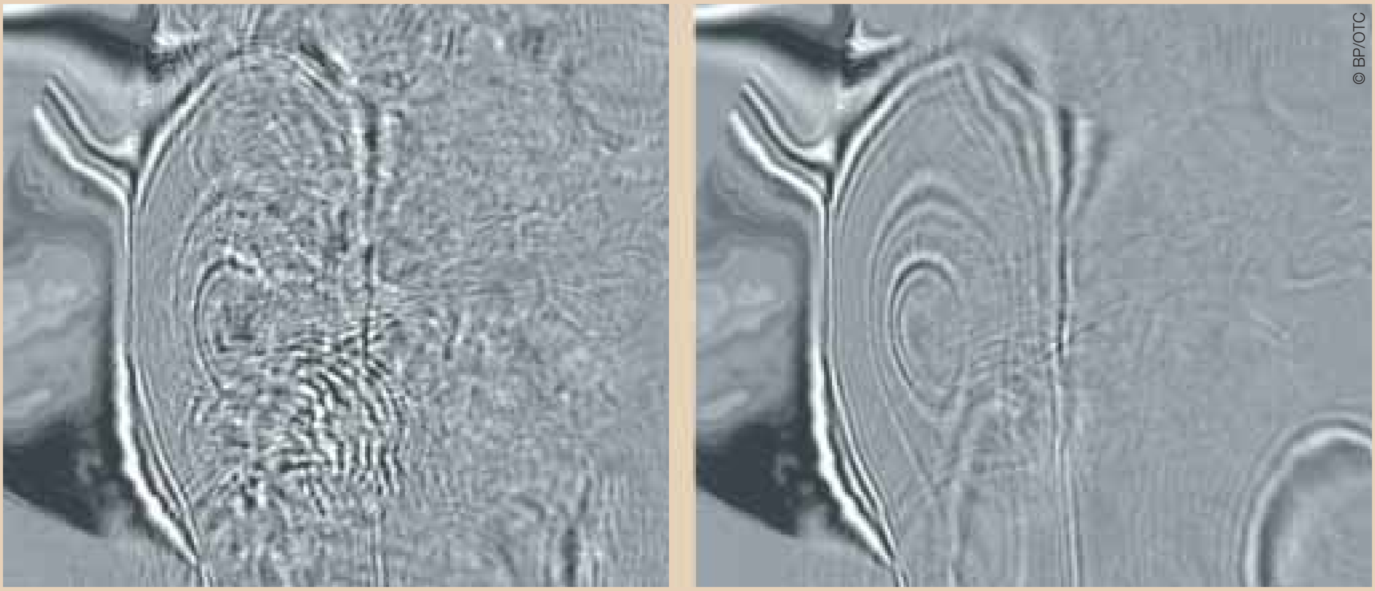


The six-azimuth stack process produces a much more reliable image of the deep reservoir system in the offshore Nile Delta.

Imaging deep water fields

Ocean bottom cable surveys, where the sensors are laid on the seafloor rather than towed, have also proved very effective in acquiring wide azimuth surveys. In deep water, however, they have limited operational depths and are very expensive to deploy and position, requiring two dynamically positioned cable vessels as well as a sound source ship. They are also not so effective in areas where the seabed topography is rugged or heavily obstructed by infrastructure.

Fairfield Industries have an alternative system, Z-3000, for conducting wide azimuth surveys using sensors or 'nodes' laid individually on the seabed. Steve McIntosh, Regional Sales and Marketing Director of Fairfield Industries, explains the technique. "The Z-3000 system consists of a series of sensors deployed individually on the seafloor, operating completely independently with no inter-connecting cables. The nodes record data continuously from deployment



Comparison of single and six-azimuth seismic depth slice from the Gulf of Mexico.

to retrieval and can measure both compressional and shear waves, working in water depths up to 3,000 metres. Each node is positioned using GPS and a remote controlled vehicle (ROV) to any desired receiver geometry, while the source vessel sails a conventional grid, effectively undertaking a multi-azimuth survey. At the end of the data acquisition sequence the nodes are retrieved onboard the mother vessel, where the data is downloaded, quality controlled and the batteries recharged, ready for re-deployment."

As Steve says "while Fairfield Industries was developing nodes for shallow water, BP was actively seeking ways to image under and around the salt in deep water. In 2004 BP commissioned Fairfield to manufacture deep-water sensors and acquire the industry's first large-scale deep water node survey, starting in October 2005 and completed in March this year. Over 900 sensors were deployed on the Atlantis Field, in the Gulf of Mexico, in water depths between 1,400 and 2,200m.

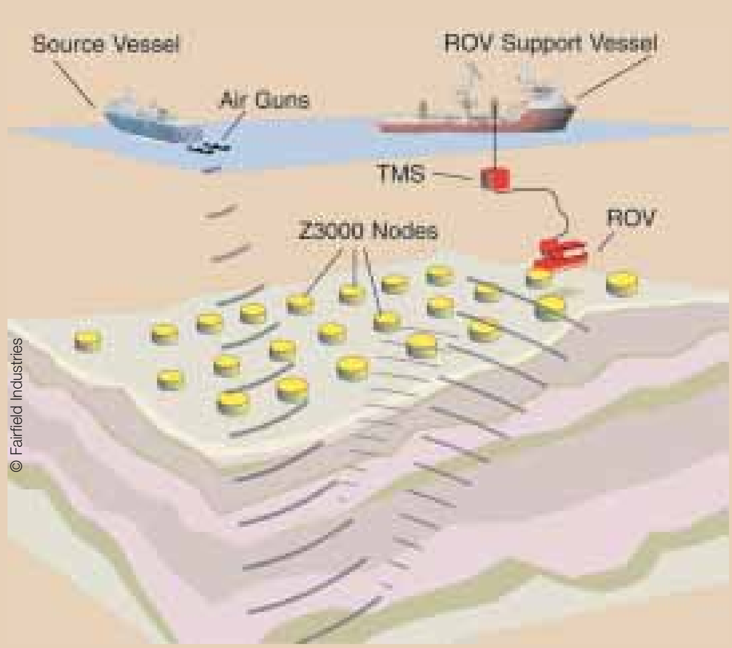
BP and Fairfield have been equally satisfied with the project from both the acquisition and the operational side. For Fairfield Industries, Steve McIntosh says "the system proved to be both efficient and reliable. This initial survey proved that we can effectively operate in a deep water environment with highly variable complex water bottom and acquire data at the field scale. From a commercial standpoint, only one receiver handling vessel is required, reducing operational costs."

Successful Results

BP is still processing the data from the Atlantis Field survey and are encouraged by the results so far. "This is a very effective and efficient method of acquiring wide-azimuth seismic in deep water in extremely challenging environments," Tim explains. "The nodes acquire shear waves in addition to the P-waves, which will enable us to illuminate and define reservoir properties for a broad range of subsurface challenges."

BP, in conjunction with their various partners in the industry, have already come up with a number of innovative and successful ways of seeing the horizons and potential hydrocarbon accumulations below the ubiquitous salt in many parts of the world. As Tim Summers says, "We have extended the principles learned from ocean bottom cable surveys to provide wide and multi-azimuth seismic solutions for deep water. We are developing these different techniques so that we have a variety of options, meaning that we can choose the most appropriate application for the circumstances. One size doesn't fit all; we need to use the acquisition solution that suits the subsurface challenge, the operating environment and position on the value chain from exploration to production."

Who knows, in a few years time, salt may not be considered a barrier to successful exploration and production at all?

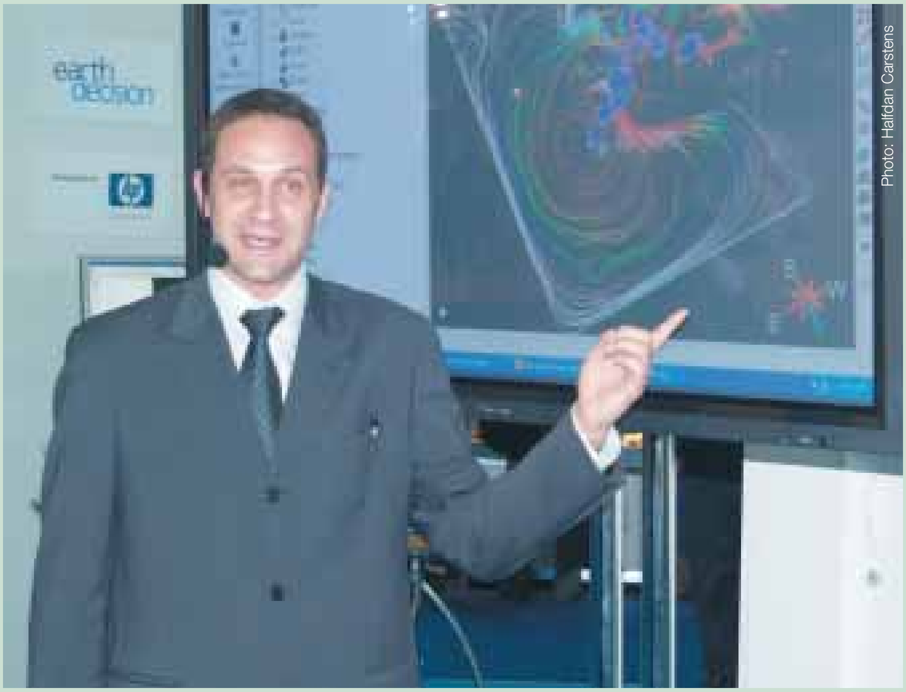


The Z-3000 nodes technique uses an array of seabed seismographs to collect different types of waves reflected from the subsurface.

Ten Reasons why 3D Geo-modeling and Flow Simulation Must Be Integrated

Emmanuel Gringarten, Paradigm

Flow simulation is the reservoir engineer's tool of predilection, providing understanding of how fluid flows through the reservoir and how it can optimally be extracted. 3D integrated geo-modeling software is becoming the platform of choice for geophysicist and geologists who are slowly leaving their single discipline workstation. The 3D modeling environment provides ways to integrate all sorts of geophysical and geological data to provide a numerical representation of the reservoir architecture that is then used as input to the engineers' flow simulation.



Emmanuel Gringarten, demonstrating the Reservoir Simulation Interface module of the Earth Decision Suite at EAGE tradeshow in Vienna this June. Emmanuel Gringarten is Product Manager at Paradigm for the Reservoir Product Line of the Earth Decision Suite, powered by Gocad, focusing on the development of workflow-driven integrated applications for consistent construction of reliable 3D reservoir models. He holds a BSc in Mathematics from Imperial College, London, and Masters and PhD in Reservoir Engineering from Stanford University. Emmanuel has been involved in many reservoir modeling projects, specializing in geostatistical and uncertainty modeling.

Today, what links geoscientists and engineers is the hand-over of the 3D reservoir grid filled with petrophysical properties. This "link" is currently accomplished through awkward file exchange formats that loose all knowledge relating the creation of the final 3D model. Nonetheless, this is the model that will be used by engineers to estimate reserves and optimize development plans. It is accepted that the integration, which exists between the geosciences based on the concept of a shared earth model, has proven to be fundamental to the increased accuracy of reservoir models. Yet, at the most crucial stage of the process - the one where production decisions are made, multi-disciplinary software integration is often dismissed as being too cumbersome by both geoscientists and engineers.

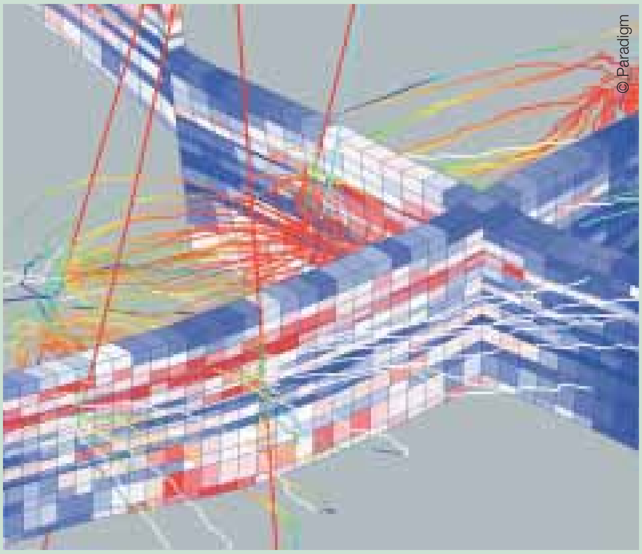
We strongly believe that a direct integrated link between the two is fundamental to allow quick iterations that ensure consistent reservoir models. It is the logical next step after a decade of talking about integration, which started with the introduction of corporate databases. These enabled the smooth transfer of interpretation data between distinct disciplines, essentially geophysics, petrophysics and geology. To continue the smooth transfer of information, one must be able to launch flow simulations from the geo-modeling environment; routine-engineering tasks such as history matching and field development optimization must consider the geological model and, most importantly, the uncertainty inherent to that model.

The following 10 points will highlight some of the key reasons why 3D geo-modeling and flow simulation must be part of the same software package.

1 - Validation of up-scaled reservoir models

Up-scaling is a required step in most reservoir studies; it consists of creating a 3D reservoir grid at a resolution coarser than the geological model then averaging the rock properties (generally rock type indicators, porosity, and permeability) distributed on the finer scale model, to the resolution of the coarse scale flow simulation model. This step is done most of the time by the geoscientist who constructs the geological model. Yet, there are two very important aspects of this task which require engineering input. The first one is the construction of the flow simulation grid; it must address fluid flow issues and conform to the direction of flow, unlike the geological model which must be aligned with the depositional processes. The second is the up-scaling of permeability, which is a dynamic property, whose non-linear coarsening behavior must be assessed using small-scale fluid flow simulation.

The coarse flow simulation grid is an abstraction of the detailed geological model into which much data integration and geological expertise has gone. It mimics geological reality. Therefore, the one thing that one should ask from the up-scaled model is that it honors key features of the geological model and the only way to truly assess this is to guarantee that they have the same dynamic behavior, i.e. simulating flow on both grids should give similar results. Of course the fine scale model may be too big for full field, full history simulation, but the model can be decomposed into smaller pieces and/or computationally less expensive flow simulators such as streamlines can be used. The number of iterations that this process may require means that flow simulation must be launched from the same place the grid coarsening and property up-scaling is done, i.e. the geo-modeling environment.



Flow simulation grid showing non uniform grid layering defined from a geostatistically distributed 3D permeability field. This gridding approach guarantees that thief zones and flow barriers are captured during the upscaling process and provides more accurate flow simulation models.

2 - Assessment of grid quality

For convergence purposes, conventional flow simulators require that the cells of the reservoir grid be "well-behaved", i.e. they should be hexahedral with orthogonal edges, and each row or column should have the same number of cells. However, the geological structure of reservoirs can be fairly complex. Any accurate "corner-point" geometry representation of faulted environments will deform the grid cells. Typically, engineers will manually null the cells that give numerical convergence problems and this can be a very cumbersome and time-consuming task. It is of course possible to check static measures of grid cell quality but the best way is to run the flow simulation. Having a flow simulator integrated to the geo-modeling software where the 3D grid is build, allows to rapidly assess the flow ability of the grid and either iterate on the way the grid is constructed or easily tag the problem cells as not active. As a result, flow simulator "problem-free" grids are created.

3 - Understanding of the behavior of reservoir models

The main purpose of constructing a geological model is to use it as input to a flow simulator. Therefore, features of that model are really only important if they influence fluid flow. A great deal of details can be built into the geological model since geology can be interpreted at different scales. This results in large parts of the reservoir study being spent on pieces which, in the end, may have no real impact. Not all features have consequence on fluid flow and this is often difficult to know *a priori*. Understanding which aspects of geology impact, in a significant way, reservoir production under the recovery schemes considered can make the construction of the geological model more efficient. Thus, interpreters and modelers can focus on what matters and model it accurately from the beginning. Additionally, it allows screening various conceptual geological models and identifying the ones that should be rejected immediately. This can only be done routinely if modelers can easily launch flow simulations as they are building the reservoir model.

4 - Uncertainty assessment and geological scenarios

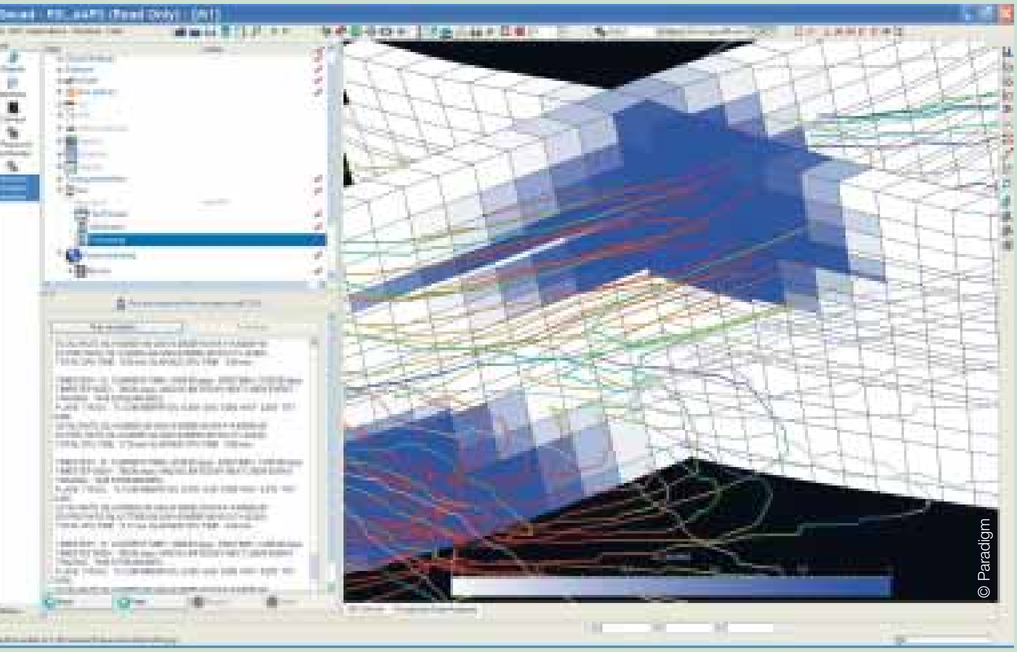
Constructing multiple geological models is now an almost accepted practice in order to tackle the inevitable uncertainty associated with reservoirs and volume estimations. Yet, when it comes to flow simulation (and therefore reserves assessment) all these geological models are rarely considered. One, sometimes three, but rarely more models are selected; they will be assumed to represent either the most likely model or be representative of the variability in possible reservoir models. Criteria for choosing representative models are usually "static" volumes. However, oil-in-place and reserves are not necessarily correlated since different parameters contribute to their quantification, e.g. permeability and fault transmissibility are not considered when computing hydrocarbon volumes, but they play a key role in the modeling of fluid flow. Furthermore, it is necessary to ensure that the scenarios and realizations considered yield a large enough spectrum of production responses in order to properly estimate the uncertainty in reserves. The only way to properly assess the representativity of the selected models and insure that the range off uncertainty is thoroughly swept is to perform a flow simulation on all the different geological models. This can only be done in a software environment which can generate and manage these multiple geological models.

5 - Screening of reservoir models

For fields under production, it is important that the reservoir model reproduces historical production data, yet there is still uncertainty in the geological model, and it is still quite difficult to guarantee *a priori* that the multiple models generated will match history. Performing systematic flow simulation enables screening of multiple realizations to identify those that would be more easily history matched.

