VOL. 9, NO. 6 – 2012

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

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GEOPROFILE: Intisaar Al Kindy

GEOLOGY
The Miocene Monterey Formation

EXPLORATION
Heavy Oil from an Ancient Reef

TECHNOLOGY
Making the Impossible, Possible

GEOLOGY GEOPHYSICS RESERVOIR MANAGEMENT

GEO ExPro
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Dodging icebergs – all in a day's work when shooting seismic in the Arctic

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This edition of GEO ExPro Magazine focuses on the Americas

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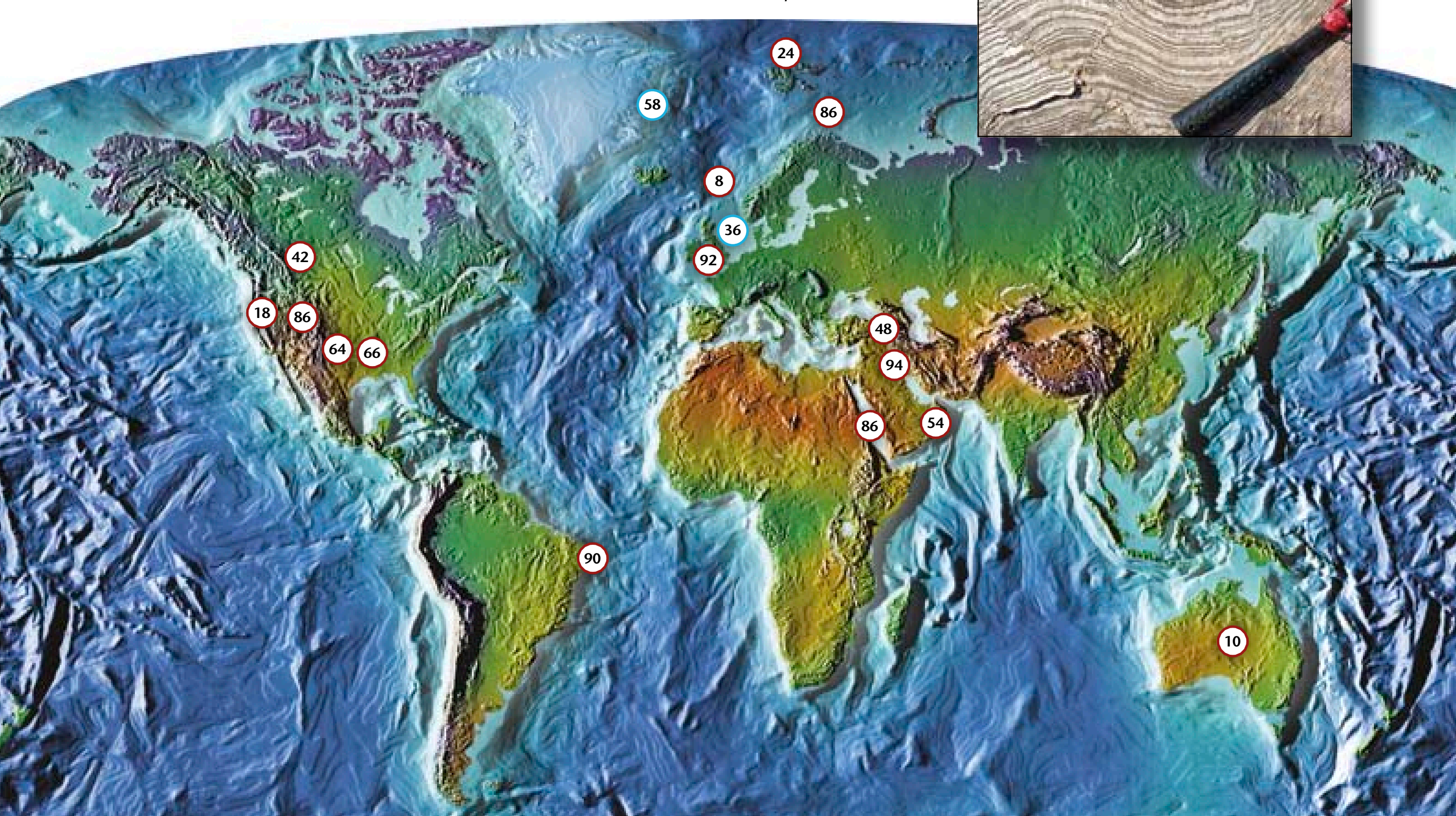
FEATURES

In the Guadalupe and Delaware Mountains of the New Mexico-Texas border you can study a complete depositional system from outcrop to the subsurface



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An Imprecise Science

Collapsed house after the 2009 earthquake in L'Aquila

In October this year, six geoscientists were jailed for not predicting the imminence and severity of the earthquake which hit the Italian town of L'Aquila in April 2009, killing 309 people and leaving thousands homeless. The justice – or injustice – of the sentences is obviously a matter of debate. But there are a number of lessons to be learnt from this tragic story.

Geoscience is for the most part an imprecise discipline. Where other scientists deal with nanoseconds, geologists consider five million years to be a mere blink of an eye – give or take another million. We are getting much more accurate at estimating the thickness of a sedimentary layer identified on a seismic record, but know that the figure suggested may easily change when we are able to clarify it through drilling. I suspect that the words 'probably', 'possibly' and 'may be' are used far more frequently in the average geological report or dissertation than in any other science. Geology is often described as an 'imaginative science'; being able to imagine what is happening, or has happened, inside the earth is a vital part of the geoscientist's toolkit.

But such vagueness is not readily understood by the general public and it is important that geoscientists are aware of this. It is, perhaps, an argument for an increase in the study of earth sciences in our schools. Few of us will be required to predict the possibility of earthshattering events, but the responsibility of making sure any audience fully understands the implications and range of our statements, and the science behind them, cannot be ignored.

The sentences also suggest that in future all scientists will be wary of making any predictions or statements which could conceivably be proved wrong. Alternatively, they will err so much on the side of caution that their audience will accuse them of continually 'crying wolf' and cease to take them seriously – not a triumphant result for either science or the human race.

The jailing of the L'Aquila scientists is also a fine example of the 'blame culture' so prevalent today. Since describing such catastrophic and unpredictable events as 'Acts of God' has fallen out of favor, we seem obliged to attribute them to Man – or men in this case. But that, of course, is quite a different discussion.

JANE WHALEY
Editor in Chief

THE MIOCENE MONTEREY FORMATION

The Miocene Monterey Formation is California's primary petroleum source rock and an increasingly important reservoir in some areas. It is well understood in much of the State, but has been little studied in the highly petroliferous Los Angeles Basin. The cover photo shows a large recumbent fold of either tectonic or gravitational origin in the tuffaceous/siliceous lithofacies of the Lower Monterey Formation, Whites Point, San Pedro, California.

Inset: Intisaar Al Kindy is the first Omani Exploration Director of Petroleum Development Oman for forty years

GEO ExPro

www.geoexpro.com

GeoPublishing Ltd
15 Palace Place Mansion
Kensington Court
London W8 5BB, U.K.
+44 20 7937 2224

Managing Director
Tore Karlsson

Editor in Chief
Jane Whaley
jane.whaley@geoexpro.com

Contributing Editors
Thomas Smith
Thomas.smith@geoexpro.com

Halfdan Carstens
halfdan@geo365.no

Rasoul Sorkhabi
rsorkhabi@egi.utah.edu

Paul Wood
sciwrite@btinternet.com

Editorial enquiries
GeoPublishing
Jane Whaley
+44 7812 137161
jane.whaley@geoexpro.com
www.geoexpro.com

Marketing Manager
Kirsti Karlsson
+44 79 0991 5513
kirsti.karlsson@geoexpro.com

Subscription
GeoPublishing Ltd
+44 20 7937 2224
15 Palace Place Mansion
Kensington Court
London W8 5BB, U.K.
kirsti.karlsson@geoexpro.com

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Regulating Oil Prices

Investigations into commodity pricing may bring oil benchmarks back into spotlight

In November regulators were forced to re-focus on relationships between the physical and derivative commodity markets when a whistle-blower reported possible manipulation of the UK wholesale gas market. This came just days after the state of California announced it is pursuing Barclays for alleged manipulation of the electricity market between 2006 and 2008. It is likely that both events will re-open questions regarding the role of the oil price reporting agencies (PRAs), which began in 2008 but were dropped in September 2012.

Ever since world attention was focused on the highest ever oil price spike, questions have been raised regarding the lack of transparency with which benchmarks for commodities, but particularly for Brent and West Texas Intermediate, are set. Three privately owned agencies dominate the market – Platts (owned by McGraw Hill, which also owns credit rating agency Standard and Poor's), Argus Media and ICIS. They operate by asking traders for details of offers and bids as well as actual trades, information that is then processed according to non-transparent and unregulated 'proprietary' methodologies. Benchmarks are produced, for which the agencies receive a fee, and these provide the basis for the majority of physical oil contracts and an estimated 60–70% of 'Over the Counter (OTC)' swaps and options.

Parallels have been drawn to the setting of LIBOR, the inter-bank lending rate, which has been under investigation since summer 2012 and has sparked a rash of staff dismissals and legal proceedings around the world. The PRAs, however, claim that their work is 'journalism', matters of opinion protected by 'freedom of speech', which traders choose to use. Similarly, in the interest of 'protecting their sources', calculations are not open to scrutiny. They are based on reports from as few as five market players on occasions. The question for regulators is whether traders are manipulating benchmarks by selective reporting or by using tactics such as 'wash trades', where one trade cancels out another, leaving the price unaffected but impacting on the index, and whether the PRAs are effectively manipulating prices by excluding some price-reporting groups. The fact that Platts has its own e-trading arm, linked to the InterContinental Exchange, appears to be a further conflict of interest.

Regulators Climb Down

In 2011 the G20 asked the International Organization of Securities Commission (IOSCo), the body that regulates the world's futures and securities markets, to come up with recommendations. A report was produced in March 2012, suggesting that all market participants should submit price information to the PRAs, but only of completed trades. In response, the PRAs themselves announced a new 'code of conduct', which would include an independent review of compliance. However, in September 2012 IOSCo revealed that the PRAs were threatening to withdraw their services altogether if regulation became a reality, a situation that would have made the physical market totally impenetrable to all but the most powerful participants. The PRAs are, apparently, backed by the majority of oil majors, the IEA and OPEC, who do not wish to see mandatory reporting of trades. Despite citing several actual cases of market manipulation and concluding that the 'potential for such misconduct is not mere conjecture', regulators finally suggested retaining the status quo.

Although in September it appeared that the PRAs had successfully faced down their critics, the continued revelations of the Libor scandal, the investigation of Barclays and the investigation of the UK gas market – which involves the PRA ICIS – make it unlikely that either regulators or the public will be satisfied long-term with the lack of oversight and reliance on market ethics.

NIKKI JONES

ABBREVIATIONS

Numbers
(US and scientific community)

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

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

Gas
MMscfg: million ft^3 gas
MMscmg: million m^3 gas
Tcfg: trillion cubic feet of gas

Ma: Million years ago

LNG
Liquified Natural Gas (LNG) is natural gas (primarily methane) cooled to a temperature of approximately -260 °C.

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

Reserves and resources
P1 reserves:
Quantity of hydrocarbons believed recoverable with a 90% probability

P2 reserves:
Quantity of hydrocarbons believed recoverable with a 50% probability

P3 reserves:
Quantity of hydrocarbons believed recoverable with a 10% probability

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

Record Response to UK License Round

Towards the end of October 2012 the UK Department of Energy and Climate Change (DECC) announced the winners of what was a record-breaking 27th Licensing Round and declared that UK oil and gas investment looked set to flourish as a result.

A total of 167 new licenses have been offered by DECC covering 330 North Sea blocks, with a further 61 blocks under environmental assessment. The latter are close to, or in, certain Special Areas of Conservation (SACs) and Special Protection Areas (SPAs), and will be subject to environmental assessments before any offer is made. Consultation will be carried out on the recommendations of these assessments before any decision is made on whether to offer any of these blocks. In making the announcement Energy Minister John Hayes said: "This successful licensing round shows we are taking the right action to offer certainty and confidence to investors. Our fiscal regime is now encouraging small fields into production and our licensing regime supports new faces as well the big players to invest."

Range of Companies

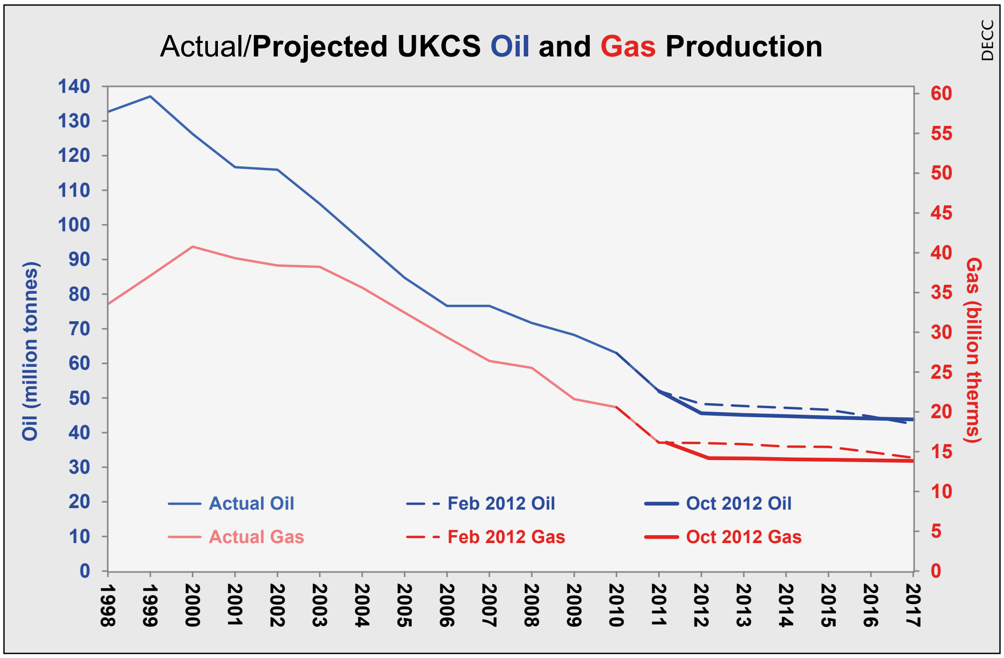
Winners include majors Apache Corporation, BG Group, Maersk, Nexen, Premier Oil, Royal Dutch Shell and Total. Apache has been offered 14 blocks in the northern part of the North Sea, where it will be required to acquire 3D seismic data, whilst BG Group and Shell have been offered seven and five blocks in the central North Sea respectively. Also in the central North Sea, Maersk has been offered four blocks while Nexen has been offered 17, which includes a commitment to drill at least four wells on two of the blocks. Premier Oil has eight blocks in the central North Sea while Total has been offered 16 blocks in the west of the Shetland Islands, four blocks in the northern North Sea and two blocks in the central North Sea. The inclusion of several AIM quoted firms among the winners in the North Sea licensing round is seen as a further endorsement of the confidence the government has in the smaller operator. Of note, Xcite Energy, shortly to bring its Bentley field onstream, won licenses containing four new prospects, claiming the new acreage enhances the potential of the greater Bentley area. Trapoil was awarded three new licenses with one near its part-owned Athena field, one near the Forties field and another next to its existing Sienna prospect. Faroe Petroleum was awarded seven licenses, Valiant Petroleum won five while Bridge Oil received three.

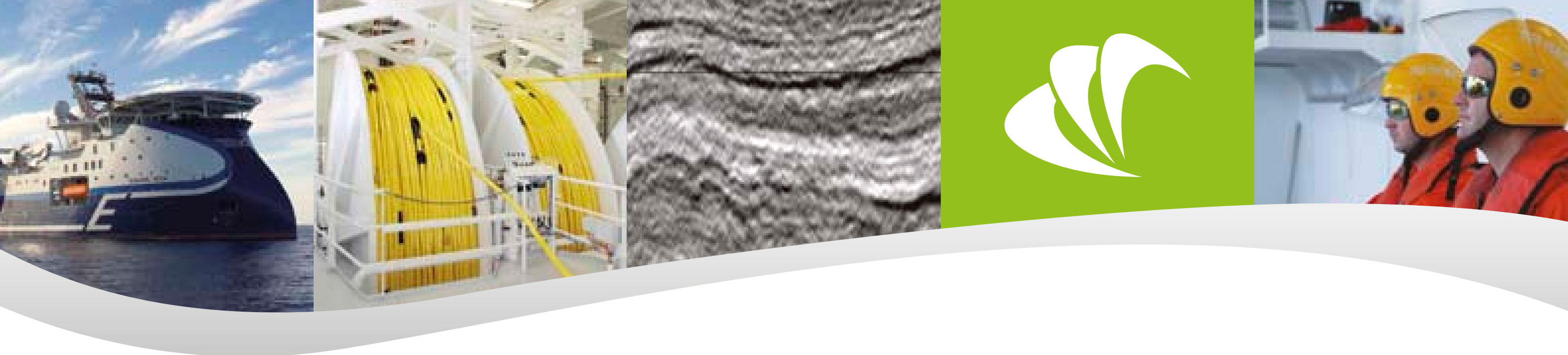
Confidence Returning

Commenting on the oil and gas exploration licenses offered in the round, Mike Tholen, Oil and Gas UK's economics and commercial director, said the outcome was very welcome and that "it reflects the vast opportunity that remains for business and provides reassurance of the government's support for the long-term health of our industry". Industry response to the 27th Licensing Round suggests that investor confidence is returning, following 18 months of constructive engagement with the Treasury and the announcement of several measures aimed at boosting activity. He added that as 2011 witnessed the lowest exploration for many decades, "We must do everything we can to ensure that the award of licenses translates into actual exploration for the billions of barrels of so far undiscovered oil and gas." It is estimated that there are up to 24 Bboe recoverable remaining in the North Sea.

Industry analysts suggest fiscal changes introduced by the government earlier in 2012, specifically the shallow water gas allowance and those that offer some clarity on the complex issue of decommissioning tax relief, were particularly influential on the outcome of this round. The results climaxed a week of mixed fortune for the North Sea. On the positive side, Shell agreed to pay US$525 million to acquire the stakes held by Hess in the Beryl area fields, together with certain gas assets, having earlier revealed that it had received approval to proceed with the development of its Fram field in the Central North Sea. This is due onstream in 2015 and should achieve peak production of 35,000 bopd. Similarly, Talisman declared that it was moving ahead with its US$2.5 billion project to redevelop the Montrose field. On the negative side, official figures show that UK crude oil production was 3.9% lower in the three months to August, compared with the same period in 2011. Energy Aspects, a research consultancy, said it does not expect any material changes to the UK's production outlook, despite recent tax incentives. ■

KEN WHITE





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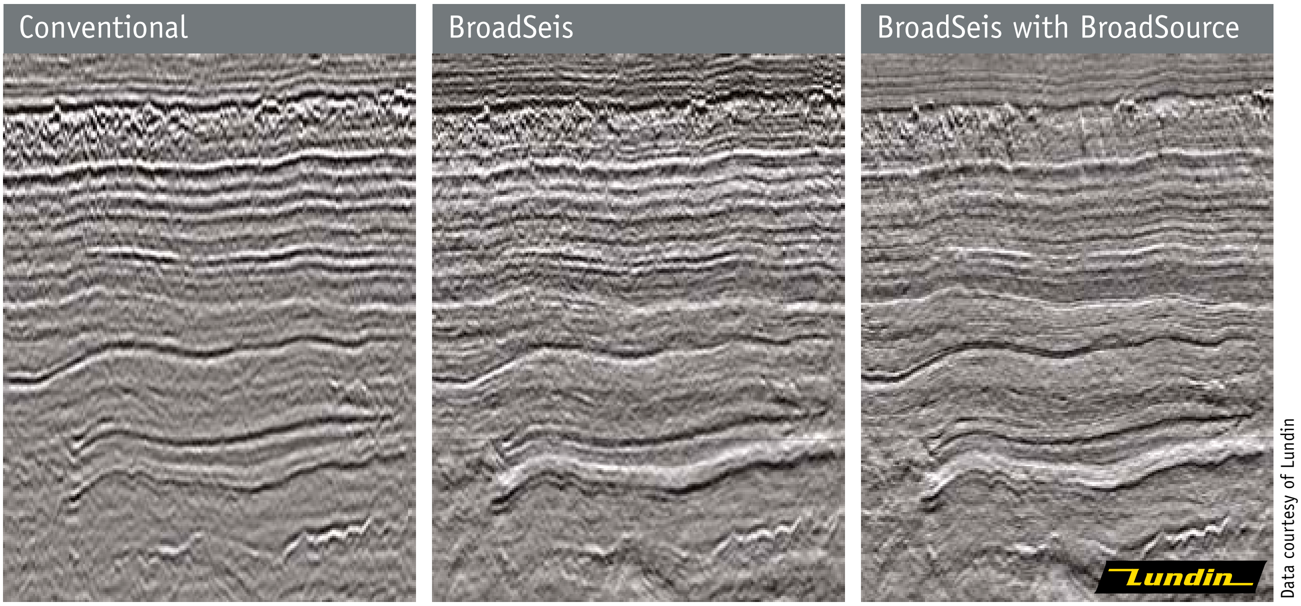

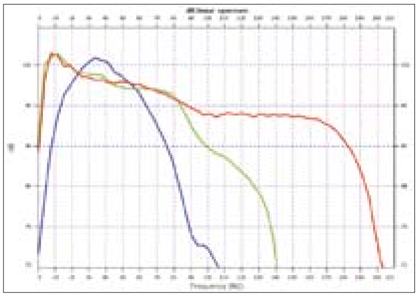

On this data from the Luno Field in Norway, BroadSeis with BroadSource provides over 6 octaves of frequency, from 2.5Hz to 200Hz, the 2ms sample interval anti-alias filter cut-off. This combination provides sharp wavelets with minimal sidelobes for the highest-resolution ghost-free images, the best deep penetration and the most accurate inversion attributes.

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What's the Future for LNG in Australia?

Barely a year ago, Australia was predicted to become the biggest global producer of LNG – but things have changed

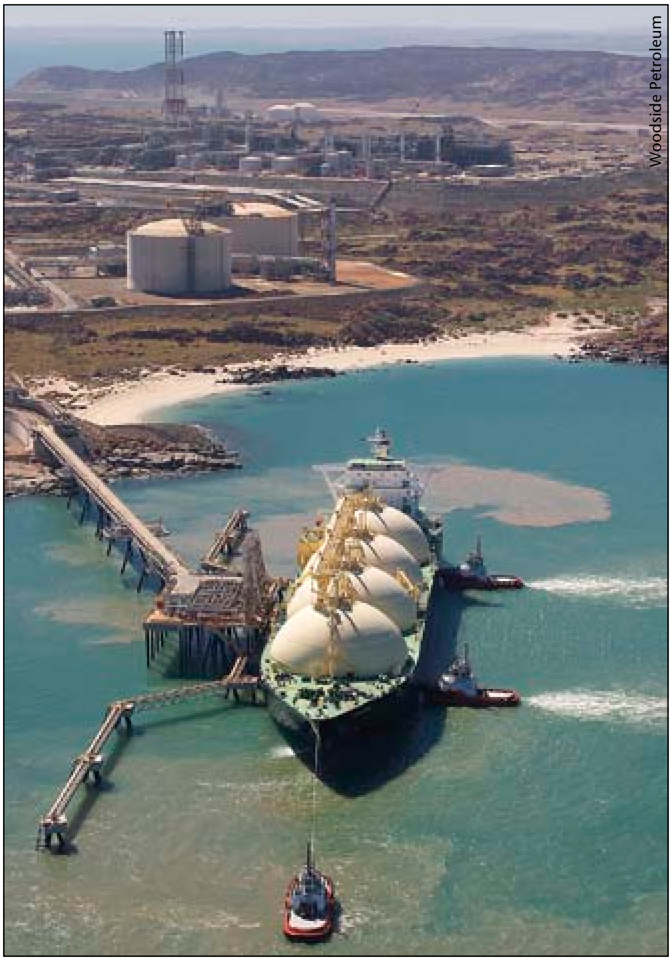
According to a study published by GBI Research, Australia's offshore drilling expenditure in 2011 was US$1.9 billion – US$1.3 billion of which was dedicated to deepwater hydrocarbon production. GBI Research predicts the deepwater portion will grow to US$2.5 billion by 2016 as natural gas exploration has intensified, steadily increasing from 72 wells in 2009 to an anticipated 153 in 2016. This reflects about US$180 billion of planned investment in several LNG projects in Australia. While not all are offshore, the projects as a whole are set to make gas the country's fastest-growing export over the next five years and move it ahead of Qatar as the biggest global producer of LNG.

At least, that was the forecast of many analysts just 18 months ago, but things have changed. In March 2012 BG offered a stake of up to 20% in its Queensland Curtis Island project and many expected a quick sale, with strong interest from Asian buyers keen on acquiring holdings in LNG projects to guarantee or hedge supply. At that time Japanese utilities were particularly active seeking alternatives to nuclear power following the Fukushima disaster, and imported gas was the favored alternative. Only at the very end of October 2012 did BG sign a Heads of Agreement with CNOOC for the sale of certain interests in Queensland Curtis LNG (QCLNG) for US$1.93 billion and the sale of LNG from BG Group's global LNG portfolio. The lack of interest has been described as 'ominous' both for the company and the Australian gas industry.

Project Delays

The reality is that cost overruns, labor shortages, increased competition from North America and potentially East Africa, and some regulatory issues, mean that delays to the final investment decisions on at least four multi-billion dollar offshore projects have been acknowledged by Martin Ferguson, Australia's natural resources minister. These four developments, with a current value of around US$104 billion, are the Browse and Sunrise projects operated by Woodside, the Scarborough gas field involving ExxonMobil and BHP Billiton and Hess's Equus project. Not mentioned by the minister was Arrow Energy's US$20 billion LNG export project on Queensland's Curtis Island, where a decision is due late 2013, or the Gladstone LNG Fishermans Landing, a joint venture between LNG Limited and a subsidiary of CNPC.

Currently, there are three operating LNG processing plants in Australia: the North West Shelf (NWS) LNG project in Western Australia, the Darwin LNG plant and most recently the Pluto project. There are several other conventional LNG ventures at various stages of development, with the massive Gorgon Project under construction and due to commence in 2014–2015. More recently, final investment decisions have been taken for the Wheatstone project, due to be operational in 2016, and Ichthys, which will follow in 2017. Shell's Prelude project, which will use Floating LNG technology, is to be operational by 2016–2017. As yet, there are no operational CSG-LNG export projects in the world. The Queensland Curtis LNG, Gladstone LNG and Australia-Pacific LNG projects (where both Origin Energy and ConocoPhillips are looking to sell a combined 15% stake) are all currently under construction in Gladstone, Queensland, and will become operational from 2014.



Woodside Petroleum

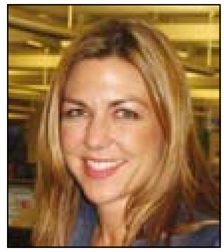
LNG tanker receiving commissioning cargo at the Pluto LNG onshore gas plant in Western Australia

The Australian government has been strongly promoting the usage of LNG as a primary source of fuel for heavy goods transport along its highways, spurring on further investments by creating a consistent demand. Many analysts now believe that a switch to East Africa, where discovered volumes look to present a challenge to Australian LNG projects, would hold back Australia's market share in China and India, where energy consumption is forecast to rise more than 60% by 2030. Key domestic players remain upbeat, however. The Santos CEO, David Knox, is adamant that his company can compete "provided we keep our productivity up, our cost base under reasonable control and we can unlock the resources". Woodside CEO, Peter Coleman, commented that given the maturity of oil and gas regulations and the lack of infrastructure in East Africa "some of those projects probably won't come on as quickly as people think they will."

KEN WHITE

Facing the Cliff

US fiscal drama could trigger a sharp fall in oil prices



THINA MARGARETHE SALTVELT, PH.D

The political debate about the fiscal cliff kicked off in both the Senate and the House of Representatives in late November when the US reopened after the Veterans Day holiday. After the reelection of Barack Obama as US President, political leaders of both the Democrats and the Republicans have struck a conciliatory tone, but this may not last for long. With the election now behind us, financial market players are likely to focus on the pending debate on the US fiscal cliff – one of the single biggest near-term threats to global recovery.

The fiscal cliff is the result of the unfortunate coincidence of about US$700 billion in tax increases and spending cuts which will take effect at the beginning of the calendar year 2013, should Congress fail to act to change the current law. Failure to avert the fiscal tightening could knock as much as 4.25% of US GDP next year (estimated at 2% for 2013), enough to push the economy back into recession.

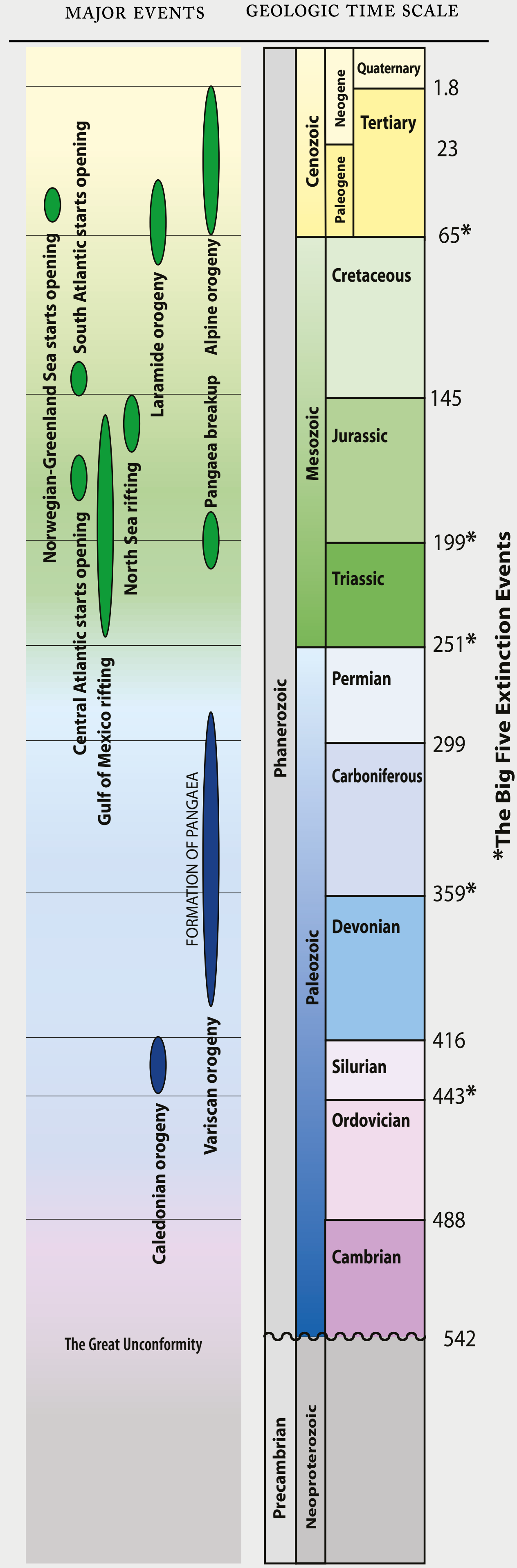
A sharp fall in economic activity by the world's largest oil consumer will also have a significant impact on oil demand. We expect US oil demand to be around 19 MMbopd in 2013, but if no solution is found to the fiscal cliff, US oil demand could be cut by around 800,000 bopd, assuming that oil consumption relative to GDP (oil intensity) remains unchanged. If oil intensity falls by the same proportion as during the financial crisis, oil demand may drop as much as 1.5 MMbopd, although we find this less likely as higher oil prices and energy efficiency gains have constrained or dampened a strong rebound in oil consumption in sectors like power, electricity and industry since the financial crisis.

The short-term effect on oil prices if the US economy is pushed outside the fiscal cliff and US oil demand falls by 800,000 could, all other things being equal (ceteris paribus), trigger a sharp fall in oil prices by around 35% to around US$75/barrel (based on short-term elasticity of demand).

Uncertainty Expected

Although the US will still have a divided government after President Obama's reelection, our base case scenario is that the US economy will avoid the fiscal cliff, as both parties will eventually reach a temporary 'kick-the-can' compromise. Nevertheless, we still expect that the uncertainty about whether a solution to the fiscal cliff issue will be found will make financial players cautious and thereby weigh on oil prices through year-end, pushing the average Brent oil price down to US$109/barrel in Q4 from US$110/barrel in Q3.

If the policymakers have learned their lesson after last year's experience, a major setback in risk sentiment may be avoided in the lame-duck session, the period after the US election to New Year. But there is still a risk that we will see a more messy policy process, which may trigger more substantial short-term selloffs in risky assets such as oil, despite our expectations that Congress will find a solution at the 11th hour. This could push oil prices well below our average Brent oil price forecast at US$109/barrel from time to time when political risk rises through the year-end. ■

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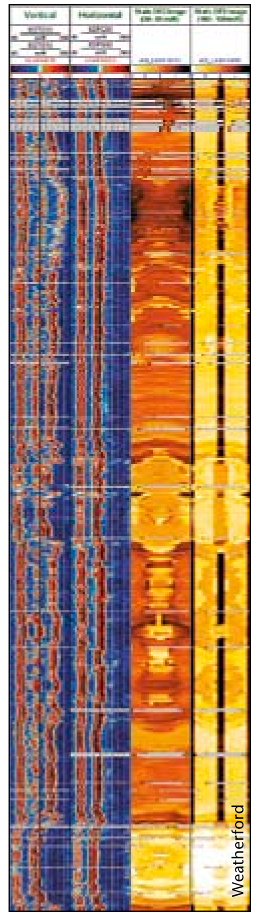
New Weatherford Sonic Tool

Organically rich shale reservoirs have become an important hydrocarbon resource, but achieving economically viable production rates entails horizontal drilling and hydraulic fracturing. Successful well placement and maximum hydrocarbon recovery requires real-time access to downhole data, and operators rely on data from logging-while-drilling (LWD) tools to identify sweet spots, optimize wellbore placement and plan fraccing and stimulation programs.

Understanding the geomechanical properties of the shale is key to success in a shale reservoir. Most organic shales exhibit significant anisotropy in their geomechanical properties, showing variations in the horizontal plane due to differences in tectonic stress, and in the vertical plane due to intrinsic bedding features of the formation. **Weatherford's** new **CrossWave™** LWD sonic tool provides 360°, azimuthally focused measurements of compressional and shear wave velocities, allowing three-dimensional characterization of geomechanical properties along the length of the horizontal wellbore in mechanically anisotropic shale reservoirs. This lets the operator select the best areas for frac stage placement while optimizing frac design and execution.

