Special report
Transforming Subsurface Interpretation
Finding Petroleum forum in London - Apr 13 2015
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Transforming Subsurface Interpretation

Finding Petroleum’s forum in London on April 13, 2015, "Transforming Subsurface Interpretation", looked at ways that subsurface interpretation could be improved by using state of the art technology, traditional geophysics / geology skills, and structured work processes.

The opening talk was from Keith Holdaway, advisory industry consultant with SAS Institute, and author of a book, “Harness Oil and Gas Big Data with Analytics: Optimize Exploration and Production with Data Driven Models”, published in May 2014 by Wiley.

Mr Holdaway was followed by a talk on seabed seismic recording with John Moses, Sales Director with Seabed Geosolutions.

A session on data integration included a talk on gravity gradiometry recording and data integration with Claire Husband, Senior Geophysicist with ARKeX, and John Brennan, Analytics and Data Management Strategy Lead, Oil & Gas, Hewlett-Packard.

This special Digital Energy Journal report includes an outline of all of the talks. For most of the speakers, the videos and slides are available free of charge online - you can see how to access from the links at the end of the article.

Karl Jeffery, editor, Digital Energy Journal

Keith Holdaway – how to do oil and gas data mining

Data mining in the oil and gas industry is about trying to work out which hidden trends and relationships in the data coupled with appropriate data-driven models will lead you to the right answer, with data scientists working together with domain experts, said Keith Holdaway of SAS

Data mining in the oil and gas industry is about working out which dependent and independent data relationships are identified and mapped to your business objectives, said Keith Holdaway, advisory industry consultant with SAS Institute, speaking at the Apr 13 Finding Petroleum London forum “Transforming Subsurface Interpretation”. It usually involves both data scientists and domain (oil and gas) experts, he said.

Mr Holdaway worked as a geophysicist at Shell for 15 years, and subsequently has been working on ways to develop ‘machine learning’ systems to try to complement traditional ways of looking at oil and gas data.

He is also the author of a book, “Harness Oil and Gas Big Data with Analytics: Optimize Exploration and Production with Data Driven Models”, published in May 2014 by Wiley.

Data mining techniques can be used to try to work out ways to make models with the data, and generating hypotheses worth modeling, to help you achieve your results.

“We try to integrate some of these analytical workflows and see if the data tells you a story,” he said.

All of the work needs to be geared around working out an ‘objective function’, the relationship between data elements which will help you achieve the objective you are looking for (usually, more oil).

A common trap is that people get very excited with the relationships they discover, but the relationships don’t actually help achieve the business objective, he said.

“Putting these [models] together from a data scientist perspective is one thing, but you must be able to operationalise these models in an existing architecture. If you can’t operationalise you can’t really gain,” he said.

Deterministic and probabilistic

Subsurface oil and gas data has many variables, and works best with probabilities, to help people make the best decisions, he said. You need to work out which variables will help you work out the probabilities in a high dimension input space.

The oil and gas industry has traditionally worked in a very deterministic way, looking for the right answers, using ‘first principles’ based on traditional scientific calculations and equations, he said.

Oil companies have got to a situation where they are only using 20 per cent of the data they have, because they only use data which enable these equations.
“We need some kind of visualisation along the roadmap, so experienced people can say, yes you’re going in the right direction here. We may need to tweak something to improve that process,” he said.

Trying to find the right answer is an iterative process, not a process where you can enter your data into a ‘black box’ and get the answer out.

In one example, Mr Holdaway gave subsurface data for a field in Oman, which contained a known oilfield, to someone with data mining expertise in the medical sector, but no geophysics expertise, and without telling him where the oil was. Deep Learning workflows were implemented to identify features indicative of DHIs based on a recursive set of neural networks.

“I said, do your thing as you did in the other industry,” Mr Holdaway said.

“He identified other areas close to a producing well. It worked very well.”

**Understanding production**

In another example, you might have one well which delivers good oil production, and a well nearby which doesn’t deliver anything, and you can’t understand why.

You can apply data mining techniques to try to identify the variables which are consistent in both regions, and then use those as a basis to understand the second well.

You could use this to come up with a better fracturing strategy for the second well, perhaps with a different proppant, based on what you have identified as the more important geomechanics of the field.

In one big oil company example, the company had an employee who was one of the world’s biggest experts on reservoir water level. He claimed that he knew everything there was to know about water level in the company’s reservoirs, and no computer system would be able to say why water cuts in some wells are higher than others.