6 - History matching

Too often History Matching consists of tuning (or tweaking) parameters of the flow simulation model and locally applying multipliers to geological parameters, essentially on pore volume, permeability, and fault transmissibility, sometimes leading to geologically unrealistic models. This assumes that the (up-scaled) geological model has the correct connectivity from the start; therefore, it should have been screened and selected amongst alternative realizations. (Assisted) history



Reservoir Simulation Interface workflow that allows launching flow simulations from within the Earth Decision Suite. The flow simulation grid displays water saturation during a waterflood process. Streamlines that show where the water actually moves from injectors to producers are also displayed. The flow simulations where performed using the streamline simulator 3DSL® from Streamsim Technologies.

matching must consider the impact of the geological scenario assumptions at some point in the process and ensure geological consistency at the end of that process. Current attempts to perturb or deform the geological model require a direct link between the software platform where the model is constructed (the 3D geo-modeler) and the tool used to assess the goodness of each iteration (the flow simulator). In the end, the geological model is still intact and the simulations match the production history.

7 - Field optimization

Optimal well placement, whether for early development planning or infill drilling, cannot be correctly assessed on a single representation of the reservoir's geology. Uncertainty on the geological model must therefore be considered. Any optimization algorithm should therefore have access to the alternative geological models (and more efficiently, to the way they are created) and, similarly to history matching, to the flow simulator.

8 - 4D seismic

Integration between geosciences modeling and flow simulation is undeniably obvious when considering 4D time-lapse seismic and reservoir monitoring. In addition to the tools required for constructing the 3D geological model, 4D seismic studies require the integration of geophysical tools such as velocity modeling, inversion, and rock physics.

9 - Collaborative environment

3D integrated modeling software provide, above all, a collaborative environment: a place where all subsurface data can co-existing and be visualized simultaneously. This environment stimulates discussion and provides multi-disciplinary understanding and agreement. Reservoir engineers and geoscientists can jointly construct a reservoir model, and constrain the model to exhibit the observed dynamic behavior. They can pin-point the "plumbing" of the reservoir by appropriately representing large scale features, such as fault zones and fault blocks, channel belts, etc. Working in a 3D environment has the important advantage of advanced visualization tools and algorithms, routinely used for seismic interpretation, which can now bring new understanding and insight to the engineers' view of the reservoir.

10 – Full preservation

A good 3D modeling software comes with a workflow-oriented approach that captures the audit-trail and manages scenarios. The way to insure that reservoir engineers have the necessary knowledge to make decisions is for them to be aware of the choices made by the geologist and the reasoning behind them. Having integrated software is the best way to access such information that is recorded during each step of the geological modeling construction. The workflows can generally be replayed automatically when parameters are modified, furthermore ensuring that all the information about the multiple iterations between geological modeling and flow simulation are tracked.

Conclusion

As discussed above, it is crucial to have strong links between geo-modeling software and flow simulators. Reservoirs come in different forms, with opposite geology, fluid composition, recovery mechanisms, questions asked, and decisions to be made.

Few would argue that commercial multi-purpose flows simulators are truly that, i.e. acceptably accurate at numerically modeling all aspects of fluid flow and production. Furthermore, flow simulation models must be scalable, balancing speed of results, number and size of models to screen, and precise modeling of fluid flow physics. Geological modeling software must be able to seamlessly connect to different flow simulators, enabling fit-for-purpose solutions. An integrated environment is key to future advances in sub-surface modeling processes. As it also promotes the integration and collaboration of fairly opposite disciplines, each one must be at ease in the software environment. The solution is pre-defined, yet flexible, workflows that enable the geoscientists to easily launch flow simulations and analyze the results, and where the engineers can be confident that modifications to the flow simulation model can be quickly done and that all the options needed are available. These workflows greatly enhance productivity, consistency, quality, communication, and audit trail.

Integrating 3D geo-modeling and flow simulation guarantees more accurate reservoir models and reduces the turn around time of model validation.

Paradigm will release later this year a Reservoir Simulation Interface that allows geoscientists and engineers to prepare, launch, and analyze flow simulations from within the Earth Decision Suite environment by connecting to commercially available streamline and conventional flow simulators.

For more information:
www.earthdecision.com

Revolutionising History Matching and Uncertainty Assessment

When planning future production, new technology that replaces manual history matching of reservoir models represents a key advance for reservoir engineering.

Jens-Petter Nørgård, MEPO, Scandpower Petroleum Technology AS

Traditionally, history matching of the reservoir model has been done manually and methods from the 1980's are still widely used. Runs are usually launched sequentially, all files are prepared manually and the evaluation is done by visually comparing line plots. This is time consuming and it is difficult to absorb all the information available, inevitably, such an approach is very subjective. Being constrained by a time frame, the engineer frequently has to finish after finding only one single match.

Through the history matching process we aim to calibrate the model to reproduce historical observations such as production rates or formation pressure in a reservoir simulator. When calibrated, the model can be used for predictions and decision making for future field development.

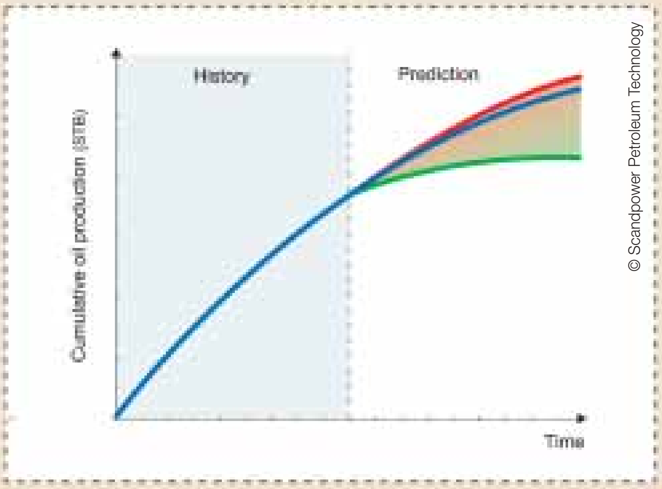
In order to history match the model we need to adjust parameters like permeability, porosity, fault transmissibility and PVT within a given uncertainty range. Similar to a mathematical problem with more unknowns than equations, there will multiple solutions. This means that it is possible for several combinations of parameters or models to give a good match. Typically, we end up having a handful of new, calibrated models, all of which are as likely as each other. These models give quite different dynamic results. Using only one single model for prediction and decision-making purposes will result in increasing risk.

Leading oil and gas companies are now experimenting with assisted history matching because of the shortcomings of the manual method. Companies that have applied these methods report very successful results which have directly impacted on financial performance.

A Question of Philosophy

History matching is as much a question of philosophy as technology since there are different workflows to follow. Three of these are discussed below.

Uncertainty in predictions



The blue line shows the manual match. The area between the red and the green line indicate possible future production based on results from MEPO. This chart clearly shows that the manual match is quite optimistic and not well suited as a P50 case.

As previously mentioned, a common workflow method is *manual history matching*. This usually results in only one solution and is very time consuming.

Another approach is to run a number of models - for example 100 dynamic simulations - and use approximations to generate *proxy models* in an attempt to find all possible solutions. Proxy models are polynomial representations of the full dynamic simulation model. The advantage of this approach is speed, since calculations are done using the simple proxy model, not the reservoir simulator. With 100 simulations this can be expensive, while the quali-

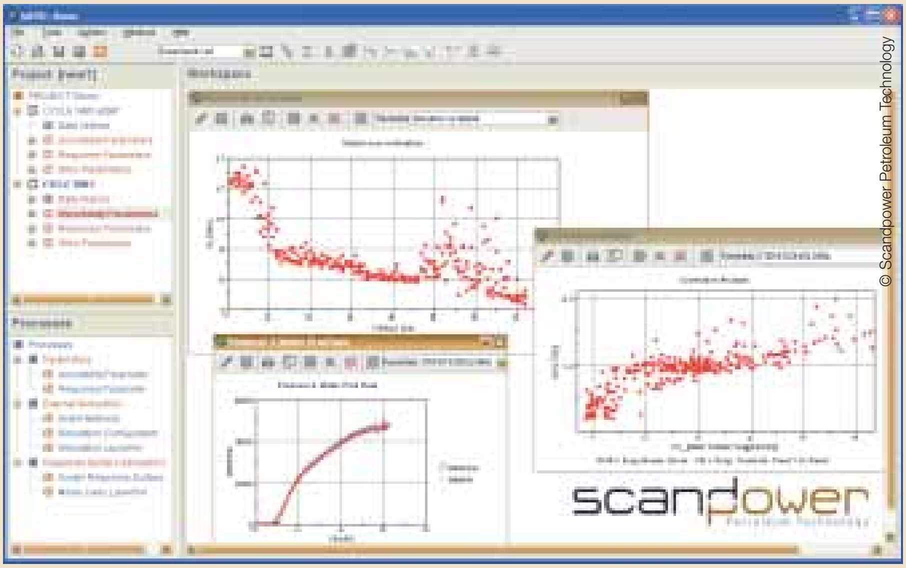
Evolutionary Algorithms

Evolutionary algorithms in particular have proved to be well suited for history matching. Genetic Algorithms and Evolution Strategy are two sub-groups of Evolutionary Algorithms. The Evolution Strategy has been proven successful to complex optimisation problems in the oil and gas and other industries.

The Evolution Strategy (ES) generally imitates the biological principals of evolution, 'survival of the fittest'. This means that the algorithm will continue the search around the best combinations of parameters to further improve the match and reject the bad ones. During every iteration the software analyses the results, trends and correlations to further adjust the parameters to improve the match. This is done in a matter of seconds.

The ES contains a destabilisation feature that will force the algorithm to try out totally different combinations when the match cannot be improved further. By doing this the algorithm will find more possible matches in the solution space.

This approach is very pragmatic, but the artificial intelligence in MEPO makes the search for acceptable matches extremely efficient. This means that the engineer can cover the whole solution space finding the possible matches and have much more confidence in the final result.



The MEPO user interface makes the analysis easy and efficient. The engineer gets the full overview by looking at the global match error and can at the same time investigate all the important details.

The Solution Space

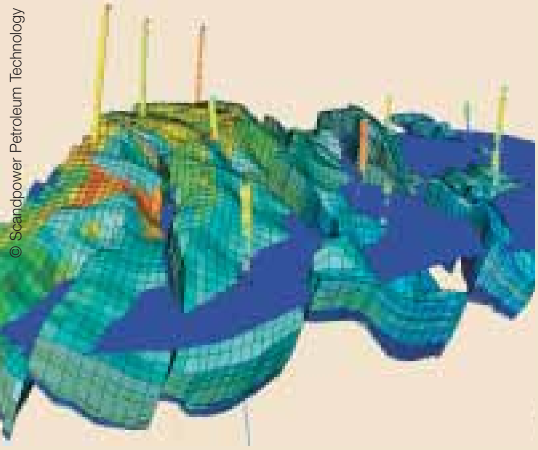
To illustrate the complexity of history matching, a simple model with only two parameters is used. Different parameter combinations of X and Y will result in a match quality seen on the vertical axis. Each simulation case is shown as a dot in the solution space. A surface is displayed to better see the vertical position or quality of each case.

With manual history matching there is not time to do a large number of simulations. The red arrow indicates the lowest mismatch error found. This single model is then used for future predictions.

Using MEPO you have time to do a large number of simulations and efficiently search the solution space. In this way you can find the possible solutions and make reliable predictions.

ty of the proxy model decreases with the increasing number of parameters and the degree of complexity. As a result, proxy models are not well suited for complex models or cases where there are several parameters that need adjusting.

A third option is to run *multiple dynamic simulations in parallel* and efficiently search the solution space. This approach has proved to be very successful. It copes with hundreds of parameters as well as the non-linear variable interactions and dependencies that proxy models fail to include. There is no doubt that this approach can provide valuable information about the reservoir behaviour if the information is extracted and presented in a proper way.



The same algorithms that find history matches can also easily find optimal well position or well length for infill drilling. It also accounts for the uncertainties in the model so that the potential risk is reduced.

The Technology is Available

MEPO, an example of this third option, was made commercially available in 2004 (GEO ExPro No. 1, 2006). The software utilises cheap and fast CPU's and modern cluster technology.

The software prepares all the files, executes all runs, analyses all the data and searches to obtain as many good matches as possible. This frees the engineer from time-consuming file handling and allows more time to be spent analysing and evaluating results. Based on knowledge and experience, the engineer can steer the process as desired.

Running 2,000 simulations in 2 weeks has no value unless it is possible to efficiently extract information of importance. Therefore, a variety of sophisticated analysis techniques are included. Plots showing trends, correlations and match quality provide the engineer with much more information than can usually be seen from normal line plots. The information helps the engineer to fully understand the model behaviour.

MEPO has been shown to speed up the history matching process by up to 10 times. History matching projects that used to take months can now be done in weeks or days and can even generate alternative match realisations within that time frame.

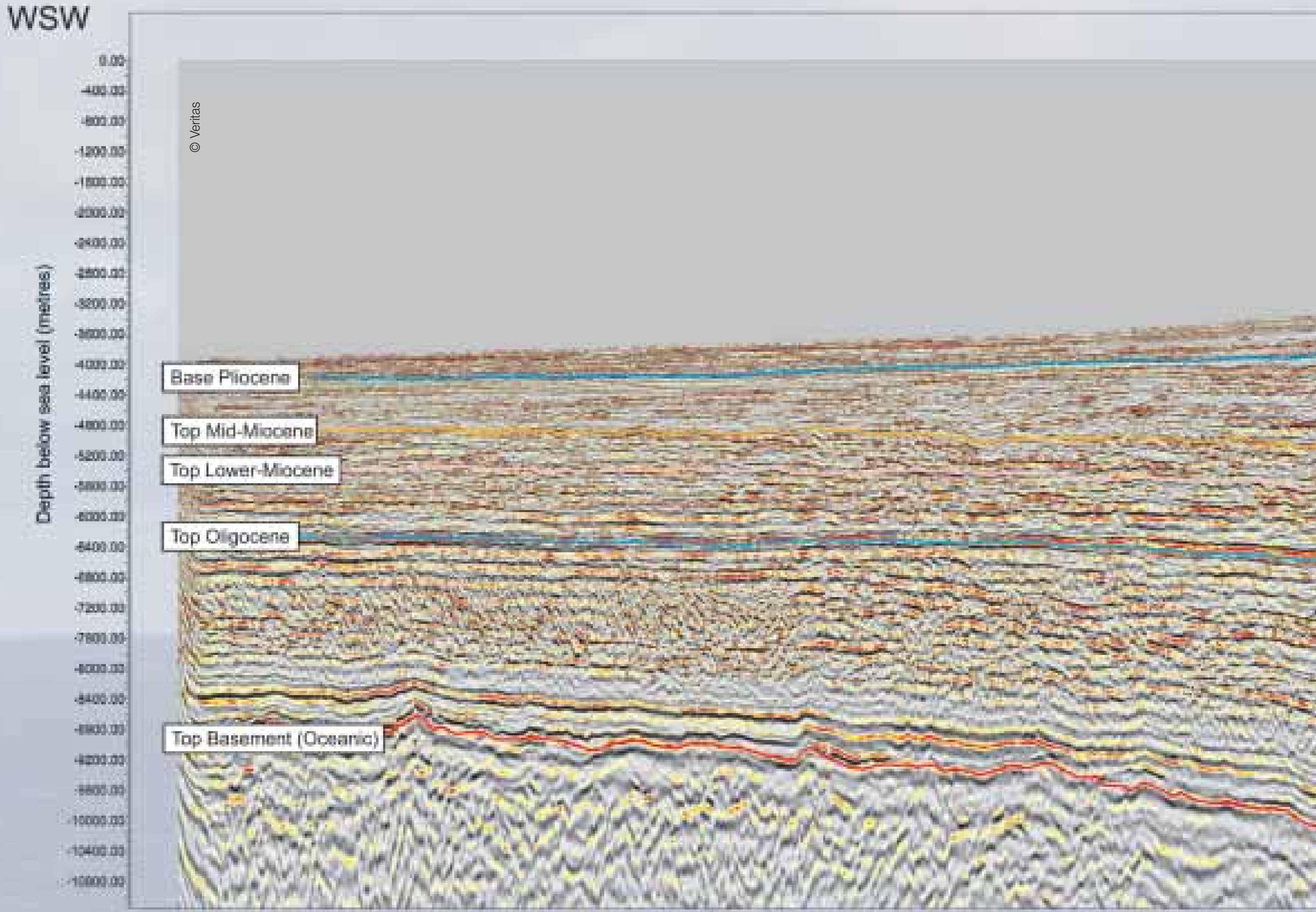
Uncertainty Assessment

History matching is often done in order to calibrate the model so it can be used for predictions, but there is normally a large degree of uncertainty attached to these.

Many different methods are used today to assess uncertainty. Running thousands of Monte Carlo simulations in order to find the P10, P50 and P90 case is probably well known. However, all of these methods have one thing in common; they imply that the single match realisation is a sound basis for the uncertainty assessment. Assisted history matching studies have, however, shown the pitfall of assuming that a single match realisation is a reliable P50 (base) model. A traditional uncertainty description will generally deliver an uncertainty range surrounding the base model, but since the base model is seldom suited for such use, it would appear pointless to use such false descriptions of reservoir uncertainty in the decision process.

The new approach through MEPO makes it feasible to explore the solution space and find several possible resolutions. These multiple solutions are run in prediction mode to find a more realistic uncertainty range. The result will help visualise both the up and down side potential associated with drilling decisions such as well placement.