This technology has been successfully tested in horizontal shale reservoir wells in north-eastern US, where borehole images constructed from azimuthal shear slowness data clearly visually indicated the orientation and magnitude of the shear wave anisotropy. ■



CrossWave™ LWD Sonic Tool

Rock Sample Washing

RockWash is a small independent private company based in South Wales which has successfully developed a unique automated rock-sample washing and photographic process that enables its clients to gain a higher level of primary geological information from their well samples. This process is particularly effective in the rapid cleaning and standardized photo-documentation of ditch-cuttings samples (rock chippings), providing basic yet fundamental geological data in an easily accessible form. The automation of the RockWash process is central to the business, in which speed, consistency and environmental factors provide significant benefits. **Schlumberger** recently agreed to provide investment and international expertise to future RockWash operations around the world, which will allow it to accelerate into new business areas, delivering enhanced photo-visualization of wellbore geology from both new and previously existing well samples. ■

Exploration Revived in Norway

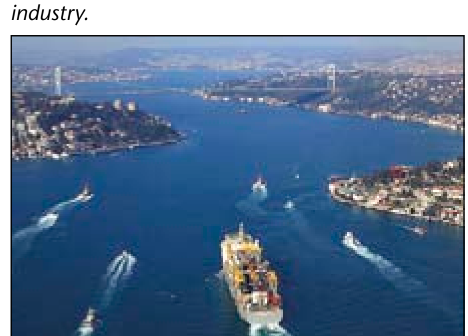
Bergen in March 2013 will be the venue for the **5th NPF Biennial Petroleum Geology Conference**, which focuses on exploration on the Norwegian continental shelf (NCS). A range of papers have been lined up, from case histories integrating geology and geophysics, through basin exploration overviews, exploration strategy and key discussions on important exploration issues. A record 445 participants attended the previous conference in 2011. In addition, the much-coveted Exploration Revived Award 2013, designed to stimulate exploration on the NCS, will be announced during the conference dinner. This is given to groups or companies who have contributed to moving exploration forward by such means as testing new play concepts or exploration models, or reducing exploration risk by developing new techniques. ■

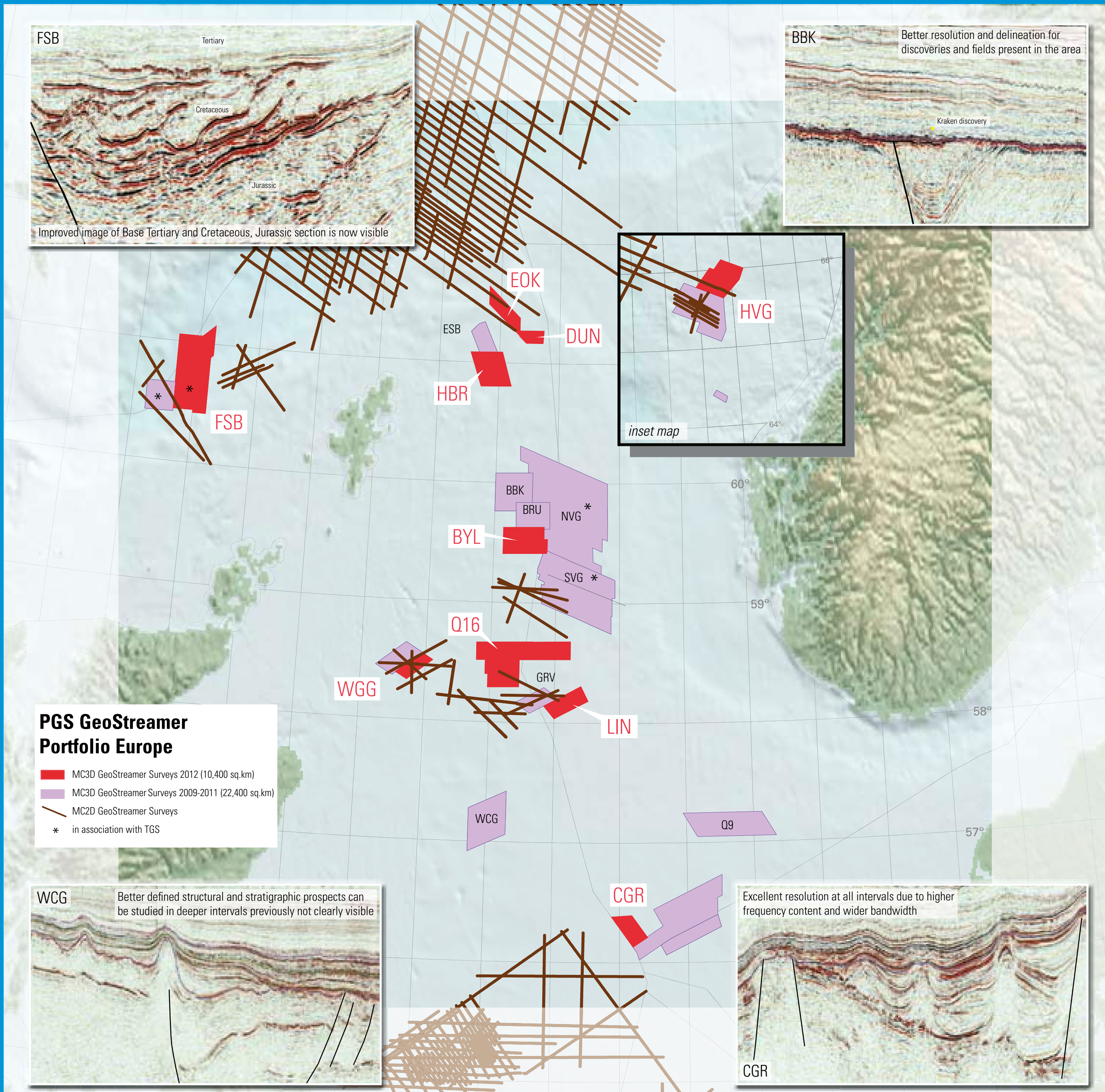
Istanbul Hosts AAPG Event

The inaugural **APPEX Regional 2012 Conference**, organized in association with Turkey's National Oil Company, TPAO, took place in November 2012 in **Istanbul**. Nearly 200 attendees from 29 countries came together to make deals and discuss challenges relating to the regional exploration of Eastern Europe, East Mediterranean, Former Soviet Union and Northern Iraq. The event was built on the success of the annual APPEX Global conference in London, an established forum for those looking to build partnerships and promote prospects for oil and gas exploration and production all over the world.

The program was split geographically, starting with a broad focus on Central and Eastern Europe and then diverging into sessions on other regions. Highlights included Tony Hayward describing Genel Energy's exploration activities in Kurdistan as well as talks on maritime border issues and the potential for diplomatic confrontation between countries in the region. A unique aspect of APPEX conferences are the prospect forums, which here gave independent oil companies the chance to pitch current exploration opportunities in Italy, Tunisia, the Sicily Channel, Albania, the Arabian Sea and, of course, Turkey. ■

Istanbul: A hub for deal-making in the oil and gas industry.





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Jodie Gillespie

The passing, tragically and suddenly, on October 5, 2012, of Jodie Gillespie, Business Development Manager for Fugro Geoscience division, is received with great sadness. Jodie will be remembered as a very beautiful woman both inside and out. She had sparkling eyes, a radiant smile and a loving, caring spirit. Jodie was philanthropic, a humanitarian, socially conscious and deeply concerned about the state of the world. She will be remembered for her friendliness and for her kind, sweet and cheerful way. Jodie was exceptionally intelligent and an amazing networker, who loved to travel and was always impeccably dressed, even on remote field trips. She always represented her company, her industry and herself in the most professional manner, mixing comfortably with people from every walk of life. All who met her could not help but like her.

Jodie came from New South Wales, graduating from the University of Sydney in 1994, and worked in oil, gas and minerals exploration in both technical and management fields. For the past six years Jodie was Business Development Manager representing the Fugro Geoscience division, and was also Chair for the International Association of Geophysical Contractors, Asia Pacific region.

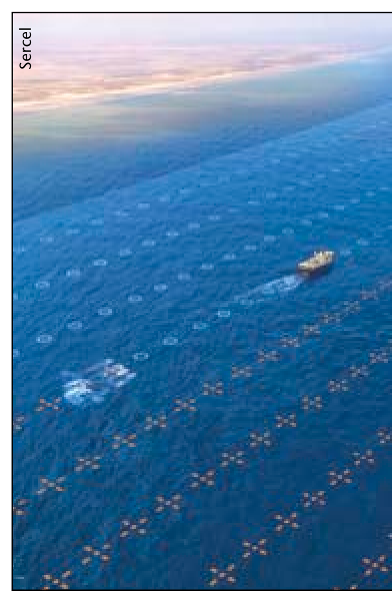
Her life was indeed cut short in this world, but Jodie was here long enough to gain the love and admiration of all those who knew her. Her beautiful nature leaves an indelible legacy in the hearts and lives of her family, friends and colleagues who had the pleasure of her wonderful company. Her loss will be greatly felt throughout the exploration industry. ■

Seismic and Drilling Integration

By using **Baker Hughes**' reservoir models that integrate log-derived, near-wellbore geomechanical and petrophysical properties, with calibrated seismic data from international geophysical company **CGGVeritas**, operators can optimize well placement and completion design earlier in the asset lifecycle for more efficient well construction and more productive wells. The products and services of the companies complement each other well: Baker Hughes has a broad portfolio of oilfield expertise and services, geomechanical models and its JewelSuite™ reservoir modeling software, with which sweet spots can be accurately pinpointed; CGGVeritas geophysical technologies include differentiating methods for shale reservoirs characterization, such as Hampson-Russell software products, and, with the acquisition of Fugro's Geoscience division, will soon include Jason technologies for high-end reservoir characterization and Robertson expertise in exploration and geology. While the long-range goal of the collaboration is to help operators optimize full-field development projects, the initial phase focuses on integrating near-wellbore log data with reservoir characteristics away from the well. ■

Survey Design Software

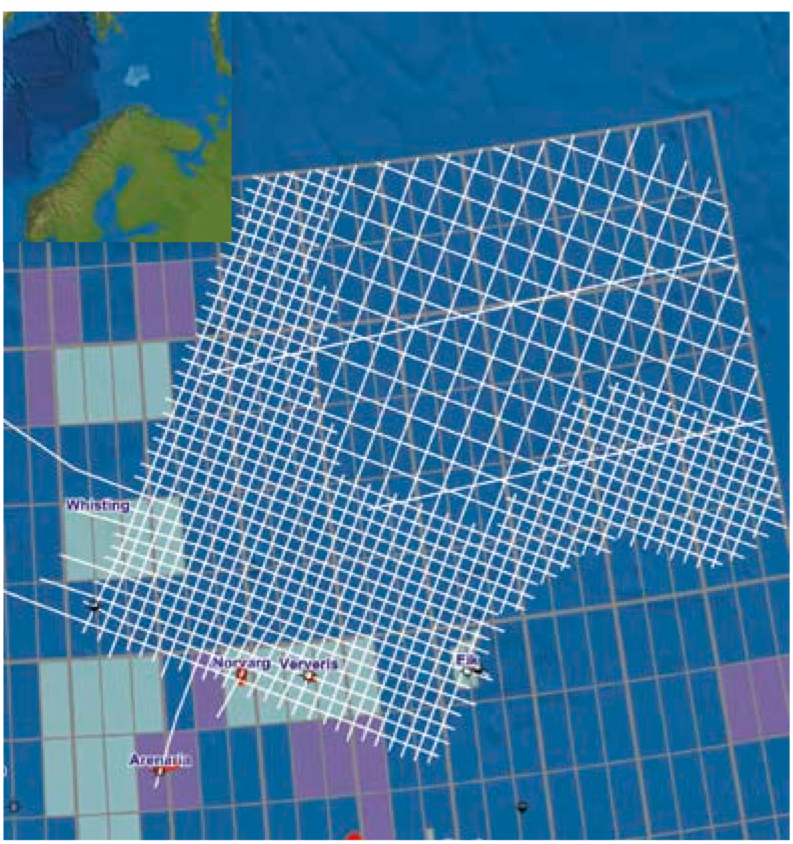
SeaPro Design is a new, highly versatile tool for generating everything from simple geometry to complex designs for all types of marine surveys, whether 2D, 3D or multi-vessel seismic surveys. The software provides an enhanced graphic interface and all the advanced features needed to design surveys in a few simple clicks. Functionalities include geodetic definition, survey outline, streamer configuration, line direction and anchor point. This is a new module added to **Sercel's** proven marine navigation software portfolio, SeaPro Nav, which now offers users all the tools they need from survey design up to navigation data processing in a single comprehensive navigation portfolio. ■



Sercel

Snøspurv 2D Seismic Survey

12,000KM - Barents Sea - Norway



The Snøspurv 2D

High Resolution Seismic Survey

- Searcher Seismic and Seabird Exploration have allocated a 2D seismic vessel for a 12,000 km regional seismic survey covering the Bjarmeland Platform in the Norwegian Barents Sea. The survey is scheduled to commence early 2013.
- The Snøspurv Seismic Survey is designed to enhance the seismic resolution of the prospective Triassic-Jurassic sections of the southern and western part of the Bjarmeland Platform. The Carboniferous/ Permian in addition to the Triassic section are the main exploration targets at the northern part of the survey area.
- Data will be available from Q3 2013 for participating companies.

SeaBird Exploration

SEARCHER SEISMIC

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The Miocene Monterey Formation

The Los Angeles Basin is the most productive basin by area in the world – and the Miocene Monterey Formation, which is exposed along the coast and in the hills of the Palos Verdes Peninsula, is the prolific source rock for this basin.

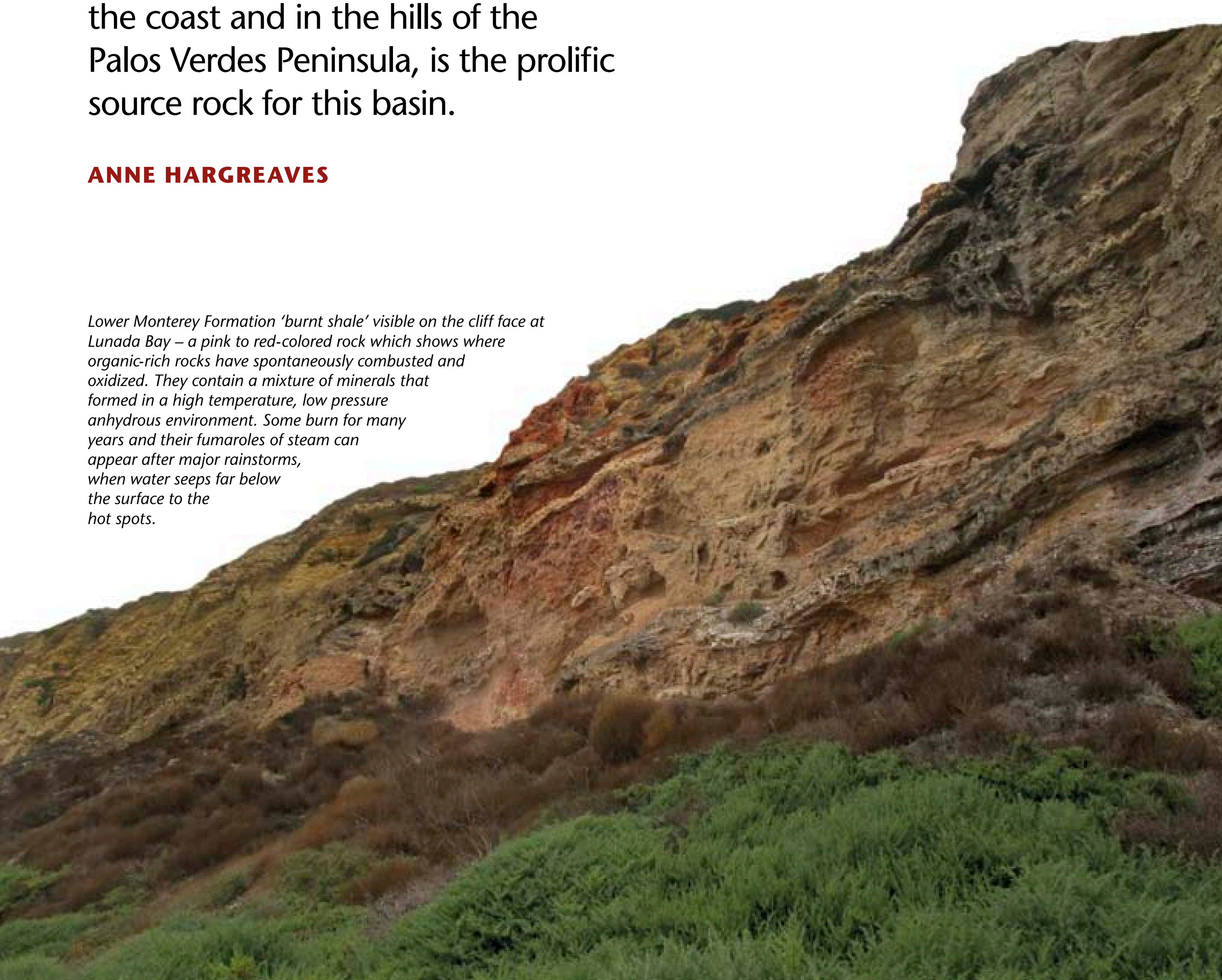
ANNE HARGREAVES

The Monterey Formation is a bio-siliceous, very organic-rich deposit found in southern California. It was deposited between 17 and 5 million years ago during a time when tectonic forces were shifting, and localized subsidence during a time of high eustatic sea level, along with coastal upwelling, affected the area. The Monterey and its equivalents, the Puente and the Modelo Formations, are the primary source rocks for oil production in the Los Angeles Basin.

Thanks to a field trip offered at the recent AAPG convention in April of 2012 at Long Beach, California, participants were able to visit the Monterey in the tectonically active highlands surrounding the Los Angeles Basin, in particular along the coast on the Palos Verdes peninsula west of downtown Los Angeles, where a 600m thick section of the Monterey is exposed. Dr. Richard Behl of California State University at Long Beach, who has studied this region for many years, led the trip.

Complex Geological History

The geological history of California is quite complex, but the following is a brief summary. 200 million years ago the western edge of North America was approximately at



Lower Monterey Formation 'burnt shale' visible on the cliff face at Lunada Bay – a pink to red-colored rock which shows where organic-rich rocks have spontaneously combusted and oxidized. They contain a mixture of minerals that formed in a high temperature, low pressure anhydrous environment. Some burn for many years and their fumaroles of steam can appear after major rainstorms, when water seeps far below the surface to the hot spots.

the current border of California and Nevada. Then, as the mid-Atlantic Ridge began to spread, North America began to move west colliding with the floor of the Pacific Ocean, which was subducted beneath it. Oceanic sediments and volcanic islands were too buoyant to sink, so they crumpled into the North American continent, eventually becoming California.

This happened in three main events. The first one, during the Mississippian, was the Antler orogeny which created the Shoo Fly metamorphic complex, now part of the eastern Sierra Nevada. The Shoo Fly complex became the 'new' west coast. Next, when the mid-Atlantic ridge began to separate in earnest at the end of the Triassic, the new coastal deposits being shed off the Shoo Fly were compressed and accreted onto the continent, becoming the Calveras complex, which is now a central range in the Sierra Nevada. At the same time, an old volcanic island arc was included in the accreted mix, becoming the Western Jurassic Terrane. The third important event occurred in early Cretaceous times, when the subduction zone jumped west by 60 km for an unknown reason, creating an inland sea over what was to become the Great Valley. Also at this time a chunk of the Sierra Nevada detached and moved west, becoming the Klamath Mountains of northern California. A new trench began to form offshore: the Franciscan Trench, which collected sediment during the Cretaceous until the Oligocene. At that time general uplift created the Coast Range on the newest west coast, and the broad expanse of the Great Valley, now an inland sea, continued to fill with sediments.

In the middle of the Miocene, about 17 million years ago, a lot of volcanic activity in Oregon resulted in massive flood basalt flows over that state and in California. One theory is that a huge meteorite hit south-east Oregon, allowing more than 100 cubic miles of lava easy access to the surface through the resulting fractures.

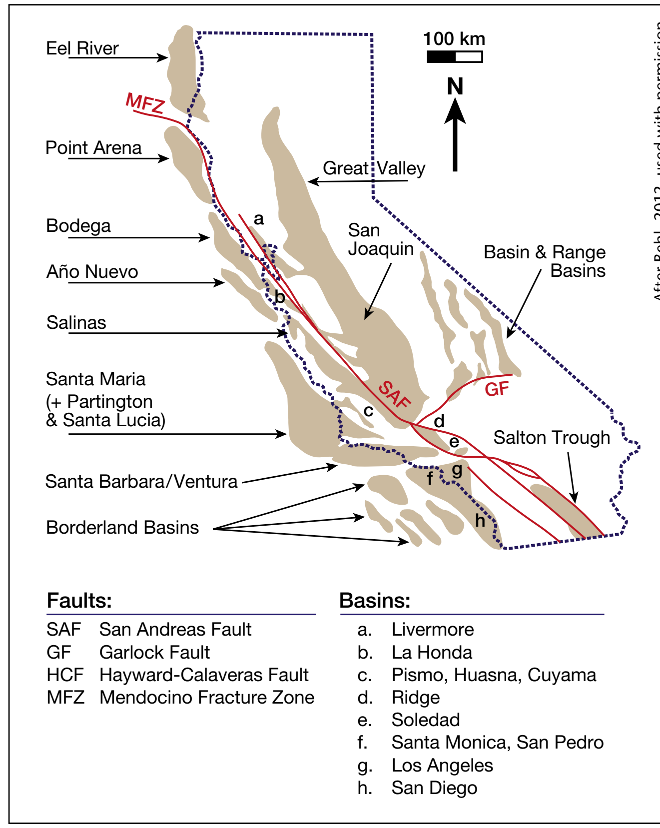
At this time, the San Andreas fault (SAF) came into its own. This strike-slip fault occurs at the juncture between the Pacific plate and the North American plate. Currently the Pacific plate moves northward at a rate of two inches per year and to date has carried California west of the fault northward at least 560 km.

Meanwhile the Basin and Range areas east of the SAF began to form due to crustal tension and stretching. This province consists of isolated mountain ranges separated by desert plains. It is estimated that this area has widened and thinned, and is currently twice as wide as it was before the great event which initiated this action around 17 million years ago.

Finally, the Coast Ranges began to uplift and deposition of the Monterey Formation commenced.

Wide Range of Sediments

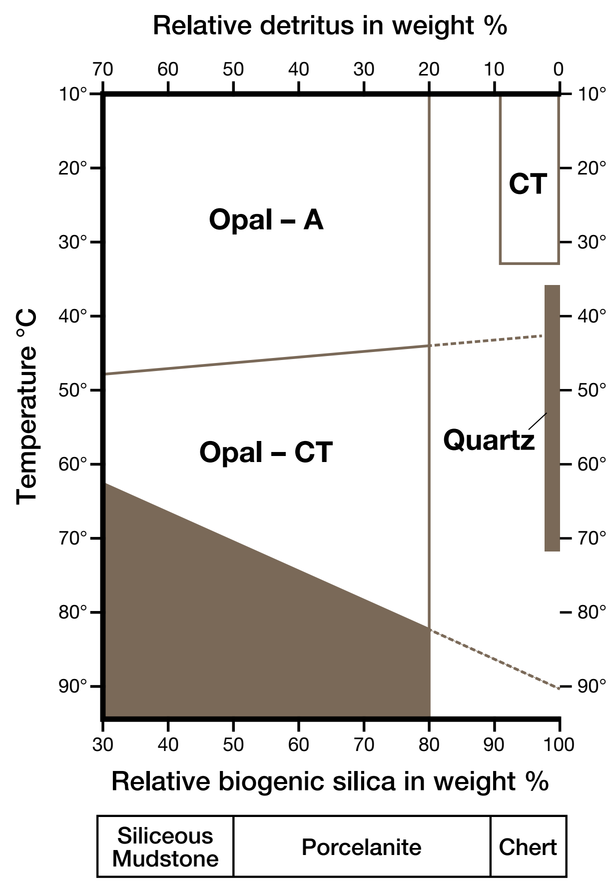
The Los Angeles Basin is one of more than 20 Neogene basins in California that were created due to action on the boundary of the North American and Pacific plates. The basins are part of the California Continental Borderland where sedimentary basins alternate with ridges to the west of the SAF; one of which is the Palos Verdes Peninsula; another being Catalina Island. The area that is the city of Los Angeles today is one of the Borderland Basins and was formerly under water, eventually in-filled with sediment deposits shed from the surrounding mountain ranges.



Neogene basins of California

The section of the Monterey Formation found on Palos Verdes has been transported northward approximately 20–30 km from where deposition first occurred. The lower Altamira formation was deposited directly on the early Mesozoic Catalina Schist basement. In fact, the distinctive blue schist can be seen as rip up clasts in these basal breccia and/or conglomerate sediments. Overall it thins to the north and east, and shows great lateral variation in thickness, degree of deformation and stratigraphic continuity.

Phosphatic marlstone or mudstone/shale outcrop. Organic-rich, bituminous, calcareous phosphatic shales are interbedded with dark mudstone, Lunada Bay, Palos Verdes Peninsula, Los Angeles.



After Behl, 2012, used with permission

Relationships between silica phases, temperature and sediment composition.

Anne Hargreaves

Schist and phosphatic breccia rubble from the lower Altamira turbidite deposit (Lower Monterey Formation).

The Monterey deposits include carbonaceous, calcareous and phosphatic mudrock, dolostone, limestone and marlstone in addition to siliceous diatomite, porcelanite and chert. It was the massive amount of diatomite created from many millions of silica-rich diatoms that provided the oil that supplied the Los Angeles Basin. In fact, the Monterey Formation can have an organic content as high as 24%. Due to the high sulfur content, it generates hydrocarbons at an early stage and without being as deeply buried as one would expect.

Silica Diagensis Important

Detailed study of the Monterey Formation has allowed for extensive insight into silica diagenesis and chert and porcelanite formation, as it is possible to see all stages of burial diagenesis and all silica phases and the significance of these on the petroleum geology of the basin.

Silica phases observed include: a) biogenetic opal-A which is a hydrous silica found in the shells of diatoms and radiolarians, many of which were deposited in the Monterey; b) metastable opal-CT which is hydrous silica which forms with burial, increased temperature or the passage of time as an alteration product from opal A through dissolution and re-precipitation; and finally c) the end result of stable diagenetic quartz, which is found as fibrous chalcedony or cryptocrystalline or microcrystalline quartz or chert. Temperature and time contribute to these three phases, but the amount of clay, organic matter and calcium carbonate also affect the amount of silica diagenesis. The presence of clay and organic matter slows the opal-A change to opal-CT, but the presence of calcium carbonate speeds up the formation of opal-CT and also possibly quartz formation.

Concentrically fractured chert nodules or spheroids indicate early and shallow silica diagenesis.

Jane Whaley

The Los Angeles Field

Oil was first discovered in the Los Angeles city oil field in the modern sense in 1890 (see *GEO ExPro*, Vol. 4, No. 3 and Vol. 9, No. 5). Of course, the local people had been using the 'brea', consisting of sand, silt and heavy oil, from the local tar pits for a long time. The first economic well, producing two barrels of oil per day, was drilled first by hand and then using a rustic cable drill in 1892. By 1913 there were over 1,300 wells drilled in the immediate area. Production is from three zones at 300m, 335m and 457m depth, all from the Puente Formation. To date, 23 MMbo have been produced, with 50 wells still producing in Los Angeles city.

Although both diagenetic siliceous rocks, chert and porcelanite show the importance that additional material such as clay make to the final rock. Chert is a fairly pure siliceous rock which is dense and hard, with a smooth conchoidal fracture and waxy luster, and normally is composed of 90 to 95% diagenetic silica. Porcelanite, on the other hand is only 50–85% diagenetic silica, with the rest being clay content and/or porosity. This makes it less dense than chert, with a blocky to splintery fracture and a matte surface resembling unglazed porcelain – hence the name. The porosity can be as much as 15–25% and often it is layered with dark shale. ■

Acknowledgement: This article was previously published in the CSPG magazine Reservoir, Vol. 39, No. 9, and is reprinted with permission

Weathered piece of siliceous shale sandwiching a thin chert layer in the Monterey Formation – this is a perfect example of mechanical stratigraphy which is so important in exploiting unconventional reservoirs. The chert layer is highly jointed and fractured, but the shale above and below is not, even though they were all exposed to the same stress field. Undoubtedly weathering has deepened the joints perpendicular to the bedding plane.

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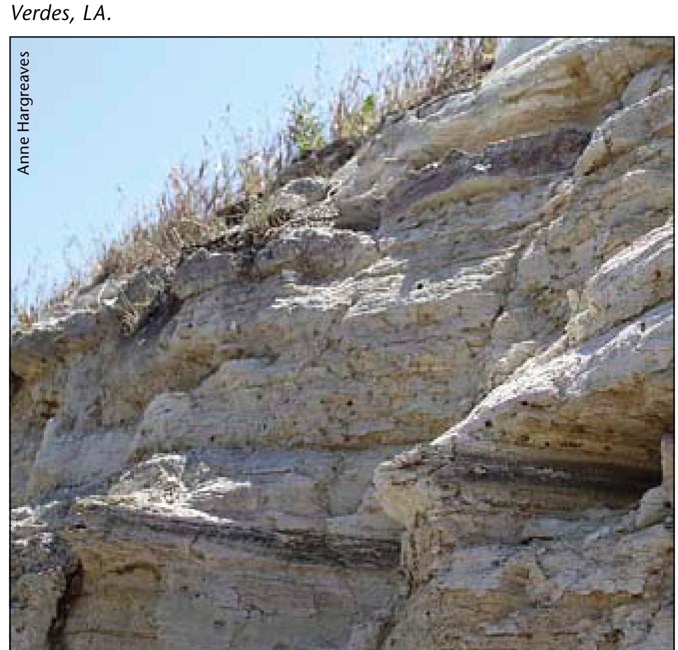
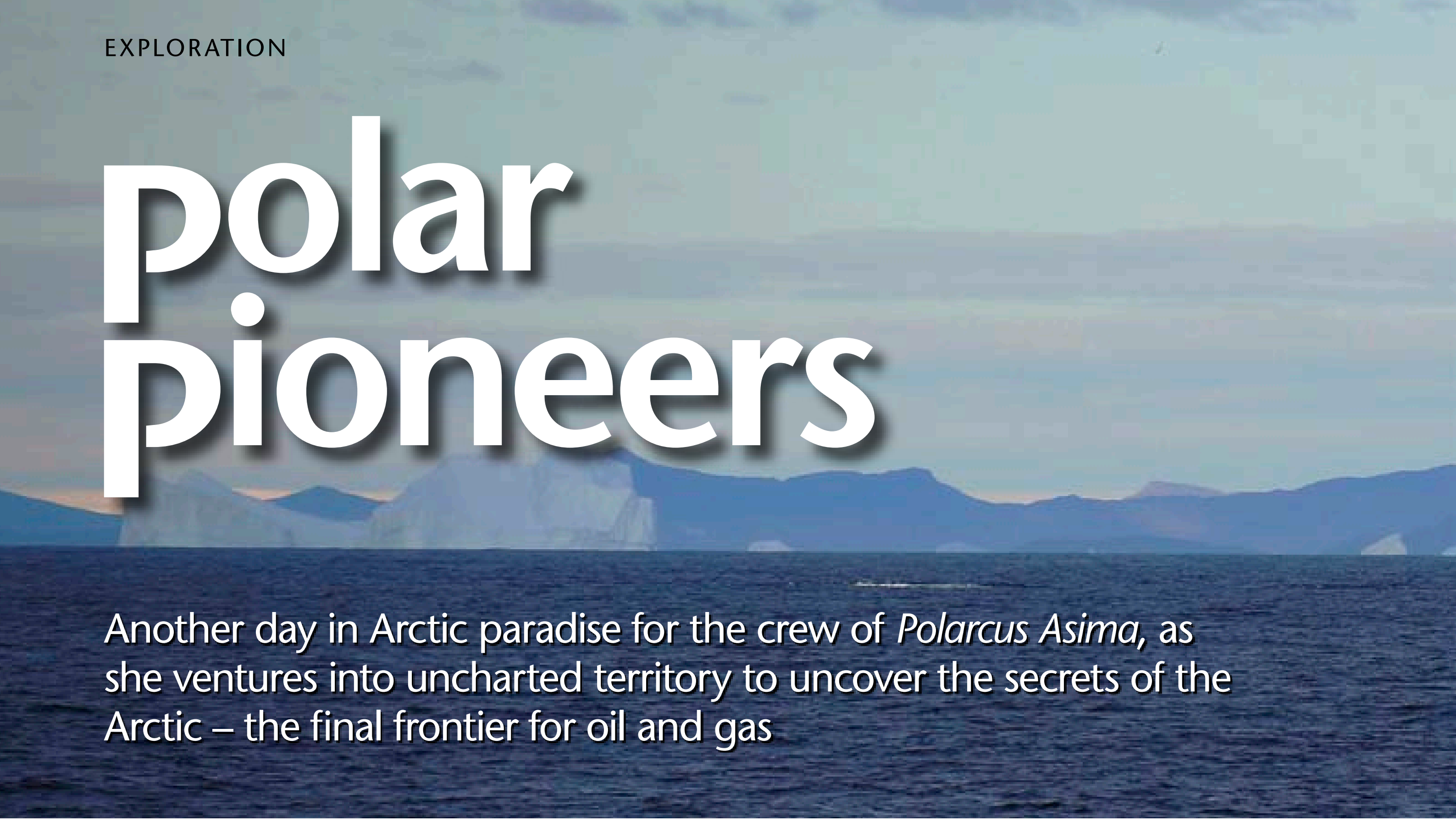
Valmonte diatomite member of the Monterey Formation – white to light grey laminated diatomite and diatomaceous shale with some grey-brown Opal-CT chert beds and nodules in Del Cerro park, Rancho Palos Verdes, LA.



About the Author

Anne Hargreaves has a B.Sc. in Geology from the University of Calgary. She has worked for over 20 years for several companies working with geological data and collections. Currently she is Vice-President of Canadian Stratigraphic Services (2000) Ltd, which is better known by the trade names of Canstrat and Amstrat, and which supplies well log descriptions from Canada and the US to the oil and gas industry.



polar pioneers

Another day in Arctic paradise for the crew of *Polarcus Asima*, as she ventures into uncharted territory to uncover the secrets of the Arctic – the final frontier for oil and gas

CARLI ALLAN and REBECCA ERICSON-GRANTHAM, Polarcus

Just before dawn and in the cold of approaching winter, the crew of *Polarcus Asima* prepare for their last day after a six-week rotation of Arctic exploration.

A tiny speck in the vast wilderness off Greenland, the vessel navigates a treacherous Iceberg Alley, where enormous towers of blue ice speckle the steel grey waters. As the *Asima* carves a path through the ocean, up to ten streamers trail behind, capturing groundbreaking 3D images of what lies beneath. It's yet another day in Arctic paradise for Party Manager Glenn 'Cass' Cassim and his crew, and the closing chapter on Polarcus' first Arctic seismic survey.

"Every person has a slightly different perception of the Arctic, but the scenery at times has been nothing short of breathtaking," recalls Cass. "We have experienced eerie scenes in the fog when icebergs would appear like ghosts from a forgotten world. Then there were days of almost glassy seas and brilliant sunshine, where the white and blue ice contrasted with a deep blue and sometimes cloudless sky."

This is a corner of the world where the Arctic atmosphere dazzles, with icebergs appearing to be suspended in mid-air. And, aside from the creaking and thumping of bergs, there is the deafening sound of no noise at all.

Cass adds: "The sunsets and sunrises produced the deepest oranges and purple hues; when laced with the dramatic black and grey clouds, this creates a scene of timeless tranquility mixed with a strange menace."

Potential Riches

Pods of narwhals, midnight sunsets and Arctic special effects were all in a day's work for the crew. But natural beauty and wonder aside, why brave the extreme hazards and challenging conditions of Greenland's frozen coast? It's all part of Polarcus' master plan and vision – as boldly declared in 2008 – to pioneer surveys in environmentally sensitive areas while causing minimal impact on the environment. And the Arctic is the ultimate goal.

The US Geological Survey estimates that the Arctic may be home to 30% of the planet's undiscovered natural gas reserves and 13% of its undiscovered oil – and up to 160 Bboe could lie undiscovered beneath the Arctic. The figures speak for themselves, explaining why the world's biggest oil firms are clamoring for a piece of the Arctic action.

Polarcus is well positioned to secure a dominant market share in the Arctic. It has the industry's first true Arctic standard 3D seismic vessels, with design features such as a double hull, ICE-1A/ICE-1A* class notation, DP2 dynamic positioning, and advanced ballast water treatment. These were put to the test this summer, when Polarcus deployed three ICE-1A class vessels – the *Amani*, *Samur* and – during a 12-week 3D seismic survey in Baffin Bay, about 400 miles north of the Arctic Circle and just off the coast of Greenland.

"Conducting the survey with minimal impact to the environment and local communities was paramount in surveying such a frontier area complicated by icebergs and very challenging remote logistics. The project was a success, with no recordable EHSQ incidents onboard, very low technical down time and a high quality data set delivered to our client," explains Glenn Werth, Vessel Manager *Polarcus Amani*.

At the End of the World

From Russia to the Congo, Polarcus has a reputation for innovation and environmental responsibility, but nowhere has tested this pioneering company to the limit quite like the Arctic. The offshore survey had to be carried out in the short summer (August to October) while there is sufficient open

water for towed-streamer deployment. Past this date and the sunlight hours reduce to zero, temperatures plummet to -12° C, the sea freezes over, and even humpback whales migrate to warmer waters.

Cass explains: "We are in an environment where the temperature, even in summer, is not too far above freezing and there is a high wind-chill factor. Both people and machinery have to be well prepared to work in such an environment. We are also working in very isolated conditions, well away from the support services, resources and supplies that are normal in, for instance, central Europe."