The SAS data mining techniques showed that he might be wrong in how he was interpreting the fracture network.

“He’s ego wasn’t so big that he entertained the idea,” Mr Holdaway said.

“He decided to change the location of an injector well and producer well and it obviated some of the problems.”

“The data told him a story and he tried to give it some credence, and managed to increase production in that asset.”

The systems have also been used on production data, by one oil company which nearly destroyed part of its reservoir with water flood.

The data mining techniques came up with a probabilistic system which could forecast production for a particular well with 90 per cent confidence, he said.

This helped the company work out which stages of the well to leave open and which to close.

“All those kind of answers came through integrated production data, PLT data, and some of the geologic, petrophysical data,” he said.

**Expertise**

A company in Oklahoma City in the US has put together an ‘analytical centre of excellence’, where it uses many different software techniques to try to help upstream engineers, he said.

The company hired data scientists who have some understanding of the oil and gas industry.

“You have to be able to steer these guys so they are not trying to create algorithms, trying to be Newton and Einstein, and come up with something incredible which isn’t useful to the business,” he said.

Sometimes you need a lot of expertise to develop the right methods, but once they have been developed, you have a repetitive methodology which does not need so much skill to use.

“There’s a lot of interaction between data scientists and geoscientists,” he said.

“The output from predictive models is fed back into the traditional tools. It will give you a much more robust visualisation.”

**Managing data**

There are three different systems in upstream oil and gas – the reservoir, wellbore and facilities. All of these generate many different sorts of data.

The data has many different forms, including structured, unstructured, “big” data, high velocity data, real time data, batch data, spatial (related to space) and temporal (related to time).

Compared to other industries, the volumes of oil and gas data are not particularly large, but the variety of data can be very large, he said.
“Data management is one of the key issues,” he said. “We have to aggregate the data, integrate in an analytical data warehouse.”

Data mining techniques

There are two basic data mining techniques, supervised and unsupervised.

With “supervised” data mining, you split the variables into explanatory (or independent) variables and dependent variables. The aim is to try to find a relationship between independent and dependent variables.

With “unsupervised” data mining, all variables are treated in the same way (there is no distinction between explanatory and dependent variables) and you are trying to spot patterns and trends that cluster into characteristic profiles.

The data mining methods will look at many different models which could be used to give you the answer you are looking for.

Examples of data mining techniques include fuzzy logic, cluster analysis and neural networks. “These are all approaches to let the data do the talking,” he said.

“We have to quantify the uncertainty in those variables and evaluate the value inherent in the patterns,” he said.

The process looks for trends and hidden patterns.

Principal component analysis is a methodology to reduce the high ‘dimension’ of the data, if you can figure out which components are worth paying most attention to.

Watch Mr Holdaway’s talk on video at www.findingpetroleum.com/video/1336.aspx

Transforming Subsurface Interpretation

There are many areas of the world which have been surveyed many times by towed streamer, such as the North Sea. Using seabed seismic recording could illuminate the fields in a new way, he said, which helps understanding of the reservoirs and optimises the way they can be exploited.

Seabed seismic recording is not a new technology, but in the past has mainly only been used for areas which could not be accessed with conventional streamers, Mr Moses said. This was because seabed seismic used to be relatively expensive and had technical limitations. The latest advances have removed the barriers that previously existed and are also starting to close the cost gap. At the same time the uplift in the value of information is now being recognised.

The quality of seismic data improves with seabed recording. The receivers are able to record both P and S waves thanks to their 4 component sensors. The sources and receivers are completely decoupled which gives the oil company complete freedom to design full offset and full azimuth data sets, recorded in a quiet environment with full frequency bandwidth. Receivers can be placed in obstructed and shallow areas which are inaccessible by conventional means. Both imaging and reservoir attributes are dramatically enhanced and offshore field infrastructure is no longer a barrier to data acquisition.

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Seabed Geosolutions – acquiring seismic on the seabed

There is growing interest in recording seismic data with nodes on the seabed, particularly with areas hard to access with streamer vessels, said John Moses of Seabed Geosolutions.

Seabed seismic can offer a much clearer picture, and give you more flexibility in how you do your survey, than towed streamer, he said, speaking at the Finding Petroleum London conference on April 13, “Transforming Subsurface Interpretation”.

The cost per km2 of seabed acquisition is still relatively high compared to towed streamer methods for anything but reservoir scale studies, but the added value of information combined with evolving operational methods has been enough to persuade many oil companies to take the plunge to the ocean bottom.