The Niger Delta: An Active, Passive Margin



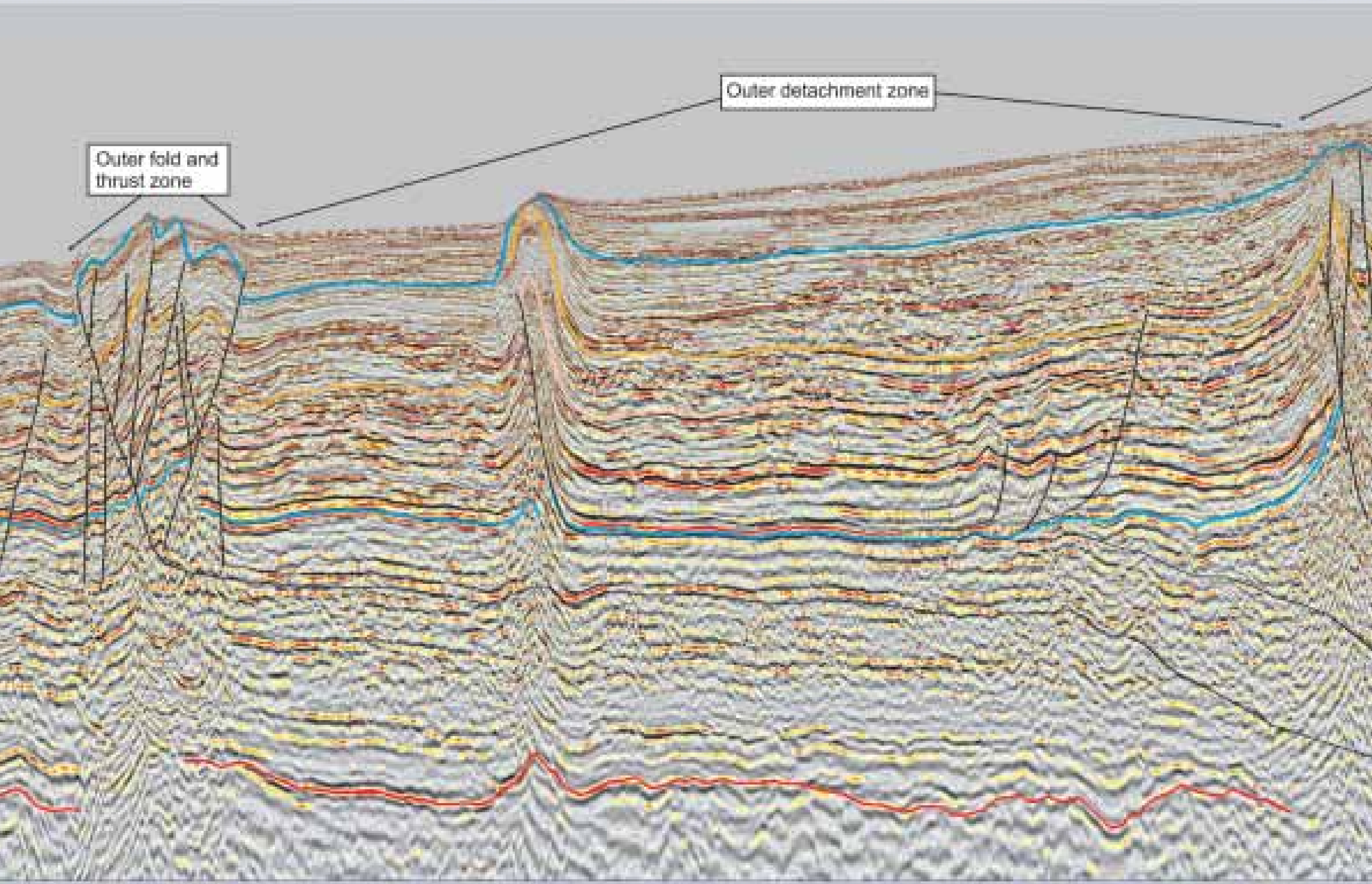
Lots of sediments – and plenty of oil

The Niger Delta, situated in the Gulf of Guinea, formed at the site of a rift triple junction related to the opening of the southern Atlantic.

The Gulf of Guinea is one of the most prolific hydrocarbon provinces of the world. Intensive exploration efforts since the late 1960's in the Niger Delta led to a succession of significant discoveries. However, the full potential of the continental slope and rise seaward of the shelf break has only recently become apparent, with a number of world-class discoveries being made. Modern seismic data and improved models of sand distribution indicate that prospective acreage can extend up to 300km from the coastline.

Three depositional cycles have been identified in the wave-dominated delta, of which the third cycle - deposited from Eocene to Recent - marked the continuous growth of the main Niger delta. The Niger delta geological province is identified by USGS in their World Energy Assessment as one, single petroleum system in what they term "the Tertiary Niger Delta (Akata-Agbada) petroleum system".

The three depositional cycles give a threefold subdivision for the Niger delta subsurface, comprising an upper sandy Benin formation (fluvial and backswamp deposits up to 2500m thick), a middle unit of alternating sandstones and shales named the Agbada formation (paralic, brackish to marine, coastal and fluvio-marine deposits), and a lower shaly Akata formation (up to 6500m of marine pro-delta clays). These three units extend across the



whole delta accumulating sediments that total over 10 kilometers in thickness. The Niger delta is thus one of the largest regressive deltas in the world with an area of some 300,000 km^2.

The primary source rock of the Tertiary Niger Delta petroleum system is the marine shales of the upper Akata Formation, with a possible contribution from interbedded marine shales of the lowermost Agbada Formation. Shales of the Akata Formation are overpressured and have deformed in response to delta progradation.

Oil is produced from sandstones in the Agbada Formation. Turbidite sands in the upper Akata Formation are targeted in deep water offshore and beneath currently producing intervals onshore.

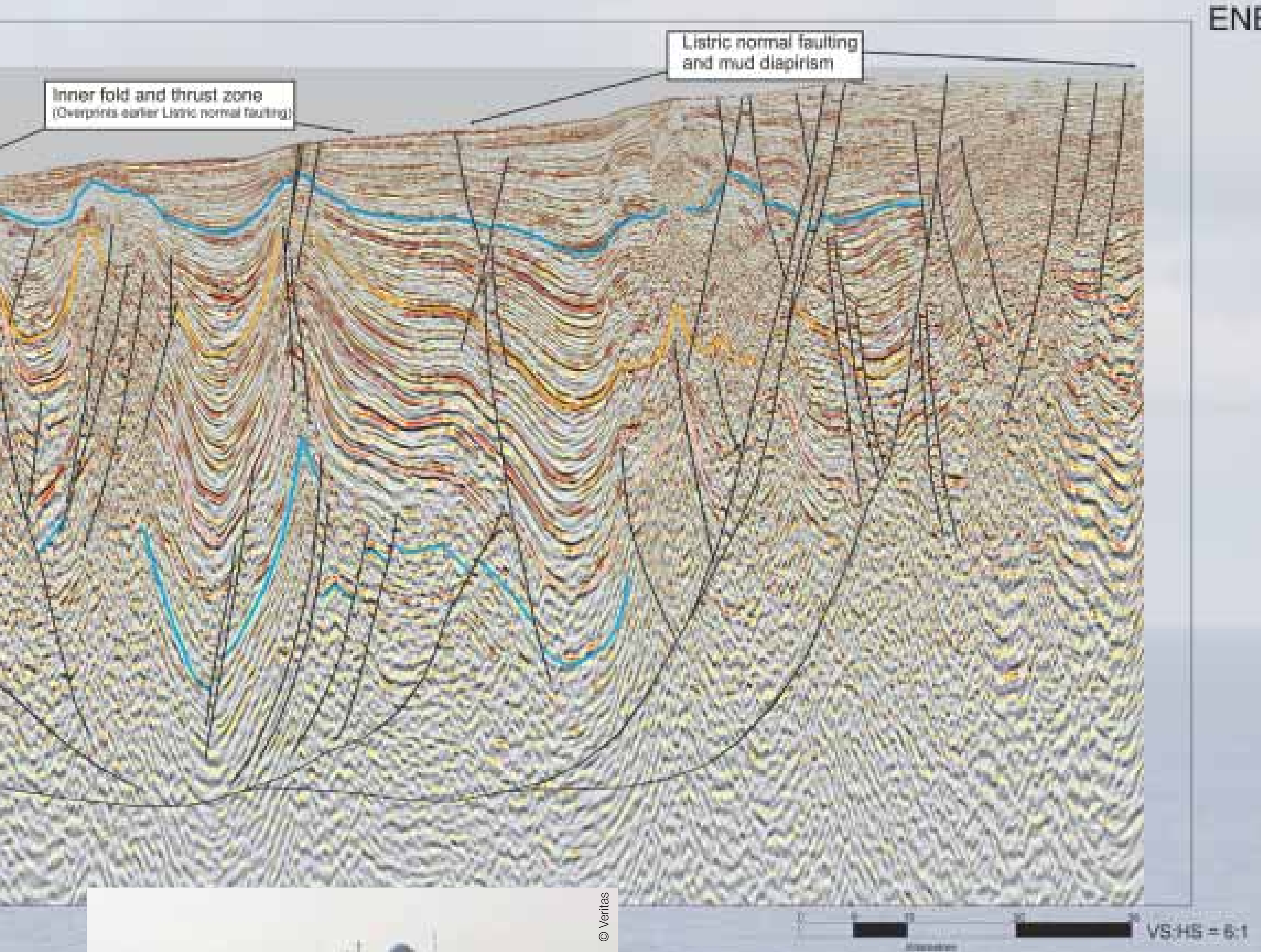
In 1908, the first wells were drilled in the vicinity of tar seep deposits in the northern part of the delta. However, significant oil shows were not found in Tertiary rocks until the early 1950's. The first well was brought on stream in 1958 at approximately 5000 barrels per day.

Today's production is approximately 2.6 million bopd and 2 billion ft^3 per day (BP Statistical Review of World Energy, 2006). This production rank Nigeria as the twelfths largest oil producer in the world, and the biggest in Africa.

Known oil and gas resources of the Niger Delta also rank the province as the tenth largest in the world. All together, 36 billion barrels of recoverable oil and 5 trillion m^3 of recoverable gas have been discovered and classified as reserves by BP.

The Niger Delta is also present in Cameroon and Equatorial Guinea. Recoverable oil and gas resources are, however, significantly smaller than in Nigeria.

Oil production in Nigeria in bopd from 1965 to 2005. Source: BP Statistical Review of World Energy.



Veritas Vantage.

A Major, Petroliferous Delta

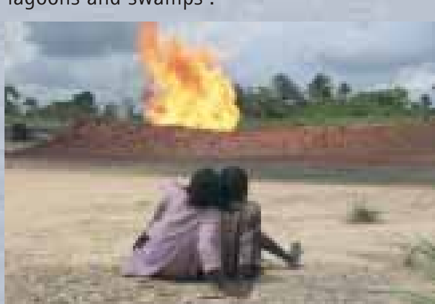
The Niger Delta is one of the major Tertiary deltas of the World. It is also volumetrically the largest of a number of examples that occur along the western continental margin of Africa. These deltas record a period of time within the Miocene-Pliocene (Neogene) when run-off rates from the land were far greater than we see today and enormous volumes of sediment were carried to the continental margin. In the case of the Niger Delta this process created a sedimentary apron in excess of 10 km in thickness in the centre with a slope that extends far out onto the oceanic crust.

The West African deltas are all subjects of current hydrocarbon exploration at various stages of maturity and among these the Niger Delta is recognised as one of the global exploration hotspots. Why is this the case?

At the simplest level the delta apron holds the promise of large oil reserves in water depths that although deep, are steadily being brought into range by the advance of technology and sustained high oil prices. Unpacking this situation a little, the Niger Delta appears to be extensively underlain by source rocks of Eocene and Oligocene (Paleogene) age. This makes the delta somewhat different to many other West African margin petroleum systems that rely on Aptian to Turononian (Cretaceous) age source rocks formed during the earliest phase of Atlantic spreading.

Outline of the Niger Delta. Line location shown in red.

The delta is covered with mangrove forests, lagoons and swamps .



Gas flaring in the delta.

Source rock

Source rock deposition in association with the early period of delta formation from the Eocene onwards may point towards terrigenous gas-prone source rocks, but this has not been the case. Oil analyses have consistently shown high levels of marine, and therefore oil-prone, source contribution, something borne out more tangibly by the large volumes of oil discovered in the delta area to date. Oddly, it could be the high burial rates during phases of delta build out that is a key factor in source rock distribution, rapidly burying and preserving source rock intervals before the organic matter is re-cycled by the creatures living in the sea-floor sediments.

Reservoir

Niger Delta reservoirs are exclusively marine clastics formed by sands occurring in a variety of depositional settings from tidal, shallow water shelf to distributary channel splays on the lowest parts of the continental slope. These reservoirs were deposited during the Miocene-Pliocene (Neogene), the period that saw the most rapid expansion of the delta apron. Stacked reservoirs have been frequently encountered in the onshore parts of the delta associated with repeated regression-transgression cycles on the shelf, whereas slope channel sands dominate in the outer shelf and slope areas.

Trapping

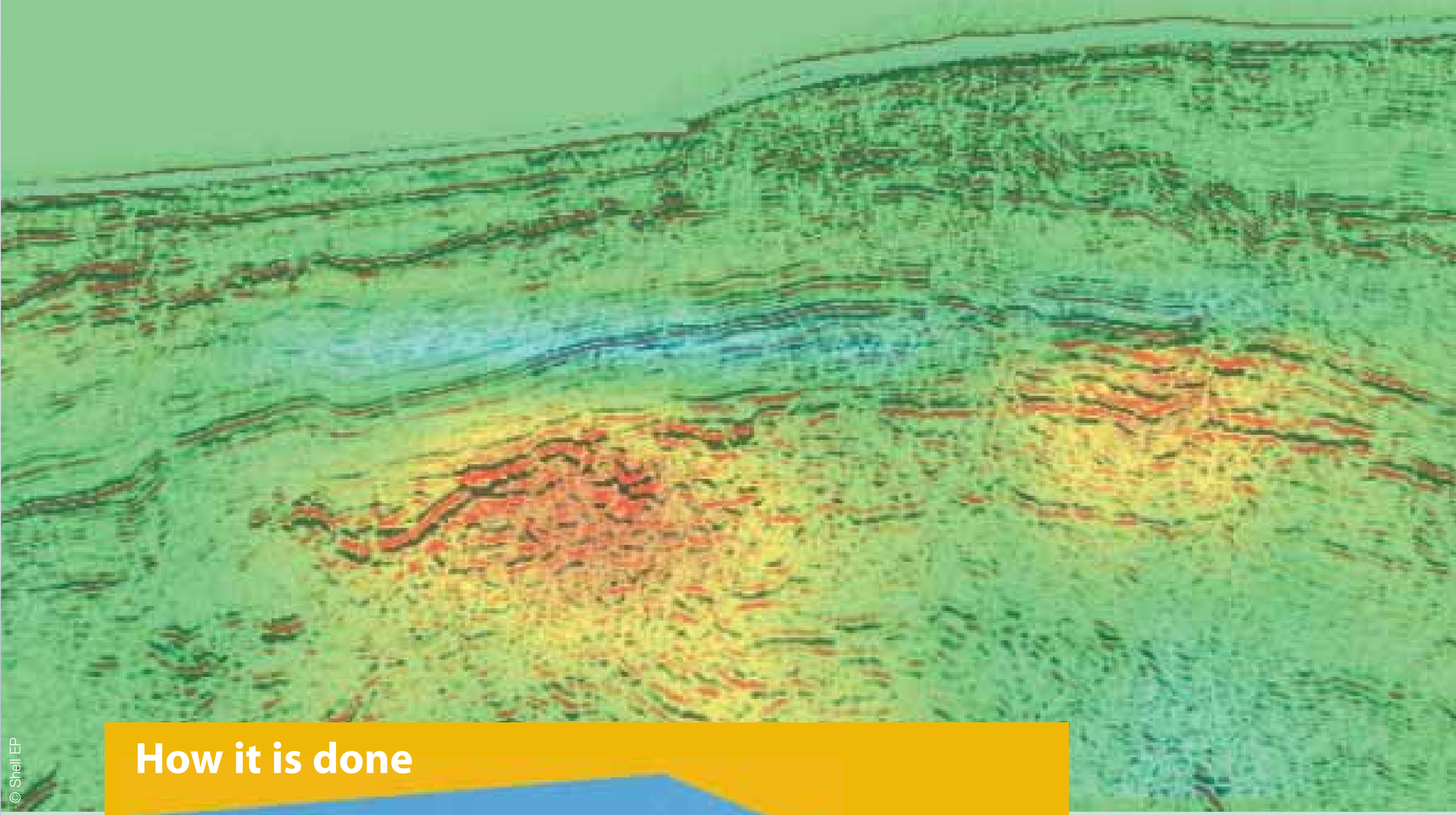
The most obvious element of the prospectivity present in the Niger Delta is structure. Structures have formed due to the partial collapse down-slope and oceanward of the sediment apron on a slip surface created by over-pressured mudstones; a landslip on a crustal scale. Normal faults have formed on the up-slope side of the detached apron while thrust faulting occurred on the down-slope side. The large-scale flow of over-pressured mud was associated with faulting in the thickest parts of the apron creating complex, diapir-like structures. Consequently, the delta contains an abundance of potential traps in listric normal fault, faulted mud diapir and toe-of-slope thrust fault settings. Crucially, the faults also connect source to reservoir with respect to fluid migration pathways and faulting and hydrocarbon expulsion events are probably intimately connected.

In conclusion, the Niger Delta can be viewed as a self-contained petroleum system where the growth of the delta apron has both captured and matured the organic matter, provided the conduits through which the hydrocarbon products have migrated and caused the formation of the traps in which these have accumulated. What makes this area so interesting to explorers is the way these mechanisms have combined to facilitate hydrocarbon accumulation in large volumes.

Dr.Richard Morgan
Manager Geological Services, Veritas DGC

Towards a new era

Sea Bed Logging is a new technology that offers the opportunity to detect trapped hydrocarbons in the subsurface prior to drilling. Shell EP has recently conducted a number of very successful data acquisition campaigns throughout the world based on this technology, leading it to substantially expand its use of this technique in the future.



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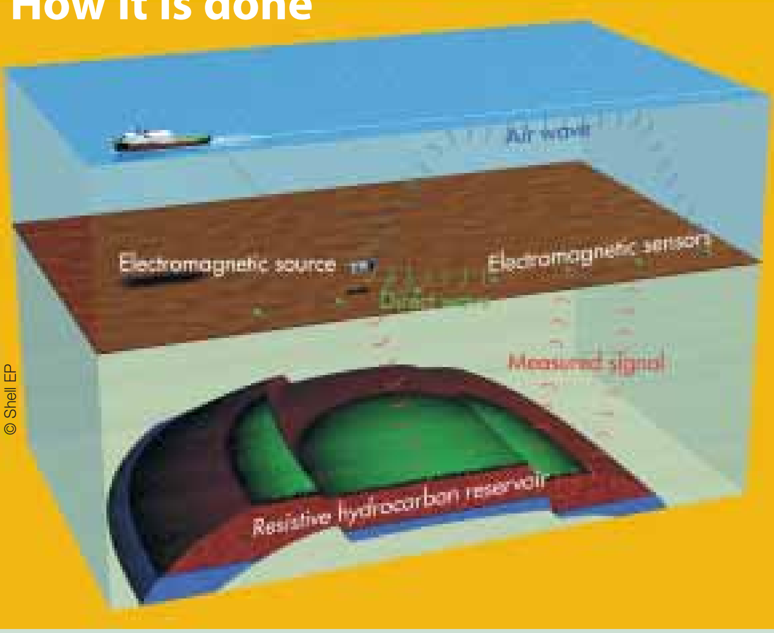
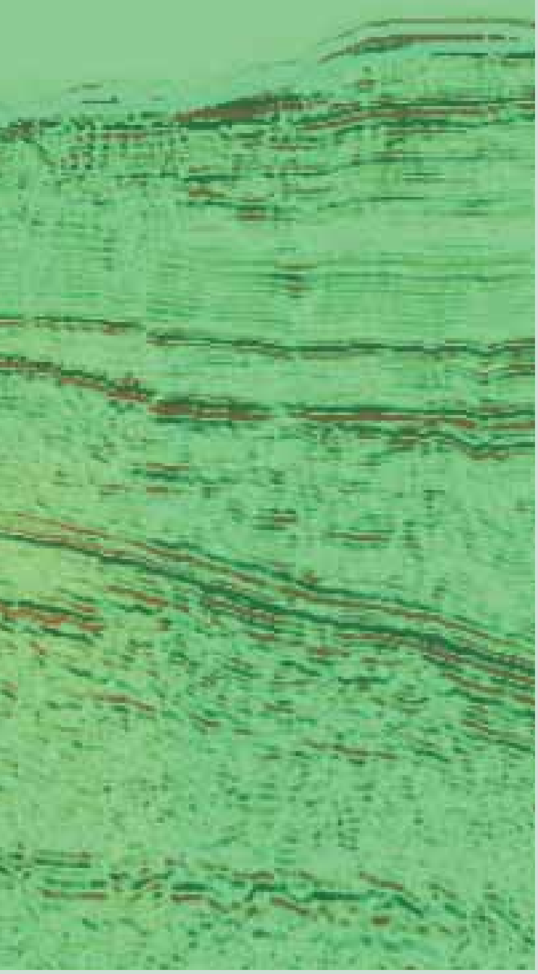
How it is done



© Shell EP

The receivers are first placed on the seabed. Then a vessel with a transmitter passes over them. Signals arrive directly through the water (green line), through air (blue line) and through the reservoir (red line).