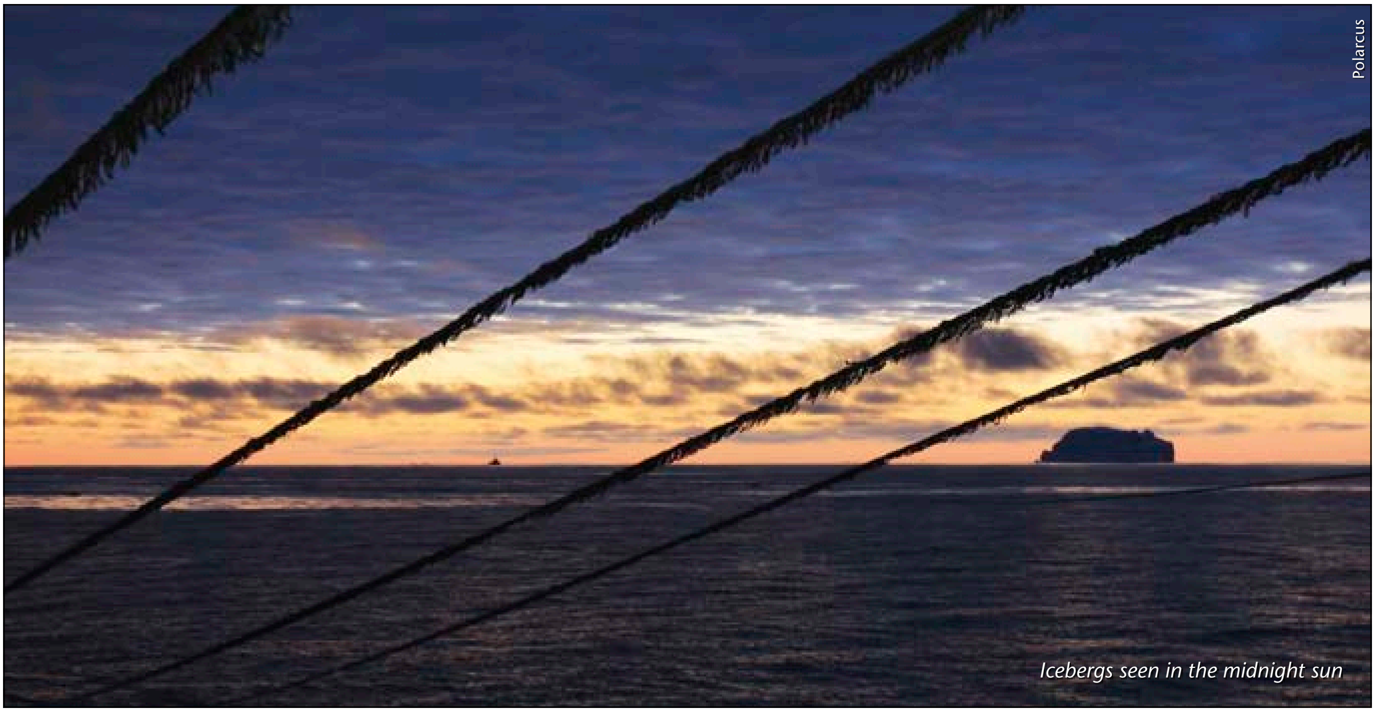
To avoid depleting the small Inuit community of Upernavik where Polarcus operated from, fresh provisions were transported via charter plane from Iceland, dry-stores came by container from Denmark, and an offshore tanker supplied fuel for the vessels.

And then there were the specific challenges of completing a seismic survey safely and successfully. Cass says: "The *Asima* is towing a spread of equipment one kilometer wide and more than six kilometers long in an environment where we are surrounded by icebergs, bergy-bits and ice-growlers. This, combined with bad visibility due to fog and snowstorms, as well as the onset of longer nights towards the end of the project, meant that we had to take some special precautions to keep both equipment and crew safe."

Polarcus has the only ICE-1A class fleet in the world. Its vessels can passage in first-year ice of up to a meter thickness without the assistance of icebreakers; they are ice-reinforced with thicker ribs and skin plates, have de-icing and ice-preventing systems at critical tanks and pipelines and their propellers, gears and thrusters can withstand operations in ice. In short, they are Arctic-ready.

"Due to the high reliability of the equipment, periods outside were kept to a minimum," adds Cass. "The closing-in of daylight as the project progressed was more a hindrance to the watchkeepers on the bridges of all vessels, as it made it more difficult to search out ice-particles in the water. However, this was greatly helped by a special radar designed for detecting ice.

Towing a spread of equipment one kilometer wide and more than six kilometers long when surrounded by icebergs presents a considerable challenge.


Polarcus

Icebergs seen in the midnight sun

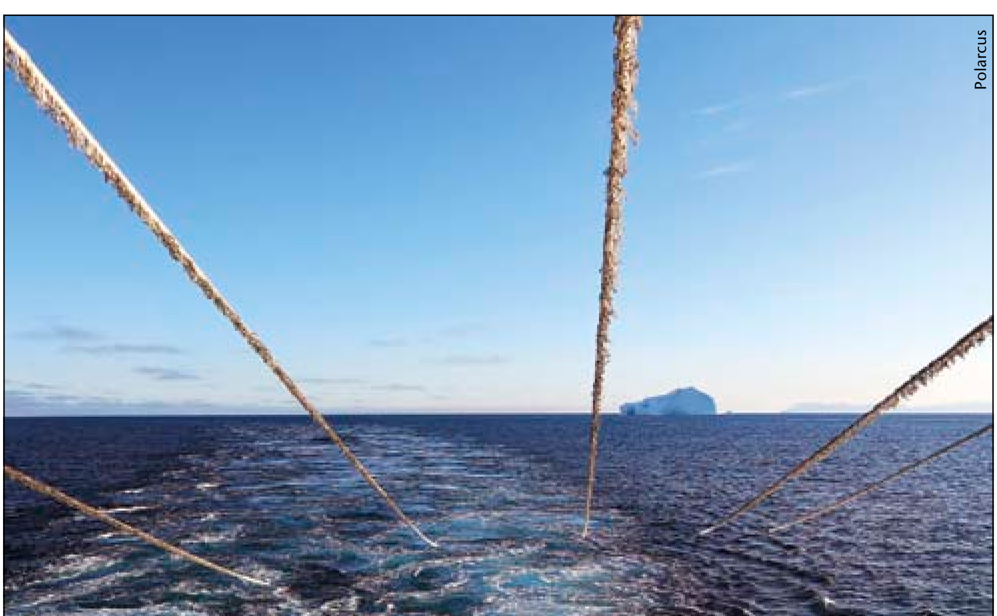
Breaking the Ice

This year, the amount of solid summer polar ice was at the third lowest level on record. The result? The Arctic becomes more accessible, with stretches of sea that are normally blocked now open to vessels such as the *Asima*. However, far from plain sailing, the waters are still scattered with potential hazards.

Between 10,000 and 15,000 icebergs are calved each year, primarily from 20 major glaciers along Greenland's west coast. Operating just off this coast, the Polarcus vessels would bump through blocks of ice the size of washing machines. "Floating bergs with millions of liters of frozen water are the starting point after they break off from a glacier. These solid frozen blocks slowly break down due to temperature, wave-motion, natural fracturing and interaction with the sea-bed, breaking down into smaller bergs, bergy-bits and eventually into small ice 'growlers' of only one or two cubic meters," explains Cass.

"All these ice particles can damage both the vessel and the equipment. The main challenge was to acquire the data necessary in the survey area without letting the vessel or equipment come into contact with these particles. We are towing six-km-long streamers, but they don't necessarily follow the course of the vessel. It takes a lot of time and attention to keep operations running smoothly."

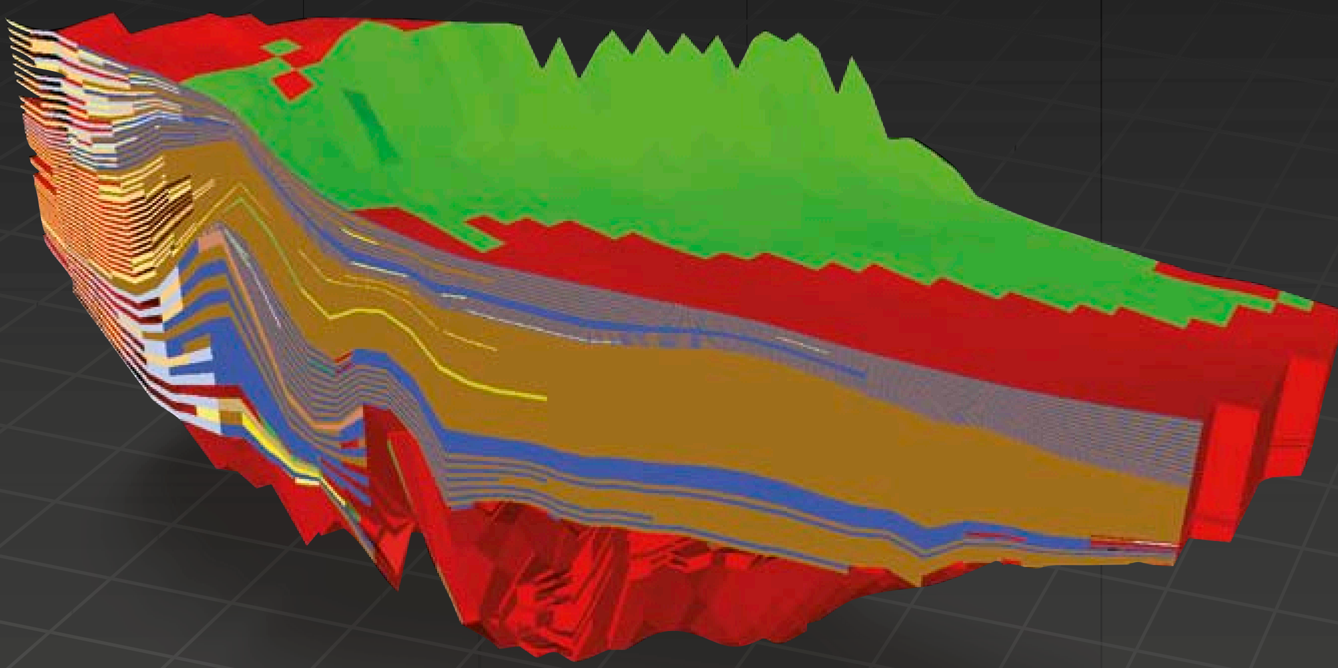
Modern and traditional methods coexist to steer the three Polarcus vessels and their support fleet through safe waters – from satellite technology to the expert pair of eyes of an ice pilot. Cass says: "Essentially, we used visual lookouts and electronic radar, as well as satellite images to ascertain the position and drift of the ice, in addition to monitoring currents, weather and knowing the exact positions of all of the towed equipment. From this information, safe traverse paths and escape routes were formulated collectively by the ice-coordinators, bridge and navigation teams."


Polarcus

Leave Only Footprints

Polarcus launched 2012 with a goal to lead by example and 'be the most environmentally responsible towed marine seismic service provider' – and its commitment really shows through when operating in fragile areas such as the Arctic.

"We take every precaution to prevent or minimize our environmental footprint," says Peter



Zickerman, Executive Vice President, Polarcus. "The *Asima's* double hull and its advanced bilge water cleaning system and ballast water treatment system reduce emissions to water down to a minimum. The vessel, like the other vessels in our fleet, runs on marine gas oil (MGO) with low sulfur content and has high specification exhaust catalysts. The vessel's X-BOW hull line design is another of its many green features, in that it reduces fuel consumption and therefore emissions to air."

The X-BOW also provides a safe, comfortable workplace. "The X-BOW's gliding movements allow us to relax and sleep uninterruptedly – a definite benefit for the people on board," says Cass.

There is life at the ice edge, with herds of muskoxen and walruses, pods of whales and narwhal, and much more. And Polarcus' primary goal is to conduct its surveying operations while protecting these very mammals.

Marine Mammal Observers (MMO) on each vessel stake a 24-hour lookout for all wildlife within visual distance of the vessel (see *GEO ExPro*, Vol. 9, No. 5) They monitor exclusion zones and record wildlife observations, map sightings and log identification and behavior information. Source 'soft-start' techniques warn marine mammals and polar bears of pending seismic operations and allow time for those animals to leave the area.

"Additionally, Passive Acoustic Monitoring (PAM) operators kept a constant vigil, listening and logging any acoustic noise that might be generated by cetaceans, using specially designed in-water listening equipment. This was especially useful in the hours of darkness," says Cass.

Land of Promise

Polarcus is simply translated as 'arc to the polar region', and *Asima* is derived from an Arabic female name meaning 'protector'. So, how apt for the *Polarcus Asima* to forge the path for seismic exploration in the Arctic while safeguarding this environmentally sensitive area.

The initial success of the Arctic projects has proved that there are no barriers of entry to this region. And, by performing its work cleaner and greener than the competition, Polarcus continues to set new standards for a traditionally 'black' industry. The data collected from the *Amani*, *Samur* and *Asima* are all that's been taken from this fragile corner of the world – that and some lasting memories of the Arctic's dazzling beauty.

Cass concludes: "I am in awe of what I have seen. My hope is that whatever happens here in the years to come, the beauty and mystique of the place will always remain. For all of us on *Asima*, it will be one of those trips we'll never forget." ■

To learn more about exploration for hydrocarbons in the Arctic and see more stunning photographs of the region, download the GEO ExPro iPad edition on the Arctic, available free from the Appstore.

Community Spirit

Upernavik in Greenland has all the bare essentials: rock and ice, sea and sky. Yet despite feeling like the last place on Earth to the survey crew, it is 'home' to just over 1,100 indigenous Greenlanders, Inuits.

To some degree it exists in a bygone era: halibut fishing is the main industry, hunting is the heart and soul of Greenlandic culture, and there are no roads or rail lines to nearby towns. But it is also progressive and modern: there is wireless broadband in most homes, Greenland has been self-governing since 2009 and the younger generation speaks both Danish and English.

The Inuits are economically and spiritually linked to the land, the sea and the wildlife it supports, and so it is important to move ahead sensitively with any Arctic exploration. The impact of more than 300 Polarcus crew and 12 vessels on this small town had to be kept to a minimum. Time was invested to engage the hearts and minds of the local community before the start of the project; Polarcus then used the expertise of indigenous people as MMOs and ice-coordinators.

"Asima's support base in Upernavik provided a first-hand face to our operations, ensuring that the local people were kept informed and engaged in the project," explains Cass. "It is important that the people feel that this work is being carried out as part of a long-term effort that will benefit them."

Polarcus

neptunecanada

Gas Hydrates

PART IV: WHERE ARE GAS HYDRATES FOUND?

The need for energy is driving much of the current natural gas hydrate research.

A remote-controlled vehicle, known as an 'osmosampler', retrieves samples from a gas hydrates mound in Barkley Canyon, May 18th, 2010.

LASSE AMUNDSEN, MARTIN LANDRØ and THOMAS REICHEL

"While research on methane hydrates is still in the early stages, these research efforts… could potentially yield significant new supplies of natural gas and further expand US energy supplies."

On August 31, 2012 US Secretary of Energy, Dr. Steven Chu, announced an investment of $5.6 million in research on methane hydrates.

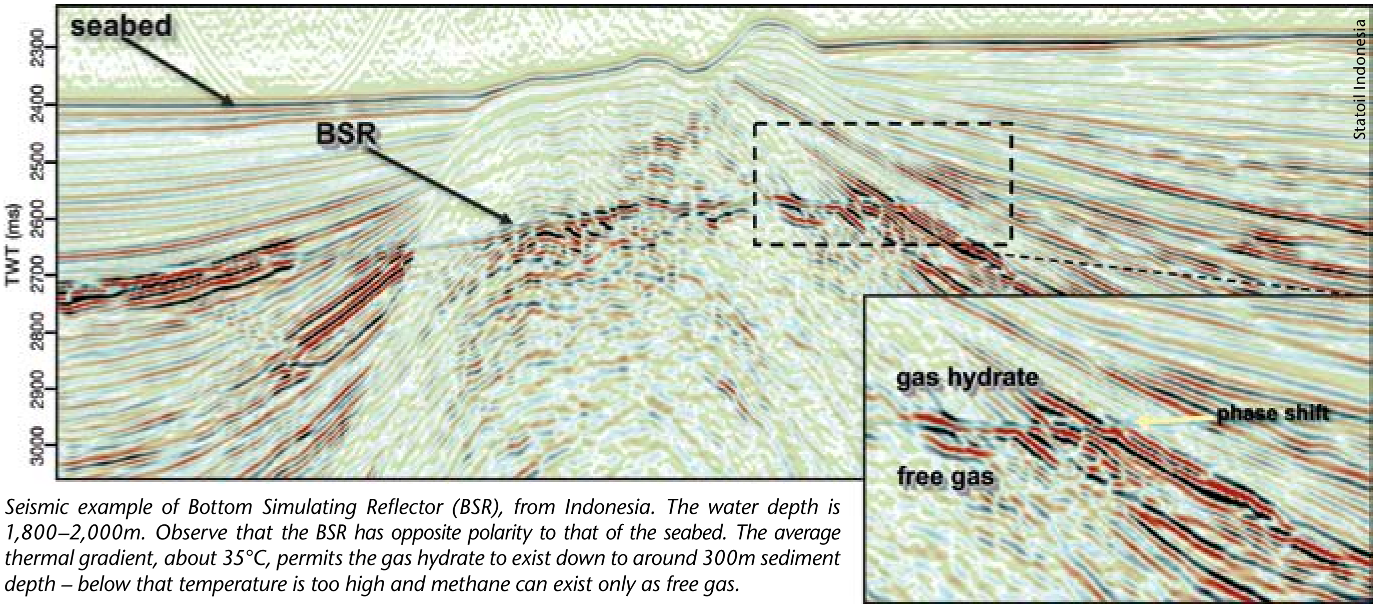
From Part I (*GEO ExPro* Vol. 9, No. 3) of our series on gas, the key learning is that four 'magic ingredients' must be present for gas hydrates to exist. They form when there is a sufficient supply of water and gas, predominantly methane (99%), at relatively low temperatures and high pressures, with temperature and pressure in the so-called Gas Hydrate Stability Zone (GHSZ), *(see box, p34)*. Favourable hydrate formation conditions exist off the coasts on the continental margins and below the permafrost.

In marine settings, temperature is controlled by the ocean bottom water temperature and the geothermal gradient at any given location, while pressure is controlled by sea level. In aquatic sediment where water depths exceed about 300m and bottom water temperatures approach 0°C, gas hydrate is found at the seafloor to sediment depths of about 1,100m. The general temperature range is from 2 to 20°C.

In a permafrost setting, however, temperature gradients are considerably lower than in the ocean. The ambient temperature and the thickness of the permafrost layer therefore are of significant importance for the stability of gas hydrate. In polar continental regions, methane hydrate can occur at depths ranging from 150 to 2,000m, with a general temperature range from -10 to 20°C.

Bottom Simulating Reflector (BSR)

The geothermal gradient is important. At a certain depth in ocean sediment the geothermal gradient makes the sediment too warm



Seismic example of Bottom Simulating Reflector (BSR), from Indonesia. The water depth is 1,800–2,000m. Observe that the BSR has opposite polarity to that of the seabed. The average thermal gradient, about 35°C, permits the gas hydrate to exist down to around 300m sediment depth – below that temperature is too high and methane can exist only as free gas.

to support the solid gas hydrates, so any methane produced below this depth will be trapped as a layer of free gas in the pore space beneath the solid gas hydrate layer. Often, but not always, the interface between the gas hydrate and the free gas is an anomalous seismic reflector called a Bottom Simulating Reflector (BSR), as this reflector necessarily is roughly parallel to the seafloor morphology along isotherms. BSRs therefore need not follow the trend of stratigraphic horizons, but may intersect them.

In seismic sections, BSRs are usually characterized by large amplitudes but exhibit reversed polarity compared with the sea-bottom reflection.

The BSR indicates the lower boundary of gas hydrate stability. Consequently, gas hydrate is often assumed to exist above the BSR; otherwise, the free gas below the BSR would have migrated upwards. But, while a BSR does illustrate the volume of sediment inside the stability zone it does not provide information on the actual hydrate saturation in-place. BSRs can be observed even when very little hydrate is present, and BSRs need not always be observed in hydrate-bearing sediments.

Exploration for Gas Hydrates

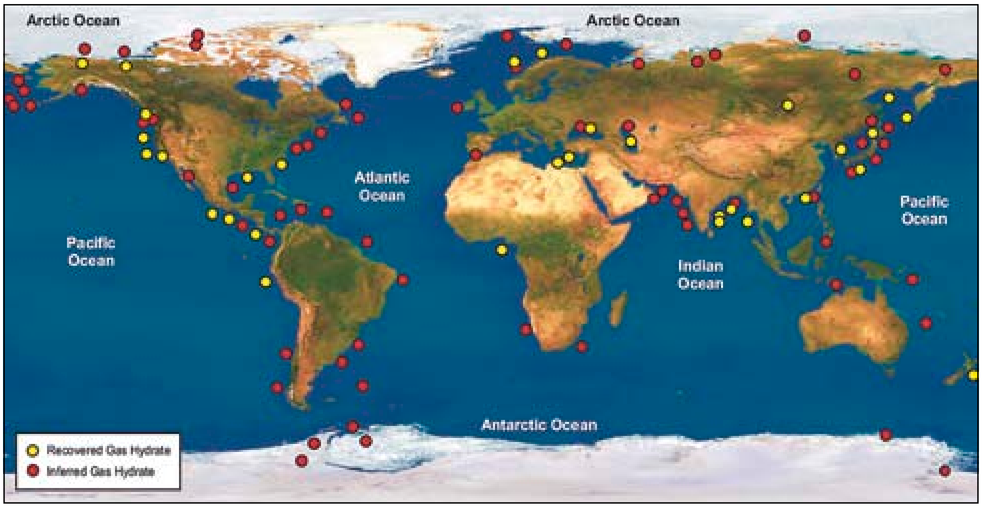
To date, around 100 sites have been identified as containing gas hydrate deposits. Samples have been taken at approximately 20 different sites, while at another 80 sites the existence of gas hydrate has been suggested by seismic evidence, in the form of BSRs.

Exploration for gas hydrates is not much different from exploration for conventional hydrocarbons: important factors to recognize are source, migration, reservoir, and seal.

If there is not sufficient gas supply, there will be no gas hydrates. Two distinct processes produce hydrocarbon gas: biogenic and thermogenic degradation of organic matter. Biogenic gas is formed at shallow depths and low temperatures, up to 75–80°C, by anaerobic bacterial decomposition of sedimentary organic matter. It is very dry and consists almost entirely of methane. In contrast, thermogenic gas is formed at deeper depths, much deeper than the GHSZ, in the temperature range 50–200°C by thermal cracking of sedimentary organic matter into hydrocarbon liquids and gas. This type of gas, which is common in conventional gas reservoirs, can be dry, or can contain significant concentrations of 'wet gas' components (ethane, propane, butanes) and condensate.

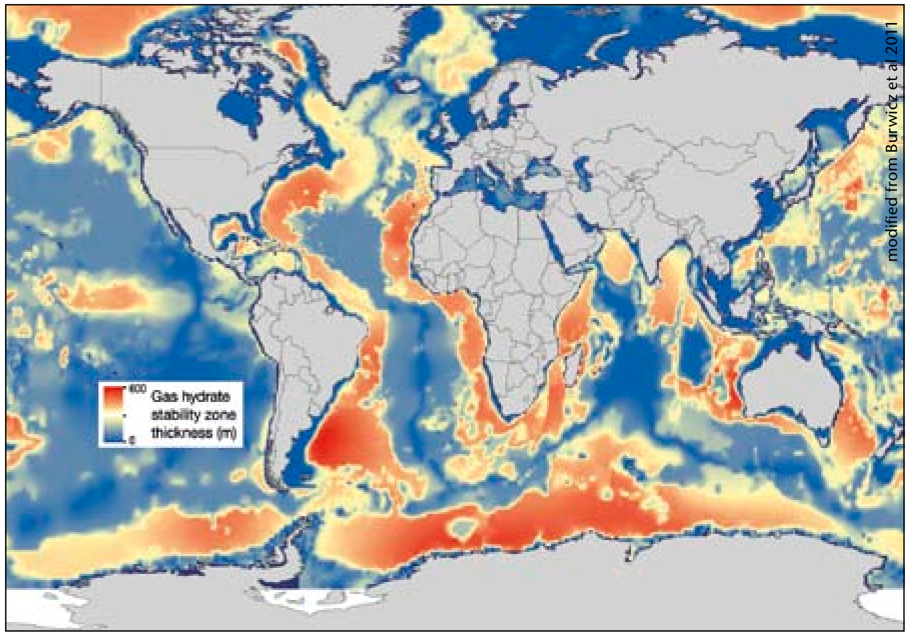
Fluid migration from the source through faults, folds, and fractures into the GHSZ plays a critical role in the formation of a gas hydrate accumulation. Rapid gas transport is required to

Distribution of known methane hydrate accumulations. The yellow dots show where actual samples of gas hydrate have been recovered whereas the red dots show where gas hydrate occurrences have been inferred based on BSRs and well logs. It is evident that gas hydrates are found along most continental shelf and slope regions and in many permafrost areas. Hydrates have also been found in inland seas (e.g., Black Sea and Caspian Sea) and in fresh water lakes (Lake Baikal). (Courtesy of Council of Canadian Academies (2008), based on data from Kvenvolden and Rogers, 2005.)



concentrate gas in permeable reservoir sediments where gas hydrate crystallizes. Water transport is usually thought to be less important because water is virtually omnipresent in sediments, although it may be a limiting factor for gas hydrate crystallization in some areas. Sand-rich reservoir environments are better than clay-dominated systems. As far as seals are concerned, gas hydrates themselves are the seals.

The possibility of production from hydrates is highly dependent on the particular reservoir characteristics. Many of the known marine deposits are probably unfeasible for hydrate production. The candidates that are currently being explored are high concentration accumulations in coarse-grained sand environments with high porosity and permeability.

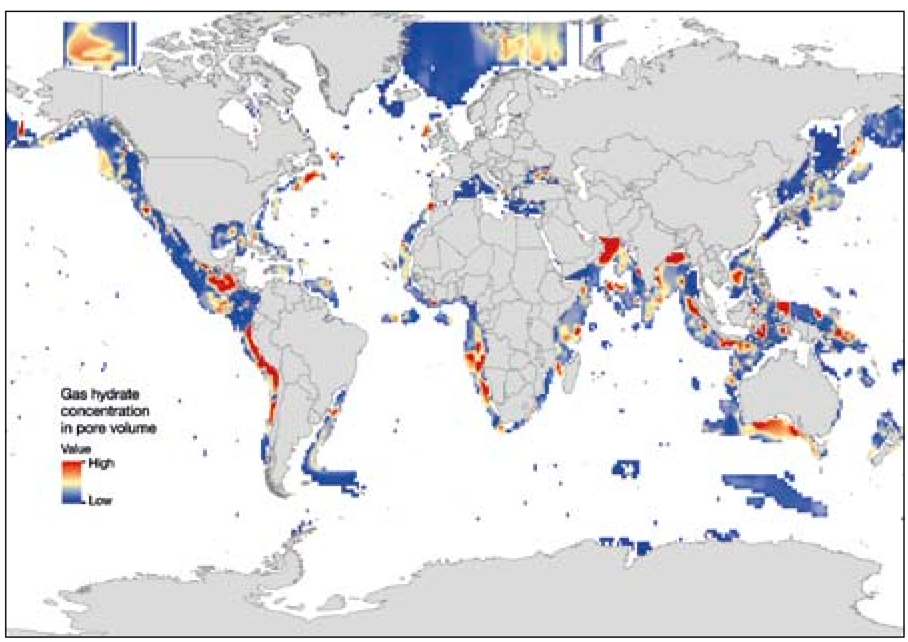


Predicted thickness of the global GHSZ. The thickest zones (600–800m) are mainly situated in high-latitude regions (Arctic and Antarctic) due to low bottom water temperatures which maintain conditions required for hydrate formation. Extended GHSZs are also observed along continental margins (>500m) where thick sedimentary sequences are deposited. In these settings the extent of the GHSZ is not limited by sediment thickness so that free gas can accumulate in sediments below it. Note that this definition of the global GHSZ gives an upper limit to possible gas hydrate occurrences.

Global GHSZ Thicknesses

Burwicz et al (2011) have calculated GHSZ thicknesses based on the global bathymetry, salinity, bottom water temperature, and heat flow (as a proxy to geothermal gradients as they are not globally available).

GHSZ thicknesses can be considered a proxy for potential hydrate deposits distribution but not necessarily for the real volume of hydrate-bearing sediments. The formation of hydrates is mainly controlled by methane supply either through the direct degradation of organic matter within the GHSZ or through an upward flux of deeper biogenic and thermogenic methane. Global estimates of methane fluxes from deep sediments are poorly constrained.



Gas hydrate saturation of the pore space, modified from Klauda & Sandler (2005)

Acknowledgement: *We would like to thank the Directorate General of Oil and Natural Gas at the Ministry of Energy and Mineral Resources of Republic of Indonesia for permission to show the seismic example.* ▶

The authors…

Lasse Amundsen is Chief Scientist Exploration Technology in Statoil. He is adjunct professor at the Norwegian University of Science and Technology (NTNU) and at the University of Houston, Texas.

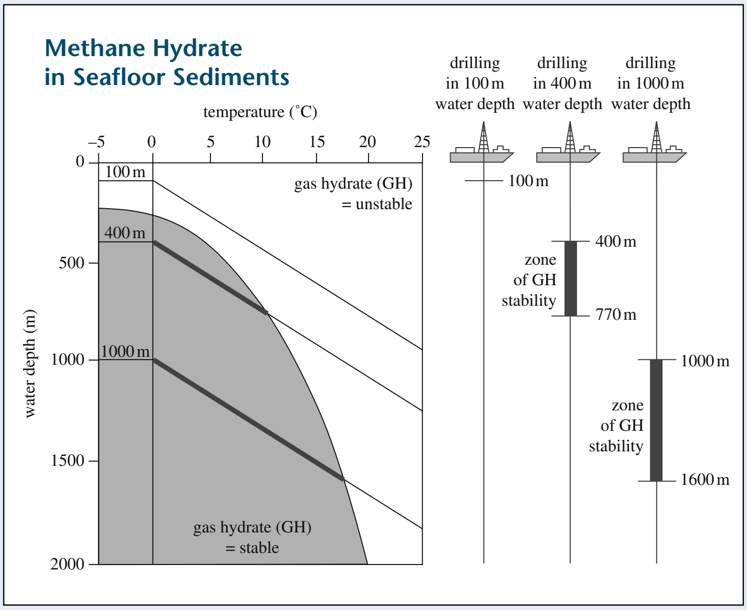
Martin Landrø is professor in Applied Geophysics at NTNU, Trondheim, Norway.

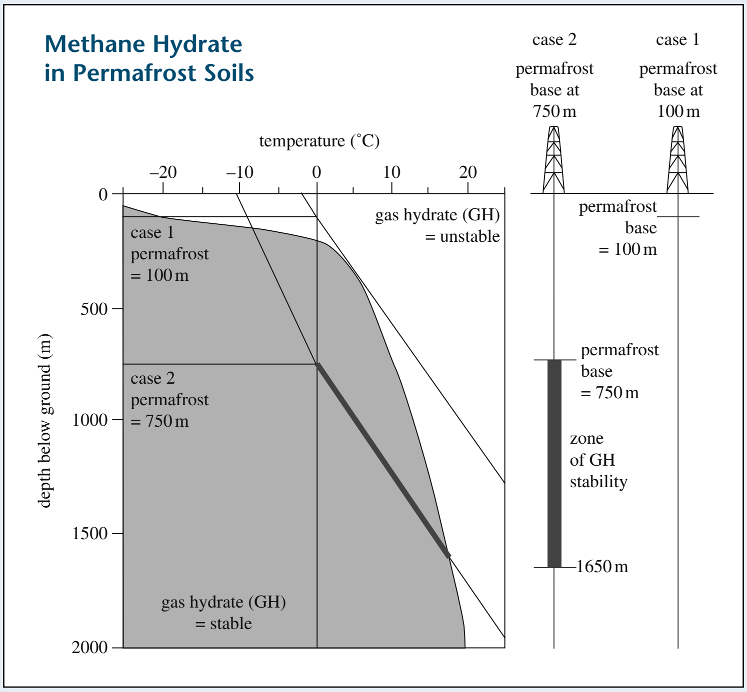
Thomas Reichel is a Global New Ventures Exploration Geologist in Statoil. He has previously worked as a Researcher at the BGR (Hannover, Germany) and as a Geophysicist at EMGS in Trondheim, Norway.

Gas Hydrate Stability Zone

The most common type of gas hydrate is methane hydrate and the conditions required for its stability can occur in marine sediments and in permafrost soil. The phase diagrams redrawn from Kvenvolden and Lorenson (2001) show the physical conditions (temperature and pressure) required for the stability of methane hydrate in the marine environment (top) and the permafrost environment (bottom).

First, we discuss the marine setting. Salty oceanic water can be no colder than about –1.8°C before freezing. Assume that you are in a polar region, where the sea bottom temperature is 0°C. Furthermore, assume that the average temperature increase is 3°C per 100m sediment depth. The figure then shows that methane hydrate cannot be stable at a water depth of 100m. But it may occur in a seafloor that is 400m below sea level. When drilling at a water depth of 400m, you can expect or hope to find a 370m thick hydrate layer. Beneath this depth the temperatures get too high for a formation of gas hydrate, so that free gas and water is found. For a case of 1,000m water depth, the hydrate layer will be 600m thick. Obviously, the thickness of the hydrate zone will depend on the temperature gradient. In sediments that display a stronger increase in temperature, which can be the case, for example, at active continental margins (4–6°C per 100m depth), the hydrate zone will generally be thinner.





Next, we look at the permafrost setting, where temperature gradients are considerably lower than in the ocean. Typically, the temperature can be expected to change by 1.3°C per 100m within the permafrost zone, and with 2°C per 100m in layers below the permafrost zone. The ambient temperature and the thickness of the frozen layer are therefore of significant importance for the stability of gas hydrate.

Consider the case where the base of the permafrost is at a depth of 100m or less. The figure shows that the physical conditions will not be adequate for the formation of gas hydrate. If the permafrost base is, say, at 750m, the thickness of the gas hydrate zone is 900m.

Since the stability of gas hydrates is related to relatively low temperatures and high pressure, any change in these two parameters can increase or decrease the stability of the gas hydrate. For example, if either the temperature is increased or the pressure is reduced, the gas hydrate will change phase from a solid to a gas and liquid.

Gas hydrates are not chemical compounds since the sequestered molecules are never bonded to the lattice. The formation and decomposition of hydrates are first-order phase transitions. However, the detailed formation and decomposition mechanisms are still not well understood on a molecular level.