The company is a joint venture between Fugro and CGG.

In the current oil price environment, spending money on good data can be a cost cutting measure, Mr Moses said, if it enables drilling to hit the reservoirs more efficiently. “It is about de-risking the [drilling] decisions,” he said. Good decisions have to be based on the best information.

The Dan Field showing the reservoir and wells - there are 58 oil producers and 50 water injectors.

Helping you get a clearer subsurface picture by using seabed data acquisition - John Moses, sales director, Seabed Geosolutions

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Towing streamers in the vicinity of platforms is a risky undertaking. It can only be done when current conditions are pushing the cables away from the obstruction which inevitably leads to a large gap in data coverage. Usually in the most critical area.

**Technology**

The technology, put simply, is to record seismic data using devices on the seabed, rather than from streamers towed behind a vessel.

The sensors (hydrophones or geophones) for recording the data can either be fixed to cables laid on the seafloor, or installed in standalone ‘nodes’ which are laid by a remote operated vehicle (ROV) or attached to robust connecting ropes.

The jargon is “Ocean Bottom Cable” (OBC) and “Ocean Bottom Nodes” (OBN).

**Azimuth**

With conventional towed streamer survey, the acoustic source is also towed behind the recording vessel. The sound waves echoing back from the sub-surface are only registered or sampled in a narrow azimuthal field.

Sometimes, a narrow azimuth is all you need, but a wider or full azimuth will give you much more ability to understand what you are looking at, he said.

“If your geophysical challenges are harder, you need more accurate information,” he said.

You can get multiple azimuth with a conventional towed streamer survey, if the vessel passes over the same area of subsurface three times in different directions. “But this multiplies your cost by three,” he said.

You could also do it by having a number of source vessels making seismic waves from different directions, but this also means more costs.

But with the seismic data being recorded with receivers on the seabed, you can record in any geometry you like. You can create seismic waves in different positions on the water surface and the nodes record everything they hear.

To illustrate the importance of multi-azimuth, consider if you were trying to work out the location of an object at the bottom of a swimming pool in the night, using a torch.

The torch light bends (refracts) as it goes through water. But since you don’t know the depth of the swimming pool or the degree to which the light refracts, you can’t calculate the location by shining the beam from one position.

The only way to do it is to shine the torch in the swimming pool from many directions and many distances, and then you will have enough data to make a calculation, he said.

Similarly, with seismic recording, if you can look at a subsurface object from many different azimuths and offsets, you can make a more accurate calculation and have confidence in locating your sunken treasure.

**Geophones and hydrophones**

Another benefit of recording on the seabed is that you can use geophones, which directly record ground movement directly as well as hydrophones.

Hydrophones can only record plane (P) waves, where the wave ups and downs are in the same direction as the direction of travel of the wave, as you would get from hitting the surface of water.

But geophones can also record shear (S) waves, where the ups and downs of the wave are perpendicular to the direction of travel of the wave (like waves on the surface of water). Shear waves are extremely interesting as their propagation in rocks charged with hydrocarbons is markedly different to their propagation through non charged rocks. It means that reservoir attributes can be more reliably estimated.

Shear waves are very useful when sending seismic data through an area with lots of gas bubbles (as often found over a reservoir). P waves will undergo interference as they pass through gas, which makes them very hard to interpret. If there is a gas cloud above a reservoir it can be very difficult to see the reservoir beneath using P-wave data recorded by hydrophones, but shear waves recorded by the geophones allow a clear...
The area had very strong water currents, which offshore West Africa.

In a second example, the area to be imaged was offshore West Africa.

The area had very strong water currents, which made it impossible for a streamer vessel to approach the tension leg platform located above the reservoir.

Seabed Geosolutions delivered nodes to the region in containers, then using in-field ROV facilities a carpet of nodes was positioned on the seabed centred on the platform in water depth greater than 400m.

The inevitable huge hole in the streamer derived data was seamlessly filled by the node data, which also showed improved detail thanks to the full azimuth characteristics.

A third example from the North Sea, looking for shallow gas below the platforms, which could not be imaged using streamers.

A fourth example was from South East Asia, where the oil company had a problem with shallow gas cloud disturbing the seismic image of the reservoir. The P-wave data even recorded on the seabed showed a lot of disturbance above the reservoir, but the S-wave data was much cleaner. By being able to safely put receivers near the obstructions on the seabed you can complete the missing data and have a much improved image of the reservoir.