Seismic section and possible interpreted resistive body (red and yellow colours) indicating the presence of hydrocarbons in an imaginary prospect.

More than 180 electromagnetic surveys have been carried out by emgs alone worldwide. Shell, which has recently embarked on a joint research and development initiative with emgs to develop this technique further, has participated in over 50 surveys, the vast majority contracted directly with emgs. Geological provinces surveyed include the North Sea, the Norwegian Sea, the Barents Sea, the US Gulf of Mexico, offshore Brazil, offshore West Africa, the Nile Delta, offshore India and the South China Sea.

Halfdan Carstens

Seabed logging, which is the application of Controlled Source Electro-Magnetic surveying (CSEM) to finding hydrocarbons, has proved to be a rewarding tool to add complementary information to the seismic interpretation. The introduction of this innovative technology only four years ago has been proven to give oil companies a much better chance of finding oil and gas in frontier as well as mature basins.

Increased competition

The research department of Statoil developed seabed logging from the late 1990's onwards, and in 2002 formed a separate company, Electromagnetic Geoservices (emgs), to implement the technology (GEO ExPro, No. 1, 2004). emgs is headquartered in Trondheim, Norway, with fully staffed operational and technical support offices in Houston and Kuala Lumpur, and with sales offices in Stavanger, Paris, London, Rio de Janeiro and Mumbai. To date it has recorded more than 180 surveys, with a total distance logged close to 15,000km, under a wide range of conditions, and in water depths ranging from 50m to more than 3,000m. The client list now encompasses in excess of 30 operating companies, including supermajors like Shell and ExxonMobil, independents as well as national oil companies (NOC's).

emgs, however, is not the only provider of CSEM-data. At least three other companies are offering these services, including AOA Geomarine Operations LLC (AGO, GEO ExPro No. 3, 2004), now owned by Schlumberger, MTEM, a spin-off from Edinburgh University (operating on land only so far, but working their way into the offshore), and OHM (Offshore Hydrocarbon Mapping), formed in 2002 as a spinout from the UK's prestigious National Oceanography Centre at Southampton University. OHM has completed in excess of 50 surveys as well as numerous reprocessing and interpretation projects using data collected by third parties.

ExxonMobil has also been developing its own technology, named Remote Reservoir Resistivity Mapping (R3M), which it has already used on more than a hundred surveys worldwide.

Successful testing

Since its introduction, seabed logging has been shown time and again to improve exploration efficiency. Several cases have been published to prove this. Most renowned is the Troll case (North Sea) in which the technology was demonstrated to successfully detect the gas field, and at the same time proving that seabed logging can be used in shallower water (350m) than previously thought (>500m). In fact, a later survey across the Grane oil field in the North Sea, where the water depth is only 100m, also proved successful.

While the Troll case was "after the fact",

Saad Saleh joined Shell in 1991 after receiving a PhD in electrical engineering from the University of Wisconsin. In the 1991-95 period, he worked on the development and implementation of a variety of seismic processing algorithms at the Bellaire Technology Center and at Shell Western E&P, Inc. in Houston. From 1996 to 2004 he worked on direct hydrocarbon detection research problems, such as seismic AVO, with emphasis on the application of statistical detection and estimation techniques. He is currently project leader of the New Detection Methods team at the Bellaire Technology Center, investigating the application of electromagnetic, potential fields, and remote sensing techniques in frontier exploration areas.

another published case in the Norwegian Sea clearly demonstrated seabed logging as a valuable tool in exploration. Based on 3D and 4C data, the Linerle prospect, in about 300m water depth was considered promising. With evidence of hydrocarbons nearby, a seabed logging survey was conducted that showed high resistivities in the subsurface. Drilling subsequently confirmed the presence of hydrocarbons in a 20m column.

Further breakthrough in the acceptance of this technology came when the Norwegian Ministry of Petroleum and Energy recently included seabed logging modelling and acquisition in the work commitments attached to selected licenses. Another petroleum agency has also used seabed logging as a tool in the administration of offshore licenses. An operator was released from a drilling obligation on condition that a seabed logging survey was conducted.

Lately, it has also become known that Falklands Oil & Gas has signed a letter of intent with OHM to assess a series of prospects in the frontier South and East Falklands Basins. Seabed logging "is an extremely cost effective method of high grading an extensive inventory of exploration prospects and leads. This programme has the potential to indicate which of our numerous prospects may contain hydrocarbons," the company says.

Tim Bushell, Chief Executive Officer of Falklands Oil & Gas, commented that the method "can help to significantly reduce risk, improve the chance of success and allow us to focus on the best prospects for drilling in 2008."

Nevertheless, it is important to point out that electromagnetic surveying is not a tool that should be used in isolation. "Average exploration success rates of less than 20% demonstrate the pitfalls of trying to solve several unknowns with a single measurement technique, although until recently explorationists had no choice. In the borehole domain, geoscientists enjoy the benefits of using use many different measurements in an integrated manner (e.g. resistivity, density, neutron porosity, acoustic, NMR) to evaluate reservoir and fluid properties more accurately. And whilst each measurement has its own particular strengths, individual measurements are rarely used in isolation from the rest. It's time for the exploration industry to embrace the same integrated approach, not stopping at seabed logging, but continuing to incorporate other reservoir scale diagnostics as they become available," says Ken Feather, Vice President Marketing in emgs.

Shell gets involved

Shell has been involved with SBL since 2001, and early in 2004 the company contracted emgs to carry out a global campaign. Surveys were carried out in a multitude of geological settings in north-west Europe, West Africa, South America, the Far East, the Mediterranean, and the Gulf of Mexico.

"The campaign had two main objectives," says Saad Saleh, project leader of Shell's R&D efforts in seabed logging. "First, to confirm that the technology works in clear cases of large, relatively shallow hydrocarbon accumulations, and second, and more important, to interpret data in conjunction with other data such as seismic attributes in more difficult settings where advanced processing would be required."

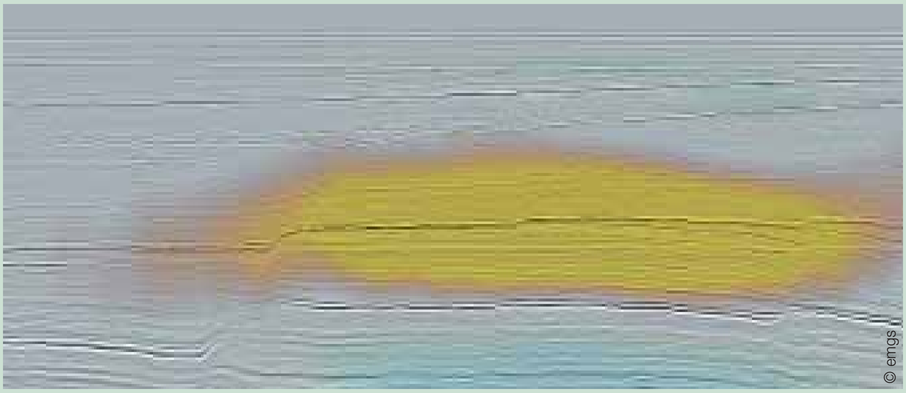
Most surveys were acquired over prospects not yet drilled. With Shell's reputation at stake, this, one should think, would be the ultimate test of the technology that was introduced as a commercial product only four years ago.

Hard to find more

Finding oil and gas is no longer an easy business. Most of the giants have been found. This is true for the North Sea, West Africa, the Gulf of Mexico, and many other mature, prolific offshore provinces. As a result, oil companies are now moving into new geological provinces including ultra-deep water and ultra-hostile areas, while at the same time they need to find the remaining oil in mature basins.

"In the next exploration wave, technology integration is the key, in particular merging non-seismic with seismic methods," says Mike Naylor, Shell's exploration technical director to Changes magazine.

"We are now approaching the limits of what exploration-scale seismic can tell us.



Depth migrated image from a one line survey across the giant Troll field in the North Sea. The reservoir is in Upper Jurassic sandstones situated below the prominent reflector in the middle of the section. The hydrocarbon filled reservoir at a depth of approximately 1000m has resistivities approaching 250 Ωm, while water wet sandstones and overburden shales have resistivities in the order of 1-2.5 Ωm.

Drilling is bee coming more costly, so we need independent techniques to back the seismic up, telling us more about the conditions several kilometres below the Earth's surface. This embraces not just the structure, but the nature of the rocks, and the type of fluid they contain," Naylor explains.

Seabed logging now proves to be just such an independent technique, giving information on the types of fluids the reservoirs may contain.

Three successful cases

As of today, Shell has acquired more than 50 surveys over a wide range of reservoir and subsurface conditions. Three examples illustrate how this new innovative technology may cause a significant reduction in exploration risk and drilling success.

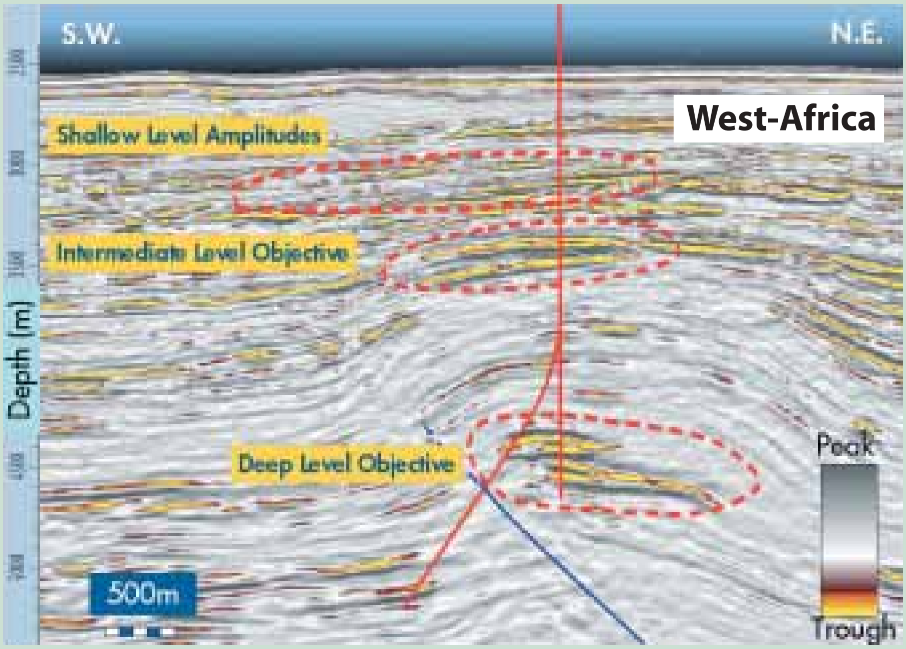
Offshore West Africa, Shell evaluated a prospect with several different fill possibilities. Three models with shallow and deep reservoirs were developed based on the seismic interpretation. The first model included hydrocarbons in both reservoirs, in the second model only the deep reservoir was filled with hydrocarbons, and in the third model a shallow gas layer was removed.

"The measured response matched a model in which only the lower reservoir was hydrocarbon saturated. The result was later verified through drilling, demonstrating that the technology can also be used where multiple reservoir beds are present," says Saleh.

In Brazil, Shell identified a potentially large prospect in a block that would become available in a forthcoming licence round. While a reservoir model could be developed based on the seismic data, detailed seismic amplitude studies were inconclusive with respect to hydrocarbon saturation. A seabed logging survey was therefore acquired, but no anomaly was identified, suggesting that the reservoir is water-wet.

"This evidence, when combined with hydrocarbon charge evaluation studies, was sufficient to make the decision not to pursue this opportunity which would have involved considerable licensing and drilling costs," says Saleh. The company therefore felt comfortable walking away from this prospect.

"This is a tremendous step forward in the acceptance and confidence placed in seabed logging results. Shell made an intelligent choice in walking away. The



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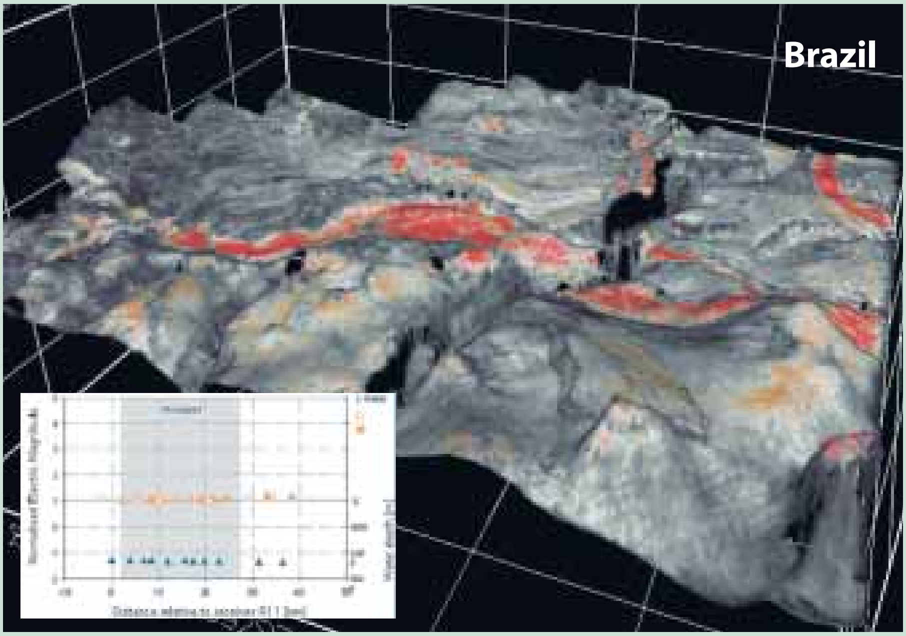

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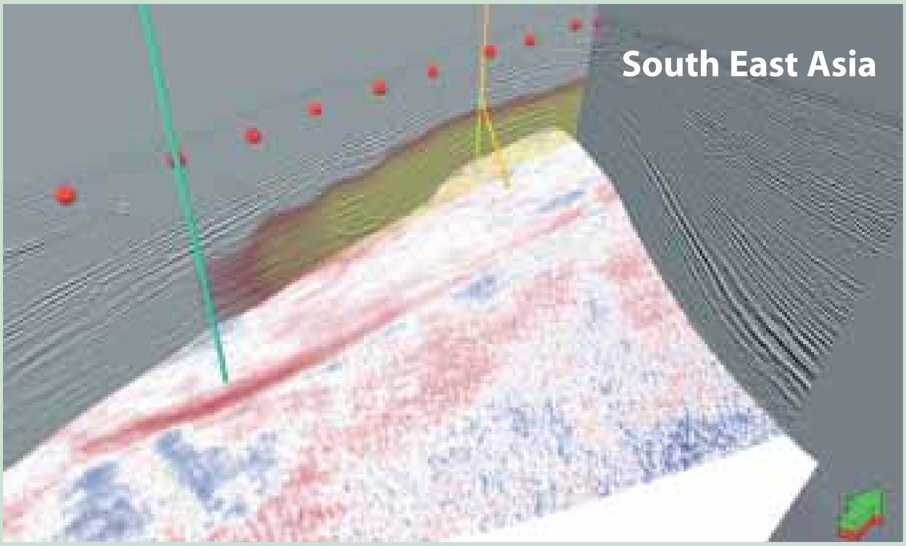

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prospect became very high risk and they were able to eliminate it from their portfolio, thus improving overall valuation and at the same time prioritising finite exploration resources, comments Ken Feather.

In South East Asia, Shell is actively exploring a thrust belt play in which the main exploration uncertainty is trap integrity. Shallow gas reduces the quality of seismic imaging, in particular over the crest of the structures. Down flank, data quality improves and direct hydrocarbon indicators such as flat spots can be observed. However, the pitfall is that such flat spots may be paleo oil-water or gas-water contacts.

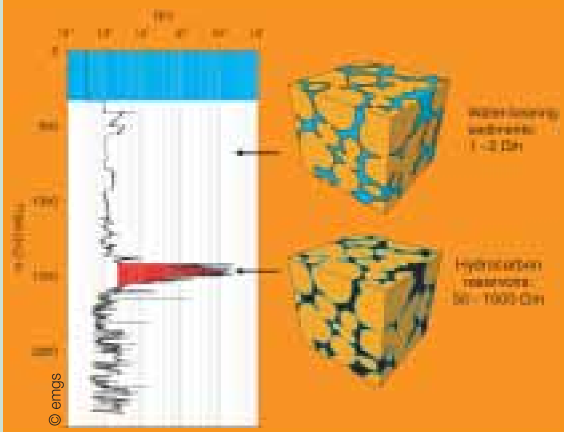
"Our seabed logging data indicated that hydrocarbons would be present updip from a dry well with only residual hydrocarbons. This was confirmed by a second exploration well, a well that may not have been drilled if there was no independent, complementary information available in the form of resistivity data," Saleh says.

The survey results also demonstrate that seabed logging, in cases where it was used across known fields, shows the locations of those fields. Further, in several cases the depths of the reservoirs can be measured with reasonable accuracy.

"The technology holds a great potential, although we stress that the technology is not a "silver-bullet", and as with any new technology, not all examples allow for a

Svein Ellingsrud (left), VP R&D emgs and co-inventor of seabed logging, receives the prestigous Harts Meritorious Engineering Award in the "exploration system" category, for its seabed logging survey method, from Bill Pike (middle), editor of Hart's E&P, accompanied by Stuart Goldstein, business development manager, emgs Americas, at OTC in Houston, May 2006.

What is seabed logging?



All fluid-filled rocks are characterised by electrical conductivity. The difference in conductivity between, for example, shale and sandstone is relatively small when these rocks are water-saturated (resistivity 0.2-5 Ωm). If the sandstone is filled with oil or gas, however, its conductivity falls markedly (resistivity 20 - >200 Ωm). This is the principle applied in well resistivity logging.

The Schlumberger brothers introduced well resistivity logging to the oil and gas industry almost 80 years ago following their first measurements in an oil well in France. Measurements of the conductivity of a rock, based on a transmitter and receiver lowered into a borehole, can tell whether the reservoir contains water or hydrocarbons, and resistivity has since the 1920's been the de facto hydrocarbon indicator used by the industry. Acoustic measurements were first introduced to the borehole measurement portfolio in the 1960's.

emgs has shown that the principle of resistivity borehole logging also functions on a much bigger scale. With the electromagnetic field generated from a transmitter towed approximately 30m *above* the seabed and registered by a receiver placed *on* the seabed it is now possible to "view" the reservoir from above and not just from an instrument in a borehole. To achieve deep penetration – several thousands of metres down – it is necessary to have a powerful source and low frequencies (typically 0.25-10 Hz) in the outgoing signal.