References:

K. A. Kvenvolden and T. D. Lorenson 2001. The global occurrence of natural gas hydrates. In Natural gas hydrates: occurrence, distribution and detection (eds C. K. Paull & W. P. Dillon) AGU Geophysical Monograph 124 3–18

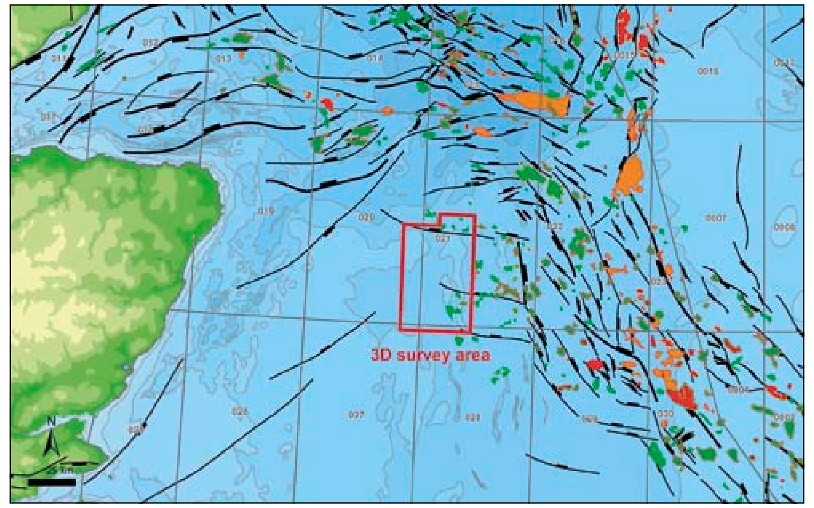
E. B. Burwicz, L. H. Rüpke, and K. Wallmann 2011. Estimation of the global amount of submarine gas hydrates formed via microbial methane formation based on numerical reaction-transport modeling and a novel parameterization of Holocene sedimentation: Geochimica et Cosmochimica Acta 75 4562-4576

Klauda J. B. Sandler S.I. 2005. Global distribution of methane hydrate in ocean sediment. Energy Fuels 19:459–70

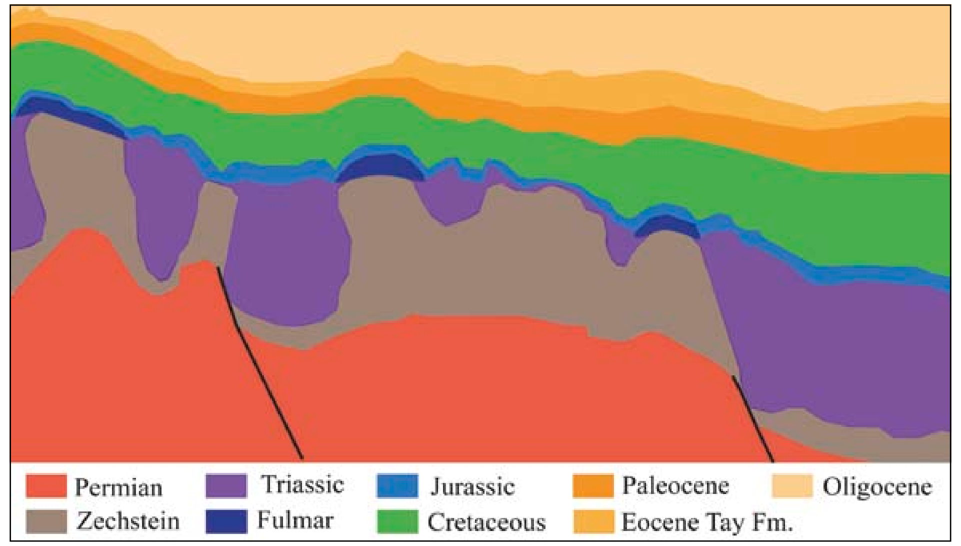
Western Margin of UK Central Graben

The multiclient 3D UK Q20/21 fast track dataset from the West Central Shelf (previously Blakeney) considerably improves the understanding of distribution of hydrocarbon reservoirs and migration pathways. The main targets for the 3D dataset are the Upper Jurassic Fulmar Formation, Paleocene and Eocene channel-fan complexes. The 3D data was acquired using a cable length of 6,000m, enabling very good imaging of the Mesozoic and Cenozoic sedimentary successions.

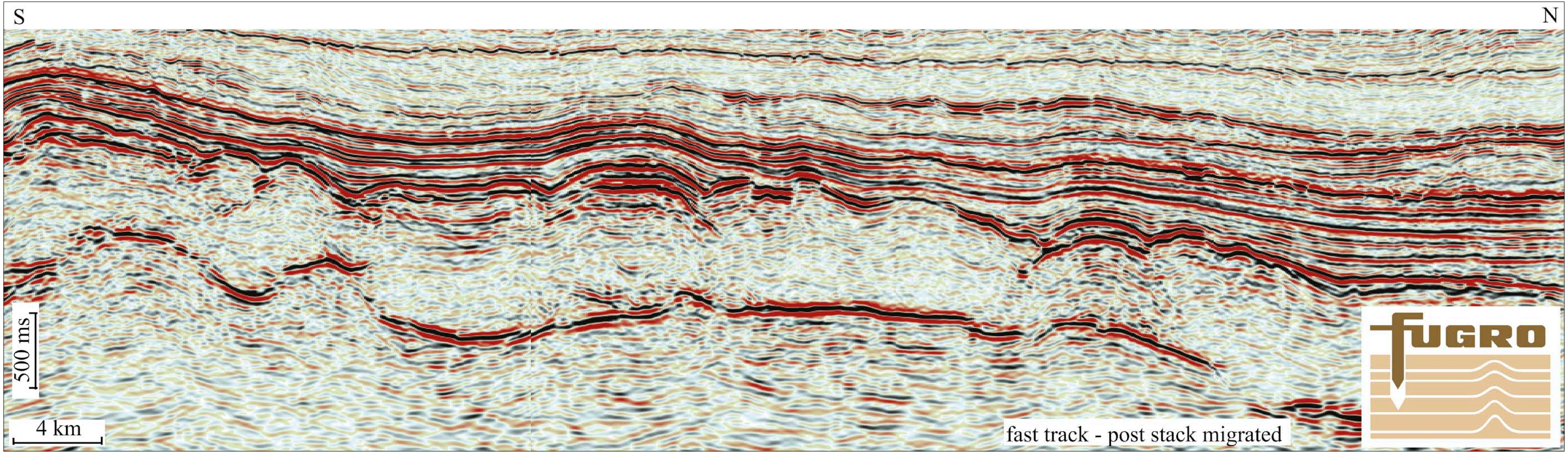
New Multiclient UK Q20/21 Survey Provides Insight into Proven and Emerging Plays



The 3D survey covers parts of the western margin of UK Central Graben; UK Q20/21.



Geoseismic representation of an inline within the 3D fast track cube.



New and Proven Plays

The recent successful Blakeney discovery in UK Q21 improves the potential for more successful discoveries on the West Central Shelf

**ERLEND M. JARSVE, BRIT I. THYBERG, CHARLOTTE MOSS, ANTONY PEDLEY*
and SVERRE BERSTAD*; Fugro Multi Client Services**

As the recent 27th UK licensing round demonstrates, the West Central Shelf remains one of the most interesting hydrocarbon provinces in Europe. The high resolution multiclient fast track UK Q20/21 3D, together with recent discoveries, opens up new and promising hydrocarbon exploration and revisits proven plays. The new high resolution long-offset 3D seismic data enhance the understanding of reservoir distribution and hydrocarbon migration.

Geological Overview

The West Central Shelf represents the western platform relative to the Central Graben. The area is filled with Mesozoic and Cenozoic sedimentary successions, which were deposited prior to and after the Late Jurassic rifting event. Only minor extension took place in the West Central Shelf during the Late Jurassic rifting event, excluding the well known rift play as characteristic for most of the North Sea petroleum province. Also, large parts of the Triassic and Jurassic successions are missing due to Late Jurassic erosion. The Zechstein evaporites had a significant control on sedimentation in both middle to late Triassic and in Late Jurassic times. Eastwards and south-eastward progradation from East Shetland Platform, and deposition of significant amounts of sand took place in the Paleocene and Eocene times. This has given rise to some of the greatest oil fields (e.g. Forties field) in the nearby area, with inversion along salt diapirs in Late Paleogene times creating structural traps.

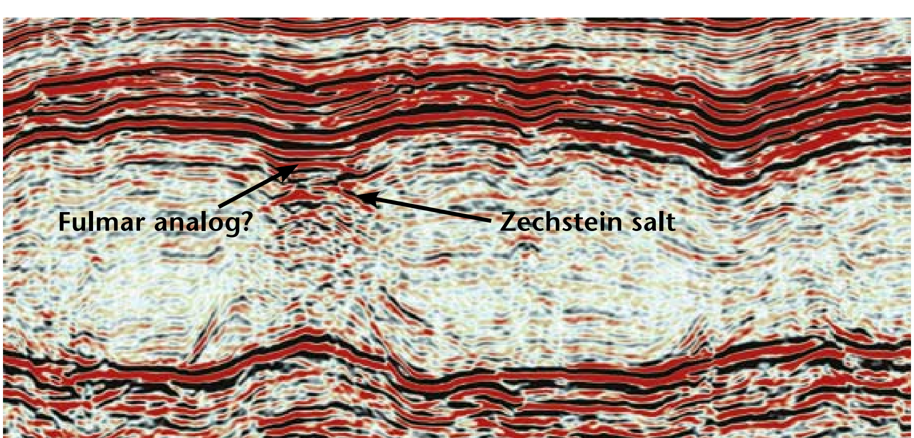
The new multiclient 3D dataset is situated within UK quadrants 20 and 21. Several of the largest UK oil and gas fields are producing in the West Central Shelf area, including Kittiwake, Durward, Dauntless, Forties, Nelson and Goosander. Although the West Central Shelf is considered a mature hydrocarbon province, recent discoveries in the Eocene succession, such as the Blakeney field, have proven the potential of discovering more high quality reservoirs in the area. The main targets within the 3D survey area are the Upper Jurassic Fulmar Formation, Paleocene marine and Eocene channel-fan complexes. The Upper Jurassic and Eocene plays are already proven commercial driven plays, but less interest has been shown in the emerging Paleocene play.

Hydrocarbon Potential

The new acquired dataset reveals three main reservoir levels in the UK Q20/21 survey area, all of which have the potential for trapping hydrocarbons in structural and stratigraphic traps. These are the Late Jurassic, Paleocene and Eocene sedimentary successions. In addition, Early Cretaceous and Triassic may be producible across large parts of the survey area. The source rock is believed to be the Upper Jurassic Kimmeridge Clay Formation, with migration from the Central Graben. Long migration pathways have been demonstrated to work along the Dauntless-Kittiwake-Mallard trend in the northern part of quadrant 21 and on the eastern side of the Central Graben (e.g. Siri, a Paleocene discovery). Producing fields just east of the survey area show that the Kimmeridge Clay is mature and may involve potentially shorter migration pathways.

The new high resolution long-offset UK Q20/21 seismic dataset enhances the understanding of reservoir distribution and hydrocarbon migration in the area, allowing evaluation of both proven and emerging plays. ■

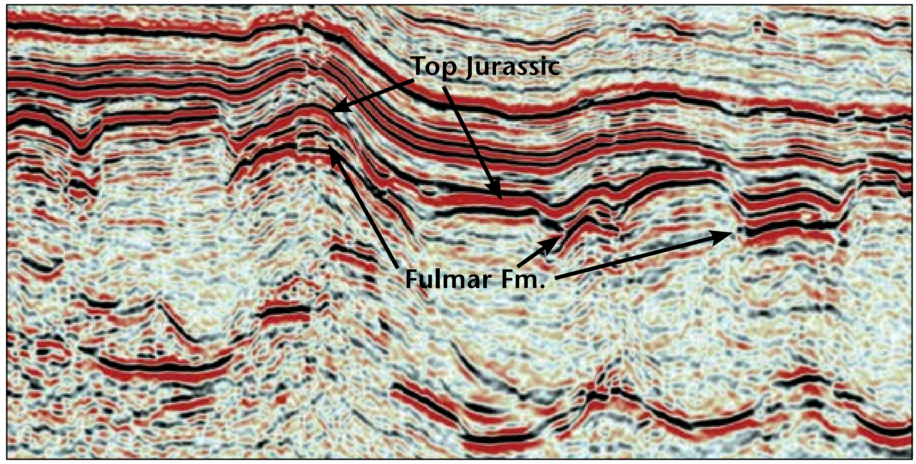
This project was carried out in conjunction with Dolphin Geophysical.



Analog Jurassic Play on the Norwegian Continental Shelf

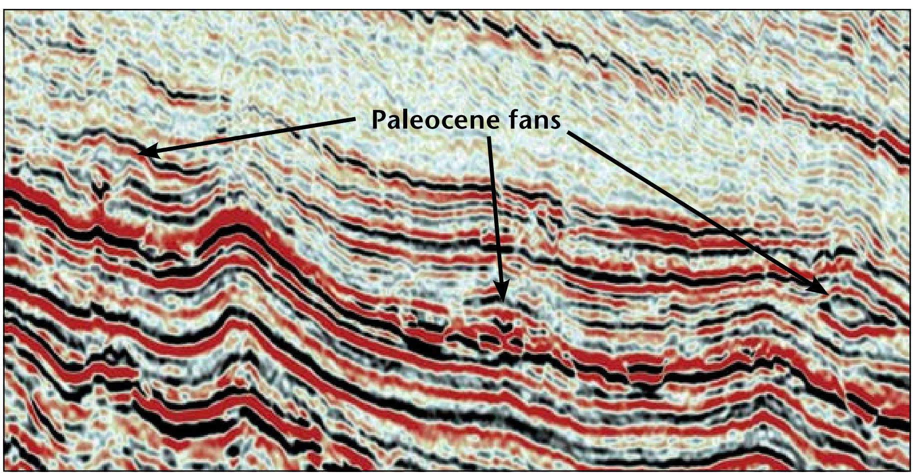
The Upper Jurassic has been explored throughout the last decades on the Norwegian Continental Shelf. By utilizing datasets acquired by FMCS, a Fulmar analog has been identified. This play remains to be tested on the Norwegian Continental Shelf and requires new high resolution 3D data to increase the understanding of the reservoir distribution and hydrocarbon migration.

Jurassic Play: Fulmar Formation – salt dissolution creating accommodation space



The geological model for the Upper Jurassic interval suggests that Fulmar sand distribution was largely controlled by pre-existing topography (Stewart et al., 1999). Salt dissolution took place within salt structures in Late Jurassic time, creating accommodation space, whereas Triassic mini-basins acted as barriers. Here, shallow marine/shoreface sedimentation prevailed throughout Late Jurassic, with irregular deposition of the Fulmar Formation. The Fulmar sands represent one of the most important proven and emerging hydrocarbon reservoirs in the Central North Sea, UK, including discoveries in several nearby oil fields (e.g. Kittiwake, Durward, Dauntless). Predicting and interpreting the Fulmar sand distribution has often been problematic throughout the basin, especially so on the West Central Shelf (Stewart et al., 1999).

To date, the wells that have drilled the Fulmar Formation in the survey area have targeted four way dip closures above the salt structures. However, the new dataset shows that significant parts of the Fulmar Formation are also likely to be present in stratigraphic traps above salt structures which have not been remobilized. A thorough interpretation of the stratigraphic traps requires high resolution 3D seismic. A complete interpretation and mapping of the Late Jurassic Fulmar Formation and its irregular sand distribution is possible, revealing the potential for several more hydrocarbon prospects by utilizing the new dataset.

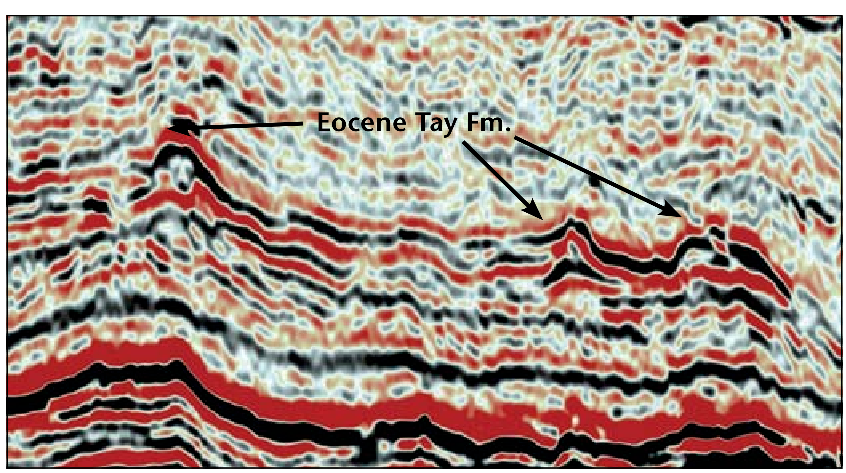


Paleocene Play

The Paleocene play on the West Central Shelf includes deep marine fan complexes which were sourced from the East Shetland Platform area in the north. Traditionally, the Blakeney area has been considered to be too distal relative to the East Shetland Platform for deposition of sands with good reservoir quality. However, utilizing the new high resolution UK Q20/21 3D dataset, deep marine channel-fan complexes are identified within the survey area. Clinoform geometries are observed in the eastern part of the 3D area, invoking the potential for a more proximal source area to the west. Differential compaction and Paleogene salt diapirism develop robust closures reflecting potential for both structural and stratigraphic traps.

Eocene Play: Tay Formation

In the Eocene, major progradation took place in the southern parts of the survey area, with sediment dispersal eastwards and north-eastwards. A complete shallow marine – channel – deep marine fan system is mapped out on the 3D survey with large potential for trapping hydrocarbons in different sedimentary facies. Differences in amplitude strength reveal numerous deep marine channel-fan complexes within the survey area. Less than ten wells have been drilled over the northern part of the area with the Eocene succession as the target, constraining the depositional model. Most of these wells were dry, allocated to the lack of understanding of hydrocarbon migration pattern. Interpretation of the new 3D dataset indicates westwards migration, giving rise to the possibility of more successful drilling in the future.



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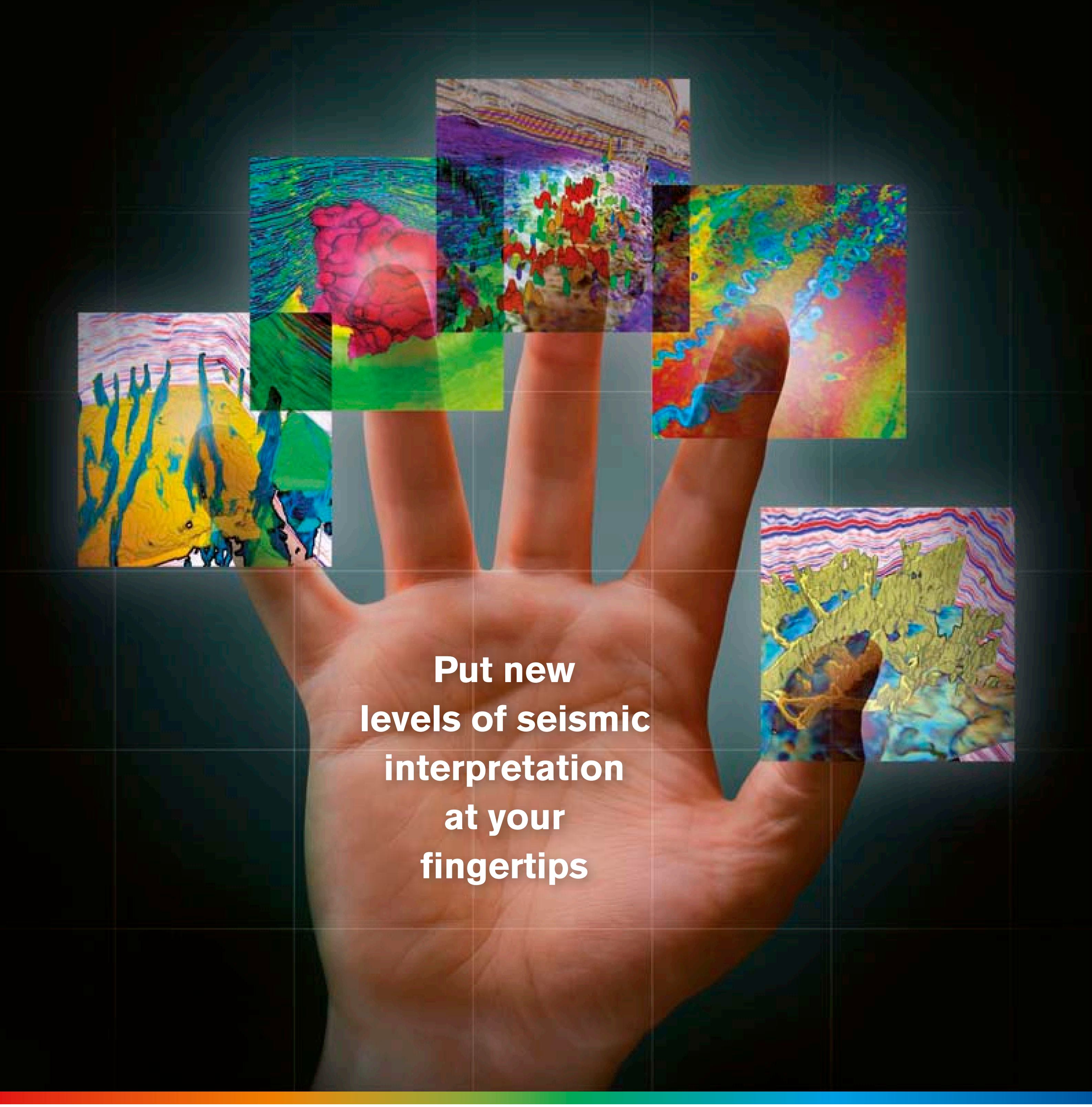
**Anthony Pedley FMCS UK:.Email: a.pedley@fugromcs.co.uk, Tel: +44 (0)1491 820602 / Mob: +44 (0) 797 019 3993. Web: www.fugromulticlient.com*

**Sverre Berstad FMCS Norway: Email: s.berstad@fugro.no, Tel: :+47 2213 4611 / Mob: +47 9961 761. Web: www.fugromulticlient.com*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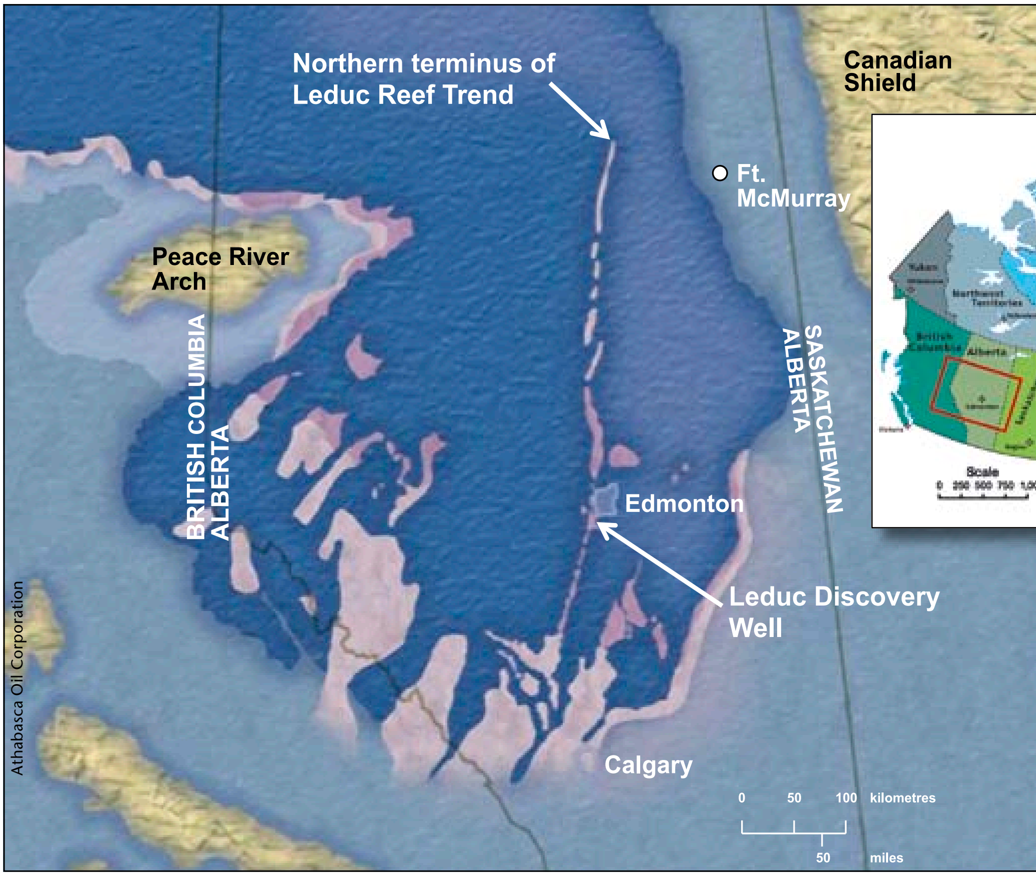
Heavy Oil from an Ancient Reef

New data from the northern terminus of the Leduc reef trend in western Canada shows a karsted carbonate reservoir with exceptionally high porosities and permeabilities and, in places, bitumen-filled caves. This area is a prime prospect for bitumen development and a new technique, thermal assisted gravity drainage, is being used to recover the hydrocarbons.

EUGENE A. DEMBICKI and **TOM J. PODIVINSKY**
Athabasca Oil Corporation, Calgary, Canada

A very porous reef containing bitumen-filled caves is enough to get anyone excited about exploring an area. This bitumen (inset photo on right) was recovered from an ancient, subsurface cave along the northern end of the Devonian Leduc reef. The Devonian Cairn Formation which outcrops near Canmore, Alberta, Canada exhibits caves and vuggy porosity very similar to that found in the subsurface at the northern terminus of the Leduc reef.

Athabasca Oil Corporation



Devonian paleogeographic map of the Leduc reef trend. The initial discovery well was located just south-west of Edmonton, Alberta in the Rimbey-Meadowbrook reef trend.

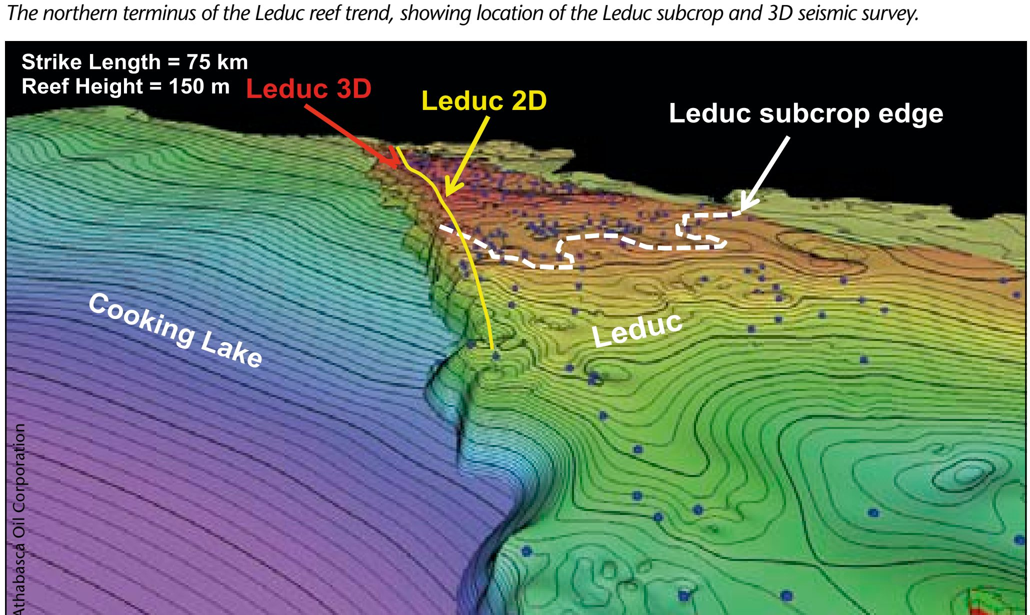
The 1947 Imperial Oil Leduc No. 1 discovery near Edmonton, Alberta ushered in a new and modern era for oil exploration in Alberta. The oil discovery was in a north to north-east Late Devonian reef trend that extends over 480 km across central Alberta. More discoveries of light gravity oil followed along the trend with recovery rates exceeding 80%. About one quarter of Alberta's recoverable conventional oil reserves have been found in the Leduc Formation carbonates.

The northern terminus of the reef trend is about 100 km north-west of Ft. McMurray, Alberta, where this reef subcrops beneath the well-known Cretaceous oil sands reservoir, the McMurray Formation of the Athabasca deposit. This deposit contains the world's largest accumulation of hydrocarbons, estimated at 1.7 trillion barrels that are primarily bitumen: a heavy, viscous oil. The porosity in the underlying reef trend in this area is also filled with this very heavy oil and new data has confirmed excellent reservoir quality. Athabasca Oil Corporation is currently testing a unique recovery method called Thermal Assisted Gravity Drainage (TAGD) for this portion of the reef.

Northern Terminus of Reef

The northern terminus of the Leduc reef trend has been poorly understood because of the limited well control and the lack of core information. However, recent exploration activity is providing new subsurface information that has made it possible to characterize the Leduc's reservoir potential in this area.

The northern terminus of the Leduc reef trend, showing location of the Leduc subcrop and 3D seismic survey.



A typical comparison between the producing trends to the south and the northern subcrop area. Both are excellent reservoirs with the enhanced porosity and permeability seen clearly in the core pictured at the bottom.

Light Oil Leduc

Wizard Lake

Pool Average:
Porosity: 5.5%
Kmax : 1,270 md
R.F.: 85%

Peak Well Rate:
13,000 bpd

Imperial 5-22-48-27W4

Bitumen Leduc

AOC

Pool Average:
Porosity: 15%
Kmax : 2,870 md
R.F.: ?

Peak Well Rate:
?

Leduc in northern Alberta has higher porosity & permeability than reefs in Rimbey-Meadowbrook reef trend (KARST)

AOSC 6-8-95-18W4

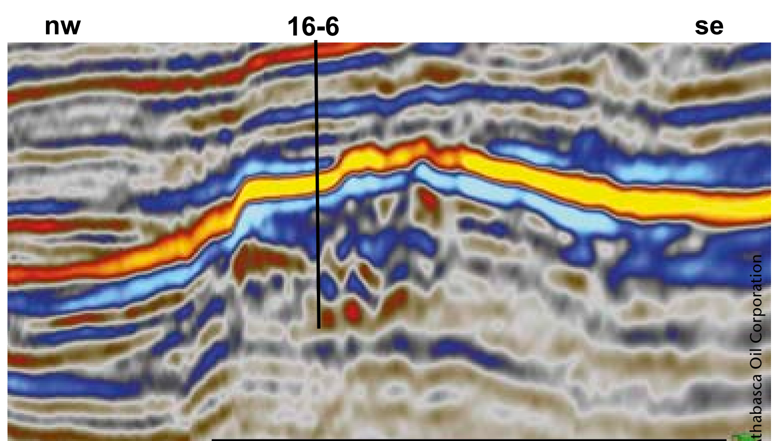
Athabasca Oil Corporation

Similar to the Leduc reefs in south-central Alberta, the Leduc Formation in north-eastern Alberta has excellent reservoir properties. Typical Leduc reservoirs are characterized by original vuggy and moldic porosities in a high permeability dolostone. The big difference is that this already excellent reservoir has been enhanced by karst-related dissolution near the subcrop area in north-eastern Alberta. This ranges from large vugs, bitumen-lined sub-vertical to vertical fractures and to the extreme cases where metre-size caves are filled with bitumen. CT scans of cores reveal the spatial connectivity of porosity and fractures in three dimensions.

A Karsted Reef on Seismic

Initial 2D seismic mapping clearly defined the western reef front, and additional 2D seismic along strike confirmed a single, continuous reef complex that extends over 100 km. This is in contrast to the many separate reef buildups encountered in central Alberta. Detailed 3D seismic has greatly enhanced the reservoir understanding by imaging the real distribution of karsted collapse features, and distinguishing between the fore-reef, reef crest and back reef.

3D seismic has proved a very good porosity predictor. Core-calibrated porosity logs are used in conjunction with dipole sonic data to forward model seismic response. The seismic data is used to derive rock mechanical properties away from well control and to produce a deterministic porosity volume which can be used in the modeling of the reservoir.



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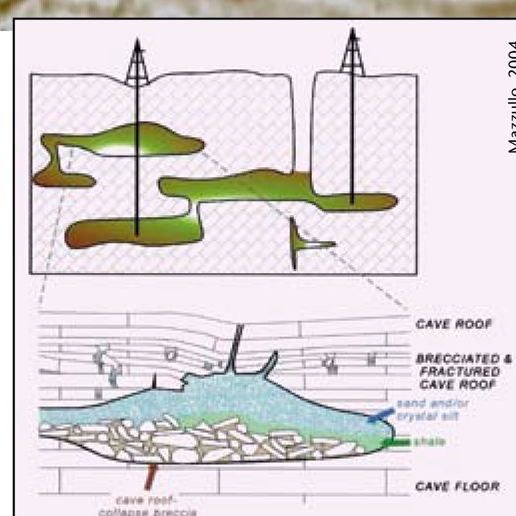

Mazzullo, 2004

The 3D imaging clearly shows karsted features along the reef and, in this case, several interconnected caves.

Reference: Overview of Porosity Evolution in Carbonate Reservoirs in Kansas Geological Soc. Bull, V 79, no. 1 and 2, S. J. Mazzullo, 2004.

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Producing the Heavy Oil

Athabasca Oil Corporation has developed the thermal assisted gravity drainage (TAGD) method for the in-situ recovery of bitumen from these very porous carbonate reservoirs. TAGD uses minerally insulated electric conduction heaters installed in horizontal wells to heat the reservoir and bitumen gently through thermal conduction. Athabasca is using the conduction heaters to heat the reservoir to 140–160°C. At that temperature, the viscosity of the bitumen is similar to medium crude oil. Via gravity drainage, the bitumen flows to the bottom of the reservoir and is then recovered by the horizontal production wells.

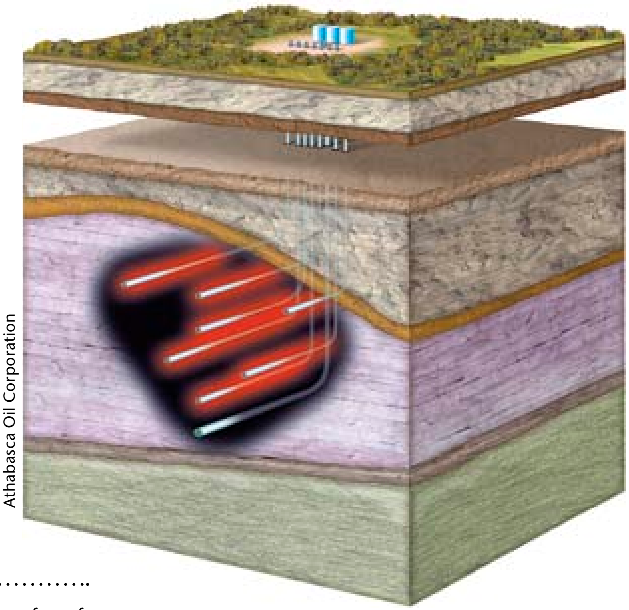
This process offers several advantages over steam assisted gravity drainage (SAGD) in the carbonates. First of all, this gentle technique heats both the matrix and the bitumen evenly, allowing for efficient gravity drainage in this fractured and complex reservoir. Secondly, internal drive and voidage replacement is provided by in-situ vaporization of water and gas expansion through the recovery process. Finally, one of the most attractive aspects of the TAGD process is that there is no steam plant or water processing infrastructure required which results in a large upfront capital savings for the project. ■

Depositional Setting

The Devonian Woodbend Group consists of a sequence of carbonate reefs (Leduc Formation) and platform carbonate units (Cooking Lake and Grosmont Formations), that were deposited with shale (Ireton Formation) and basinal organic rich shale (Duvernay Formation).

One of the most important reservoir rocks in the Woodbend Group is the Leduc Formation that developed on the regional Cooking Lake carbonate platform. The transgressive Leduc unit is made up of linear reef chains, isolated reefs and reef complexes, and an extensive shelf complex, not unlike the modern day Caicos Islands. In places, stacked Leduc reefs exceed 275m in thickness. Extensive dolomitization has enhanced the porosity of these rocks. The kerogen-rich source rocks of the basinal Duvernay Formation generated the majority of the hydrocarbons found within the Upper Devonian carbonate reservoirs. These shales are now shale oil and gas targets.

The TAGD recovery process for carbonate reservoirs will provide reservoir-wide heating and should lower operational costs. Proof of concept is underway and construction of the first pilot is scheduled to start in 2014.



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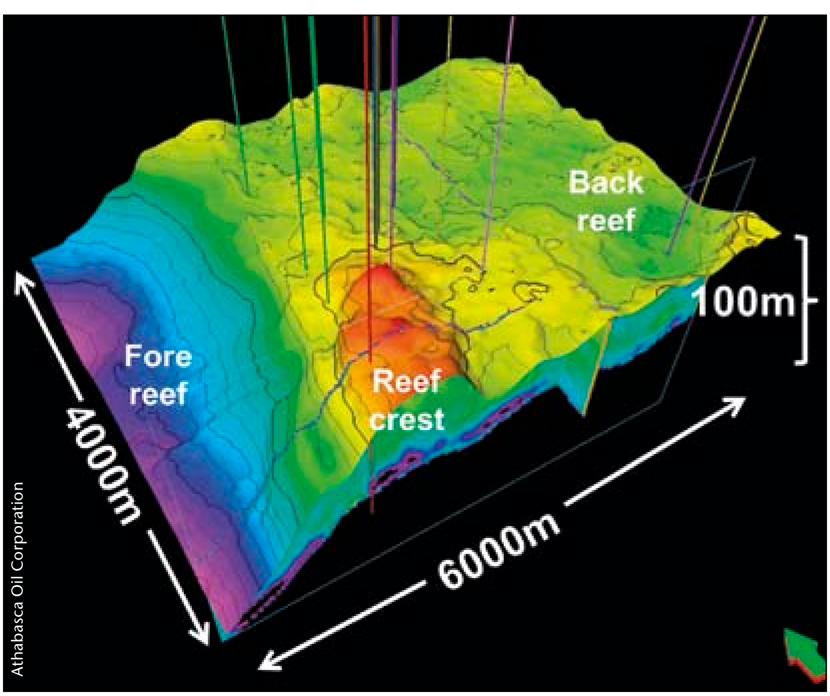
The 3D Leduc surface from seismic showing well control and location of the fore-reef, reef crest and back reef facies.