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Transforming Subsurface Interpretation

**ARKeX – integrating gravity and seismic data**

Claire Husband, Senior Geophysicist with ARKeX, explains the benefits of integrating broadband gravity data with seismic at different stages throughout the exploration work cycle.

The technique provides a broadband gravity dataset that can be integrated with existing seismic to add an increased understanding of the subsurface.

As a dataset that can be used throughout the exploration phase, it is cost effective to acquire early in the project life cycle in order to gain maximum value, said Claire Husband, Senior Geophysicist with ARKeX, speaking at the Finding Petroleum forum in London on April 13, “Transforming Subsurface Interpretation”.

During the presentation Claire Husband explained the difference between gravity and gravity gradiometry then went on to show gravity gradiometry and seismic integration examples from various stages of the exploration workflow from regional reconnaissance to final interpretation.

**Gravity and Gravity Gradiometry?**

Gravitational force or acceleration due to gravity on the Earth’s surface can vary spatially for geological reasons.

For example if you are standing above a high density body, you will experience a slightly higher acceleration due to gravity than at surrounding locations. The converse is also true, if you stand above a geological body which is less dense than the surroundings, you will experience a slightly lower acceleration due to gravity.

Lithologies vary in density depending on composition. This varies from igneous rocks, which tend to be the densest, to coal and salt which are commonly the least dense materials in the subsurface. So by measuring gravity, or how gravity changes, you can get an understanding of the subsurface structure.

The instruments used to acquire conventional gravity and broadband gravity/gravity gradient data are fundamentally different.

A conventional gravimeter can be thought of conceptually as a mass on a spring. As the mass on a spring is moved over the ground, the ‘pull’ on the mass will vary with the mass in the subsurface.

However, the gravity gradiometer has conceptually, although not in practice, two masses on springs located one above the other.

This measures variation in gravity between two points otherwise known as the ‘gravity gradient’. Modern gravity gradiometers, such as an FTG instrument, conceptually comprise of an assembly of ‘masses on springs’ oriented in different directions to allow the measurement of the horizon components of the gravity gradient as well as the vertical component.

Gravity gradient surveys and conventional gravity surveys can be conducted from moving platforms, such as a boat or aircraft, which can be highly advantageous as large areas can be covered quickly. However, the conventional gravimeter is hindered as it cannot distinguish between acceleration caused by turbulence motion and the acceleration caused by a geological origin.

In order to overcome this, conventional gravity data are filtered to remove the high frequency turbulence related component. This high frequency filtering process also removes geological signal and decreases the resolution of the data.

There is no way round this. However, gravity gradiometry does not suffer from this issue and does not need to undergo the same high frequency filtering.

A common question which is asked is “What is the smallest feature that gravity gradiometry/broadband gravity can resolve?” The resolution of the gravity gradiometry data (and size of the smallest object detectable) primarily depends on the magnitude of the density contrast between the target and the surrounding lithology, the target depth and survey line configuration, she said.

**Regional Reconnaissance – Northeast Greenland**

The first example was from North East Greenland where in April to June 2012 ARKeX conducted a 50,000sqkm broadband gravity survey in conjunction with Ion Geophysical’s 2D seismic acquisition campaign “Northeast GreenlandSPAN.”

Differences in interpretation before and after the integration of broadband gravity data with seismic were presented.

Fundamentally, however good the seismic data acquisition and processing, a 2D seismic campaign is, by definition, spatially limited. In the case of the Northeast GreenlandSPAN, the seismic lines are regularly and sensibly spaced throughout the survey area. Dr Husband showed examples from two blocks where the seismic had not traversed over the salt or major faults which were both clearly visible in the broadband gravity data. The broadband gravity survey revealed a significant area of salt in both blocks which had not been covered by the 2D seismic acquisition.

As well as gaining an increased understanding of the subsurface, this information can also be used to plan future seismic surveys. Both salt and faults can cause major challenges to seismic processing and imaging workflows.

But if you know in advance, you might plan the seismic acquisition more effectively which might entail the use of more advanced seismic acquisition configurations, such as MAZ, WAZ or coil, to overcome potential seismic illumination issues, she said.

**Aiding seismic processing – offshore Gabon**

The next examples showed the integration of gravity gradiometry with 2D seismic data from offshore Gabon at both the reconnaissance and the seismic depth imaging stage.