The source is an electric dipole consisting of two poles, a lead and a tail electrode, each about 10m long. The two poles are located 300-400m apart and connected by a cable. Passing an oscillating high-power current from the lead to tail electrode creates an electromagnetic field that sends out waves in all directions. When a wave meets a low-resistivity layer, it passes through and becomes slightly weakened or attenuated. Encountering a high resistivity layer, the wave is deflected along it and attenuated to a much lesser degree.

The source thus generates a signal that is distorted by resistive bodies in the subsurface. The distorted response shows as anomalous readings that differ from the background. The resistive bodies showing these anomalies could be oil or gas reservoirs.

The strength of the electric field, for a specific receiver placed on the seabed, is measured and registered as a function of distance between transmitter and receiver ("offset"). When the distance from the transmitter to the receiver increases (the boat moves away from the receiver), the signals diminish in strength. All measurements above the reservoir are compared with reference measurements outside it.

Signal strength from resistive bodies increase with offset up to a point; at offsets approximately equal or greater than 3x the burial depth, the energy from the resistive body dominates all the other energy paths.

The electromagnetic source is towed near the seabed, while receivers are placed on the seabed in a regular grid. Depth migrated data can be presented as an image (compare also illustration on page 40) with resistive bodies correctly located in depth. When overlain on depth-migrated seismic data, seabed logging can indicate the presence of hydrocarbons.

clear and unambiguous interpretation. The optimal impact comes through careful integration with complementary data such as seismic", Saleh says.

Multipurpose use

Terje Eidesmo, managing director of emgs, recently gave a presentation of the company to the Norwegian Minister of Oil and Energy, Odd Roger Enoksen.

Referring to the close cooperation with Shell and their successful application of the methodology worldwide, he emphasized three different applications of seabed logging in exploration.

"First, the method can be used to reduce exploration costs by avoiding drilling prospects that appear not to contain hydrocarbons," Eidesmo said. "Furthermore, extensive use of seabed logging data can assist in making better decisions when prioritizing a drilling campaign in a given sedimentary basin, thereby making seabed logging a valuable technology that can assist in risk assessment significantly. Thirdly, by running surveys in areas where previous disappointments have increased the risk considerably, hydrocarbons can be found in prospects that would otherwise not have been drilled."

Svein Ellingsrud, Vice President Research and Development, added that the future use of seabed logging might play a significant role in reservoir delineation and reservoir monitoring. In fact, a calibration survey in 2002 on the giant Ormen Lange gas field in the Norwegian Sea successfully located the field boundaries as defined by seismic amplitude anomalies.

The Innovators

Electromagnetic surveying was proposed in the academic world in the 1970's and has been used for years by researchers to carry out lithosphere studies and examine hydrothermal and volcanic systems on mid-ocean ridges. The technique involved towing an electromagnetic source close to the seabed and recording the responses on detectors, also placed on the seabed.

In the late 1990's, two research scientists then working at Statoil, Terje Eidesmo and Svein Ellingsrud (GEO ExPro No. 5/6, 2005) evolved the method and advanced the technology to enable the detection of hydrocarbon reservoirs. They introduced the technology to the oil and gas exploration industry after having learned about a powerful new source with the potential to propagate electromagnetic energy more than 2 km into the subsurface. They termed the new technique seabed logging because of its similarities with borehole resistivity logging that they were actively working with at that time.

The idea was that electromagnetic measurements could give information about the resistivity profile of the subsurface, a profile which to a large extent is controlled by the resistivity of the saturating fluids. The concept is thus based on the principle that an electromagnetic field is rapidly attenuated in a conductive media (water-wet reservoir rocks) but less attenuated in highly resistive media (hydrocarbon saturated reservoir rocks).

A test survey, carried out by Statoil offshore Angola in 2000 in collaboration with Scripps Institution of Oceanography and Southampton Oceanography Centre, in about 1200m of water and above a known shallow hydrocarbon reservoir, turned out to be successful and laid the ground for further development. This event, a mere six years ago, is also the true start of seabed logging as we know it today.

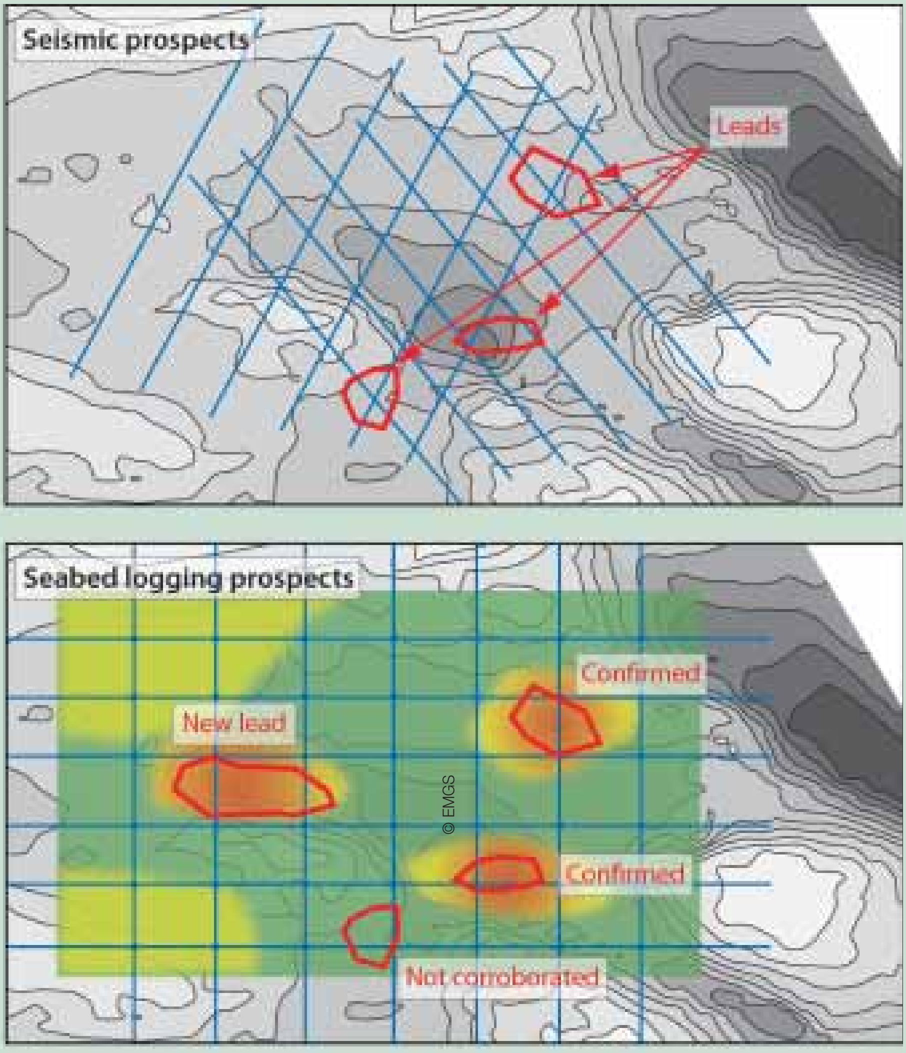
Eidesmo and Ellingsrud demonstrated that electromagnetic energy is guided, with low attenuation over long distances, by resistive subsurface bodies such as oil and gas reservoirs. They also showed that low-frequency electromagnetic energy, emitted by a source close to the seabed, can propagate to the depths of typical reservoirs, and that, by applying tailor-made survey design, the signals can be large enough to dominate energy arriving by other propagation modes.

Photo: Halfdan Carstens

Nine years after the idea struck on a flight out of Houston, Svein Ellingsrud (left) and Terje Eidesmo, both with a strong background in geophysics, can claim that seabed logging has been accepted by the conservative oil industry. Eidesmo and Ellingsrud were portrayed in GEO ExPro No. 5/6, 2005 (www.geoexpro.com [people])

Photo: Halfdan Carstens

Government recognition: Ståle Johansen (right) of emgs explains seabed logging to the Norwegian Petroleum and Energy Minister, Odd Roger Enoksen, during the Minister`s recent visit to the company's headquarters in Trondheim, Norway.



While seismic data define prospects and leads, seabed logging is capable of confirming the presence of hydrocarbons. In this example, two of three leads seem to be promising. A fourth area, which is missed by the seismic, should be pursued. The figure thus illustrates how seabed logging helps to prioritize an exploration campaign.

Less restrictions

"We expect further advances based on 3D acquisition, imaging and inversion. Shell and emgs have therefore recently embarked on a joint research and development initiative to develop such techniques," Saleh says about the future of seabed logging.

"At present, the use of the seabed logging technology is largely restricted to water depths in excess of 200m, but through ongoing R&D efforts, techniques will be developed that remove the depth restriction. Also, the depth of investigation below seabed will be extended from today's 3000m+ restriction. We will also focus our research on ways of removing the influence of distorting bodies such as salt and volcanics that in some areas may be prohibiting the use of this technology. Moreover, we will conduct experiments into methods of 3D surveying," says Saleh.

"Our examples from three different geological settings demonstrate that seabed logging will be part of a tool kit that explorationists can use when they evaluate prospects and associated risks. Seabed logging should, however, not be used in isolation, but as part of an integrated evaluation process," Saad Saleh concludes.

No doubt, exploring for hydrocarbons will never be what it used to be. We are moving fast into a new era.

Moving offshore

The MTEM technique – the multi-transient electromagnetic technology – injects multiple transients into the earth at each source point and records the resultant voltage between pairs of electrodes along the recording line. Because the system inputs a known coded sequence of current signals, this has the effect of delivering a broad range of frequencies into the earth.

When an EM source emits an electric field, some of the energy – the airwave – travels upwards until it reaches the surface where it flashes across the surface at the speed of light. "In MTEM this is not a problem: we exploit the differences in the properties of the transient air wave and the transient earth response. Processing enables us to separate the events completely," says Anton Ziolkowski, Technical Director of MTEM.

"Competing techniques use a source that is outputting the same square wave signal continuously. The airwave is continually contaminating the data from the reservoir. However, since water absorbs electromagnetic energy, the deeper the water, the less the airwave is a problem. This explains why first generation companies have been focusing on deep water. For

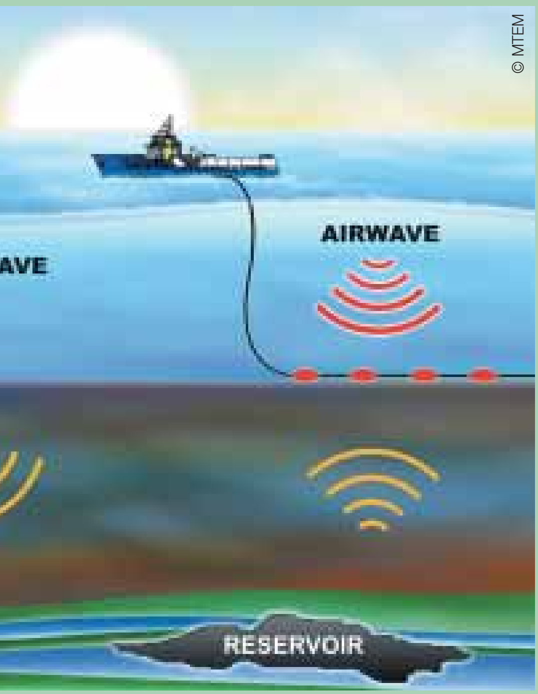
MTEM the water can be any depth, including zero," Ziolkowski says.

"MTEM® has been used on land with great success, with our first commercial crew starting operations in the second half of 2005. All our scientific analysis and tests also indicate that the method will be equally successful for marine reservoirs".

MTEM last year successfully tested its electromagnetic hydrocarbon survey technology in shallow water over coal measures in the Firth of Forth near Edinburgh. Deploying a 2km ocean bottom cable and using a low power experimental source, data were recorded at offsets of up to 8km, allowing the detection of resistive rock layers up to 2km below the sea bed. With water depths of 12m to 20m, this is the first use of such technology in shallow water.

"I am very pleased to see that the signals we measured and analysed in real time are just as predicted by the theory and the computer modelling. This confirms that the earth responds to our transient input current source just as it does on land," says Anton Ziolkowski.

This breakthrough enables the company to commercialise its application in shallow waters up to 300m. "We are currently building a commercial marine system, capable of recording and analysing data in real time, which will be ready for operations in November 2006, and we are now seeking clients with suitable reservoirs in the North Sea and other offshore prospects," says Leon Walker, Chief Executive of MTEM.



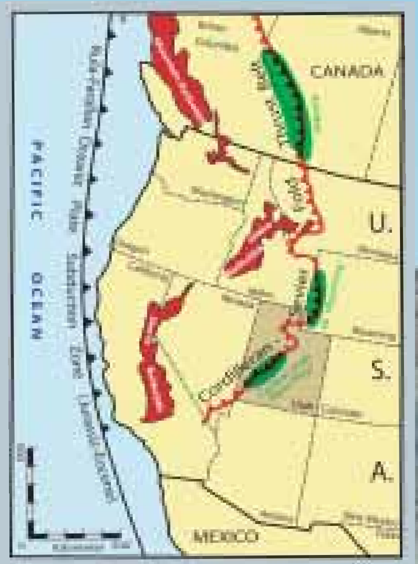
Central Utah Thrust Belt:

Tectonics of a New Exploration Province

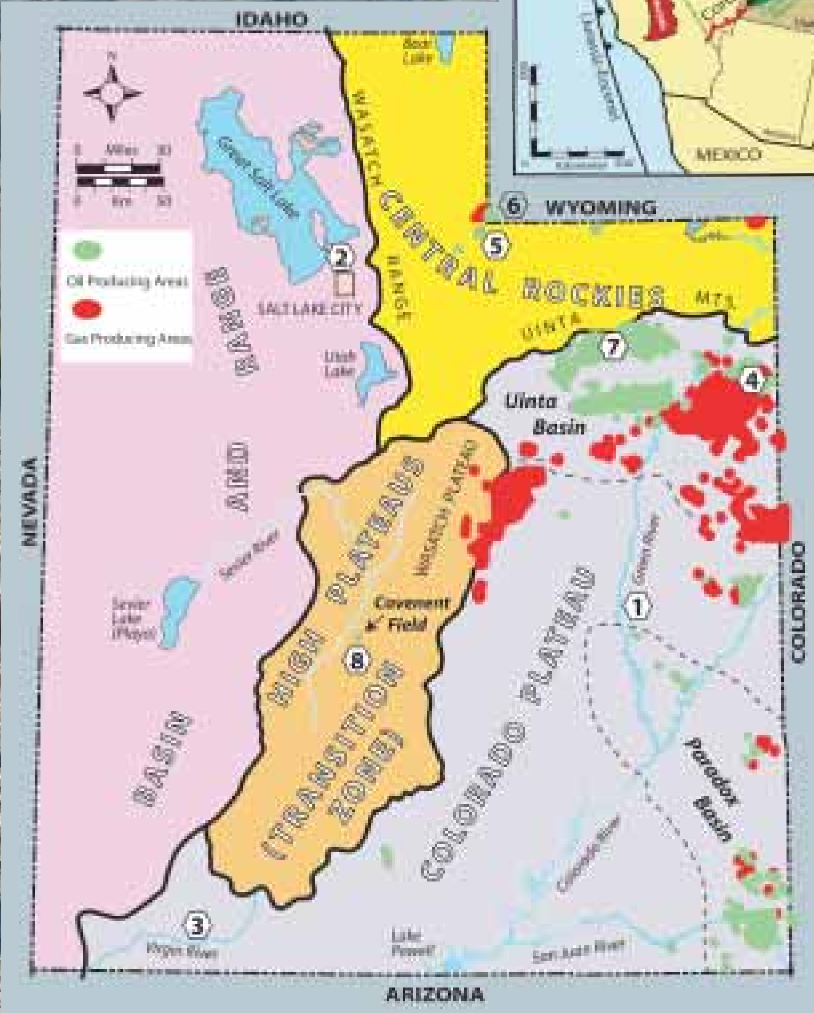
The Middle-Jurassic Arapien Shale in central Utah as major cap rock for petroleum traps.

The recent discovery and development of the Covenant oil field by Wolverine Oil & Gas Corporation in the Central Utah fold-and-thrust belt opens a new exploration province in North America, and gives new impetus for research on the geologic structure and evolution of the area.

Photo: Halfdan Carstens



The Sevier orogenic belt formed as a retro-arc, fold-and-thrust belt from Late Jurassic-Eocene. The basins in Alberta (Northern Rockies, Canada) and western Wyoming (Middle Rockies, USA) are classic petroleum provinces. Central Utah has recently joined its petroliferous sister basins.



Geologic divisions of Utah showing the distribution of producing oil and gas fields, and the location of the recently discovered Covenant field in central Utah. Numbers 1 through 8 are described in the table. The majority of Utah's oil and gas field are concentrated in two large basins – the Uinta basin in northeast, and the Paradox Basin in southeast.

Rasoul Sorkhabi and Greg Nash, Energy & Geoscience Institute (EGI), University of Utah, Salt Lake City

Utah is divided into four geologic regions:

Central (Middle) Rocky Mountains in northeast which includes a fold-and-thrust belt extended from western Wyoming as well as two mountain ranges – the north-south running Wasatch Range and the east-west running Uinta Mountains.

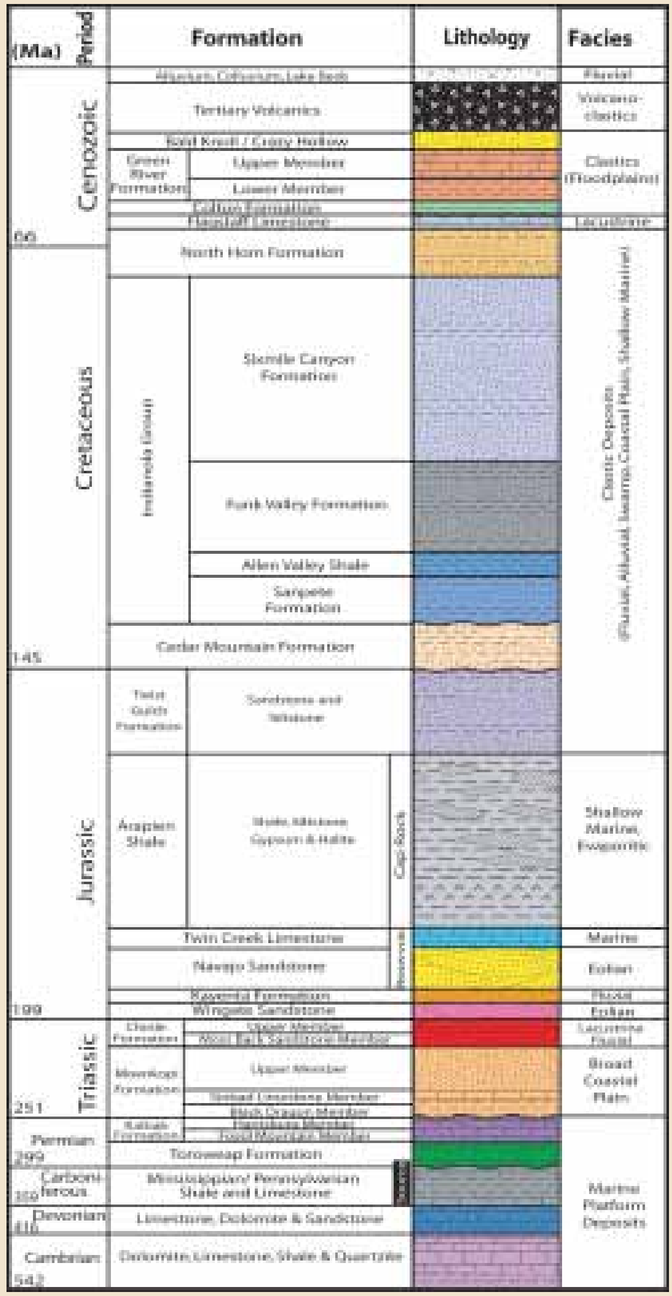
The Colorado Plateau in eastern Utah which also includes parts of Colorado, New Mexico, and Arizona. Several major rivers notably the Green, Colorado, San Juan, and Virgin Rivers have carved out deep and vast canyons on the Colorado Plateau in southeast Utah. This river incision coupled with the arid climate has created a colorful and unique landscape on Earth - the Red Rock Country dominated by red and white sandstones and shales of Mesozoic age. These canyons provide a valuable opportunity for geologists to examine sedimentary formations which are largely buried in central Utah.