Athabasca Oil Corporation

Athabasca Oil Corporation

Athabasca Oil Corporation was founded in 2006 as an Alberta, Canada-based company focused on the sustainable development of oil sands in the north-eastern Alberta Athabasca region and light oil resources located in north-western Alberta. They are poised to be producing 220,000 barrels of oil equivalent per day by 2020, about half from their Thermal Oil Division and the other half from their Light Oil Division.

The Thermal Oil Division is currently involved in five project areas that include over 9.2 billion barrels of contingent resources. Commercial production is expected in 2014. The Light Oil Division has three initial development areas that are targeted to be producing 10,000 – 11,000 boe/d by the end of 2012 using horizontal drilling and multi-stage hydraulic fracturing technology.

For more information see www.atha.com

Understanding the Zagros

ANDREW HORBURY

The Zagros fold-thrustbelt is one of the oldest studied and exploited petroleum provinces of the world, yet for mostly political reasons it has not been fully developed and its exploration has generally taken place in a very piecemeal fashion. Attempts are now being made to develop play concepts that may encompass the whole orogenic belt.

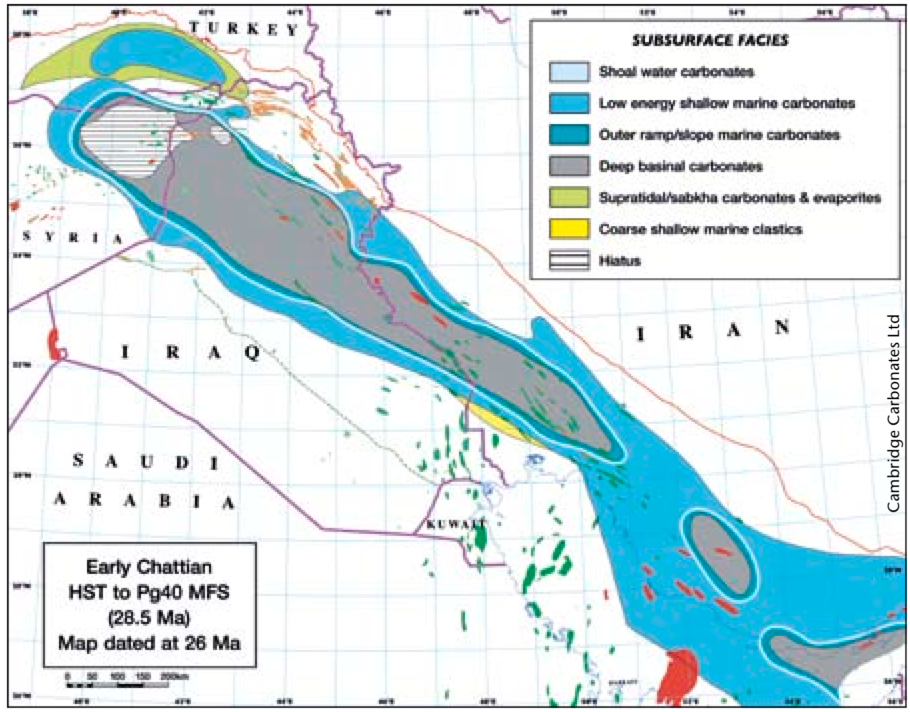
Asmari carbonates above Pabdeh marls, Tang-e Gurguda, adjacent to Gachsaran oilfield, showing progradation of slope systems from top left down to bottom right. These Oligocene-age carbonates form the main shallow reservoir system of the Masjid-i-Suleiman, Kirkuk and Gachsaran fields, amongst others.


Neil Pickard

Aside from historical occurrences of extraction of petroleum from the basin, the initial modern commercial discoveries of petroleum in Iran (then Persia) at Masjid-i-Suleiman in May 1908 and Iraq (Kirkuk, October 1927) marked the beginning of a period of prolific development. Production was initially from Cenozoic reservoirs and during this early phase of exploration there was considerable interchange of pertinent information between the Iranian (mostly Anglo-Persian, later BP) and Iraqi operations (IPC, a consortium mostly comprising elements of the 'Seven Sisters').

Some remarkably insightful pieces of work, which can be considered industry 'firsts', emerged from the region during this early phase of work. Probably the most significant of these were Dunnington's (1958) review of the petroleum geology of northern Iraq, Henson's studies of larger benthic foraminifera (1948) and his 1950 paper on reef distribution as influenced by changes in relative sea-level, which preceded the Vail model by

24 years. Similarly, the pioneering use of microfacies and micropaleontology in calibrating reservoir-scale models of Oligo-Miocene carbonates of the region, pre-dating the carbonate microfacies 'classics' such as Wilson (1975) and Flugel (1982), was developed in the works of Thomas (1950) and van Bellen (1956). On a production scale, the history of the development of the Masjid-i-Suleiman field by Gibson (1948) is a remarkable account of the early trial-and-error development of the first-discovered field in the region; whilst later work of Daniel (1954) and McQuillan (1970s) on mesostructures has proven critical in the understanding of production-scale fracture networks.



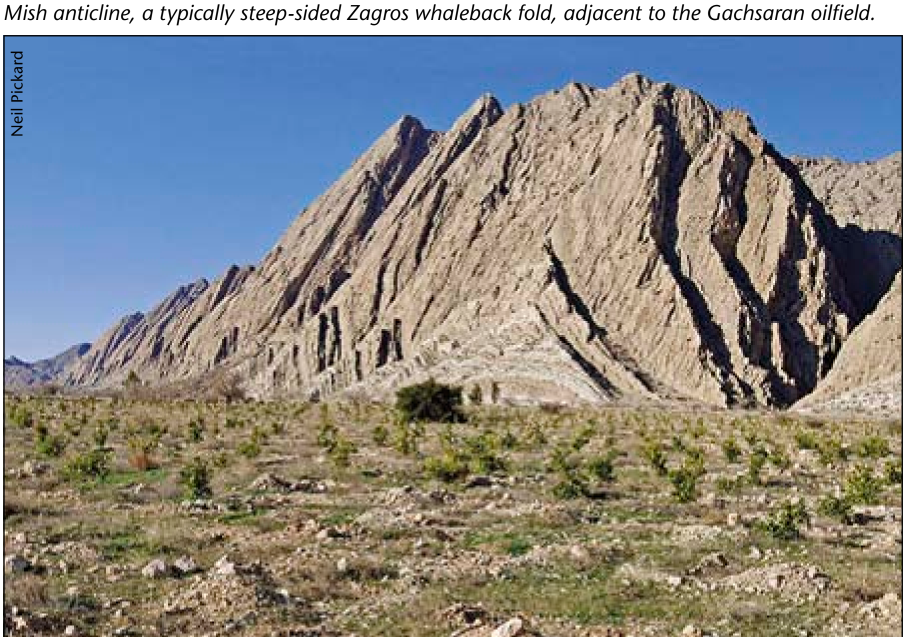
Mid-Oligocene palaeogeography 'Highstand above the Pg40 MFS of Sharland et al., 2001' showing extent of basin and adjacent shelf systems, produced by integrating data from the whole Zagros orogenic belt.

Complex Lithostratigraphy

During this phase, however, there was a tendency for over-complex litho-stratigraphic schemes to develop, that reflected differences between subsurface and outcrop, and the individual license areas. For example, in Iraq the Campanian-Maastrichtian shelf formations were named the Hartha and Tayarat in the Basra area and to the west, Pilsener in the Mosul area, but Bekhme and Aqra in outcrop areas of the Iraqi Zagros; all are essentially the same unit/facies. Formations of the same age in Iran and Turkey are named differently again. Any along-strike integration of models and nomenclature was cut short by the nationalization of IPC in 1961, and was then further hindered by the Iranian Revolution of 1979, followed by the various major conflicts in the region.

By this time, exploration had extended stratigraphically into the mid-Cretaceous reservoirs, of which the understanding was relatively good, but deeper Cretaceous, Jurassic and Triassic/Permian reservoirs were relatively poorly understood. Consequently, and particularly for these deeper formations, national industries tended to develop their own 'in house' models. There was also much re-naming of formations for political reasons (such as the Lower Fars Formation being re-named Gachsaran in Iran, and Fat'ha in Iraq) that often veered away from the possibly more integrated earlier stratigraphic models. Several events in the recent past have caused a reverse in this 'local' thinking. Firstly, the re-opening of the Iranian petroleum industry to western companies in the mid-1990s until the late-2000s, and the later opening of the Iraqi petroleum industry in the mid-2000s (ironically at a time when it was becoming more difficult to work in Iran). Added to this, a more plate-wide approach in terms of both fold-thrust belt tectonics and stratigraphy (e.g. Alsharhan and Nairn, 1997; Sharland et al., 2001) emerged at about the same time. Whole-country syntheses, such as Jassim and Goff (2006) and Aqrawi et al. (2010) have also assisted in regional-scale integration of data. In addition, the ability to build large map-based datasets in ArcGIS and Petrel has allowed a properly integrated view of the margin, possibly for the first time.

Mish anticline, a typically steep-sided Zagros whaleback fold, adjacent to the Gachsaran oilfield.



Inversion Structures

In terms of structural geology, a big factor

Pir-i-Mugrun Mountain in Iraqi Kurdistan, the significance of which to the understanding the Middle Cretaceous basin margin was first noted by Henson (1950). These carbonates and their Iranian equivalents of the Sarvak form a deeper reservoir system in the Jambur, Kirkuk and Gachsaran fields, amongst others.

that has proven to be of importance along the whole Zagros fold-thrustbelt is the absence of any significant long-distance overthrusting, or development of complex structures, like imbricated thrusted stacks with internal seals, which are successful in other fold-thrustbelts such as the gas plays of the Canadian Rockies. Most folds are very simple, steep-sided whalebacks. The consequence of this is that play types are relatively simple and rely upon the preservation of only one or two regional seals.

Another feature that has emerged relatively recently is that there are wide areas of the folded zone where anticlines have a largely inversion origin, after reverse movement of early normal faults of Triassic and/or Late Cretaceous age. Fields such as Ain Zalah (norh-west Iraq) and structures like Jebels Sinjar and Abd-el Aziz (north-west Iraq and north-east Syria respectively) fall into this category. Development of inversion structures has important consequences for play development because wells placed on the anticline crest are, by definition, testing former basin-center facies (e.g. the fractured basinal limestones that produce at Ain Zalah). Meanwhile, traditionally better reservoir facies may instead be developed on untested footwall blocks, where reserves could be present within stratigraphic or combination traps. Thus, a full investigation of the origins of individual structures may reveal many details that impact prospectivity; it should not be assumed that every structure is a purely late Neogene feature with no history of earlier deformation.

Significant Unconformities

The structural complexity of the Zagros belt and identification of major phases of generally extensional basin development and Cenozoic foreland basin evolution have important consequences for stratigraphic development and thus reservoir distribution. Basin extension occurred in the mid-Permian, intra-Triassic, mid-Jurassic and latest Jurassic/earliest Cretaceous, with strike-slip passing into more compressional basins during the late Cretaceous. By way of contrast to the ‘stable’ Arabian Plate interior stratigraphy of countries such as Saudi Arabia and U.A.E., the Zagros margin shows the development of many very significant unconformities. These both destroy reservoir potential by removing regionally-widespread reservoir and source rocks, such as much of the Middle and Late Jurassic, as well as provide new reservoir potential where karstification of carbonates has enhanced reservoir properties, as in the Oligocene reservoirs of the Kirkuk Field.

Indeed, it can perhaps be said that the major influence on much of the stratigraphy and petroleum potential of complex areas, such as northern Iraq, are the unconformities and the way they interact with structural development; and in the often thick and localized formations that were then deposited in the intervening basins. Thus, a lack of appreciation of the significance of these unconformities and consequent careless application of formation names has led to extreme confusion in stratigraphies that have been applied to some of the more recent wells, particularly in Iraqi Kurdistan. For example, on some Late Cretaceous fault footwalls, up to 2 km of stratigraphy can be eroded (note the blocks of Carboniferous or possibly older olistoliths sitting in the Maastrichtian basin fill of Jebel Abd-El Aziz in Syria); whilst lower-relief regional erosion has removed much of the Jurassic and later Triassic from regional paleohighs such as in the Khleisia-Mosul area.

Promising Iraqi Kurdistan

Probably of most interest to the oil industry at the present-day is Iraqi Kurdistan. Licensing here is undertaken in an environment that, in general, can be considered more favorable than has been offered in neighboring areas over the past fifty years, confirmed by the very high uptake in license areas and the general high level of activity. In terms of reservoirs and stratigraphy, Iraqi Kurdistan offers an interesting insight into the use of along-strike analogs because both the exploration history of south-

east Turkey and south-west Iran are relevant. Parts of the Turkish petroleum province extend into Iraq and indeed the 2006 Tawke discovery in northern Kurdistan can be seen as having more in common with some of the Turkish fields than with fields in adjacent parts of Iraq.

By contrast, the main part of Iraqi Kurdistan is proving to have much in common with many of the deeper Iranian plays, in that fields such as Kabir Kuh and Veyzenhar, which produce gas and condensate from Liassic-Triassic strata, clearly function in the Iraqi Kurdistan region. Recent discoveries have been reported from these reservoir units in the Miran West and Shaikan structures. Other plays that have proven to be worthwhile are shallower reservoirs at Pila Spi (Eocene) and Shiranish (Campanian-Maastrichtian) level, originally suggested by old discoveries considered sub-commercial, such as Chemchemal and Taq Taq. However, these only function properly in the outer parts of the foldbelt because they ideally require the presence of Lower Fars caprocks. In the inner parts of the foldbelt these are absent, so viable plays require lower regional seals – usually Middle–Upper Jurassic and Lower Cretaceous bituminous marls and shaly limestones – to be present and not breached.

Mountains near Erbil in Iraqi Kurdistan

Developing Play Concepts

Other reservoir types that have emerged in recent years include the regionally important hydrothermal dolomite bodies. The importance of these was first recognized in Iran, with the discovery and appraisal of the Azar field, based in large part on analogs of the dolomitized Sarvak Formation in the Anaran Mountains (Sharp *et al*. 2005, 2006, 2010). This has led to a revision of examples of unusual dolomitization which can be listed, beginning with the dolomitization of the Shiranish Formation in Taq Taq, and massive late diagenetic dolomitization of the Qamchuqa Formation along much of the Iraqi fold-thrustbelt. Identification of these dolomite reservoirs pre-drill requires some degree of good fortune because commonly seismic data quality is not good over anticlinal areas and may not be sufficient to determine rock properties at depth. It would appear that the dolomite bodies developed during the main Neogene compression of the basin. This is similar to high temperature dolomites elsewhere (e.g. Jurassic and Cretaceous dolomite reservoirs of southern Mexico) and it is likely that their formation was in response to orogenic breaching of regional seals and mobilization of deep formation waters rich in magnesium that had been trapped for millions of years in a passive margin setting.

Finally, our understanding of the petroleum systems has developed significantly since the 1958 publication of Dunnington's masterly review. Dunnington recognized the overriding importance of the Middle Jurassic-Lower Cretaceous source rocks, but subsequent exploration and advances in organic geochemical analysis have highlighted the importance of other sources, not least of which is the Silurian, critical for gas generation and responsible for the success of Khuff reservoirs in the foreland basin. More recent work on the Triassic in northern Iraq, Syria and south-east Turkey has demonstrated an active petroleum system in that part of the stratigraphy, which is ripe to be tested in other parts of the orogenic belt. In fact, the main issue with understanding hydrocarbon migration in the basin is that it may prove to be very difficult to unravel the relative importance and significance of each system because there is likely to be a high degree of superimposition and mixing of active petroleum systems of different ages and types within any given area.

Thus, the present time is the ideal opportunity for the development of play concepts that may encompass the whole orogenic belt. In this regard a forthcoming conference at the Geological Society of London (January 23–25, 2013) aims to address issues where concepts developed in one part of the Zagros fold-thrustbelt can be applied to exploration elsewhere, as well as presenting the first glimpses of new data that are emerging from the first thorough exploration of the Kurdistan region of Iraq.

It is to be hoped that lessons learnt from present Kurdistan exploration can in the future be applied to analogous areas of Turkey and Iran which at present see little activity.

For further information on the structural geology of the Zagros Mountains, see GEO ExPro Vol. 9, No. 1 ■

Exploring The Mediterranean: New Concepts In An Ancient Seaway

A rich human history of civilisation, trade and war is deeply rooted in the complex ancient geology that underlies the Mediterranean region, having evolved through the convergence of the European and African plates and the closure of the Tethys Ocean. In more recent times, oil and gas exploration has found success in the diversity of resulting extensional and compressional tectonic regimes, with a procession of new plays being identified over decades of industry and academic activity. Despite intensive exploration, the region continues to deliver tangible success through its rich diversity of play types, as recent discoveries in the Eastern Mediterranean have testified.

This significant conference will assemble some of the best current thinking in Mediterranean petroleum geology, from the tectonics that underpin the basin, to the Messinian salinity event and its impact on exploration. From North Africa to the Adriatic, this conference will bring together the multiple cultures that surround this diverse region to reflect on a common geological framework and the petroleum systems that transcend political boundaries.

With its position to the west of 2.5 million sq. km of water, Barcelona will form the ideal backdrop to this timely event.

Themes will include:
- Geotectonic evolution of the Mediterranean.
- The impact of the Messinian Salinity event in exploration.
- Carbonate plays in the Mediterranean.
- Petroleum systems and source rocks.
- New exploration in the Eastern Mediterranean.
- The Nile Delta revisited.
- Recent exploration along the North African coast.
- The Western Mediterranean and the Alboran Sea in focus.
- Prospectivity and new plays in the Adriatic Basin.

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Thriving on Challenges

Intisaar Al Kindy, the first Omani Exploration Director of Petroleum Development Oman (PDO) for forty years, drifted into geology almost by accident – but it proved to be a lucky turn of fate

JANE WHALEY

Jane Whaley

When Intisaar Al Kindy was growing up in Oman, scholarships to universities and colleges of further education were awarded according to the needs of the country at the time, rather than the ambition of the student. So although she liked the idea of becoming a doctor, the science-oriented student was instead offered a PDO-sponsored chance to study geology in the United States.

"I went to Tulsa University in Oklahoma and found I loved the subject, so it was a decision I never regretted," she says. "In addition, I spent a year staying with an American family and working on my English before I started studying."

Her English is excellent, but with a noticeably English rather than American accent. "That's down to Bob Stoneley and Dick Selley," she laughs. "After my first degree I did an MSc in Petroleum Geology at Imperial College in London, where they were professors – and they made sure that we all both wrote and spoke English properly! I enjoyed the course and I love London; there are so many cultures there, it gives me a great feeling of liberation."

After graduating from Imperial Collage, Intisaar joined PDO, which at the time was operated by Shell, as a trainee in the Exploration Department. She went on to develop her exploration skills both in Oman and through two postings abroad, spending several years with Shell in Aberdeen and London. "That is the PDO way; we send Omanis out of the country to build not just their technical knowledge but also relationship skills, so they have all-round talents to offer the company on their return. In the same way, we bring foreign experts into PDO in Oman to give us the benefit of their wide knowledge. When I first joined PDO there were not many Omanis in the company. I was given the opportunity to learn and develop my skills rapidly. PDO is a company that recognizes talent very early on and it has provided me with more development opportunities than I could ever have imagined."

In 2001 Intisaar returned to PDO in Oman, working first as an Exploration Portfolio Analyst and then with the Exploration 'Government' Gas Team for two years, before becoming the Exploration Manager of the North Oman Oil Team in 2005.

Meteoric Rise

"I get bored easily, so I like to be kept on my toes and I thrive on change and challenges," Intisaar admits. And just two years later she was given quite a challenge when she was appointed by Shell, which has a 34% stake in PDO, to manage its major Oil Shales Project in Jordan.

"This was a completely new project, and I had to set up the company and resource it from scratch, so it was very exciting, particularly for a country like Jordan, where the oil industry is not really firmly established. From having no employees in Jordan five years ago, Shell now has 300, almost all Jordanians, because many professional Jordanians and expatriates jumped at the opportunity to return home and help build a new industry; I was very proud of that fact. The project developed well, and it is now at the exploration phase." In 2009 she was also appointed Shell Country Chair for Jordan, one of only a handful of women to hold such a position with the company anywhere in the world.

Intisaar's stay in Jordan came to an end after four years, as her rapid rise within the ranks of PDO continued. In July 2011 she returned to Muscat as PDO Exploration Director. She is the first Omani to hold that post for over forty years, and also one of only four women to have a seat on the MDC, the main Managing Committee of Petroleum Development Oman.

"It was a proud moment when I was made Exploration Director and I received many congratulations from my colleagues and countrymen – but now I will have to live up to their expectations! Following in the footsteps of such great geologists as Pieter de Ruiter is such an honour." Intisaar's promotion also means that the MDC is now fully 'Omanized'.

"There is never a dull moment in this job. PDO is a huge organization, very different from my relatively small Jordanian group, with diverse issues and dilemmas, but I am getting a lot of support and enjoy it very much," she adds. "Sometimes I miss the technical side of things, which I really loved when I was younger, but now I enjoy motivating my staff to discover new things instead."

Unconventional Challenges

"Exploration for oil has been the growth engine of my country, but there are many challenges ahead," the PDO Exploration Director continues. "The conventional plays are seen to be slowing down, so we need to find something new. I believe that the future for the industry lies in cracking the code of our unconventional resources such as tight gas and the light, tight oil plays from our known source rocks.

"I want to set up a centre of excellence to study unconventional resources, with Omanis in Oman. In my experience a critical success factor to exploiting a potential boom is local talent, so it is important to start looking at it now and to reduce the training time. The industry still has a lot to learn about these important plays, so I want to see Oman and PDO as pioneers in the field of unconventional resources, particularly in the Middle East; then I really will be proud! We have already built up teams which are tackling the issues surrounding the identification and exploitation of unconventional resources in the country, but I believe it will be a long journey, and may not happen in my time as Exploration Director. It will also require some risk taking and some 'thinking outside the box', as I recognize from my experiences in the oil shale group in Jordan. This is something that we need to encourage the new young generation of geoscientists to do."

A Professional and a Leader

Although Intisaar feels that being a woman has been a slight advantage in her career, she thinks that it is not what people should be noticing – even though "it keeps being pointed out to me. I don't really think of being a woman as an important feature of myself – I would rather I was acknowledged as a professional and a leader." She is also obviously much prouder of being the first Omani Exploration Director of PDO for many years than she is of being the first woman in the role. "However, I am pleased to see that there are now many young women in PDO, and I want them to stand with me, and not to be afraid of taking on new roles. I tell them 'Don't think about being a woman – just be yourselves. And don't be scared of being scared by new challenges and roles; it's all part of the process'.

"I also believe that networking and building up relationships at all levels is a vital aspect of business; this has helped me manage business, especially at difficult times or during a crisis. And I also believe that if you don't know how to do something, then you pick up the phone and ask someone who does."

Earlier this year Intisaar accepted yet another challenge, when she took on the role of Chairperson of the Executive Committee of the biennial GEO 2012 conference in Bahrain, as well as leading a 60-strong delegation of geologists, geophysicists and petroleum engineers from PDO at the conference.

Dedicated to Delivering

With such a busy and high-powered job Intisaar needs to find time to de-stress sometimes – which she does with the help of the sea. "Much as I like travelling and enjoyed my posts abroad, the sea is what I missed most about Oman. I love to find a quiet spot on our beautiful coast and just sit still and watch the sea and switch off." She also enjoys spending time with her family, including her two sons, who are studying medicine in Oman, and her daughter, who studies in the US.

"My career path shows that the opportunities in this company are endless," Intisaar continues. "At PDO, if you work hard and are dedicated to delivering, the rest comes naturally. I was brought up in the company by leaders who went on to create the next generation of leaders like me by getting us to love what we do, and I want to do the same and give back to PDO something of what it has given me.

"My ambition is to get the best potential out of people. Nobody comes to work aiming not to succeed; I want to see the company and new initiatives like unconventional resource exploration succeed – and people are always the key to success." ■

Petroleum Development Oman

شركة تنمية نفط عمان
Petroleum Development Oman

The first concessions in Oman were awarded before the Second World War to the Iraq Petroleum Company, but the operations were run by Petroleum Development (Oman and Dhofar) Ltd. This company had four shareholders, each with an interest of 23.75%: the Royal Dutch/Shell Group, the Anglo-Persian Company, which would eventually become BP, Compagnie Française des Pétroles, a predecessor of today's Total, and the Near East Development Company, which would eventually become a subsidiary of today's ExxonMobil. The remaining 5% stake was held by a fifth shareholder, Partex. However, initial exploration did not look promising, and by 1960, only Shell and Partex remained.

But when oil was found at Yibal in 1962, followed by several other discoveries, things started to look up. Infrastructure, including a pipeline system, a tank farm and a marine terminal, was put in place and the first export of Omani oil took place in 1967. By now the operating company had dropped Dhofar from the title to become Petroleum Development (Oman), or PDO, and Compagnie Française des Pétroles had re-entered the consortium, which now comprised Shell which managed the company, with 85%, Compagnie Française des Pétroles 10% and Partex 5%.

Then on January 1, 1974, the Omani government acquired a 25% stake in PDO, rapidly increasing their holding to 60% a few months later. Shell retained 34%, CFP, now Total, 4% and Partex 2%, shareholdings which remain unchanged today. In May 1980 the organization became a limited liability company, registered as Petroleum Development Oman.

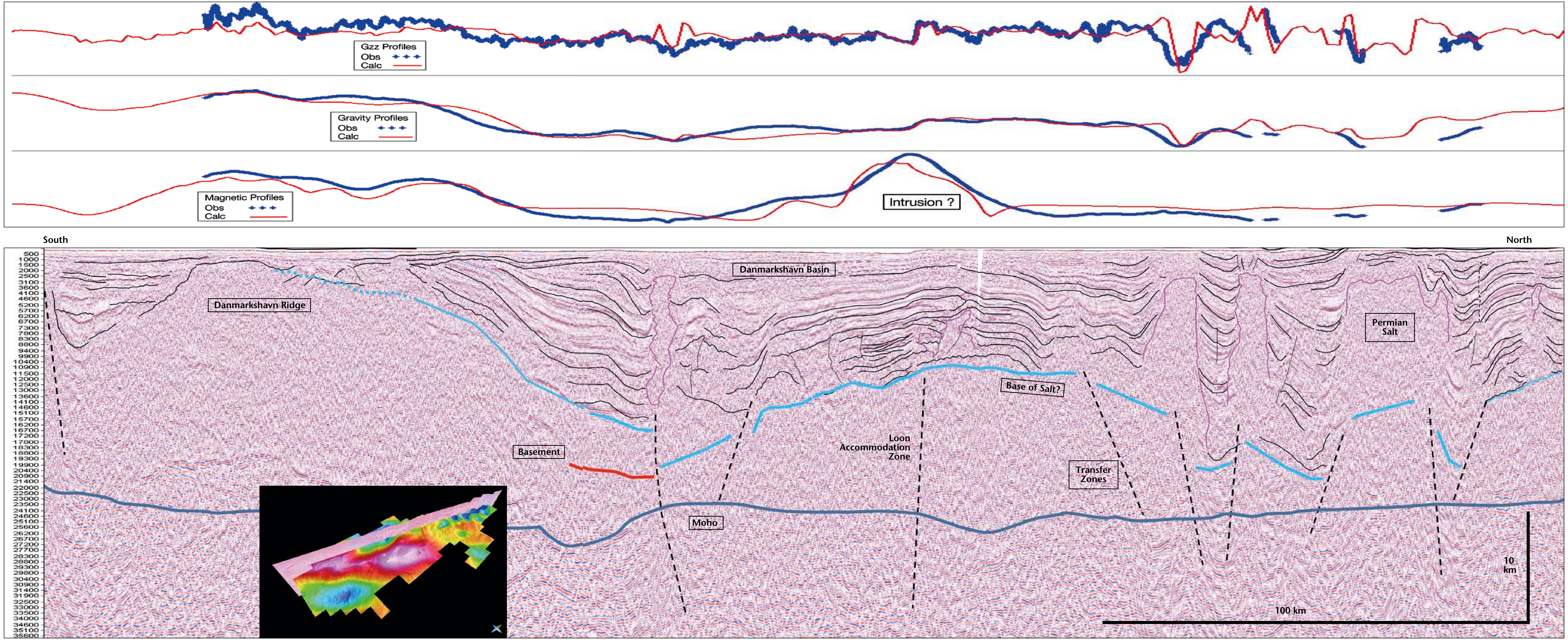
PDO has developed over 120 oil and gas fields and now produces more than one million barrels of oil equivalent a day, accounting for more than 70% of the country's oil and nearly all its gas production.

See GEO ExPro Vol. 9, No. 1 for more information about the history of oil in Oman.

One of the first wells to be drilled in Oman

The North East Greenland Danmarkshavn Basin:

Integrating the ARKeX Full Tensor Gravity Survey with the ION 2D NE GreenlandSPAN™ Seismic Survey



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ARKeX

The main tectonic elements of the line shown here, Line 5150, are the Danmarkshavn Ridge to the south and the Danmarkshavn Basin to the north. This line is chosen to show (see inset diagram of Gz field and line location) how powerful the Gz and Gzz signals (vertical gravity value and first derivative component) are in terms of identifying the presence of salt. This project is at the early stages of 3D modeling, but already it is possible to incorporate salt bodies into continually evolving 3D models of the basin architecture. The following pages discuss the potential-fields data in more detail, show a tectonic framework map, and discuss this line while also displaying results for a key dip line.

The Sky Above, the Ice Floes, and the Earth Below

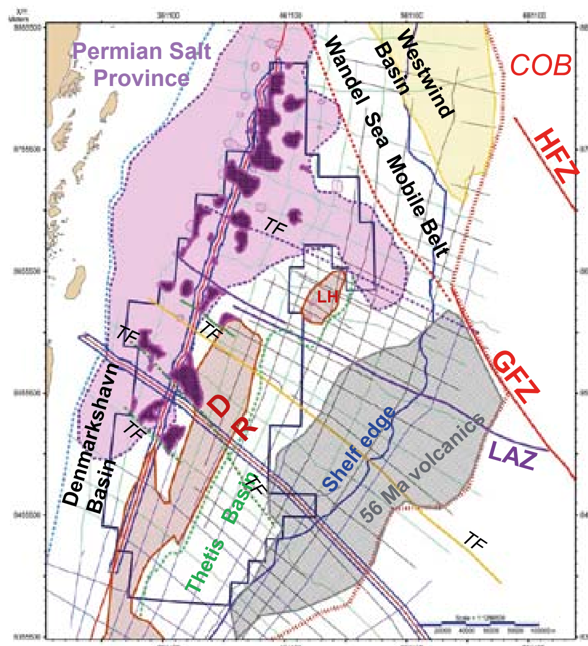
DAVID JACKSON, AL PROTACIO, MERCIA SILVA, JAMES A. HELWIG and MENNO G. DINKELMAN

ARKeX, the provider of non-seismic services, has recently completed an airborne Full Tensor Gravity Gradiometry (FTG) survey offshore north-east Greenland in conjunction with ION Geophysical. The 50,000 km^2 multi-client survey is the largest single offshore FTG survey ever carried out, and was successfully acquired above the harsh Arctic ice-laden waters according to plan in the summer of 2012.

The survey takes in key areas of the pre-round blocks that are on offer to the KANUMAS group and, in addition, the ordinary round blocks that will be offered in Greenland's 2013 license rounds. The FTG data has been integrated and jointly interpreted with ION's 2D NE GreenlandSPAN™ program to provide a better understanding of the structural development of the region. The NE GreenlandSPAN seismic survey and geological interpretation across this undrilled high Arctic continental margin have been reported on earlier in *Geo ExPro* (Vol.7, No. 6) and also in *First Break* (November 2010). The interpretation and the report of the new potential field study and its integration with previous seismic mapping, along with the data, are available to license on a non-exclusive basis.

Two lines from ION's 2D NE GreenlandSPAN program are discussed here, to highlight the benefits of multi-dataset integration. The locations of the dip and strike lines are shown on the tectonic map. The lines are also shown in perspective in a gravity gradiometry (Gzz) image. Although the major discussion in this article is confined to 2D models, 3D forward modeling and inversion techniques have been applied to the seismic and FTG datasets. The visualization of all datasets in a 3D volume allows a team approach to discuss the what-ifs generated from the 2D and 3D modeling.

Tectonic Elements with line locations and explanatory labels



Tectonic elements of the north-east Greenland shelf showing seismic surveys, potential-field study area, and geographic framework. The seismic data shows major structural features and basin stratigraphy developed in several episodes during late Paleozoic through Mesozoic, climaxed by oceanic rifting and continental margin formation in Tertiary time. On the map, salt bodies are shown in pale pink outline for seismic recognition and dark fill for gravity recognition in the Permian salt province of the Danmarkshavn Basin. Locations of strike line 5150 and dip line 1800 are shown; grid scale is 100 km. Key: COB = Continent-Ocean Boundary, DR = Danmarkshavn Ridge, GFZ = Greenland Fracture Zone, HFZ = Hovgaard Fracture Zone, LAZ = Loon Accommodation Zone, LH = Loon High, TF = Transfer Faults.

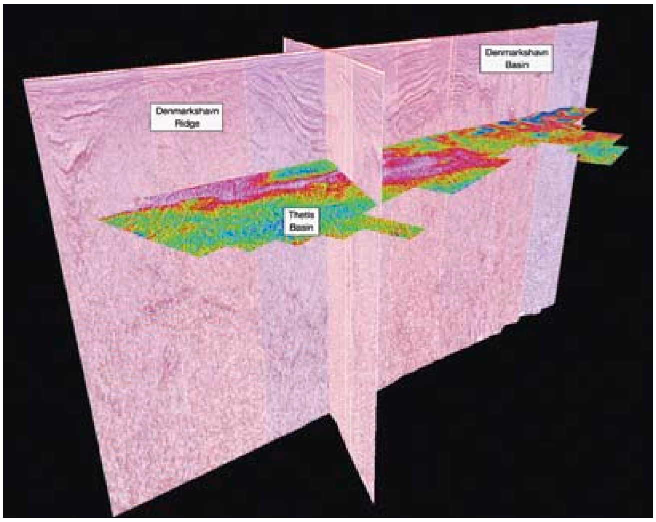
Interpretation of Strike Line

The first line, shown in the foldout, follows the Danmarkshavn Ridge northwards into the Danmarkshavn Basin, which is marked by a salt province in the north. At the southern end of the line, we see the Danmarkshavn Ridge plunging northwards, and as we progress into the Danmarkshavn Basin we see coherent seismic boundaries showing strong truncation beneath onlapping Tertiary sediments. All three profiles match nicely with the area where a steepening in dip occurs on the 'light-blue reflector' (base of Permo-Carboniferous, below the salt) on the northern part of the Danmarkshavn Ridge.

As we move into the basin, we see that a high magnetic signal occurs just over half-way along the section. Remembering that this is a strike-line, this magnetic response is observed where the Loon Accommodation Zone (LAZ) cuts the section at great depth. This is another area where work is ongoing to try to understand the signatures of all the profiles.

What is very clear on this line is the ability to define the lateral edges of the salt using the Gzz signal. Some diapirs are so large, and the salt so shallow, that the Gz profile allows interpolation away from widely spaced regional seismic control. The smaller and deeper salt bodies are much better defined on the Gzz profile and image. Before the Gzz data was available the seismic data coverage led to a map of more than 25 isolated diapiric structures, but integrating the seismic with Gzz data (underpinned by 2D detailed modeling) has led to the discovery of a greatly expanded distribution and area

View of two seismic lines and Gzz gravity



3D view of modeled lines and the full-tensor gravity Gzz data. These two lines were chosen specifically to highlight how the understanding of 'seismically difficult/high risk interpretation areas' can be improved by iterative seismic interpretation and integration with gravity and magnetic modeling. Interpolating geological features (e.g. faults-accommodation zones-salt bodies etc.) is a key component of maximizing data from both the seismic and FTG datasets, and subsequently leads to an improved understanding of basin architecture.