In contrast to the North East Greenland area, high density carbonates as opposed to low density salt, were one of the potential exploration targets. Claire Husband showed an example of the broadband gravity used with the 2D seismic data to map the lateral extent and spatial distribution of continuous carbonate bodies in the survey area.

The processing example started by showing the integration of legacy data and broadband gravity data to build a density model of the subsurface. In short, this model was converted to density using velocity-density relationships derived from well data.

The density derived velocity model was used as a starting model for the PSDM (pre stack depth migration) workflow. The standard top-down velocity model building approach was adopted.

The velocity of the first layer was updated using reflection tomography. The density was then adjusted accordingly in this layer and the other layers as appropriate. This was then converted to velocity. The new velocity forms the input to the next layer in the tomography. The initial results look promising.

**Aiding seismic interpretation – onshore Gabon**

The final example presented by Claire Husband looked at how FTG data had been successfully utilised to understand why an exploration well in onshore Gabon was dry.

The exploration well target was a reservoir located on a structural high beneath a salt body. The basis of the reservoir seal was that the salt above the target was one intact salt body.

The clients drilled the well expecting to drill through a thick, intact layer of salt. However little to no salt or hydrocarbons were discovered in the well.

Presumably, with no salt acting as a seal, the hydrocarbons (if once present) had migrated away. The client undertook a high grade gravity gradiometry/Broadband gravity survey to help understand the spatial distribution of salt.

The gravity gradiometry/Broadband gravity data clearly indicated that the well had been drilled in a saddle area between two salt bodies.

Broadband gravity data was compared to the regional wells. The correlation between producing pre-salt wells and the salt as shown by the broadband gravity data was 100%.
The best way to do analytics in the oil and gas industry is to bring subject matter experts together with data scientists, said John Brennan of Hewlett Packard.

He was speaking at the Apr 13 Finding Petroleum London forum, “Transforming Sub-Surface Interpretation”.

“You get a team of business people, IT people, and put your foot to the floor and say, what is the data, what is the hypotheses, and test in a very rapid manner.”

“Sometimes you find nothing at all and that’s a valid answer - you can park that particular problem.”

You need to make sure you start off with a specific question which you are trying to answer.

90 per cent of the effort of doing a data mining project is often gathering the data together in the first place, he said.

In the oil and gas industry, “we want to be able to learn from the data that we’ve got,” Mr Brennan said.

**Examples**

Many companies around the world are finding new ways to work with large data sets, he said.

It built an analytics system was for US stock car racing company NASCAR, to help the company sort through all the comments made on social media while races are going on, so company staff can get a better understanding of what the fans are thinking about.

NASCAR has a "Fan Engagement Centre" where all the data is gathered together and sorted. The solution includes hardware (powerful servers to store and process data) and software, such as Autonomy, to extract meaning from the data. The data is then displayed to staff on video walls.

It receives data from Twitter, other social media sites, and media outlets. The company can track what the fans are thinking about as major announcements are being made, such as a team producing a new car.

Another example is the UK meteorological office, which has ‘big data’ systems which can generate a weather forecast for a 200x200m area of land.

Data mining has also been used by supermarkets, to calculate which product sells the most after a hurricane warning (which turns out to be beer, Mr Brennan said).

Some companies are using automated tools to analyse Twitter messages to see what the public is saying about them.

“As the volume of data in the world grows, our ability to extract value from it also going up,” he said. “We can pull in multiple data sources from thousands of feeds.”

**HP’s offering**

HP has a pre-packaged system for big data called HAVEn, which stands for Hadoop, Autonomy IDOL, HP Vertica, HP Enterprise Security, and the capability for building “n” Apps.

It can be provided as software or run in the cloud.

You can pull in information from a whole variety of different systems, including video, text, call centre data and social media feeds.

“HAVEn allows you to import the data into a central area and run a range of analytical processes on it,” he said.

“You can chew through the data and see what the correlation and causation is and what the insight is,” he said.

This software was used in the London Olympics, where video from CCTV cameras was continually analysed, comparing faces with the faces of known terrorists.

HP offers analytics as a service, or provides consulting for the best way to do it.

It helps companies gather their data together so it can be analysed, and share the results through the company.

See John’s talk on video at [www.findingpetroleum.com/video/1293.aspx](http://www.findingpetroleum.com/video/1293.aspx)
Computer manufacturer Lenovo has put together a workstation computer package specifically for subsurface work in the oil and gas industry, said Mike Leach, Workstation Technologist with Lenovo.