The Basin-and-Range which is a vast region of stretched and thinned crust, normal faults, half-grabens, igneous intrusions, and deserts occupying western Utah as well as parts of California, Arizona, Nevada, Oregon, and Idaho. The Basin-and-Range province formed by the extensional tectonic activities during Oligocene to Recent times.

The High Plateaus of Utah which topographically separates the lower Canyonlands on the Colorado Plateau on the east from the Basin-and-Range on the west. Structurally, the High Plateaus are a transition zone from the compressional tectonics of Colorado Plateau to the extensional tectonics of the Basin-and-Range. This Transition Zone includes the Central Utah fold-and-thrust belt which is part of the Cordilleran-Sevier orogenic belt.

The Orogenic Belts

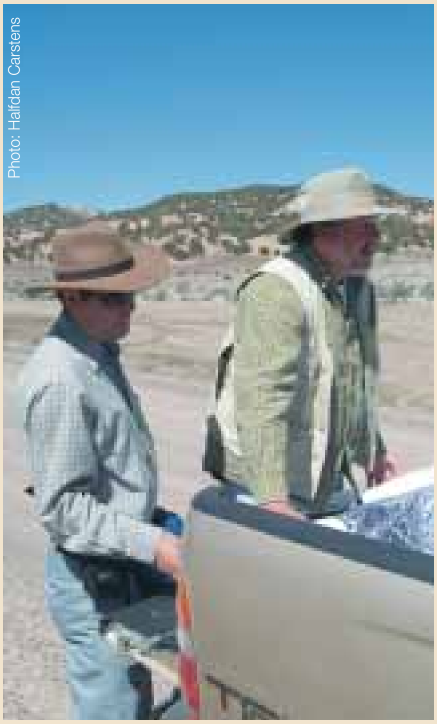
The Cordilleran-Sevier orogenic belt runs from 6,000 kilometers from Canada through western USA (Montana, Wyoming, Utah, and Nevada) down to Mexico. It formed as a result of the subduction of the ancient (now consumed) Kula and Farallon oceanic plates of Pacific side underneath the North American continental plate from the Late Jurassic through the Eocene. Large batholiths (Coast Mountain Batholith, Idaho Batholith, and Sierra Batholith) are



Stratigraphic column for central Utah (modified after Hintze, 1988, Geologic History of Utah).

An outcrop Jurassic Navajo Sandstone displaying cross-bedding structure in Zion National Park, southwest Utah (photo by authors).

An outcrop of fractured Twin Creek limestone (Lower-Middle Jurassic) within a major fold structure (Pigeon Creek, central Utah) (Photo by Authors).



Rasoul Sorkhabi (rsorkhabi@egi.utah.edu), Ph.D. in geology (1991) and Greg Nash (gnash@egi.utah.edu), Ph.D. in geography (1996) are research professor at the University of Utah's Energy & Geoscience Institute, Salt Lake City. Recently, they have been involved in research concerning the tectonic and stratigraphic framework of central Utah.

products of this subduction history and mark the extent of the Cordilleran-Sevier orogenic belt.

The Sevier orogeny should not be confused with the Laramide orogeny which also affected parts of the western U.S.A. The former was older (Late Jurassic-Eocene) thin-skin tectonics; the latter was younger (latest Cretaceous-Eocene) thick-skinned tectonics. Basement uplifts such as the Uinta Mountains and Colorado Plateau are largely products of the Laramide orogeny. Although both Sevier and Laramide orogenies are probably related to the compressional forces of ocean plate subductions, the exact mechanism and timing differentiating these two events has long been a matter of debate among geologists.

The Central Utah fold-and-thrust belt is largely included in the High Plateaus of Utah but also extends to the west comprising both exposed and concealed folds and thrust faults. This overthrust belt is tectonically an extension of the fold-thrust belt in western Wyoming and northeast Utah. Indeed, there are similarities between the Covenant field in central Utah and the Pineview and the Anshutz oil fields in northeast Utah; both produce from the Navajo sandstone and are trapped in thrust folds.

Stratigraphy

A thick succession of sedimentary rocks spanning late Proterozoic to Recent times and of various depositional environments are found in central Utah. Of particular importance for petroleum generation is the Mississippian formations. These sediments were deposited in seas that covered most of Utah at that time, and reached a maximum thickness in the subsiding Oquirrh Basin in northwestern Utah. They primarily consist of organic rich carbonates interbedded with shale layers.

Three significant organic rich Mississippian (Lower Carboniferous) shale beds, which crop out, include the Chiulos Shale Member of the Great Blue Limestone (with a maximum thickness of ~550 m), the Manning Canyon Shale (~600 m) and the Delle Phosphatic Member.

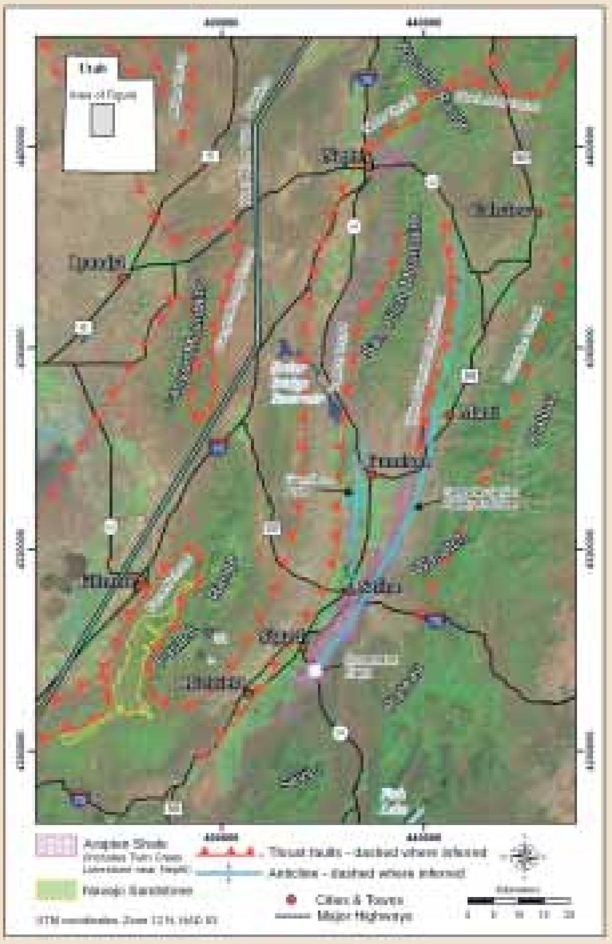
The Colorado Plateau has an abundance of Mesozoic sandstone units that can and sometimes do act as petroleum reservoir rock. Some of these extend westward into the Basin and Range and the Transition Zone, most notably Lower Jurassic Navajo Sandstone, which is desert eolian deposit forming major petroleum reservoirs in Wyoming, and outcropping in the famous natural reserves in southern Utah. This unit is overlain unconformably by Jurassic Twin Creek Limestone, which exhibits strong tectonic fracturing in folded and faulted outcrops. Together, these two units form an excellent column of reservoir rock which may reach a maximum thickness of 800 m in the area.

The Twin Creek Limestone is overlain with Middle-Jurassic Arapien Shale, a marine-evaporitic facies consisting of calcareous shale, with minor calcareous sandstones being found locally (especially at the distal margins), abundant gypsum at shallow levels, and halite (salt rock) at the base.

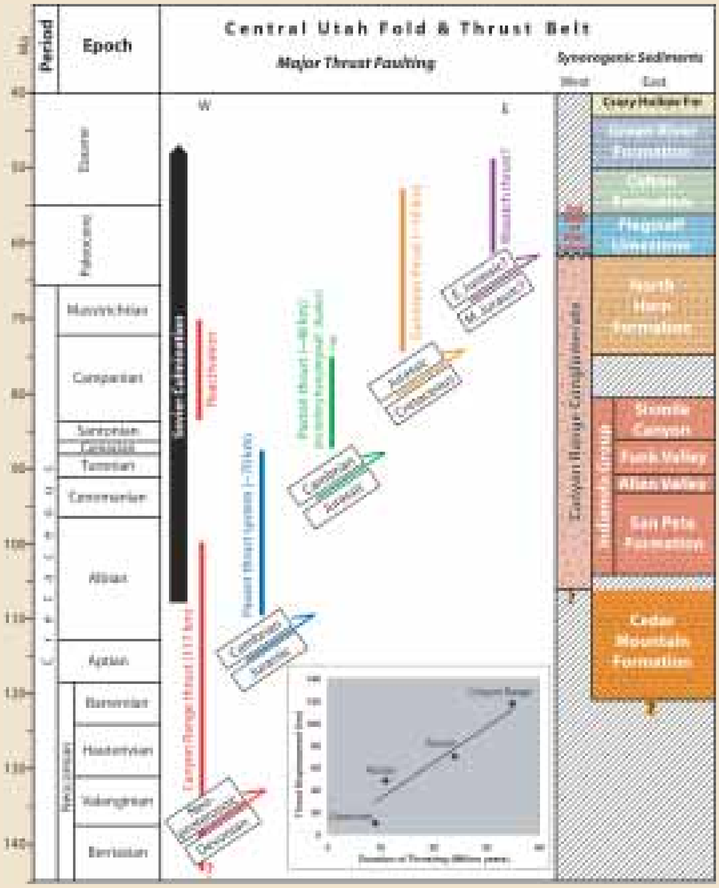
Utah's petroleum exploration and production date back to the late nineteenth century.

No.	Year	Drilling or Discovery
1	1891	First oil well in Utah (Bamberger and Millis Well #1), south of Green River town, ~300 m deep, dry hole
2	1892	Utah's first gas field (Farmington field) discovered
3	1907	First oil field (Virgin field), abandoned in 1970s
4	1948	First commercial production (Equity #1 Well) from an oil field in Uinta Basin
5	1975	Pineview oil field by Amoco Production Co. from Jurassic sandstone reservoir, Absaroka thrust sheet
6	1983	Anshutz Ranch East field by Amoco Utah's most prolific oil and gas field
7	1983	Deepest producing payzone (Brotherson 2-14B4 Well) Altamont field, ~6,242 m feet deep
8	2003	Covenant oil field in the central Utah overthrust belt (17-1 Kings Meadow Ranches Well, ~3,258 m deep)

Numbers refer to locations on the map on page 51.



Thrust faults, major towns, highways, gas pipeline, Covenant field, and outcrops of Navajo and Arapien formations.



A chart for the structural evolution of thrust faults in central Utah including synorogenic clastic deposits shed from the thrust uplifts (data sources: P. DeCelles, 2006, GSA Bulletin, v. 118, pp. 841-846; A. Villien and R.M. Kligford, 1986, AAPG Memoir 64, pp. 281-307.; G. Willis, 1999, Utah Geological Association Publication 27, pp. 1-9.)

Salt diapirism has deformed the Arapien Shale; moreover, salt has also moved along faults and fractures formed during the Sevier orogeny, which were reactivated by mid- to upper-Cenozoic extensional tectonics. The composition of evaporitic minerals and fine-grained mud, coupled with considerable thickness, makes the Arapien Shale an efficient cap rock for petroleum accumulation.

In Central Utah, Arapien Shale crops out along two major linear strips, while the reservoir rocks are buried except for the outcrop of Navaho sandstone in the Pavant Range.

Structural Evolution

The Central Utah fold-and-thrust belt consists of a series of thrust faults which become younger from west to east as deformation migrated in that direction. These thrust faults are described below:

(1) The Canyon Range Thrust (formed during Nocombain-late Albian, ca. 145-110 Ma) is exposed as a klippe (a thrust sheet isolated from the root thrust zone) in the Canyon Range. About 4 km thick rocks of Neoproterozoic-Cambrian lies on the hangingwall while the footwall consist of over 3.5 km thick Neoproterozoic to Devonian rocks. Some authors consider that the Canyon Range Thrust was reactivated during Campanian-Maestrichtian epochs.

(2) The Pavant Thrust system (Late Albian-Coniacian, ca. 110-86 Ma), best exposed in the Pavant Range, displays structural complexity with both hangingwall duplex and footwall imbricate thrust faults. Overall, the Pavant thrust system brings the Cambrian quartzites (Tintic Formation) atop Lower Jurassic Navajo sandstone.

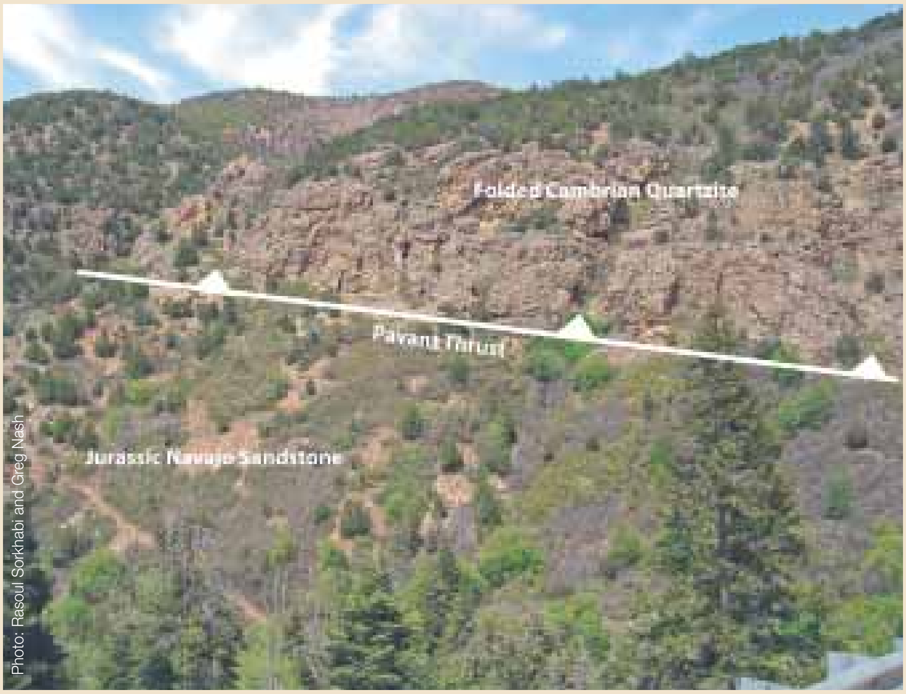
(3) The Paxton Thrust system (Santonian-Early Campanian, ca. 86-75 Ma) is mainly defined from subsurface (seismic and well) data; it is therefore a less known fault. One well (Placid Paxton #1, 1982) penetrating the Paxton thrust found Cambrian rocks faulted over Jurassic formations. Another well (the Amaco Sevier Bridge Well, 1981) discovered hangingwall duplex thrusts with displacements at the Triassic-Middle Jurassic levels.

(4) The Gunnison Thrust (Late Campanian-Maastrichtian, ca. 75-65 Ma) brings Jurassic rocks atop Cretaceous formations. The Covenant field was discovered on the hangingwall of the Gunnison Thrust. Wolverine drilling showed that the Gunnison is a duplex thrust consisting of the main thrust plane and a "back-limb thrust" on the hangingwall so that the Lower Jurassic reservoir rocks (Navajo Sandstone and Twin Creek Limestone) are repeated.

(5) The Wasatch Thrust is not exposed but is hypothesized by some geologists as the easternmost thrust fault in central Utah and beneath the Wasatch Plateau. This thrust possibly formed at 60-50 Ma and has displaced Jurassic formations.

The development of these thrust faults have been constrained from the juxtaposed sedimentary formations on the fault hangingwall and footwall as well as the age of clastic sediments shed from the thrust uplift onto the foreland basin. The stratigraphic data for thrust dating comes from outcrops as well as drilled wells.

Summarizing the thrust evolution of



A view of the Pavant thrust fault near the town of Fillmore, central Utah, one of the earliest thrust faults developed during the Sevier orogeny in Utah. The Pavant thrust strikes north-south and dips gently (about 10°) eastward (photo by authors).

central Utah, it seems that as the thrust faults have become younger from west to east, both duration of thrusting and the amount of fault displacement has decreased. Older thrusts have displaced deeper rocks, and as younger thrust developed eastwardly, they displaced younger formations. The Central fold-and-thrust belt is also affected by normal faults during the Basin-and-Range extension.