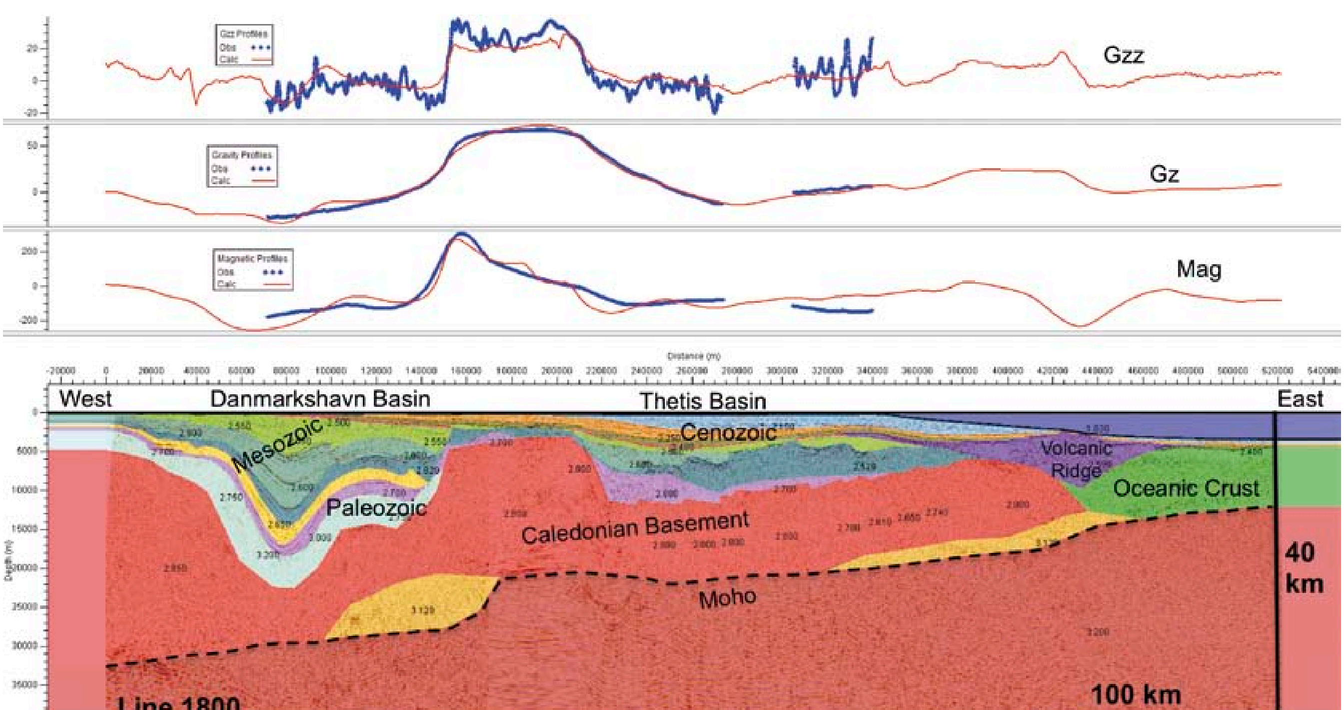
of intrusive salt bodies and the definition of significant salt wall features.

Interpretation of Dip Line

The second line is a dip line that traverses the southern Danmarkshavn Basin and continues eastward across the Danmarkshavn Ridge into the Thetis Basin, and over the shelf edge. The western-bounding fault of the Danmarkshavn Ridge is seen on all three of the potential-fields profiles, Gzz-Gz-Magnetic, but the Gzz dataset provides the clearest definition of the fault position. The magnetic profile indicates a heterogeneous basement structure, with early modeling indicating presence of magnetic and non-magnetic basement. The eastern-bounding fault of the Danmarkshavn Ridge is more difficult to define, and the Gzz and Gz profiles indicate that the fault should be positioned farther eastwards than the presently interpreted seismic data. However, another option is that the hanging-wall contains high density rocks (intrusive?), and that the fault is correctly interpreted on seismic profiles. We are at the early stages of modeling, but further analysis of all the data may well lead to a shallower basement than current mapping in this region of the Thetis Basin.

The acquisition, processing, interpretation and modeling of Full Tensor Gravity Gradiometry (FTG) data are quite comparable in complexity with advanced seismic imaging technology. Here we have not delved into the complete story, e.g. presentation of density and susceptibility models. Rather our goal here is to demonstrate the value of mapping and modeling regional airborne potential fields to infill regional structural models in frontier basins having only regional seismic coverage. Integration of gradiometry investigations with seismic datasets and interpretations affords synergistic leverage to subsurface interpretation in both 2D and 3D. This technology has proven to be technically feasible and to provide a new and expanded vision for understanding the geological architecture of the north-east Greenland continental margin sedimentary basins. ■

Dip Line 1800



Line 1800 – Seismic Interpretation plus Gzz, Gz, and Magnetic Profiles. The Danmarkshavn Basin (DB) is a post-Caledonian late Paleozoic rift-sag basin overlain by a Mesozoic sediment fill of up to 7 km. The basin is marked by a faulted shoulder against the horst of the Danmarkshavn Ridge that retains 2 km or so of Mesozoic cover and has an eastern boundary fault downthrown into the Mesozoic-Cenozoic Thetis Basin.

The Permian Basin
A Brief Overview

THOMAS SMITH

Thomas Smith

Exploratory drilling continues in the Delaware Basin, with El Capitan and the Guadalupe Mountains in the background.

The Permian Basin region is 400 km wide and 480 km long and has produced over 35 billion barrels of oil since 1921, currently accounting for 17% of total US production.

About 300 million years ago, the Permian Basin, which now covers a large area of central USA, was situated along the western margin of Pangaea, about 10° north of the paleo-equator. Being on the southern flank of the North American craton, the region was subject to moderate subsidence and primarily carbonate sedimentation. Two large, south-extending platforms, the Diablo and Central Basin, separate four basin areas, the Orogrande, Delaware, Midland and Val Verde. Basin formation resulted during the onset of a major continental collision event (the Pennsylvanian Ouachita-Marathon orogeny). During regional subsidence through most of the Permian, the basins accumulated 2,100m to over 4,200m of clastic, carbonate, and evaporate strata. At the start of the Permian, the basins were very shallow, and near the end of the Guadalupian (Late Permian) time water depths exceeded 500m.

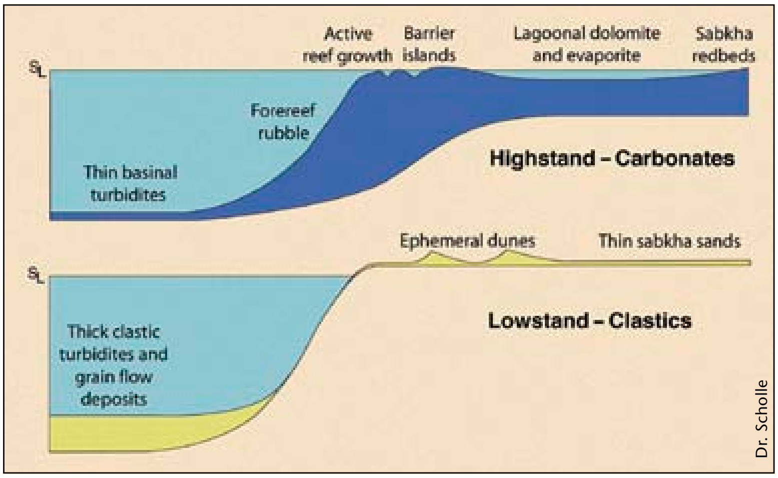
Permian Basin stratigraphy has been substantially influenced by sea-level changes, as the illustration to the right shows. While most of the shelf margin sequences are dominated by carbonate deposits, the basinal section is dominated by detrital sandstone and siltstone. During the high sea level stands, reefs and carbonate shoals developed along the platform margins. The shelf areas were covered by broad carbonate and evaporate lagoons while only thin carbonate turbidites were deposited in the basins. During periods of lower sea levels, eolian and fluvial terrigenous deposits were transported across the shelf areas and accumulated along the shelf margins, to be finally transported into the basin forming thick sandstone and siltstone turbidite deposits.

During the Mesozoic, the region was a stable, non-depositional platform province. Uplift to the west during late Tertiary Basin and Range faulting produced a 5 to 10° east dip to the pre-Tertiary strata and erosion of the Permian topography. Ground-water circulation led to dissolution and some replacement of the Permian evaporates and cavern formation in the limestones. The outcrop exposures seen today in the Guadalupe and Glass mountains as well as high-angle faulting across the region are a direct result of this Tertiary uplift.

The Road to Discovery

In 1920, a trickle of oil (10 barrels per day) at the Westbrook Field started a flurry of exploration activity in the region. Just three years later, the Santa Rita #1 well was shut-in when the

High and lowstand deposition



Dr. Scholle

NASA/GSFC

Dr. Scholle

If the Permian Basin (illustration near left) could have been seen from a satellite, it may have looked much like the modern Bahama platform region east of the state of Florida (photo far left). The primary differences would be the water depths and climate. The Permian depths were generally less than 600m while some of the Bahamian basins are four kilometers deep. The Permian climate was also much drier, more similar to that of the Persian Gulf region.

driller saw gas bubbles in the casing head after the well drilled into dolomitic sands called the 'Big Lime'. A day later, the well blew oil into the sky, becoming the first in a long list of major discoveries for the Permian Basin region, including the super giant Yates Field in 1926, which set the table for a productive future in one of the world's great oil basins.

The early finds were followed by more discoveries, primarily in the carbonate sections (75% of total production). Deeper sections were explored and over 1,300 significant discoveries have been made here. After the 1973 peak in production, a steady decline in production ensued, slowed by enhanced recovery and 'rediscovered' oil in older fields in the 1980s and 90s. That decline has now been reversed, rising steadily since early 2011, using both new and old technologies. Waterflooding and CO_2 injection, horizontal drilling, deeper drilling, and multi-stage hydraulic fracturing are all being used to recover and discover new reserves.

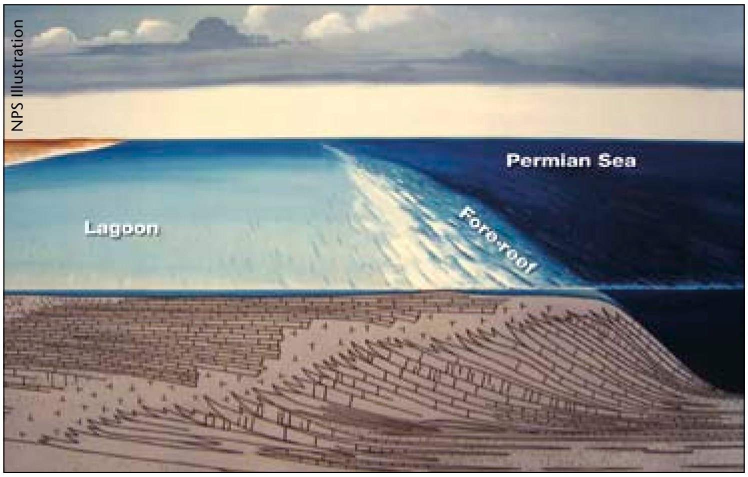
The Permian Basin production is currently estimated at over one million barrels of oil daily after reaching a peak production of 2.085 MMbopd in 1973. Some experts expect the output to reach 1.8 MMbopd by the end of 2016. The area also produces 4 Bcf of gas per day.

The deeper drilling has found new, unconventional oil plays in some of the older strata, such as Wolfcamp, Cline shale, Strawn and Atoka formations, all located below traditional producing horizons. Targets for unconventional gas include the Devonian Woodford Shale, the Mississippian Barnett Shale, and the Permian Wolfcamp Shale. Low permeability reservoirs in the basinal deposits of the Brushy Canyon sandstone have also added significant oil production.

With over 500 rigs active and more than 30 Bb of producible oil remaining, expect the Permian Basin to stay among the largest and most active hydrocarbon-producing areas in North America. ■

Back-Reef to Basin Depths

NPS Illustration



We are about to embark on a theoretical journey as illustrated in this Visitors Center cross section. We will start in the west at the far left of the section near the ancient, arid shoreline, cross a broad and shallow lagoon onto the actual reef, proceed down the steep slopes of the fore-reef and finally east into the depths of the Permian Sea.

Situated adjacent to the very prolific Permian Basin is one of the earth's greatest and most studied carbonate depositional systems, the Permian Reef Complex of New Mexico and west Texas.

THOMAS SMITH

Thomas Smith

No other place on earth offers a better opportunity to study a complete depositional system from outcrop to the subsurface than the Permian Basin region. The Guadalupe and Delaware mountains provide excellent outcrop control with very little structural deformation. These mountains are cut by canyons at nearly right angles to depositional strike, exposing natural cross sections through each of the sedimentary environments. In addition to the excellent outcrops, the same formations are present in the subsurface in the adjacent oil- and gas-producing regions to the south-east and have been penetrated by tens of thousands of wells.

This Permian carbonate system can literally be walked from shelf-interior, back-reef, across the reef at the shelf margin and down the fore-reef slope into the deep basin. (Please note: take plenty of water and several pairs of sturdy boots!) In all practicality, the geotourist can observe the entire depositional facies along US Highways 62 and 180, into McKettrick Canyon in the Guadalupe Mountains National Park, continue up Walnut Canyon to Carlsbad Caverns Visitors Center, and finally follow along Dark Canyon to Sitting Bull Falls and Rocky Arroyo. According to an online field guide by Dr. Peter Scholle and others *(An Introduction and Virtual Geologic Field Trip to the Permian Reef Complex, Guadalupe and Delaware Mountains, New Mexico-West Texas)*, to visit most of the important outcrops, road log miles exceed 240 (386 km) plus a difficult hike up McKettrick Canyon that takes about 5 hours.

Looking up at nearly original Permian undersea topography – the prominent cliff of El Capitan and the southern end of the Guadalupe Mountains as seen from US Highway 62-180 near Guadalupe Pass, Texas. El Capitan is made up of reef and fore-reef carbonates that prograde over the nearly flat-lying, basinal Brushy Canyon and Cherry Canyon formations.

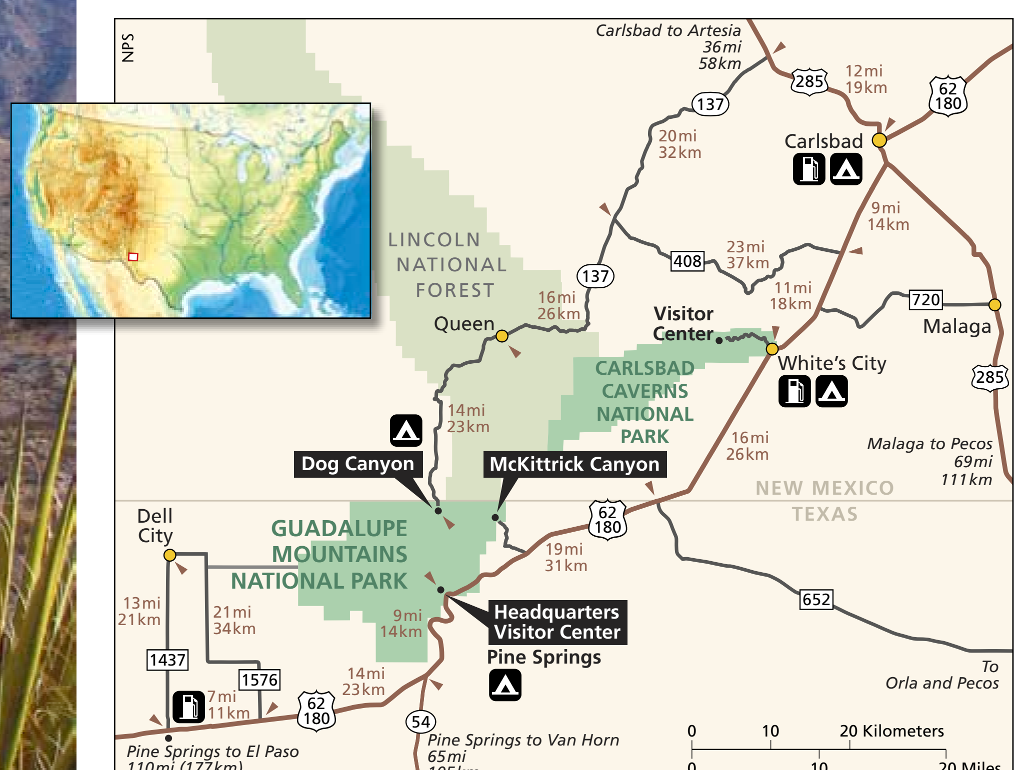
Behind the Reef Front

Now let us start our journey across this ancient depositional system. We begin in the furthest shelfward units that were deposited on a broad, sabkha-type plain. Clastic terrigenous detrital material was brought in primarily from the north, some by ephemeral streams but most of the material arrived by aeolian processes. Today, we see massive redbeds and thin sandstone interbeds that show few sedimentary structures. Beds of gypsum, commonly with nodular fabrics, are interstratified with the terrigenous deposits.

In the Permian, we would be standing on an evaporitic plain over which large dunes have migrated; the only sediments trapped here would be those held by a capillary fringe that exists above the water table.

As we ease slightly seaward (to the east), fine-grained and thin-bedded dolomicrites become interbedded with the redbeds and evaporities. Little in the setting has changed; we are still in a shallow sub-tidal or lacustrine environment on a hypersaline lagoon. On outcrop, these strata have considerable moldic and fenestral porosity but in the subsurface the equivalent units are completely plugged with evaporate minerals, particularly anhydrite.

A bit closer to the shelf edge, we encounter a pisolite facies that is over a kilometer wide and lasted through nearly a kilometer of sedimentary buildup. This zone consists primarily of pisoids that can be over 5 cm in diameter. The beds are commonly reversely graded, with finer pisoids at the base. Some marine fossils can be found in this facies becoming more abundant heading seaward. Like the other facies in this environment, outcrop porosities can be quite good



Calcareous sponges in growth position form much of the reef's framework, often coated by red algae. The dark material is early marine cement.

but nearly entirely filled by evaporate minerals in the subsurface.

Interpretation of the depositional environment suggests a similarity with some of the coastal lakes and sabkhas of southern and western Australia. Researchers have found many similar features to those found along the Permian shelf, including aragonitic tepee-pisolite beds. These beds are formed from seep-springs that are found in the transition zone between the more open marine environments and the evaporitic lagoonal environments that lie landward of this transition zone.

The Shelf Margin

Seaward of the pisolite zone, we are now walking along a variety of lithologic units that were deposited in open marine conditions. Life is abundant here and marine fossils such as fusulinids and other foraminiferas, algaes, pelecypods, and other skeletal grains make up a large part of the grainstones and packstones seen in outcrop. These units generally shallow upward from subtidal to supratidal which occurs on a small scale (over centimeters) to very large shallowing units that are 30 or more meters thick.

If we were to view this first depositional area seaward of the pisolite zone, we would see an area of small sand waves and islands with tidal cuts and passes between the islands. The landward side of this zone would be seen as nearly continuous barrier islands. These shifting islands kept the open marine waters from moving farther inland. Porosities vary in this zone as widely as the facies. Massive marine cements can block all porosity but on the more landward portions, leaching of unstable grains has aided the development of very good moldic porosities. In the subsurface, this island belt has undergone only partial dolomite replacement and has only minor pore-filling evaporates. Being capped by evaporate seals, these rocks are prolific reservoirs.

Venturing just seaward of these islands, we are at the reef. Similar to today's reefs, the Capitan reef contains the most diverse fauna and is the primary carbonate factory for the depositional system. Common to this reef complex are calcareous sponges and bryozoans which form much of its framework, with phylloid algae forming a subsidiary framework. Other organisms include crinoids, echinoids, brachiopods, gastropods, ostracods, corals, trilobites, and cryptic sponges.

The facies sequences found here are very similar to those found across Caribbean reefs. The primary difference is that the calcareous sponges are now replaced by a variety of corals and the Permian green algae Mizzia or Macroporella has been replaced by Halimeda.

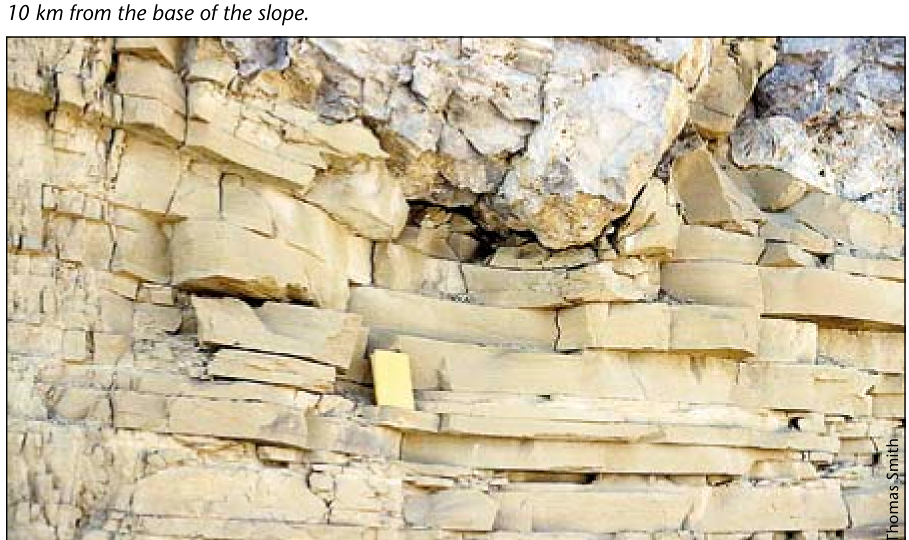
Penecontemporaneous marine cementation rapidly filled any cavities in the reef along the shelf margin. These early aragonitic and calcite cements were a major factor in the rock formation but also have reduced the porosity so that the reef facies is not an important hydrocarbon reservoir.

The Capitan reef grew quite quickly, generating more material than could be accommodated. Some of the excess material was deposited onto the back-reef but most onto the fore-reef and down slope into a 600m deep basin. Consequently, the reef prograded seaward nearly 10 km over its 5 million year life.

Beyond the Shelf Margin

As we pass the Permian reef in ancient times, we would have needed a small submarine to see what was accumulating. Today, the geotourist can simply walk down from the reef proper and onto the fore-reef talus. The steeply dipping rubble from reef, back-reef, and upper slope facies is, by volume, the dominate carbonate deposited in the system.

A large block of fore-reef material that has been transported onto the very fine-grained basinal deposits. Some deposits that contain such blocks have been mapped out into the basin as much as 10 km from the base of the slope.



Bedding exceeds 35° and gradually flattens onto the basin floor. The material was transported down the slope in debris flows and by turbidity currents forming a uniform apron along the entire slope below the reef. Brachiopods, bryozoans, and echinoderms populated the slope.

From our small submarine, we might see rock falls as the debris builds up on the slope. Some of the debris would be funneled into a small, sub-marine canyon or channel that would act as a conduit for the sediments. The channels or small canyons would get clogged with debris and new channels become active until some of the material is transported to the basin floor. As we approach the basin on the lower slope, we may see some sand-filled channels. At this setting, clastic terrigenous material thickens basinward and interfingers with the thinning carbonate beds.

Most of the slope strata have undergone a varied diagenetic history. Compaction, fluids from both basinal and shelf sources, selective post-depositional dolomitization, and porosity filling minerals such as anhydrite and kaolinite are commonly found. In spite of being rather poor reservoirs, some of these units along the basin edges produce hydrocarbons.

Now we have nearly completed our journey across this amazing depositional system. We have reached the lower slope where carbonate units, such as the Lamar Limestone, thin from 40m to 1m, approximately 15 km out into the basin. These dark, very fine-grained deposits are probably the result of distal turbidite currents. The basin centers lack evidence of burrowing and benthic organisms and may have been oxygen-depleted or even occupied by dense salt brines derived from the shelf.

Terrigenous sandstone and siltstone deposits of the Brushy Canyon and Cherry Canyon formations thicken and provide most of the basin fill. These sediments were transported from the shelf through channels in the reef and during relatively low water levels. Once out onto the basin floor, these deposits form submarine fan complexes that are compositionally very similar to the grains found in the thin clastic units on the shelf. These submarine channels and fans can be mapped in the subsurface and are major exploration targets.


Thomas Smith

Submarine fan overbank showing soft sediment deformation and channel deposits of the Bushy Canyon Formation as seen in a highway cut near Guadalupe Pass.

The Castile Formation filled in much of the Delaware Basin after carbonate production ceased and now consists of finely laminated gypsum (anhydrite in the subsurface) and organic matter with calcite. These layers represent cycles between a dry season with the gypsum layer and possibly monsoonal conditions (near normal salinity) with the organic and calcite layers. Approximately 209,000 cycles have been counted from the formation's 550m thickness.


Thomas Smith

The Final Stage

One of the reasons that we can now, over 250 million years later, walk along this intact depositional system is that carbonate production ended and the basins were rapidly filled by evaporite deposits. Once the basin was filled, evaporite sedimentation continued and covered the shelf areas. The shallowing and basin infilling continued into the Triassic with non-marine deposition.

The evaporite deposition made two things possible: it preserved the basin geometry and provided an effective seal, trapping much of the oil generated from the meager basinal source rocks. Uplift and dissolution of the evaporites during the Late Tertiary gives us the terrain we see today.

The author visited the area for the first time in 1984 participating in a field trip led by Dr. Peter Scholle and has based much of this article on the 174-page field guide. ■

GEO Education is a new column that will be published occasionally in Geo Expro. Each article briefly explains some geoscience topic that is relevant to energy exploration and development and is written in a language comprehensible to a broad range of readers, including college students and non-specialists in the field.

Know Your Faults!

Part II: In the first part of this feature, we looked at the geometric representation and identification of faults. In this concluding article, we review the slip classification, stress orientations and tectonic styles of faults.

RASOUL SORKHABI, PH.D.

Conjugate normal faults cut the Noonday Dolomite (about 800 Ma) at the entrance to Mosaic Canyon, Death Valley National Park, California.

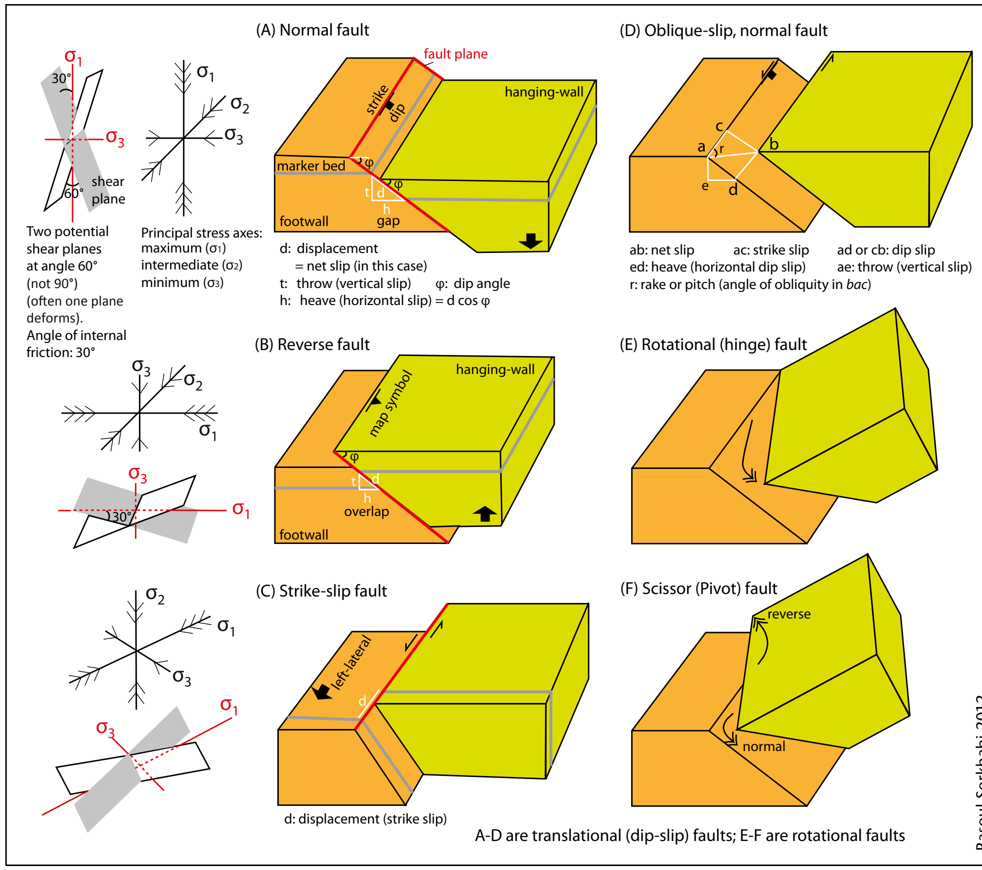
Dr. Marli Bryant Miller, University of Oregon, Eugene

One of the greatest geologists of the past century was the Scottish geologist Ernest Masson Anderson (1877–1960), who in his (now classic) work *The Dynamics of Faulting and Dyke Formation with Application to Britain* (Edinburgh, 1942, 1951) systematized our knowledge of the geometry and stress-fields of various faults.

For a three-dimensional rock volume, Anderson visualized three **principal axes of stress**, all of which are compressional but with different magnitudes: maximum (σ_1), intermediate (σ_2) and minimum (σ_3). He reasonably assumed that shear stress at the ground-air or ground-water interface is zero: no shear occurs in fluids (of course, hurricanes may uproot trees and blow off roofs, but they are too weak to produce faults and earthquakes). Therefore, one of the principal stress axes must be vertical and increase with depth as the rock overburden (lithostatic pressure) increases; the other two stress axes are horizontal.

The direction of fault movement is such that fracture *opens* along the minimum stress axis and the *slip* occurs as the rock wedge containing the maximum stress axis moves inward. The angle between the maximum stress axis and the shear plane is called the angle of internal friction, and studies show that this angle is about 30° for most rocks.

Anderson's stress model is strictly applicable if we assume that the deforming rock is isotropic (homogeneous throughout fault surface) and that structural deformation is coaxial (the stress axes do not rotate). In reality, rock types exhibit different mechanical strengths and inherit pre-existing fractures, and in the larger frame of the Earth's crust, stresses may rotate. Nevertheless, Anderson's elegant model provides a basic scheme for studying the **geomechanics** of faulting.



Sketches showing principal stress axes and slip classifications of various faults. Note that in theory all faults have a rotational component because displacement even in a dip-slip fault varies along the fault length. However, in a rotational fault the variation is too great between two nearby points along the fault strike.

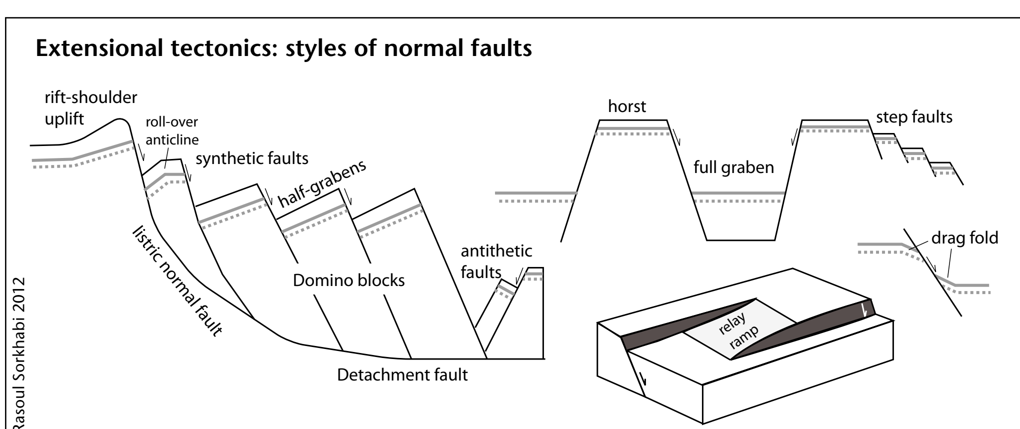
Classification of Faults

Faulting is a kind of **strain** (permanent deformation) in rock in response to stress which is usually supplied by the motion of tectonic plates relative to one another. As stress (force applied per unit area) builds up in a block of rock, a point reaches when the stress surpasses the rock strength and the rock then ruptures (yields to the stress).

Based on slip (direction of movement) of fault section and orientation of the stress axes, faults are broadly categorized into three types: normal, reverse, and strike-slip faults.

A **normal fault** is a dip-slip fault in which the hanging-wall has moved down relative to the footwall. Normal faults are produced by extensional stresses in which the maximum principal stress (rock overburden) is vertical. The faulting takes place at a point at depth when lithostatic pressure exceeds the rock strength and horizontal stress is reduced along an axis. Geometrical considerations dictate that such a fault plane dips at greater than 45°, or more precisely at 60° (that is, 45° plus 30°/2, where 30° is the angle of internal friction). Although the majority of normal faults are indeed high-angle, low-angle normal faults also occur because fault surface is not necessarily isotropic.

A very low-angle normal fault at the base of an extending block is called a **detachment fault**. In this case, a series of extensional faults, sometimes having a listric ('spoon-shape' or 'concave upward') shape, join at the detachment. A low-angle normal fault that develops on top of, parallel but in an opposite direction to a thrust sheet is a **lag fault**. Such an extensional fault forms almost simultaneously with the thrust fault at the base of the thrust sheet, and plays an important role in the tectonic



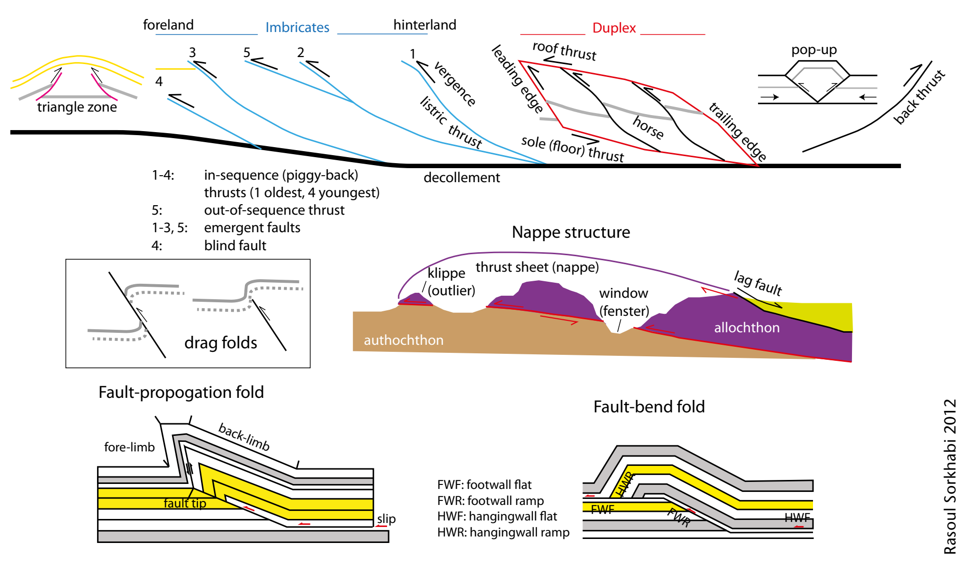
exhumation of deep-seated rocks.

A **reverse fault** is a dip-slip fault in which the hanging-wall has moved upward, over the footwall. Reverse faults are produced by compressional stresses in which the maximum principal stress is horizontal and the minimum stress is vertical. In this way, the fault section is shortened in the direction of maximum compression and the fault dips at less than 45°, or in theory, strictly at 30° (i.e. 45° minus 30°/2, where 30° is the angle of internal friction). However, in nature steeply or shallowly dipping reverse faults do occur because of variations in the properties of rocks (such as their relative strength) on a fault surface.