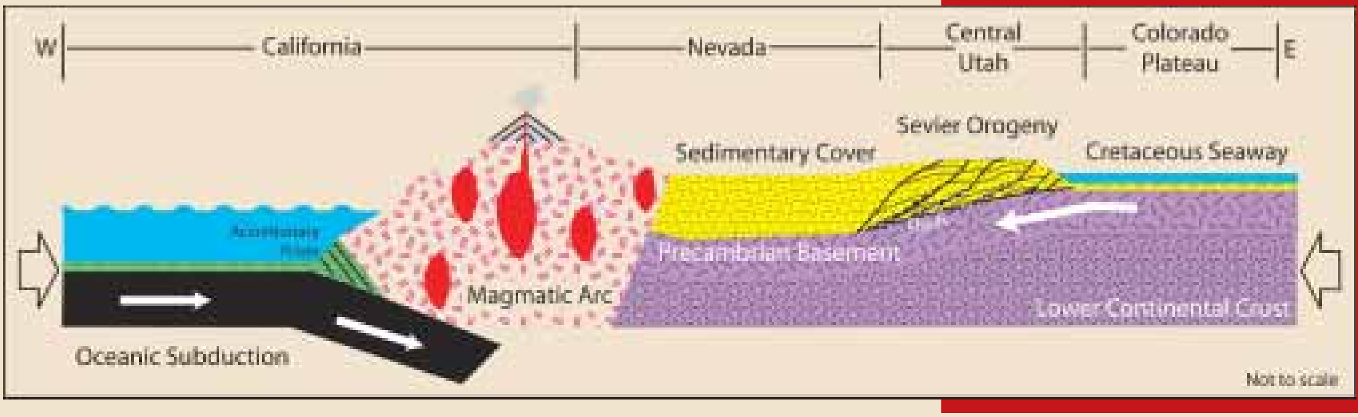
A New Exploration Focus

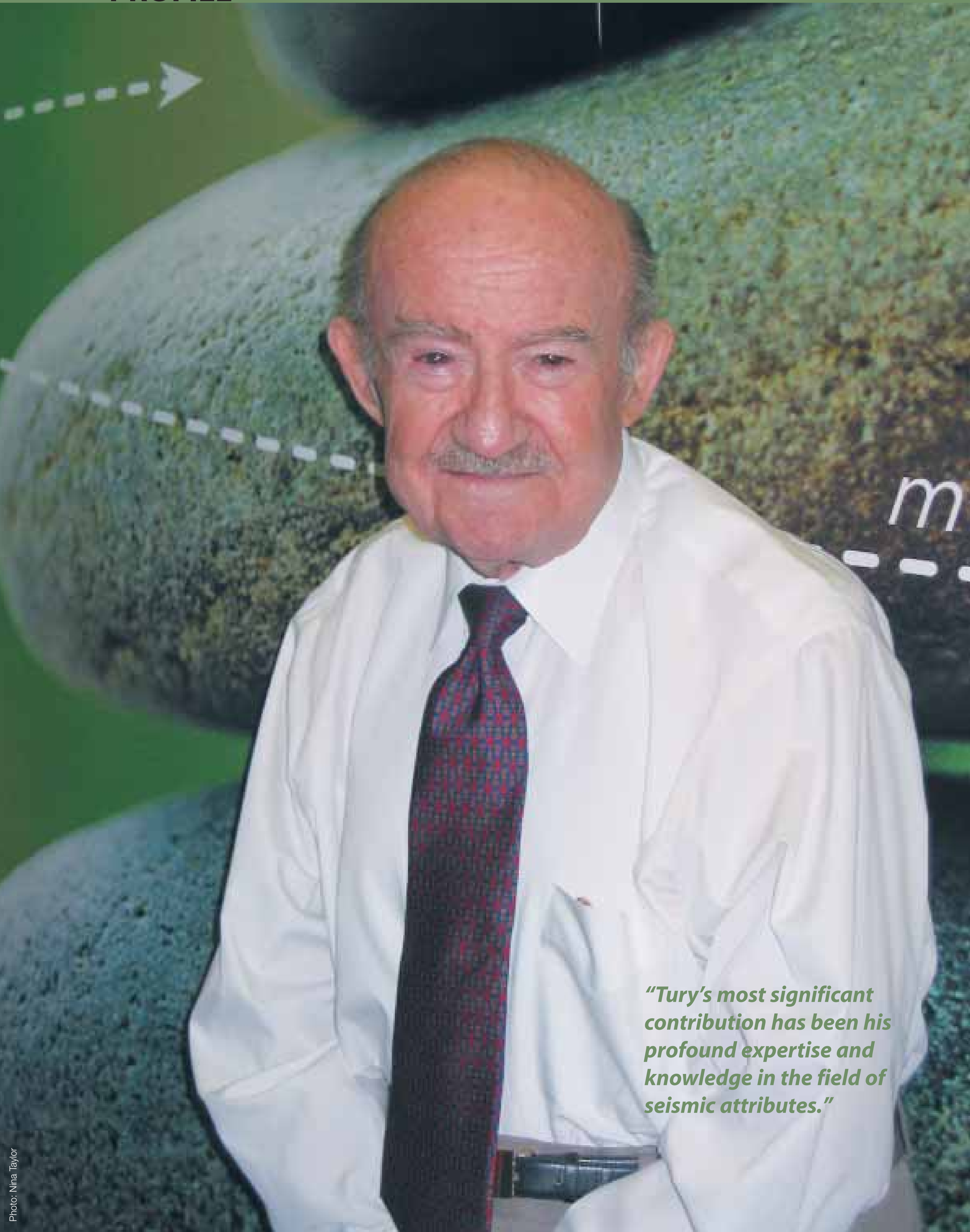
According to the U.S. Energy Information Administration, Utah with crude oil proven reserves of 215 million barrels, and with oil production of 40,000 barrels a day, ranked 12th and 13th, respectively, in the United States for onshore production in 2004. In the aftermath of the Covenant field discovery in central Utah, these statistics are already changing. Some geologists estimate that there are one billion barrels of oil hidden in central Utah. Land leasing prices have hiked from $10 an acre a few years ago to over $1000 an acre in the area presently. The central Utah fold-and-thrust belt has become a scene of oil rush with more than twelve companies already present. Almost all of these companies are independent oil firms. Only time and other oil field discoveries will tell whether and when major petroleum companies will move in (come back to) central Utah fold-and-thrust belt.

The Sevier Orogenic Belt

The Sevier belt is mainly a thin-skinned tectonic regime, meaning that the Precambrian basement has been detached from the Phanerozoic sedimentary cover along a deep decollement (detachment) fault. Moreover, this orogenic belt formed as a retro-arc ("behind arc") fold-and-thrust belt with thrust faults generally dipping west in contrast to the eastward subduction of the oceanic plates. Field observations and sandbox analog experiments have shown that a region undergoing plate-scale compressional stress often produces a doubly-verging wedge bounded by thrust belts in opposing directions. In the case of the Sevier belt, this structural setup may be explained by accounts of the juxtaposition of hot-young batholith (on the west) against the old, cold, and dense Precambrian basement of North America on the east. As a result, the Precambrian crust was detached along the soft layers at the basement-cover interface and underthrust the sedimentary cover. As compressional stress as well as fluid overpressure accumulated at particular horizons within the sedimentary cover, thrust planes were generated and thrust sheets were pushed for tens of kilometers, piling older sedimentary rock on top of the younger ones.

The various processes involved for the development of the Sevier fold-and-thrust belt.





"Tury's most significant contribution has been his profound expertise and knowledge in the field of seismic attributes."

Photo: Nina Taylor

A lucky switch benefits the seismic industry

By his own admission, prominent geophysicist Dr. M. Turhan Taner, known throughout the industry for his expertise in seismic attributes and seismic velocity computation, entered the field of geophysics by mistake, albeit a lucky one.

Nina Taylor

Armed with a section of seismic data he had no clue about, Dr. M. Turhan Taner along with Dr. Fulton Koehler, extracted a geophysical signal by utilizing sine and cosine functions as filters, which resulted in a contract offer from geophysicist Dr. Burton McCullum; Dr. Taner was elated.

"We had a $10,000 a month research contract. In those days if we had a $1,000 worth of jobs we would open a champagne bottle."

Fast Reader

Born in Akhisar, Turkey, Dr. Taner moved to Istanbul while in the fourth grade, completing a master's degree in structural engineering at the Technical University of Istanbul in 1950. During his college years and while accompanying his topographer father during fieldwork for the Turkish government, geophysics never entered his mind.

Arriving in the United Stated in 1953 to pursue a doctorate at the University of Minnesota, Dr. Taner employed computers for his engineering calculations and in 1959 co-founded Scientific Computers with his former mathematics professor, Dr. Koehler.

He relocated to Houston, Texas in 1962 to open a branch office, and at the recommendation of his friend Jim McGregor paid a visit to Dr. McCullum to offer the company's computer problem solving services.

Dr. M. Turhan Taner, who will be 80 next year, has spent more than half of his life innovating seismic techniques.

"I went to see him; he was about 73 years old, and he was just having fun researching geophysics. At the time I had no idea what in the world I was talking about, and Dr. McCullum looked at me and said, 'what do you know about geophysics?' I said nothing sir. 'Oh, he said, that's good; we know where we start from then.'"

Dr. Taner devoured every book about geophysics, 'reading them a 100 miles an hour,' the result of doctor-prescribed pills for weight reduction, which turned out to be amphetamines.

With Dr. McCollum's advice and support and Dr. Koehler's collaboration, he began creating geophysical processes on the computer.

Time To Move On

In 1964, Dr. Taner launched a new enterprise with Scott Kelso and Dr. Koehler named Seiscom Computing Corporation, serving as chairman and senior vice president director of research. He became chairman emeritus in 1973 to allow him to focus on research, including the development of seismic attributes, which was originated by Nigel Anstey of their London office. He procured a contract from AGIP for further innovation and in 1990 established The Seismic Attribute Consortium comprising 25 companies that endured 14 years.

Dr. Taner moved on once again and in 1980, and at the request of several clients for his consulting services, established Seismic Research Corporation.

"I went and got myself five folders, because I was going to give them 20 percent of my time. After I filled up the folders I got one more client, so I ended up selling 120 percent of myself, developing all kinds of seismic processing methodologies for these companies."

In 1998 Dr. Taner merged his Seismic Research Corporation with Petrosoft of California and Discovery Bay of Houston to form Rock Solid Images, a unique service company that combines geophysical, rock physics and computer technologies for seismic reservoir characterization.

The Changing Industry

During his lengthy career Dr. Taner has experienced great strides in the seismic acquisition and processing industry, especially with the introduction of computers.

"The big jump was the digital revolution when they went from analogue to digital in the sixties, and with color graphics attributes all of a sudden became useful in the late eighties."

He believes that because petroleum is now more difficult to unearth, and industry competition is becoming tighter, development must constantly move forward in order for service companies to stay competitive.

"Many giants have been found; now we're going to be looking at smaller reservoirs, and that means the exploration business has to be more refined from the technology side, acquisition side and interpretation side. It's like anything else in science; we'll be getting more and more into the specific."

Currently, one of Dr. Taner's pet projects includes developing methods for fracture detection and permeability in the carbonate environment such as that found in the Middle East, for which he and Evgeny Landa, research professor at the University of Pau in France, acquired a patent in 2005.

"We're looking for permeability; unfortunately right now we don't know how to measure permeability with the seismic data but maybe in the future. It is one of those things that rock physicists and us are cooperating. If we're able to map those we'll be quite a bit ahead of everybody else, and then they're going to catch up with us, and we'll get into something else. It's been that way all my life in geophysics."

In August 2006, Dr. Taner and Evgeny Landa were awarded another patent for a novel method of detecting earth formation fractures by seismic imaging of diffractors.

Another subject Dr. Taner finds fascinating is neural networks, the creation of artificial intelligence by allowing computers to think and make decisions, and he has developed several supervised and unsupervised neural network modules for reservoir characterization.

Although striving to discover new answers to geophysical questions, Dr. Taner finds himself returning to old information, because he believes earlier papers did not benefit from the computer age and 'what was impossible yesterday is just child's play today.'

"Looking back they did have a little bit different point of view on the problem. For example when you're doing some kind of process like filter design you may think there is nothing else to do. When you think there is nothing else to do, it's time to start anew, with a different way, because knowledge doesn't end."

The Birth Of Seismic Velocity Analysis

Besides developing seismic attributes, Dr. Taner has produced widely recognized work concerning seismic velocity computation in collaboration with Dr. Koehler.

"We were working on measuring similarity between traces, later called semblance, Dr. Koehler and I. While we were talking about this velocity analysis, all of a sudden it dawned on us that we could scan the data and compute the semblance, and whenever the semblance is maximum, there is the velocity. That Friday afternoon we were talking, and I stayed, and by Sunday afternoon I had the first velocity analysis on the computer."

Taner said he performed eleven velocity analyses on one seismic line instead of using the standard single velocity function for the entire project that was consistent with Gulf Coast seismic processing practice.

"You should have seen the difference between that and what we were doing standard; it's astounding. Everything was crystal clear. I didn't get a patent; it was very funny. I gave a paper, and after my paper there were three oil companies that came out with three different patents on the velocity analysis. I gave the paper freely for everybody to use."

Sharing The Knowledge

Dr. Taner's views concerning the sharing of knowledge has allowed the industry to benefit from his many accomplishments: "When we find a new formula or a solution of a problem we call it discovery. Discovery means the solution existed, but we didn't know it was there, and anybody could have thought about it. I feel knowledge belongs to everyone, and for that reason I don't mind sharing what I know."

During his more than four decades in geophysics, Dr. Taner has contributed numerous chapters in geophysical books and co-authored papers on a wide variety of topics. He has also lectured extensively for the AAPG and served as continuing education lecturer for the SEG since 1972. He was inducted as an honorary member of the EAGE at their 1999 meeting in Helsinki and given honorary membership in the Society of Exploration Geophysics for his significant contribution to geophysics in 1978.

"When you think there is nothing else to do, it's time to start anew, with a different way, because knowledge doesn't end."

The European Association of Geoscientists and Engineers (EAGE) recognized his lifetime achievements by presenting Dr. Taner with the esteemed Erasmus Medal in Paris in 2004, and he received the Maurice Ewing Gold Medal from the Society of Exploration Geophysics for his scientific contributions in 1993.

Dr. Taner continues to lecture during his travels as he did this May in Pisa and at his former university in Istanbul. He finds it rather humorous that although he graduated from the civil engineering faculty, he conducts his lectures for the geophysical faculty. In 1991 the Technical University of Istanbul awarded Dr. Taner an honorary doctorate for his contributions to geophysics and geophysical education in Turkey.

A Time For Travel

Although Dr. Taner feels deeply for his native Turkey, where he often returns to lecture and reunite with family, he finds the cuisine and countryside of Italy irresistible. His appreciation of great masters such as Vincent van Gogh, Monet and Renoir have inspired him to reproduce numerous art works that adorn the walls of his home and office. He is also an accomplished musician and has played jazz guitar with a band on Turkish radio and in Amsterdam after an EAGE annual conference.

"Though Tury is a scientist, I think he'd prefer to be recognized as an artist. He has a great love of all things culinary, especially super-Tuscans to complement. He's an accomplished painter and musician and is equally at home with a FORTRAN program or a music score," said president of Rock Solid Images, Richard Cooper.

Dr. Taner is the father of a daughter, two sons, and a grandfather of four. His eldest son, Jeff Taner, who has worked with his father for twenty years, commencing at Seismic Research Corporation, now serves as manager of IT at Rock Solid Images.

Richard Cooper, who has always found Dr. Taner gracious, approachable and extremely knowledgeable, sums up his career in the field of exploration geophysics: "He has made contributions in diverse areas such as deconvolution, imaging, velocity analysis, refraction statics, seismic attributes and neural networks. Tury's most significant contribution has been his profound expertise and knowledge in the field of seismic attributes. He has continued to refine the work he began at Seismic Research Corporation. Most recently, he has developed a number of novel methods for attenuation or "Q" analysis and compensation, resulting in the issuance of several patents, and commercial software and service products."

Dr. Taner confessed he is elated he made the move from engineering to geophysics and harbors no regrets. He recalled his surprise when in 1962, Dr. Burton McCullum awarded Scientific Computers its first contract.

"I thought there must be something good about this; well, that was the beginning."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Egypt's Secret Treasure

"There is no country which possesses so many wonders." So said the Roman Heroditus when he visited Egypt in 420BC, confirming that Egypt has been a magnet for tourists for thousands of years. For the earth scientist, however, there are wonderful treasures to be found in the constantly changing shapes, colours, landscapes and rocks of the desert areas surrounding Cairo and the Nile Valley.

Photos: Anne Whaley Sousou

© Infoterra/Masaoki Adachi

Despite an abundance of truly amazing cultural and archaeological features, one of the greatest sights in Egypt remains the simple phenomenon of the Nile Valley. When seen from the air one can appreciate fully how the river is the life force of the country, carving a fertile green channel sometimes less than a mile wide through the otherwise endless desert. On the ground it is fascinating to travel across the Nile Valley to the point where the irrigated fertile valley changes abruptly into barren, inhospitable desert.

Photos: Anne Whaley Sousou

Photos: Anne Whaley Sousou

The spectacularly sculpted limestone rocks and pinnacles of the White Desert, more than 500 km south-west of Cairo, are a unique example of karst topography. This area has been designated a protected zone by the Egyptian Government.

Some of the fossil whales found in Wadi Hitan have been reconstructed and are now protected, but many vertebrae and other bones have been stolen over the years, leaving only partial skeletons in most cases. The large numbers and wide variety of creatures found here were probably attracted to the warmth and security of an embayment and the abundant nutrients brought into it by the Proto-Nile, but there is no evidence that the unusual quantity of whale skeletons was the result of a 'beaching' episode.

Jane Whaley

Travelling south out of Cairo, the desert seems a very unattractive proposition for the geotourist. A flat sabkha plain, covered in a layer of small dark rounded pebbles, stretches for miles in all directions, broken only by interminable pipelines, the occasional small rig, and the rotting wrecks of large trucks. But persevere with the journey, and there are treasures in the desert every bit as spectacular and unique as the wonders of the Pharaohs.

Once known as the breadbasket of Egypt, the oasis of Fayoum lies about 100kms south-west of Cairo. This thriving town, the largest oasis in Egypt, is built around Lake Qarun, which in Pharaonic times was part of the much larger Lake Moeris, linked by a series of canals to the Nile. The Fayoum Basin initially formed in the Jurassic along the Tethyan margin, developing its present shape through subsidence that terminated in the late Eocene. It contains a thick sequence of Eocene clastics, reflecting deposition from emerging highland areas surrounding the basin. To date the area is relatively undisturbed by the Egyptian hydrocarbon industry, which is concentrated further west in the Western Desert, as well as in the Nile Delta and Red Sea.

World Heritage Site

The Fayoum Basin, which lies mostly below sea level, is a very important cultural and natural environment, with large numbers of migratory birds found near Lake Qarum. Many rare animals, such as white deer, Egyptian deer and sand foxes, are also seen in the surrounding areas. The geotourist, however, must travel out of the green oasis and into the desert to the west of Fayoum to find the greatest treasure of the region.

This is the UNESCO World Heritage site of Wadi Al Hitan, a beautiful valley of golden sandstone and shale cliffs with strangely eroded rocks. Within the 25 square kilometres of the valley the fossilised remains of more than 400 primitive whales and other vertebrates have been found, all of Eocene age, with two species particularly prominent. There are nearly 100 partial skeletons of Basilosaurus isis, a very large whale which has an unusually long serpentine body about 18m long. The fossilised remains of about 80 specimens of a smaller whale, Dorudon atrox, which has a more compact dolphin-like body, have also been found.

Both these whales have small hind legs and it is this feature that marks the fossils in this valley as being unique, as it shows the point at which the whale predecessors abandoned the land and became ocean-going mammals. This is the most important site in the world for the demonstration of this stage of evolution, gaining it UNESCO protection.

It is thought that in the Eocene the Wadi Hitan area was a protected estuary and judging from the proportion of juvenile Dorudon remains it may have been a favoured birthing ground for these animals. By contrast, only one juvenile Basilosaurus was identified, suggesting that the abundance of young and weak Dorudon probably attracted the larger predatory whales into the bay. The rich fossil record in the valley also includes sea cows, similar to the modern Manatee, as well as fossilised sharks, fish, sea snakes and even turtles.

Evidence that this area was close to land in the Eocene can be found toward the south-western end of the 'Whale Valley', where a paleoshoreline, complete with a worm-bored petrified tree, can be identified. The shoreline is delineated by an area of deeply rooted fossilised mangrove forest, which stands out impressively against the well-bedded sandstone above and below.

Wadis and Buttes

Other geological features in the Fayoum

A well rooted mangrove horizon delineates the palaeoshoreline in Wadi Hitan, the Whale Valley.

Valley include several large, well-preserved petrified forests, found in Palaeo-Nile fluviatile deposits in the north of the basin. The Paleogene strata in this area are considered to hold one of the most complete records of late Eocene - early Oligocene vertebrate evolution in Africa, including a number of early primates.

In the northern part of the basin, at a place called Widan el-Faras, there is a basalt quarry which has been worked since 3,000BC. Leading to it is possibly the oldest paved road in the world, down which basalt has been transported since Neolithic times, some of it to the Nile and on to the constructions at Giza and Abu Sir.

Also found in the Western Desert near Fayoum are magnificent examples of desert topography, as what seems like an flat, endless, barren rock plateau suddenly terminates in deep incised ravines or wadis, where the usually almost horizontally bedded rocks are clearly exposed. Thick sequences of predominantly non-marine Tertiary clastics can be observed, with coarse and gravelly sandstones interspersed by thinner and more deeply eroded shales. Prominent cross bedding can be seen in some horizons, whilst others hold evidence of beach and tidal flat deposits and sediments, with some desert areas being literally carpeted with large shells. Isolated hills or buttes are also common, their steep-sided and flat-topped, table-like forms standing out prominently from the surrounding desert.

Petrified wood is a common feature of the desert close to Cairo, with samples ranging from a few centimetres across to many metres in length. They are found in accumulations which suggest that they were carried by the flood waters of the Proto-Nile and then deposited as the water subsided. Most are considered to be Oligocene in age.

The Spectacular White Desert

To enjoy some of the greater wonders of the Egyptian desert, it is necessary to travel a little further from Cairo, preferably with a convoy of 4 x 4s, a GPS positioning system, and someone who knows the desert well! To the south and west of the Fayoum Valley, beyond the isolated oasis town of Bahariya and 500km from Cairo, lies the spectacular area known as the White Desert. This barren but fantastic land is characterised by strangely shaped chalk pinnacles, mounds and ridges, sculpted by the erosional force of the desert winds. They rise out of a flat limestone platform, which is covered by fine sand. The combination of dazzling white chalk, golden sand and brilliant, pollution-free blue sky makes this one of the most stunning and impressive sights even in a land as full of superlatives as Egypt. Add to this palette a vivid desert sunset, followed by a night under a sky bright with stars and with the moon casting shadows through the chalk sculptures; surely this is one of the strangest, most beautiful and unique landscapes in the world.

The carbonates are Late Cretaceous and the amazing karst landscape a result of years of erosion, originally by the more pluvial environments experienced during the Tertiary, followed by sand and wind attrition in more recent times. Some of the landforms now seen were initially formed through water erosion in underground caverns in the Tertiary and paleocaves are sometimes exposed on the surface, complete with isolated stalagmites. The resulting topography is made even more dramatic by differential wind erosion, with the uppermost harder horizon withstanding erosion better than the underlying softer layers, resulting in the distinctive mushroom shapes of many of the rocks.

Desert Treasures

There are other treasures which take more seeking out. When lightning strikes the desert, energy continues travelling through the sand in order to reach bedrock. The current superheats the sand, which may be liquefied or even vaporized for an instant as the current passes through it. Any air and moisture present are also rapidly heated, and the resultant explosion-like expansion forms a central tubular void. As the sand cools down, it reforms into a solid, glassy channel, known as a fulgurite. These are usually only a few centimetres in length, very delicate and fragile and as a result, extremely rare.

North of the White Desert is the less appealingly named 'Black Desert', called after small hills which are covered with what looks like a layer of soot, rather unattractively resembling slag heaps. Closer examination, however, reveals that the black colouration is a result of weathering, producing what is known as 'rock varnish', principally composed of iron and manganese oxides selectively deposited over many years on the surface rock fragments.

Even the areas of flat desert pavement can yield treasures to the geoscientist. Much of the surface of the desert area is made up of a sheet of rock fragments, all that remains after wind and water have

Spectacular barkhan dune formations in the Western Desert of Egypt. It is estimated that dunes move at a rate of between 10 and 100m a year and their width is about 10 times their height.

removed the fine particles. These are also frequently black due to 'rock varnish', but in many places the rocks are actually fossil corals and shells, petrified wood, or beautifully formed crystals, and the haematisation process gives them a beautiful shine and a strange metallic feel.

Even a short trip to the Western Desert, with its many different landscapes, long distant horizons and astonishing geological, geographical and archaeological riches, is a wonderfully refreshing and different experience. Arriving back to the hustling noise, excitement and activity that is modern Cairo seems an extreme adjustment and it is hard to believe that the peace and tranquillity of the desert are only a short drive away.

But Cairo itself has the greatest treasure of Egypt running through it; the Nile. The river, with its green agricultural islands and busy waterborne life, still dominates the city. And if the noise of car horns, donkeys, children and building sites all become too much, it is easy to escape. Just go down to the river front, hire a felucca, the elegant traditional Nile sailing boat, and float gently and silently through Cairo, watching the sun set over this amazing and magical land.

Acknowledgements:

Many thanks to John Dolson, TNK-BP, for his advice on the geology of the Fayoum Basin, and to Anne and Salem Sousou for their assistance in researching this article.

Wadi Degla

Wadi Degla lies to the south-east of Cairo and forms a haven of peace and tranquility right on the edge of the noise and bustle of the city. It is about 30km in length and up to a kilometre wide in places, with the steep valley sides rising 50m from the valley floor. It is formed in the Eocene limestone pavement, with a hard band of siliceous limestone forming the upper plateau, underlain by further limestones, some of which have been dolomitised. It is rich in fossils, including Middle Eocene nummulites and gastropods. The valley floor and differentially eroded sides clearly show the paths of the rivers that have carved their way through the limestone over millions of years. After a heavy rainstorm, which only occurs every few years, the Wadi fills with fast-flowing water, and the valley floor blossoms.

The steep sides of the wadi protect the unique wildlife found there, including the rare Dorcas Gazelle and Nubian Ibex, as well as mountain rabbits and hares, foxes, bats and up to 18 species of reptiles, some of which are very rare.

Because of its proximity to Cairo, Wadi Degla has been used for many years for quarrying to provide building stone and cement, with the consequent deterioration in environment and habitat. It has now been declared a Protected Zone by the Egyptian Government in order to maintain the fragile ecosystem.

Fulgurites form when lightening strikes the desert and melts the sand in its path, turning it to glass. These are very rare and fragile formations.

A Company Maker

The Bream (17/12-1) and Brisling (17/12-2) oil accumulations in the Egersund Basin of the North Sea were both discovered in the early 1970's. A few years later, albeit more than 25 years ago, the 18/10-1 oil accumulation was discovered in the same sub-basin.

All 3 discoveries were declared to be sub-commercial, and the acreage containing Bream and Brisling were relinquished in 1994, with recoverable reserves reported to be less than 1 million m³ (6.3 million barrels).

Following a careful geological evaluation of the basin, in 2004 PGS decided to invest in a multiclient 3D seismic survey. The first phase (600 km²) was so encouraging that PGS carried out a detailed and comprehensive evaluation report and prepared for a 3,500 km² extension.

One of the main concerns of the area has been insufficient generation of hydrocarbons to fill the structures. Our evaluation shows that the Upper Jurassic Tau Formation in the Bream area is an excellent source rock.

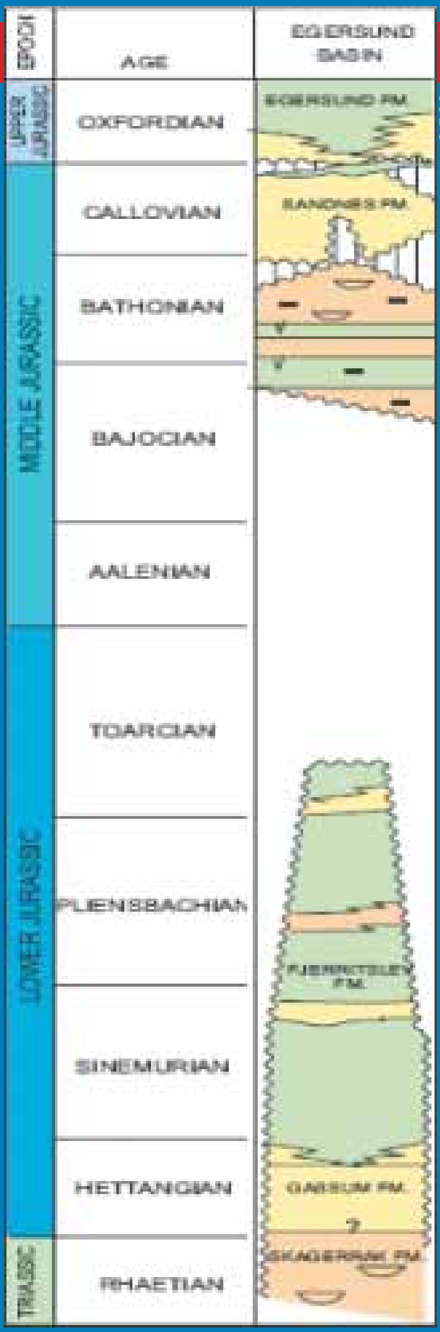
From this study it was estimated that the Bream discovery, with a 40% recovery rate, has oil reserves of 11 - 16 MMm³ (70-100 MMbo), although we claim that this is a relatively conservative figure based on a simple volume calculation. Such reserve volumes should, however, make any oil company happy with today's oil price. We have also identified at least 2 more prospects in the blocks.

The total volume of pre-stack time migrated data was available to the industry in May this year. This has allowed oil companies to fully evaluate the area before applying in the forthcoming licensing round (APA 2006). Moreover, it also enables the companies that will be awarded the acreage to immediately access a high quality 3D dataset and not be dependant on securing a 3D vessel in 2007, which promises to be a very tight seismic market. It also moves production at least one year ahead, as oil is already proven.

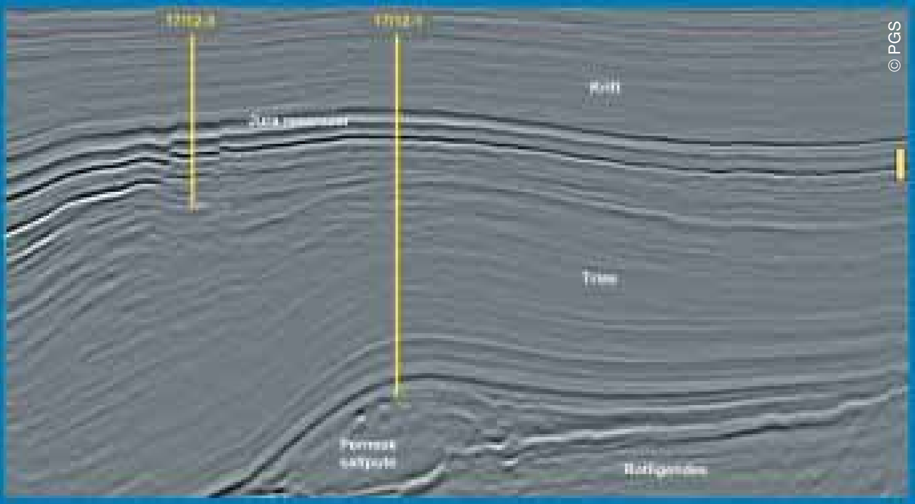
For small, independent oil companies, we believe the old discoveries in the Egersund Basin can turn out be a company maker! In fact, there are very few places on the Norwegian shelf, if any, where undeveloped oil discoveries and prospects of such size exist and are up for grabs.

Tor Aakermoen, PGS

The multiclient seismic survey in the Egersund Basin covers open blocks available in the forthcoming licensing round (APA2006), shown in orange color, as well as licensed blocks, shown in yellow. Oil fields are marked in green.



Both reservoir rocks and source rocks are Jurassic in age.



Seismic section from the multiclient 3D survey through the Bream oil discovery with the location of the discovery well 17/12-1 and appraisal well 17/12-3. The reservoir interval, Middle Jurassic sandstones, is shown with a yellow bar.

"If we are smart enough . . ."

Dr. Raymond Levey is in charge of an organisation with superb knowledge of the world's sedimentary basins, fossil energy and alternative energy sources. We have talked with him about the future of oil and gas exploration.

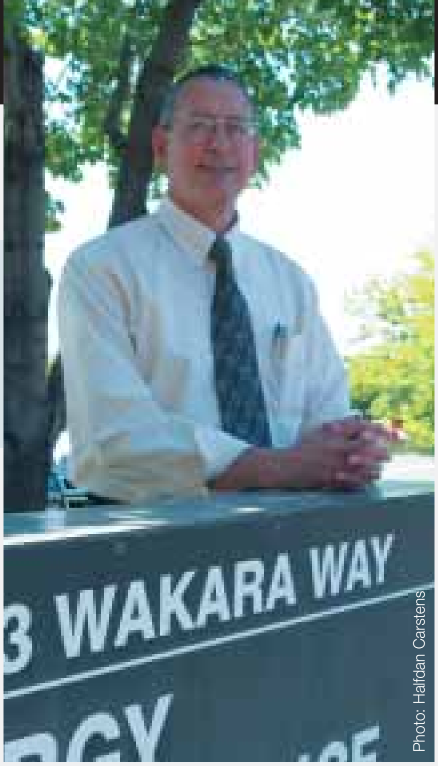


Photo: Halfdan Carstens

Dr. Raymond Levey is Director of the Energy and Geoscience Institute (EGI) located in Salt Lake City. EGI has the largest University based consortia group with 54 member companies from 20 countries. Dr. Levey was appointed Director in 1999, after serving as Deputy Director since 1997. His background includes a decade at Shell Oil where he was involved in petroleum exploration, development and research. He also spent 7 years at the University of Texas at Austin where he served as Associate Director for Fossil Energy at the Bureau of Economic Geology before coming to the College of Engineering at the University of Utah. He earned his Ph.D. in geology at the University of South Carolina. Dr. Raymond Levey is a Certified Petroleum Geologist and licensed geologist in Utah and Texas.

Q1 We are now using approximately 85 million barrels of oil every single day, and within the next 25 years, this will increase substantially. Do you think there is enough oil around to accommodate this need?

World consumption in 2006 is about to exceed the staggering level of 1,000 barrels per second. While it will be an incredible challenge for industry to find and produce the volumes needed for this rising world oil demand, I do believe there are enough additional new and remaining hydrocarbons to meet our needs to 2030, and future researchers will be part of the effort to achieve this success. However this requires that we get smarter about the way we use our liquid hydrocarbons for transportation directed purposes rather than electric power.

Q2 There are several alternatives to light, sweet crude; such as heavy oil, oil sand (GEO ExPro No. 5/6, 2005) and shale oil (GEO ExPro No 3, 2004). Which of these do you think will be the more important in the near future, i.e. the next 20-25 years?

During the last 100 years the world has used a vast amount of the easy to find and refine sweet light crude oil. This is forcing a switch to the vast remaining resources of heavy oil, oil sands and, yes, even future production from oil shale. If we are smart then we learn how too economically capture the man-made CO^2 from power generation and use it for EOR to enhance and extend production from known fields, including stranded oil. The success story in Canada of promoting development of oil sands is on the verge of being extended to the very different oil shale resource in the next 10 to 25 years. In the western U.S. we have vast oil shale resources and I believe the odds are very good that industry, academia, and government will solve the technological challenges needed for commercial production. EGI is part of the new U.S. government supported Heavy Oil Center to focus on North American heavy oil, oil sands and oil shale.

Q3 It is speculated that there are enormous amounts of gas stored in gas hydrates in the Arctic and below deep water (GEO ExPro No. 2, 2004). How do you look upon this possible resource for future gas supply?

I believe that while production from gas hydrates will ultimately occur, there are vast amounts of easier to produce conventional and unconventional natural gas resources still to be produced in the next 40 years. Hence I do not see significant economic development for gas hydrates in the foreseeable future.

Q4 USGS reports that 25% of the remaining oil and gas resources lie in the Arctic. While it is a long way to prove this, do you think this is the next frontier?

EGI is cooperating with scientific colleagues at Moscow State University, and various national geologic surveys to evaluate the chronostratigraphy of the circum Arctic region to establish a consistent and predictive geological framework for the industry. The odds are very good that the Arctic is rich in hydrocarbon resources, and given the technological progress in production in remote areas this may be achievable in the next 15 years. Major, long-lived, deltaic systems like the MacKenzie delta have fewer than 300 well penetrations. The ultimate resource potential of the circum Arctic could be enormous.

Q5 How do you look upon the main technological achievements in exploration technology in the last decades?

Actually I see this as an area of concern because the past decade and half have not produced the major "game changing" technology, such as 3-D seismic, that emerged 20 years ago. That said, the oil and gas industry is benefiting significantly by reaching to other-market advances in technology from incredible leaps in computing capability allowing more data to be processed faster and cheaper to visualization technologies that are spinning off from the gaming and movie industry and having a dramatic positive impact on subsurface imaging of reservoirs.

Q6 What do you think are the main geological achievements in exploration since we were faced with the theory of plate tectonics in the 1960's?

EGI is now evaluating the ultra deepwater, regions on transitional and oceanic crust, for hydrocarbon prospectivity. These regions have previously been written off by the industry as too "cold" for the generation of thermogenic hydrocarbons, but this traditional dogma may have limited our creative thinking and 40 years later needs to be reconsidered. These are the kinds of ideas that groups like EGI is challenging through cost-shared research for industry.

Misleading report

With more than 65% of the world oil reserves situated below the deserts of the Middle East, there is a push to discover new resources in political stable countries outside this region.

CONVERSION FACTORS

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

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

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

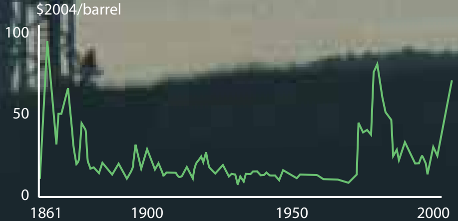
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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

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

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

Historic oil price



The BP Statistical Review of World Energy 2006 was released in June. Published annually, based on government data as well as published sources, it contains detailed data and statistics on worldwide energy production and consumption (oil, gas, coal, hydroelectricity, nuclear, renewables). This latest edition includes data up to the end of 2005.

According to BP, world oil reserves now total 1,200 billion (1.2 trillion) barrels of oil; the equivalent of 150 fields the size of Ghawar (Saudi Arabia), the world's largest oil field. This is a small increase compared to the figure given by BP one year before. However, it is a substantial increase since 1980. BP then estimated that the total world oil reserves were only 667 billion barrels. In the same period, the oil production increased from 68 to 81 million barrels per day. This gives an R/P ratio (reserves/production) of 40 for the end of 2005, meaning that we – in theory – can continue to produce 80 million bopd before we abruptly run out of oil in 40 years time.

However, the picture is much more complicated than what this simple calculation shows. Our reserves are increasing continuously (see graph), as is the demand for this efficient fuel; the question of how long the reserves will last is thus not an easy one.

As explained in the last edition of GEO ExPro, "proven reserves" is defined as "the estimated quantities of oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under current economic and operating conditions."

The BP report does certainly not take into account the new "economic and operating conditions" with oil prices op to 80 dollars per barrel. The obvious example is Canada with its vast oil sands deposits. In spite of 175 billion barrels of oil classified as reserves ("economically viable oil") by the Canadian Association of Petroleum Producers, and with resources many times higher than this, Canada's reserves are by BP estimated to only 16 billion barrels.

The same reasoning can probably be used for a number of other geological provinces around the world.

The report is therefore misleading. It does not give a true statement of how much oil that can be recovered in the future.

The development in world oil reserves since 1980.
Source: BP Statistical Review of World Energy


It is time to spread our wings
Our Ships:
Aquila Explorer
Hawk Explorer
Harrier Explorer
Geo Mariner
Kondor Explorer
Osprey Explorer
Northern Explorer
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