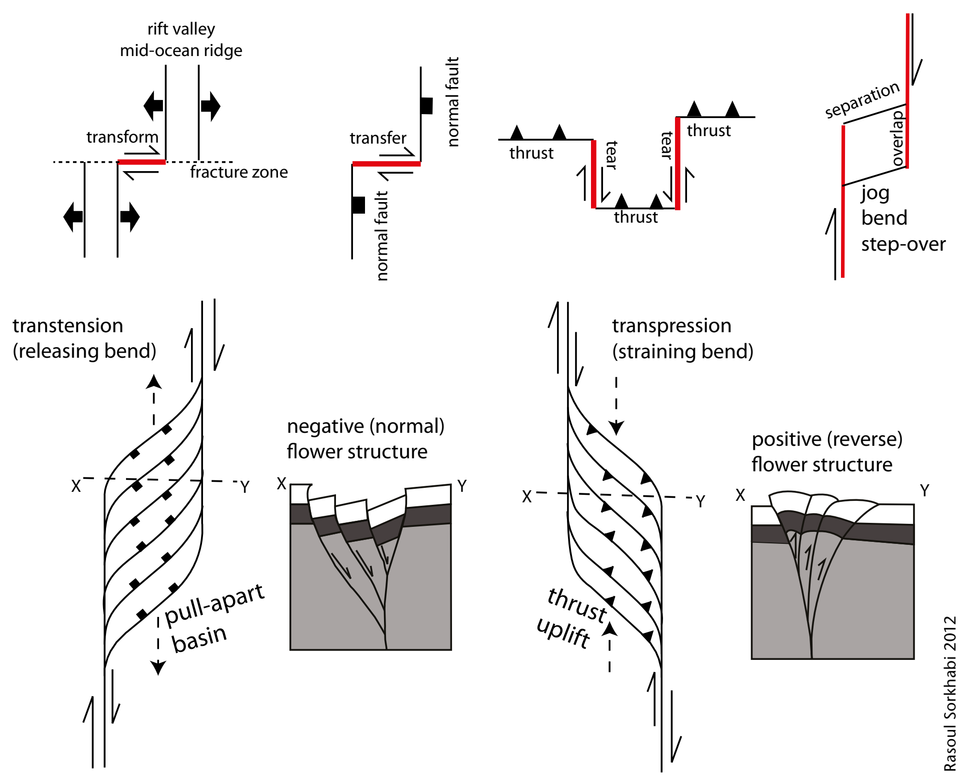
A **thrust** is a low-angle reverse fault. In orogenic belts, such as the Alps, a thrust fault may transport a thick package of folded rocks over many kilometers; such a **thrust sheet** is called **nappe** in French and **decke** in German. Nappes, some of which have moved for over 100 km, have long been a paradoxical phenomenon in structural geology, and geologists have tried to explain them as a result of gravity gliding of rock on an orogenic slope (towards foreland); hydrothermal fluid lubrication along thrust planes; and incremental movement of the thrust over millions of years. Probably all these processes happen. Plate collisional tectonics provides the fundamental stress mechanism for the generation of large thrust sheets.

Seismic images from orogenic belts show that thrust faults are often rooted in a basal detachment or **decollement**. Moreover, in orogenic belts, thrust faults become younger toward the foreland; this sequence is referred to as foreland-propagating or piggy-back faults.

Contractional tectonics: styles of reverse and thrust faults



Styles of strike-slip tectonics



The terms **overthrust** and **underthrust** are sometimes used for low-angle, regional thrust faults with the implication that hanging-wall and footwall respectively was the active element in the thrust movement (although it is difficult to verify this). **Upthrust** is a high-angle thrust with a great amount of uplift, often involving basement rupture.

Reverse faults and associated folds may deform the basement rocks (**thick-skinned** deformation), or only sedimentary cover detached from the basement (**thin-skinned** deformation), or occasionally both the basement and sedimentary cover respectively in the hinterland and foreland of a mountain system.

A **strike-slip** fault is a nearly vertical dip-slip fault in which fault blocks move horizontally, parallel to the fault strike. In this kind of fault, both the maximum and minimum principal stresses are horizontal while the intermediate stress is vertical. The direction of strike slip may be left-lateral (**sinistral**) or right-lateral (**dextral**) with respect to an observer. Large strike-slip

faults are also called **wrench** or **transcurrent faults**. A **mega-shear** is a continental-scale zone of deformation produced by strike-slip movement.

Regional strike-slip faults are usually composed of several strands. Sometimes two segments of a strike-slip fault partly overlap but are also separated by a step-over, jog or bend; the latter area is usually deformed by **transtensional** (releasing bend) or **transpressional** (straining bend) structures depending on the directions of strike-slip movements and step-overs.

Fault Inversion and Growth Fault

Tectonic inversion is the reactivation of a dip-slip fault resulting in the reversal of the sense of fault throw. Positive inversion is the changing of a normal fault to a reverse fault (reverse-reactivation); negative inversion is the changing of a reverse fault to a normal fault (normal-reactivation). Tectonic inversion occurs when a basin is a subjected to a new but contrasting tectonic regime, and stresses find it easier to build up in pre-existing faults.

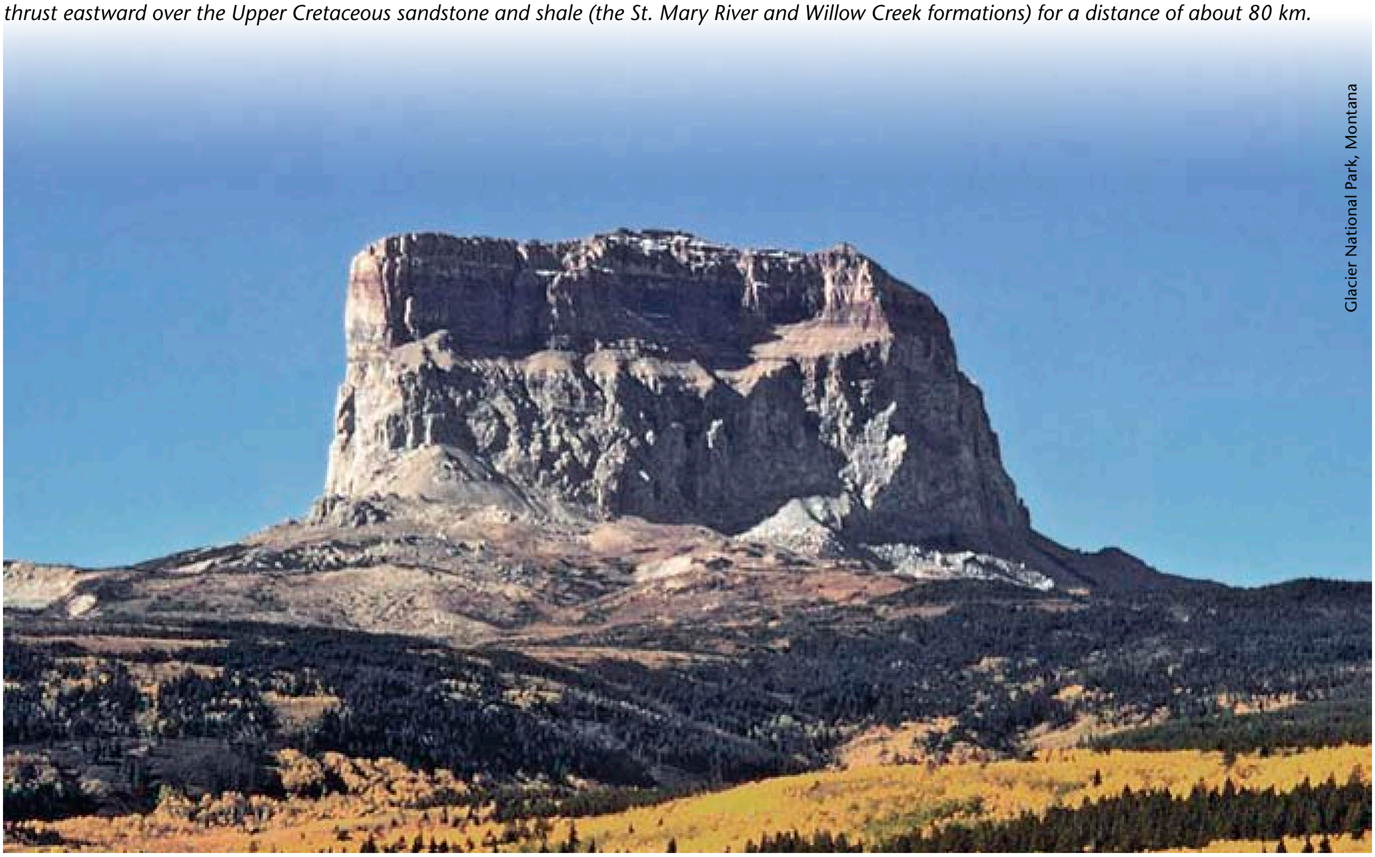
Non-tectonic **gravity-driven faults** are also common, especially in sedimentary basins. These include faults generated by ductile movement of salt and shale, and also those caused by gravity gliding of strata on a slope. The latter include **growth normal faults** and **toe-thrusts** on passive continental margins, triggered by deltaic sediment overburden and continental slope.

An important way of analyzing faults in sedimentary basins is to note their relations to strata. For example, a **bedding-parallel fault** or 'flat' often moves along an incompetent (weak) layer, while a **ramp** develops in more competent (rigid) layers. **Syntectonic sedimentation** results in thicker growth strata on the down-thrown block which can then be used to identify pre-tectonic and post-tectonic sediments. ■

A Historical and Bibliographic Note

Historically, fault terminology is biased toward the regions which have been studied in greater detail than other regions. For example, the terminology of thrust faults and folds was primarily developed in the Alps and in the Rockies, that of extensional faults in the East African-Red Sea rift system and the south-west USA Basin-and-Range province, and that of strike-slip faults in the San Andreas fault system. Fault terminology can be complex. Geologists have tried to standardize definitions of fault-related terms as structural geology has advanced. Key papers include: R. Butler (*Journal of Structural Geology*, 1982, vol. 4, p. 239-245), S.E. Boyer and D. Elliot (*AAPG Bulletin*, 1982, v. 66, p. 1196-1230), K. R. McClay (in *Thrust Tectonics*, London, 1992, p. 419-433) on thrust faults; D.C.P. Peacock, R.J. Knipe and D.J. Sanderson (*Journal of Structural Geology*, 2000, v. 22, p. 291-305) on normal faults; K.T. Biddle and N. Christine-Rick (in *Strike-Slip Deformation, Basin Formation and Sedimentation*, SEPM Special Publication 37, 1985, p. 375-386) on strike-slip faults.

Chief Mountain (2,768m), Glacier National Park, Montana, near USA-Canada border, is a 'klippe' (outlier or isolated remnant) of a thrust sheet transported by the Lewis Thrust during the formation of the Rocky Mountains. Here, Mesoproterozoic dolomite (the Altyn formation, about 1400 Ma) is thrust eastward over the Upper Cretaceous sandstone and shale (the St. Mary River and Willow Creek formations) for a distance of about 80 km.

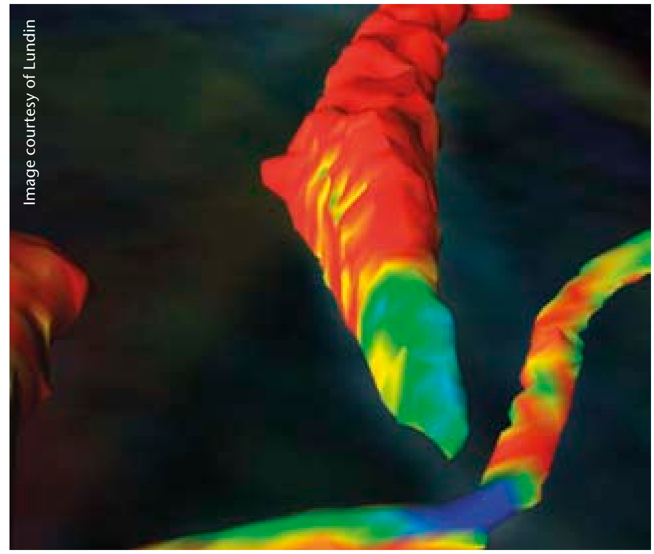


Glacier National Park, Montana

Making the Impossible, Possible!

A new paradigm in understanding the geology of the subsurface.

JONATHAN HENDERSON, ffA



The geobody adapts to the a calculation of the 'goodness of fit' or the surface confidence values between each point on the surface of a geobody. If blue, a poor fit; if red a good fit.

As we discussed in a previous article (*GEO ExPro* Vol.9, No. 3), at ffA we call the data-driven/interpreter-guided approach for understanding and defining the 3D morphology of the geological elements imaged within the seismic data the 'Geological Expression' approach. This has several components in common with a conventional seismic interpretation workflow. The big difference is that at every stage this system allows the interpreter to interact seamlessly with information provided through an objective analysis of the geological expressions contained in the data.

The Geological Expression workflow has to reconcile a number of conflicting requirements, one of which is that it should give the interpreter free reign to explore the data and to examine different scenarios and investigate new concepts. By designing the Geological Expression approach around geologically directed workflows, the interpreter can target their approach efficiently without reducing the scope of their investigation.

Color Blending

Color provides an intuitive means of examining the relationship between different aspects of the geology expressed in the data. Most of the time, we cannot gain the understanding we are striving for by looking at a single piece of information out of context. Equally if we are bombarded with a plethora of unrelated information, enlightenment is rarely achieved. How many sources of information we can deal with depends on how the information is presented and the degree to which it is correlated. Spatial registration has a large impact on our ability to understand the information in multiple images. To illustrate this we can refer again to medical imaging where it has been demonstrated that the use of color blending and overlays is a far more effective way of defining pathological changes than viewing images side by side.

Color blending generally involves creating an image where the color at each point in the image is defined by the values in three, spatially registered input images using a Red-Blue-Green (RGB), Cyan-Magenta-Yellow (CMY) or Hue-Saturation-Value (HSV) color model. The results can be incredibly striking and extremely informative.

As shown in the examples on these pages, CMY blending can be used to combine three volumes of information which differentiate between sections of faults that are represented seismically by a sharp discontinuity, a flexure or an amplitude change. In addition to showing the position and inter-relationship between different fault systems and episodes of faulting, the color changes shown in the CMY blend give indications of potential lithological variations with brittle lithologies more likely to be associated with sharp discontinuities across the fault and ductile lithologies associated with flexures or subtle amplitude changes.

Adaptive Geobodies

The understanding that can be developed through the use of these visualization techniques is enormously valuable, but what we see in these images needs to be extracted in a 'tangible' form so that it can be used in later stages of the workflow such as 3D geological and reservoir modeling. This is a non-trivial task. The human brain is an incredibly powerful image-processing engine and the process of 'seeing' is very complex. A common frustration arises when we can clearly 'see' an object in an image, but cannot extract it. To overcome this, we have to recognize that seismic data does not provide a complete and unambiguous representation of the subsurface and of the four components of seismic interpretation – information, analysis, knowledge and experience. We should only rely on the computer to provide the information and analysis parts.

ffA's Adaptive Geobodies© technology recognizes and makes geobody delineation a fully interactive data-driven/interpreter-guided process. What this means is that 3D geobodies representing geological elements imaged in the data can be defined based on a combination of data analysis and direct interpreter guidance. The process is interactive as the data-driven analysis 'grows' the geobody in real time but the interpreter can modify in 3D the position of regions of the geobody surface at any stage.

The data analysis, which underpins the

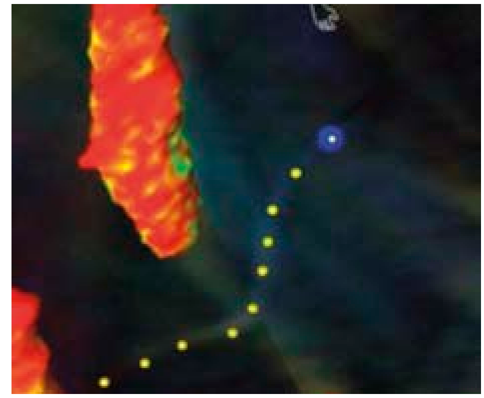
Adaptive Geobodies, has been designed to accommodate a significant degree of heterogeneity in the expression of the geological element being defined. This mimics the human visual process and maximizes the degree to which the data is driving the process and hence its efficiency. It also feeds back information on how well the geobody definition respects the data. This is important in a system which allows the output to be varied based on a subjective (user) input as it enables areas where the geometry, morphology and volume of the object are strongly supported by the data to be differentiated from those areas in which the geobody definition is based on an interpretive decision. The Adaptive Geobodies technique is an exciting development because it allows 3D geological elements to be defined from the data where previously this has been impossible. The Adaptive Geobodies allows complex geological elements to be incorporated into 3D geological or reservoir models based on a data-driven analysis rather than on a stochastic model-based estimation of what might be there.

Another example of how the Geological Expression approach can extract previously inaccessible information is in fault analysis. As mentioned earlier, looking at the different ways in which faults are expressed in seismic data can indicate lithological changes along a fault. Through utilizing an Adaptive Geobodies approach faults can be delineated as 3D entities as they are in nature rather than as 2D surfaces. Bringing these two approaches together opens the door to more effective use of 3D seismic data in fault seal analysis and understanding faults as hydrocarbon migration pathways or even reservoirs.

Bridging the Gap

A central aspect of improving workflow efficiency is making many of the processes in interpretation interactive. Seismic facies classification techniques have been an important but specialist area in seismic interpretation for a decade or more. In the Geological Expression workflow the interpreter is in direct control and can see the effect of their choices, removing the mystique associated with conventional methods, which are based on neural network approaches. As a consequence seismic facies analysis is made accessible beyond the specialist user population. It also means that results are delivered in real time rather than at the end of long processing runs.

The primary focus at the moment is on post-stack Geological Expression workflows but it would be logical to extend these into the pre-stack domain. The use of pre-stack increases the data analysis burden by a factor of 100 or more. So, can we integrate pre-stack analysis without losing the interactivity which is central to the data-driven, interpreter-guided approach and which makes the Geological Expression workflow so efficient? It is increasingly looking like the answer to this question will be 'Yes'. Interactive pre-stack gather conditioning technologies are already commercially available, such as the Pre-Stack Pro system from Sharp Reflections in Norway. From where we are today it may be a large step in terms of technology development, but is a relatively modest intellectual step to a joint pre-stack / post-stack Geological Expression workflow.

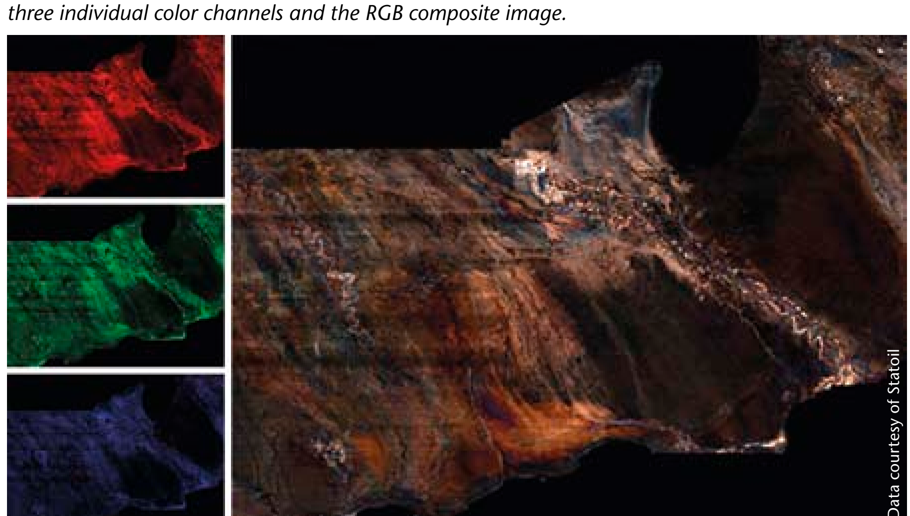


The first point in the Adaptive Geobodies workflow: multiple seed points are picked to adapt the region to be grown.

The Geological Expression approach to seismic interpretation bridges the gap between processing and conventional interpretation, increasing enormously the level of geological understanding that can be obtained from 3D seismic data. By allowing the interpreter to manually edit the growth of the geobody and to interactively change parameters while the process of growth is active, this technique makes maximum use of both the available data and expert knowledge of the interpreter. The combination of local data statistics and multi-attribute inputs means that the Adaptive Geobodies replicates some of the power of the human visual system whilst simultaneously providing objective analysis and understanding of the shape and geometry of neighboring features on a scale that cannot be achieved using surface-based horizon interpretation.

The Geological Expression workflow gives on-demand extraction of geological features, enabling the interpreter to consider and adapt what is being expressed within the geology – be this in automated fault delineation, facies classification, subtle karst features or complex fan geometries. The data-driven, user-guided approach means the speed of analysis will equal the speed of interpretation to reveal the optimum geography of the geology. Essentially it brings geology and geophysics together to directly translate geophysical data into geological understanding. ■

RGB display offshore Angola showing the incredible geological detail that can achieved by utilizing high resolution color visualization to display information derived from 3D seismic data, showing three individual color channels and the RGB composite image.



Data courtesy of Statoil

The Power of the Portfolio

Successful exploration begins, of course, with the talented geologists, geophysicists, and engineers who develop leads and prospects, secure funding, and then see their ideas tested. However, another important ingredient of a successful exploration mix is the process that underpins the exploration investment cycle.

DEAN HENNINGS

Since Anadarko Petroleum Corporation acquired Kerr-McGee in 2006, the company has established itself as a premier exploration company, drilling an average of 20 deepwater exploration/ appraisal wells each year. Since 2008, this drilling program has achieved an overall success rate of 70%, compared to an industry average of less than 50%. The company has been successful in opening new exploration plays in Mozambique and West Africa while continuing its successful exploration program in established plays such as the Gulf of Mexico and Brazil.

In this article Dean Hennings describes the exploration investment process, from the vantage point of a geoscientist who has participated in this process from several different perspectives.

Global Portfolio

Anadarko maintains one global portfolio for its exploration and appraisal inventory,

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Flow test offshore Mozambique, where Anadarko is involved in several massive gas discoveries meaning that every opportunity has to compete for capital with other investment opportunities in the portfolio, with, for example, exploration prospects offshore Mozambique competing with those in the Gulf of Mexico. This approach enables the company to optimize its investment decisions and shift capital in response to varying market conditions and changes in our understanding of prospects in the inventory.

One exception to this approach is that exploration prospects do not compete with development opportunities for capital. Anadarko is committed to exploration and intentionally invests around 20% of its annual capital program in exploration and appraisal efforts.

Explorationists generate multiple ideas. The most promising of these are developed into leads. Further technical work is carried out on the lead-inventory, and the best leads are matured into prospects, which are then fully characterized and placed into the portfolio. A key insight from the funnel model is that attrition is a normal part of the exploration process. And, typically, the larger the opportunity set, the greater the possibility of selecting the best opportunities for the next stage of the process.

There are also some challenges in this idealized process.

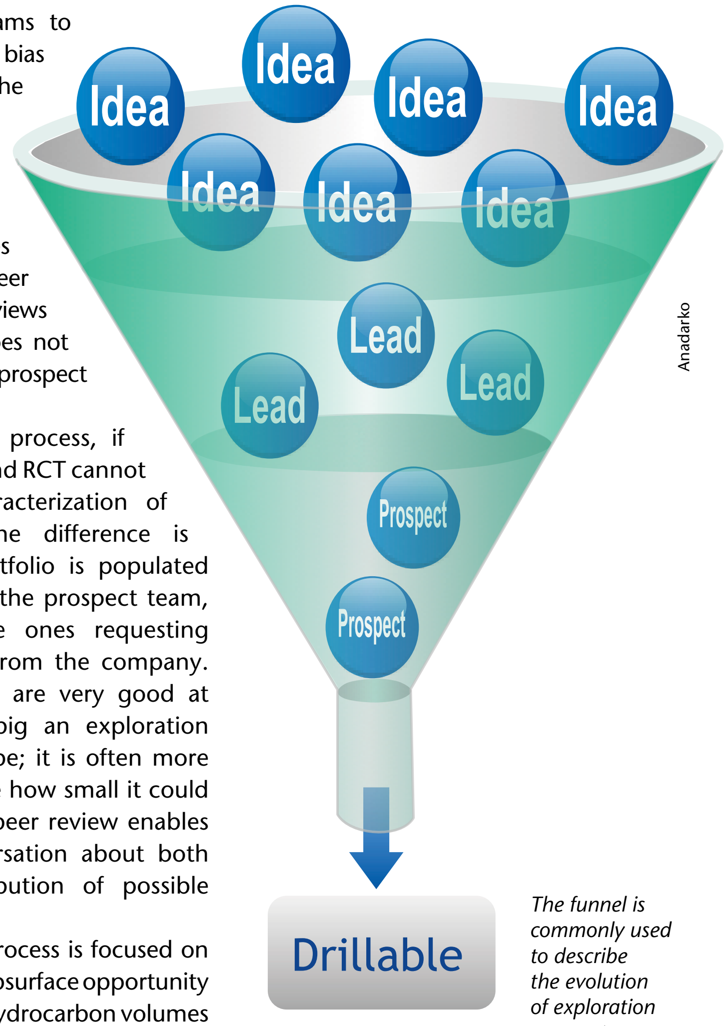
One challenge is that there can be different motivations between the prospect team, which wants to see its opportunities drilled, and the company, which wants to see the best opportunities drilled. And companies that reward successful explorers (defined as those who drill successful wells) could find themselves encouraging salesmanship and overly optimistic evaluations of exploration prospects.

Estimating Risk and Resource Potential

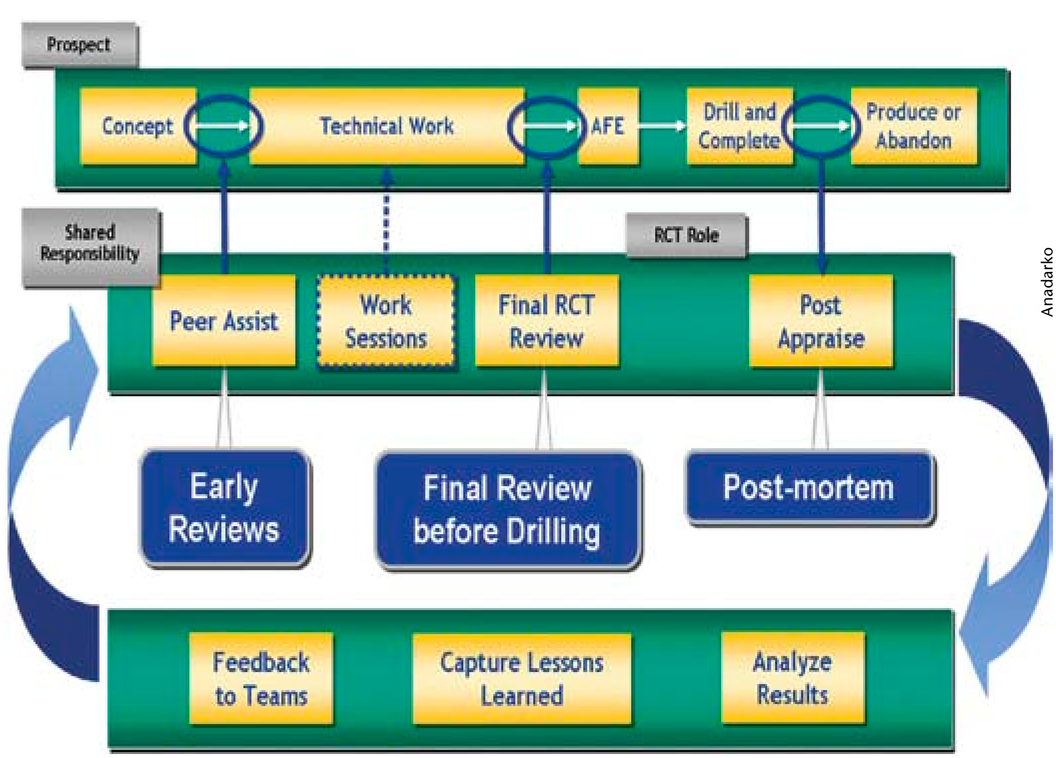
To combat this, Anadarko has a Risk Consistency Team (RCT) that works with exploration teams to minimize personal bias and characterize the subsurface risk and potential of leads and prospects in a consistent manner. The RCT accomplishes this through peer assists and peer reviews and, importantly, does not function as the 'prospect police.'

In the Anadarko process, if the prospect team and RCT cannot agree on the characterization of an opportunity, the difference is noted, but the portfolio is populated as characterized by the prospect team, since they are the ones requesting investment capital from the company. Generally, explorers are very good at figuring out how big an exploration opportunity might be; it is often more difficult to recognize how small it could be. The process of peer review enables often robust conversation about both ends of the distribution of possible outcomes.

This part of the process is focused on characterizing the subsurface opportunity in terms of possible hydrocarbon volumes and probability of geologic success.

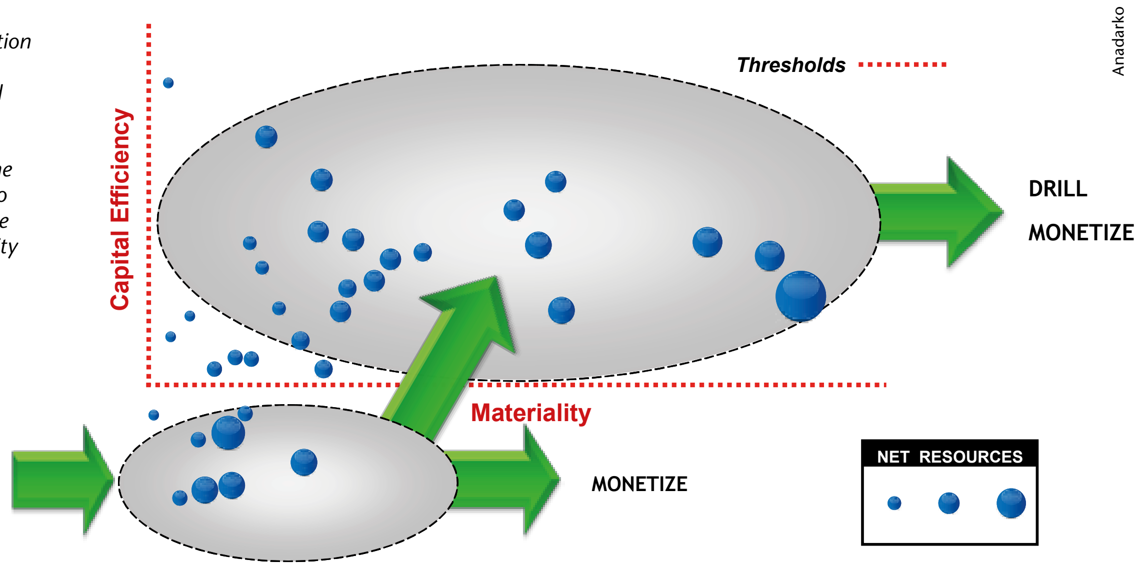


The funnel is commonly used to describe the evolution of exploration prospects.



Worldwide Exploration Net Risked Opportunities

High Grading the Exploration Inventory: Materiality, or Net Present Value, plotted against Capital Efficiency, which is a ratio of profit over investment results The size of the bubble varies to represent the Net Resource Potential of the opportunity



Exploration carries inherent risks both financially and geologically. However, risk itself is neither good nor bad, if it is accurately understood.

Probably the majority of companies who engage in exploration follow some form of this process. A frequently neglected part of a robust risk characterization process is the post-mortem. Explorers deal with the unknown and by definition cannot know what the drill-bit will discover. Post-mortems create the critical feedback loop that enables exploration teams to calibrate their risk assessment process, with questions like, "are we too optimistic (or too pessimistic) in our assessment of risk?" or "are we too optimistic (or pessimistic) in characterizing the size of our opportunities?" Since implementing its probabilistic exploration process, Anadarko has conducted rigorous annual lookbacks of its exploration program and has generated discovered volumes that are within a few percentage points of the risked-mean prediction for the portfolio.

Commercial Analysis

Estimating the resource potential of an exploration opportunity can be likened to an assay.

Once the hydrocarbon potential of the opportunity has been assessed, the next step is to characterize it commercially. Inputs from the subsurface evaluation are used to create risked economics so that opportunities can be evaluated on a level playing field.

Anadarko summarizes the results of its technical and commercial analysis of each opportunity with three key metrics, which are then placed on a graph for comparability. This stylized representation of the opportunity inventory shows a range of captured opportunities, including some that are below the company's investment threshold. Some of these are opportunities that our explorers believe could be more significant after key technical work is completed. Other opportunities below the line could be candidates for monetization.

It is important to note that Anadarko does not conduct exploration by spreadsheet. Our view is that the technical analysis is feedstock to good decision making, but investment decisions are too complex to be reduced to one set of numbers.

Comparing Apples and Oranges

Anadarko's investment process greatly facilitates the evaluation of international

It is difficult to remove subjective bias when comparing items which are inherently different

new venture opportunities. Our INV team looks at more than one hundred investment opportunities each year. The question they ask is not "Is this a good prospect?" but rather, "Would this opportunity compete for investment capital within our portfolio?"

Rather than picking prospects, let us assume our objective is to select the best piece of fruit. Is an apple better than an orange? Is a mango better than a banana? The answer depends on what we desire more, but it also illustrates the difficulty of removing subjective bias when comparing items that are inherently different.

The first thing we need to do is to compare like for like: bananas with bananas, apples with apples, etc. Then, we ask the question, "What are my needs?" Do I need mangos or bananas, or some of each? This thought experiment is very relevant to the exploration business where we are called on to make decisions like conventional versus unconventional; deepwater or onshore; short, medium or long term?

We then reach the point where we have to decide which fruit we are going to pursue, and which are the best of those? The larger the bushel of apples, the simpler it will be to select the best of the bunch. It is easier to select the best three of ten than the best three of four. This insight is very important to our portfolio approach to exploration investment decision making. We always want our opportunities to compete for capital, which means that in an ideal world we will always have more opportunities in our portfolio than we can fund in a given period of time.

We can look at our apples as long as we want, but at some point, the true test of our selection ability is to take a bite of our apple. We can predict, based on our experience and intuition, but until we bite we cannot know with certainty what the apple will taste like.

As good as we think we are, we also know that some of our

We look at our options, evaluate and decide which investments to make. This is where the power of the portfolio is so evident; it is much easier to select the best three of ten than it is to select the best three of four.

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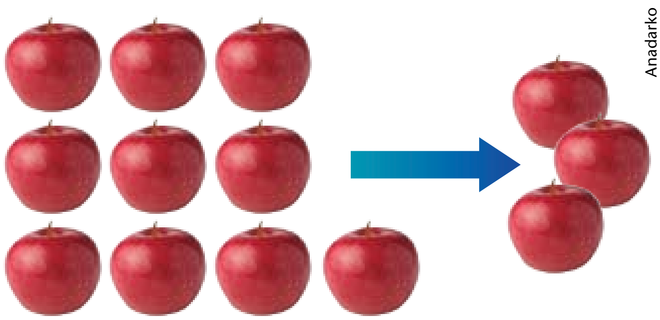
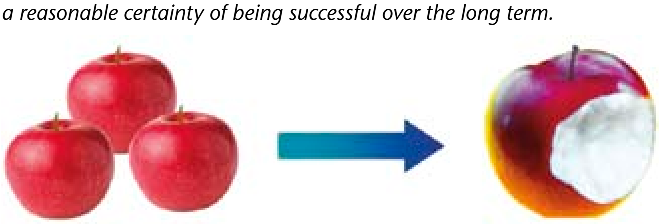


But we do not know which options will work, or how well they will work, until we take a bite! We need to invest in enough opportunities to give us a reasonable certainty of being successful over the long term.



investment opportunities will not work out. But, if we are good apple-estimators, and if we purchase more than one apple, we are confident that over time our apple-picking abilities will be vindicated.

We all learned in our Probability and Statistics courses that accuracy in predicting outcomes is improved with a larger sample size. At Anadarko, we implement this principle by actively managing our working interest in exploration opportunities. We typically target a working interest in the 30–50% range for exploration wells. This enables us to increase the number of exploration wells drilled (bites of the apple) and thereby improve our ability to meaningfully predict what our exploration portfolio will deliver.

The beautiful thing about exploration is that we will always encounter surprises. We never know as much as we think we do. Sometimes, these surprises prove to be dry holes. Sometimes, they are significant discoveries. At Anadarko the portfolio approach has created a useful paradigm for project selection and positioned the company for repeatable exploration success that has resulted in the aforementioned 70% success rate over the last five years. ■

Acknowledgment: The basis for this article grew out of a collaborative effort between the author and David O'Brien, Director, Reserves Administration & Portfolio, Anadarko Petroleum Corporation.

Dean Hennings has more than 30 years of experience in the oil and natural gas industry. He began his career with Arco in 1980 and has held management positions in subsurface risk consistency, geoscience technology, information technology, exploration and development. He recently completed assignments in Anadarko's Investor Relations and New Ventures teams prior to moving to Rio de Janeiro, where he is President of Anadarko Exploração e Produção Ltda.

Vignettes from Anadarko's Portfolio Approach

Lucius: In the Gulf of Mexico, Anadarko had several blocks that were approaching expiration. The company was aware that a competitor had drilled a nearby discovery, so the exploration team reworked the area, recharacterized the Lucius prospect and realized that the opportunity now looked attractive in the portfolio. Within nine months, a rig was on location and had drilled a significant discovery, Lucius, that is now being developed.

Gulf of Mexico: During the drilling moratorium Anadarko's portfolio approach to exploration investment decision-making enabled it to shift capital from its Gulf of Mexico program and accelerate delineation drilling in the onshore Eagle Ford play in south Texas and the Wattenberg field in northeastern Colorado.

Mozambique: Anadarko's willingness to invest in frontier exploration led to multiple, significant play-opening exploration wells being drilled offshore Mozambique. These massive natural gas discoveries have created the opportunity for Anadarko to extend its project management skills into LNG, which will benefit the company and the country of Mozambique.

Peregrino: Sometimes opportunities are more valuable in the portfolio of another company. In 2008, non-operating partner Statoil approached Anadarko with an offer to purchase our share of the heavy-oil Peregrino field development project, offshore Brazil. One rationale behind this transaction was that Statoil could value the asset more highly than Anadarko because it was intending to leverage its downstream capabilities and blend the 14° API crude to increase the overall value of Peregrino crude. This underscores the point that Peregrino was neither a good nor a bad investment opportunity. It was more valuable to Statoil than it was to Anadarko.

Ghana: In 2007 Anadarko and its partners drilled the discovery well for the Jubilee field. The subsurface characterization of these large Upper-Cretaceous turbidites was problematic. It was a new play type, and there were many unknowns. The initial areal estimates were probably not large enough, but the knowledge that came from the early drilling was quickly captured and used to update the characterization of our inventory in the West African transform margin.

The Kwame Nkrumah FPSO, offshore Ghana. The Jubilee Field is operated by Tullow Oil plc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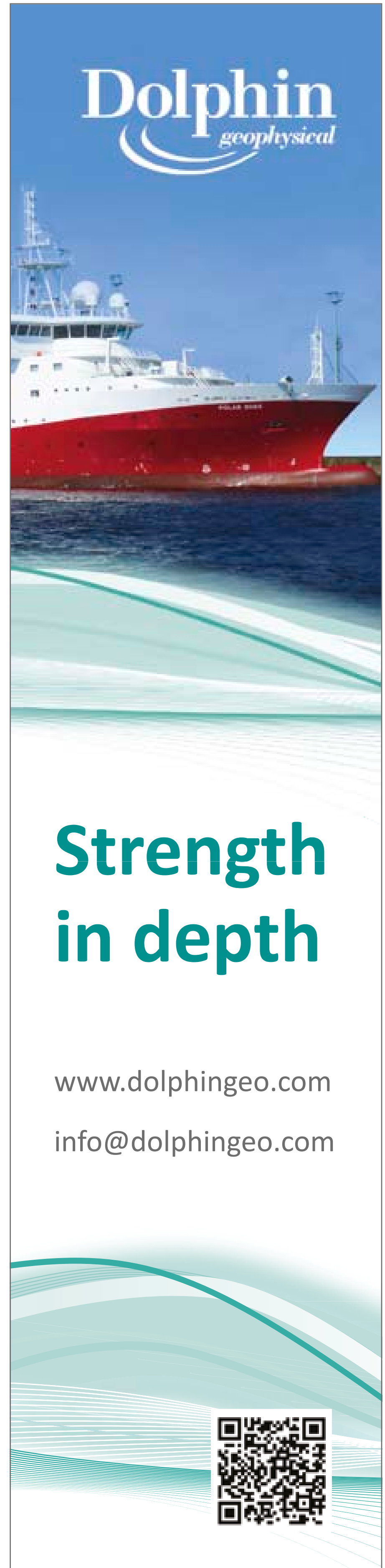
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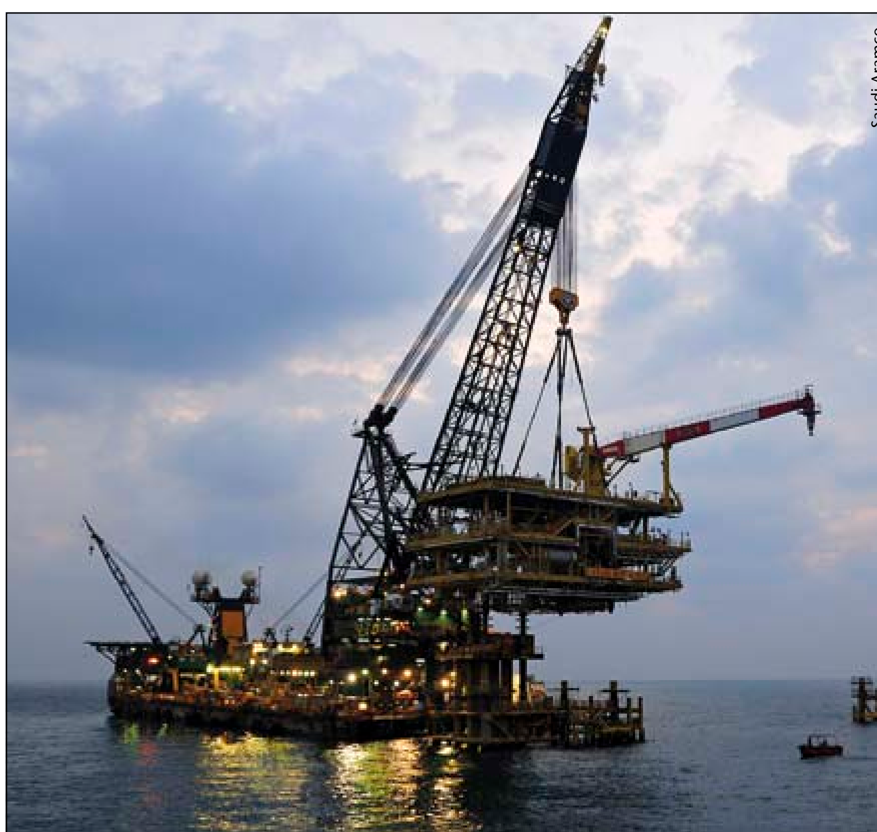
Saudi Arabia: Red Sea Gas

Saudi oil minister Ali bin Ibrahim al-Naimi has revealed that Saudi Aramco has discovered a new gas field in the Red Sea, 26 km north-west of the port of Daba. Two intervals have been tested: one at 5,265m flowed 5.2 MMcfgpd while the other at 5,394m flowed 10 MMcfgpd. Operations at the site (the well name has yet to be revealed by the company) continue but appraisal drilling is already being considered to fully evaluate the size of the find. This offshore drilling campaign follows a 15-month seismic acquisition drive that commenced in 2009 and which not only indicated the potential for significant gas reserves but also that the Red Sea is over two kilometers deep in places, with a salt sequence over 2,110m thick.

As concerns about domestic energy demand increased, Aramco has remained focused on major offshore gas developments, adding 3.6 Tcf to its gas reserves in 2011. They now stand at 282.6 Tcf, the fourth largest in the world. While it has raised gas output significantly, it has not been able to keep up with a 6% per year increase in Saudi demand. There are plans to increase gas output from 9.4 Bcfgpd in 2010 to 15.5 Bcfgpd in 2015. Teams have completed the initial analysis of offshore areas south-west of Julayjilah and Midyan in the lightly-explored Red Sea – some 800 km north of Jeddah, and near the border with Jordan.

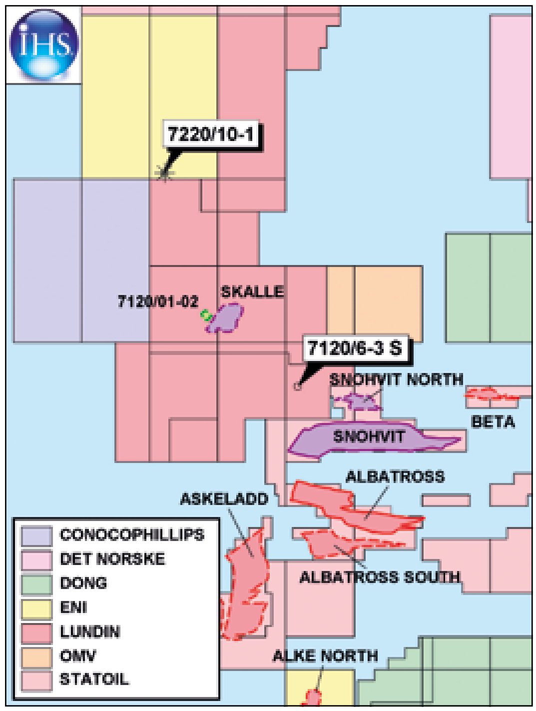
Karan, Aramco's first non-associated gas project, is on track to achieve peak production of 1.8 Bcfgpd in 2013, while the 2.5 Bcfgpd Wasit development, which will take gas from the offshore Hasbah and Arabiyah fields, should come on stream in 2014.

An offshore platform in the Karan gas field, a key discovery in Aramco's focus on offshore gas development.



Norway: More Barents Sea Gas

Operating PL533 with a 40% interest, Eni has completed exploration well 7220/10-1, located on the west flank of the Loppa High, north-west of the Snohvit area in the Barents Sea, and declared it to be a gas/condensate discovery. Drilled to a total measured depth of 2,405m on the Salina structure, the well proved two good quality gas columns in sandstone of Cretaceous and Jurassic age.



According to the Norwegian Petroleum Directorate (NPD), the first target in the Knurr formation was found to be a 38m gas-condensate column, while the secondary target in the Stø formation was found to be 54m thick. The NPD said that the preliminary estimate of recoverable reserves for the Salina discovery is between 29 and 41 MMboe. This is a particularly encouraging result given that a few days earlier, Statoil had revealed that studies of natural gas reserves in the Snohvit license area in the Barents Sea had concluded there wasn't enough there for gas export expansion.

Continuing the industry exploration drive in these Arctic waters just north of Snohvit, Lundin Petroleum, a partner in the PL533 license, spudded its 7120/6-3 S exploration well in PL490 on October 11, 2012. This is testing the Juksa/Snurrevad prospect, a Late Jurassic/Cretaceous stratigraphic play with 201 MMboe potential net to the company. ■

USA: Nevada 'Game Changer'

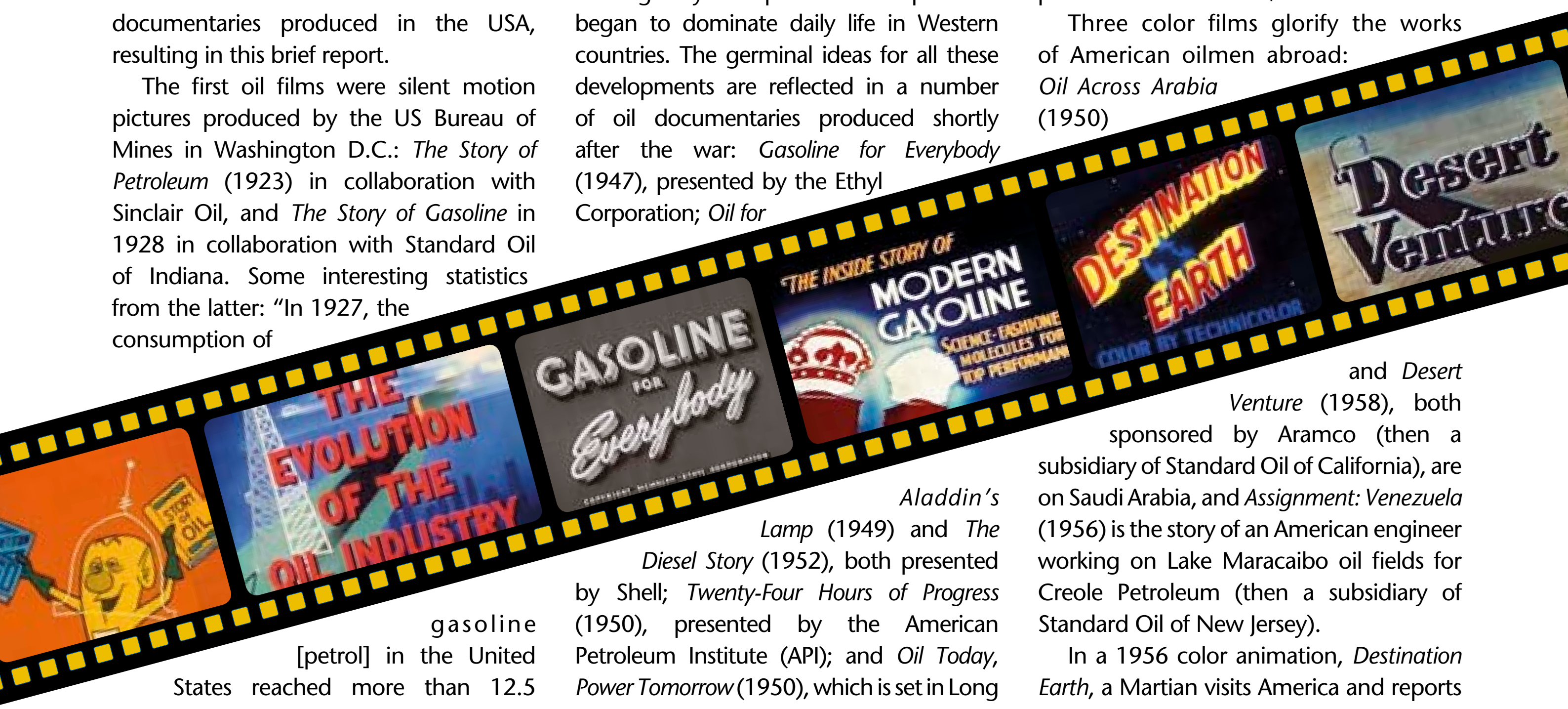
For many years geologists have speculated that there is undiscovered oil under Nevada. Through its wholly owned Major Oil International subsidiary, Irish explorer US Oil and Gas may have proved this to be something more significant than speculation. While the company's official line is one of caution until testing and analysis is complete, local media are saying the find could be the biggest of its type in US history.

Well Eblana-1, in the company's Hot Creek Valley acreage, identified nine large potential oil reservoir intervals (around 335m cumulative net pay) and associated high fracture zones, before reaching target depth of 2,606m in May 2012. Production testing to collect further data, including flow rates and reservoir pressure, commenced early in September and of the 20 potential pay zones identified, up to 15 will be perforated. The company is now planning Eblana-2.

Before Eblana-1 spudded, an independent report by Forrest Garb and Associates estimated gross prospective resources of 189 MMbo in place (P50), with 67 MMbo recoverable. Company chief executive Brian McDonnell confirmed there had been a find but emphasized that testing is not complete, adding, "We would like to verify the flow test results from this well before we say anything more, but we are very excited, and I think it is good for Nevada too." In Nevada, however, the well is already being trumpeted as a possible 'game changer' for the crippled local economy. ■

Historical Oil Documentary Films

A chronicle of historical documentary films on oil: your parents and grandparents may have watched these on their old TV sets, but you can now see them on YouTube!



Although a large number of documentary films (often negative) on oil have been produced over the past two decades (*GEO ExPro*, Vol. 9, No. 4), oil documentaries have been aired for decades. Recently, I searched for these historical oil documentaries produced in the USA, resulting in this brief report.

The first oil films were silent motion pictures produced by the US Bureau of Mines in Washington D.C.: *The Story of Petroleum* (1923) in collaboration with Sinclair Oil, and *The Story of Gasoline* in 1928 in collaboration with Standard Oil of Indiana. Some interesting statistics from the latter: "In 1927, the consumption of gasoline [petrol] in the United States reached more than 12.5 billion gallons; in addition, nearly two billion gallons were exported." In 1927, the US population was 119 million. Compare those data with today: in 2011, 310 million Americans owning 254 million vehicles consumed 138 billion gallons of gasoline. In other words, from 1927 to 2011 the US population increased 2.5 times and its gasoline consumption 11 times. (A barrel contains 42 US gallons.)

From 1935-41, during the Great Depression, the Jam Handy Organization produced dozens of promotional films for the oil and automobile industries, including *More Power to You*, narrated by Lowell Thomas, Sr.; *Down the Gasoline Trail*; and *Free Air*.

After World War II, global demand for oil increased drastically, and in addition the use of television sets skyrocketed. The US, in particular, launched an aggressive expansion of automobile transportation and highways and petrochemical products began to dominate daily life in Western countries. The germinal ideas for all these developments are reflected in a number of oil documentaries produced shortly after the war: *Gasoline for Everybody* (1947), presented by the Ethyl Corporation; *Oil for Aladdin's Lamp* (1949) and *The Diesel Story* (1952), both presented by Shell; *Twenty-Four Hours of Progress* (1950), presented by the American Petroleum Institute (API); and *Oil Today, Power Tomorrow* (1950), which is set in Long Beach, California. We learn from the latter film that "in 1950, the US produced 50% of the world's oil, worth $3 billion." This means a US production of 5.9 MMbopd in 1951 compared to 11.2 MM bopd in 1972 (US peak) and 7.8 MMbopd in 2011, which is about 9% of world production.

Color Arrives

The first color film on oil was *The Inside Story of Modern Gasoline* (1948), subtitled 'Science-Fashioned Molecules for Top Performance', produced for Standard Oil of Indiana and also presented under the title *The Story of Gasoline* by the US Bureau of Mines in cooperation with Standard Oil of Chicago. The film shows that distillation (fractionation by boiling points) of one barrel of crude oil yields gas (1%), gasoline (18%), kerosene (15%), fuel oil and gas oil (39%), lube oil and wax (7%), and residual oil and asphalt (20%). More gasoline can be produced from gas oil by catalyst-aided and thermal cracking.

Production from Bakken oil in Montana has become a hotspot in recent years (*GEO ExPro*, Vol. 7, No. 2). But this is not the first boom in the region: check out this 1953 black and white API film, *American Frontier*, which narrates how oil discovery on a wheat farm in the Williston Basin brings prosperity to the family of a local school teacher. A geologist in the film says that only one out of nine wildcats hits oil, and that a well in that part of America costs $0.5 million.

Three color films glorify the works of American oilmen abroad: *Oil Across Arabia* (1950) and *Desert Venture* (1958), both sponsored by Aramco (then a subsidiary of Standard Oil of California), are on Saudi Arabia, and *Assignment: Venezuela* (1956) is the story of an American engineer working on Lake Maracaibo oil fields for Creole Petroleum (then a subsidiary of Standard Oil of New Jersey).

In a 1956 color animation, *Destination Earth*, a Martian visits America and reports back how oil and free market have given the nation high standards of living and freedom of movement. *Progress Parade* (1960) is a collection of five brief oil-related stories including 'Fishing on Dryland', which shows how the broken drill bit – the fish – is taken out of the well.

The above-mentioned documentaries are oil industry-sponsored promotional films produced before the environmentalist movement took off in the 1960s. The films are in the public domain; more information can be obtained from National Archives and Records Administration, Room 4000, 8601 Adelphi Road, Hyattsville, MD 20740-6001 (www.archives.gov).

RASOUL SORKHABI

Brazil's Sub-Salt Discoveries Extend North

Recently announced deepwater, sub-salt discoveries in the Sergipe-Alagoas Basin extend that trend into Brazil's north-eastern continental margin, over 2,000 km north of the Santos Basin discoveries.

THOMAS SMITH

The smaller onshore portion of the 44,000 km² Sergipe-Alagoas Basin has been explored for hydrocarbons since 1935, with the first commercial oil discovery in 1957. The basin's largest field to date, Carmópolis, was discovered in 1963 and was Brazil's first giant and remains its largest onshore oil field. Oil in place is estimated at 1.3 Bb and the field has now produced more than 400 MMbo.

The Carmópolis Field was a sub-salt discovery in the Muribeca Formation, and is interpreted as deposited in a transitional environment with marine influence, as expressed by the thick evaporite sequences overlying the Aptian reservoirs. The Upper Aptian microbial boundstones were deposited along the Aracaju High, a basement structure located in the margin of the basin. These reservoirs are very similar to those found productive in the Santos, Campos and Espírito Santo basins to the south.

Deepwater Discoveries

Petrobras's first deepwater discovery in the basin was located about 100 km off the Brazilian coast from the city of Aracaju. Announced in late 2011, well 1-SES-168 (Barra) found high quality gas. In August, 2012, the company announced the completion of the Barra extension, informally referred to as Barra 1 (3-SES-165) well, drilled in 2,433m water depth approximately 10 km south-east of the Barra discovery well. This well confirmed the south-eastern continuity of both the gas accumulation in the upper section of the Mid-Cretaceous Calumbi Formation and oil-saturated reservoirs in the lower section, which is also a post-breakup, Mid-Cretaceous stratigraphic sequence. The lower reservoirs with 38° light oil were found at depths between 5,460 and 5,500m.

In August Petrobras announced another oil discovery (1-SES-168) about 85 km off the coast and 35 km south-west of the Barra accumulation. Known as the Moita Bonita discovery, the well is located in a water depth of 2,775m with a 300m oil column at a depth of 5,070m with 52m of porous sandstones. Finally, in October, Petrobras announced the presence of hydrocarbons in the Farfan well (1-SES-167) drilled at 2,720m water depth 109 km offshore and 10 km south-east of the Barra extension well. A 40m section of porous sandstone containing light hydrocarbons was detected at a depth of 5,582m. Petrobras is proceeding to drill this well up to a depth of 6,000m and will analyze the rocks and fluids before submitting an appraisal plan to the Brazilian National Petroleum, Natural Gas and Biofuels Agency (ANP).

Across the Atlantic

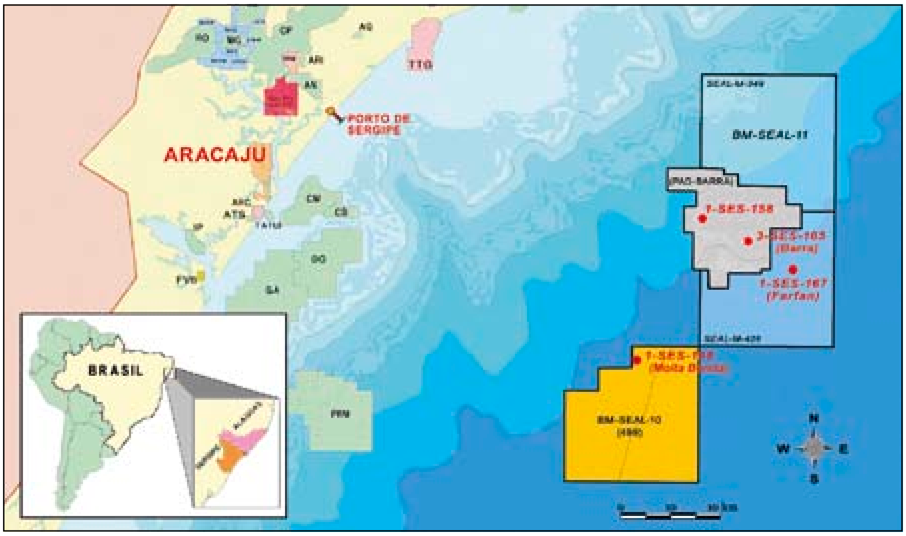
The success in the Sergipe-Alagoas Basin off the Brazilian coast has led to another hot area in the Gabon deepwater sub-salt play. Oil production peaked in Gabon in 1997 at 370,000 bopd and the country has since seen a 34% reduction in production, dropping from the third largest oil producer in sub-Saharan Africa to now sixth at 246,000 bopd. The similarities between the two areas have not been overlooked in the past decades, with several works from geoscientists from Petrobras and the University of Miami comparing the conjugate margins development and hydrocarbon prospectivity.

Harvest Natural Resources made an oil discovery in 2011 which was confirmed by a sidetrack well that encountered oil 1.2 km south-west of the first well. Petrobras has bought into Ophir Energy's two exploration blocks and other international companies such as Shell, Repsol and Cobalt have shown a great deal of interest there.

Cobalt already has a sub-salt inventory of the Rabi-Kounga Field (940 MMboe) and the 1982 Maruba #2 sub-salt oil discovery. The company has acquired 6,000 km² of 3D seismic and expects to start drilling late this year or early 2013.

Sub-Salt Estimates

The sub-salt play just keeps on getting better, with more discoveries up and down both sides of the Atlantic. The ANP sees the potential as huge. Just along Brazil's coast, the ANP sub-salt findings predict reserves of 50 Bbo. However, geologist Hernani Chaves, currently a professor at Rio de Janeiro State University and former Petrobras geologist, estimates their reserves to be at least 123 Bbo – quite a jump from the country's previously established reserves of 14 Bbo. It only follows that all the countries along the West African coast are actively pursuing sub-salt oil and gas opportunities. ■



Stimulating Exploration Growth

How can oil companies be encouraged to continue exploring in a mature area like the UK Continental Shelf? *John Austin*, Managing Director of OMV in the UK and Chairman of the Technical Committee for Prospex 2012, has a few ideas.

Can you tell me a bit about yourself and your career to date?

I am a geophysicist originally, and joined the oil industry straight after university because I loved the idea of using technology to find new hydrocarbon resources, and of working in an exciting business, key to global economic growth. Nothing's changed in 30 years! I have worked in all aspects of geophysics for various contractors and oil companies, so I gained an excellent grounding in the technical side of the business before moving into more management roles over the last 20 years – exploring South East Asia, seeking out business development deals in the Middle East, managing global exploration programs and lastly building a growing business in the UK. My formative years in the business were with Enterprise Oil – regarded at the time as a real innovative explorer – and I gained an enormous breadth of experience in a competitive and collaborative environment there. At OMV, I can bring all my experience to bear on growing the UK business through exploration and business development.

What is your role in Prospex and why did you get involved?

My main responsibility at Prospex is the Technical Program, which is generally the responsibility of the President-Elect of the PESGB (Petroleum Society of Great Britain). It's a real pleasure to see how best to put a program together that will be of interest to attendees, while also offering a good service to those sharing their prospects with the industry. The key is to get a mix of 'Prospects to Go' and presentations by industry bodies and experts who can help with solving exploration problems. I think we've got a good balance this year, with a cross-section of presenters from across the industry and across north-west Europe.

The first Prospex was initiated as a way to stimulate UK exploration growth. Was this effective?

Prospex (then called the Prospect Fair) was part of the UK PILOT initiative designed to help reverse the decline in UKCS activity and increase the chance of success. There is no doubt that the initiatives undertaken over the last ten years have helped to re-vitalize exploration in north-west Europe, and Prospex has played its part. However, the effectiveness has been limited and UK exploration activity and success rates are dropping again. I feel passionately that there is much more to come in the UK, as well as in Ireland, Faroes and of course Norway, so we will do our best in PESGB and in future Prospex events to ensure we continue to play our part.

What other initiatives can be used by countries (not just the UK) to stimulate a flagging oil industry? Can you give us some examples of good ideas?

The best stimulant to investment in exploration is for us to all keep a close eye on costs, and for governments to ensure fiscal stability and support. Norway's exploration activity has expanded in the last few years in response to fiscal stimuli, but whether this actually improves exploration success rates and reduces finding costs is still debatable. The industry does need to see fiscal stability from governments, however, and this has been less obvious in the UK than elsewhere. I think it is important for the industry to work closely with DECC (UK Department of Energy and Climate Change) to increase activity and I am co-chair of their recently established Exploration Task Force, which will look at ways to keep the UK industry motivated.

Why is it important to include service organizations as well as prospecting companies at the exhibition?

The industry can only work well with true partnerships between all companies. Operators and JV partners need to collaborate closely in order to use their collective knowledge wisely and efficiently. Similarly the relationship between contractors and exploration companies should also be seen as more collaborative. Much of the new technology comes from contractors, not explorers, and in order for the explorers to benefit from it, there must be close interaction.

How is the 10th anniversary of Prospex being celebrated?

The 10th Prospex is being marked most notably by a special Panel Session at the end of Day 1, where the question: 'What are the Prospects?' will be posed to the panel and audience. This session will look back over the last 10 years of Prospex and the exploration of the UKCS, and speculate on what are the prospects for the future, indeed also where are the prospects, and how big are they! ■

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.

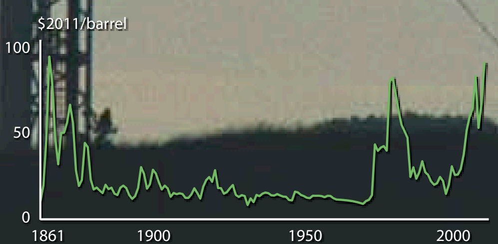
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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



Big Numbers – Substantial Growth

By increasing the daily output from today's 3 MMbo to 8.3 MMbo, Iraq will be largest contributor to global supply growth over the period to 2035

Iraq is currently producing 3 MMbopd. However, as reported by the International Energy Agency (IEA), contracts already in place with international companies imply an extraordinary increase in oil production capacity, to a level almost five times higher than today's production over the current decade. It remains to be seen if this will work out, but reaching output in excess of 9 MMbopd by 2020 would equal the highest sustained growth in the history of the global oil industry.

In the IEA's 'central scenario', Iraq's oil production will more than double to 6.1 MMbopd by 2020 and reach 8.3 MMbopd in 2035. In comparison, only Saudi Arabia and Russia were producing more than that in 2011. Saudi Arabia's and Russia's oil production averaged 11.1 and 10.3 MMbopd last year, respectively.

In this scenario, the increase in Iraq's oil production of more than 5 MMbopd by the year 2035 makes Iraq by far the largest contributor to global supply growth. By the 2030s it would make Iraq the second largest oil exporter (from third today), overtaking Russia.

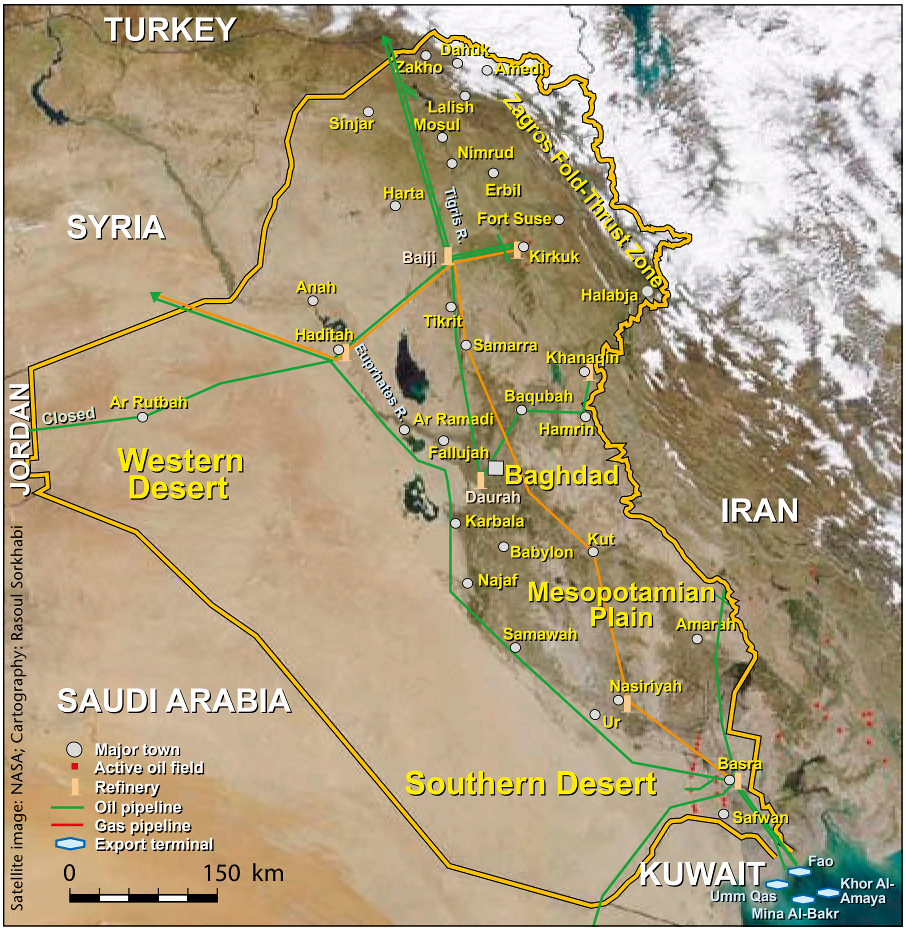
IEA believes the largest increase in production will come from the concentration of super-giant fields in the south around Basrah. In addition, there is expected to be substantial growth from the north of Iraq through contracts awarded by the Kurdistan Regional Government. Kurdistan is said to be one of the most actively explored petroleum provinces in the world.

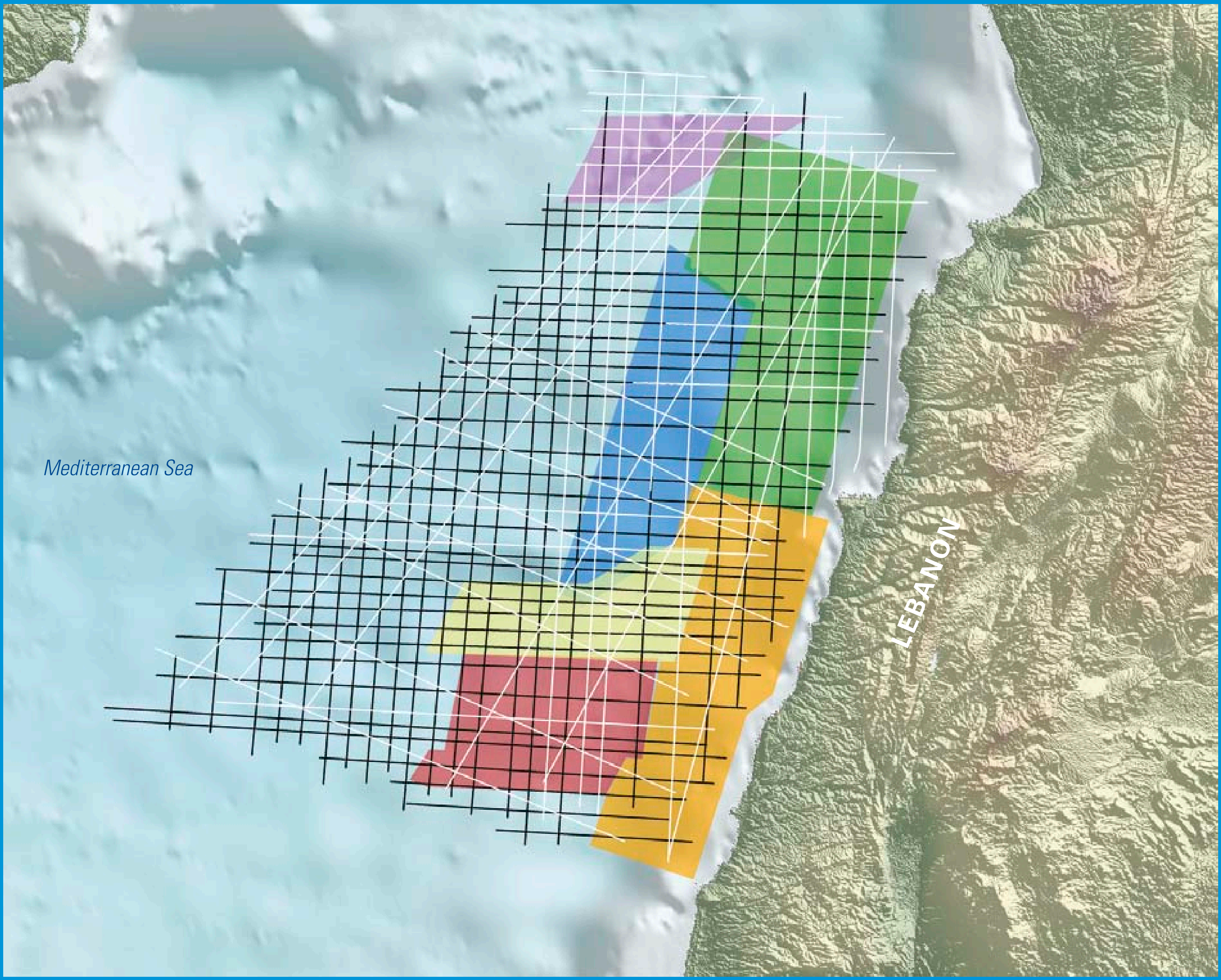
Achieving such a high level of oil production and export means a proper supply of rigs, bringing water from the Gulf for injection, as well as storage and transportation capacity.

HALFDAN CARSTENS

See also Iraq's Resource Base (GEO ExPro Vol. 6, No. 3) and Oil from Babylon to Iraq (GEO ExPro Vol. 6, No. 2)

With an area of 438,317 km², a population of 29 million, and a rich petroleum base, Iraq enjoys remarkable power in the Middle East.




Mediterranean Sea
LEBANON