He was speaking at the Finding Petroleum conference in London on Apr 13 2015, “Transforming Subsurface Interpretation”.

In general, workstations have improved performance by about 15 per cent over the past 12 months, he said.

The aim is to make subsurface data faster to analyse and interpret, he said. Its processing speed should be particularly appreciated for long, iterative workflows, avoiding lengthy waits while computer processing takes place.

The system was tested for use in a fracture detection workflow. The work started with a 610 MB subsurface data set. The interpreter needed to remove noise, identify the direction of slope of the rock layers, then four further processes - working out the fault structure, identifying the fracture, analysing fracture brittleness, looking at microseismic data.

The fracture identification work included looking at fracture curvature, understanding the fracture network, fracture services, fracture azimuth (direction), and fracture density.

“It is a repetitive and tedious workflow, involving many iterations,” he said.

Sometimes geoscientists go through the same workflow with 12 iterations to clean up an image, he said.

The workstation

The Lenovo workstation has been put together to give you the computational and visualisation technologies subsurface interpreters need, he said.

It uses Lenovo’s ThinkStation P900 workstation, configured with 2 Intel Xeon E5-2697v3 CPUs, 256 GB of 2133MHz DDR4 memory; delivering a total of 28x CPU cores (14x cores per CPU)

By adding more graphic processing units (GPUs) to your computer you can make it even faster. You can use the GPU for computing as well as graphics display. “The more GPUs you add, the faster the performance.”

You can also add high performance data storage systems to the workstation, with up to 40 terabytes of storage in one workstation. “You can load in data very quickly, analyse it very quickly,” he said.

“To get the performance you need doesn’t have to cost as much as you might think.”

The basic ThinkStation P900 computer costs under £1600, but the cost can be as much as £30,000 depending on the configuration, he said. Oil and gas users will typically spend £5,000 to £7,000, but the final price is ultimately based on end user workflow and required results.

The CPUs alone can cost £3,000 each.

The workstation can be installed under your desk, or you can access it remotely, with the workstation based in a data centre. You can have it dedicated (so only one remote person uses the workstation) or “virtualised” (so the same workstation is shared between multiple users).

Lenovo has also engineered its workstation system for the needs of finance users. They also do a lot of Monte Carlo type analysis, which requires fast computation, which can be done by the GPUs using their own memory.

Watch Mr Leach’s talk on video and download slides at http://www.findingpetroleum.com/video/1324.aspx
Transforming Subsurface Interpretation

Attendee list – Transforming Subsurface Interpretation, London, Apr 13 2015

Christian Bukovics, Partner, Adamant Ventures
Paul Murphy, Key Account Manager, Oil and Gas Division, Airbus Defence and Space
Roberto Ruiz, Geophysicist, ARK CLS Ltd.
Christian Richards, VP Sales EAME, ARKeX

Nicolas Hand, Geoscientist, Dolphin Geophysical
Helena Zapata Suarez, Interpretation
Jean Martinie, Representative, DG1
Steve Callan, VP Sales & Marketing, BGP Marine
Jonathan Watson, Geophysicist, Bridgeporth Ltd
Bryn Austin, Director & Geological/Geophysical Consultant, Bryninterpretation Ltd
Robert FE Jones, Regional Exploration Manager, Cairn Energy plc
Roger Taylor, Technical Marketing Manager, CGG
Marianne Parsons, Geophysicist, CGG

Sean Waddingham, Data Library, CGGVeritas
Will Thornton, Geologist, CGL
Anne Benfelda, Marketing Manager, Chemostat Ltd
Roger Doery, Consultant, Consultant
Andrew McCarthy, Exploration Manager / New Ventures Manager / Geophysicist, Consultant
Dominic Davey, Information Systems, Consultant
Dan Kunkle, Director, Count Geophysics
Tagbo Ndefo, Data Manager, Degeconek Nigeria Limited
Jean Martinie, Representative, DG1
Helena Zapata Suarez, Interpretation
Nicolas Hand, Geoscientist, Dolphin Geophysical

Brian Donnelly, Consultant
Timothy Culwick, Solutions Architect, DrillingInfo
Jane Wheelwright, Technical Application Specialist, Dynamic Graphics Ltd
Toyin Solanke, Consultant, Ekalos GeoTek
Martin Riddle, Technical Manager, Envi
Serge Heyer, Director, Feather Tech
Salar Golestanian, Managing Director, Infinity Asset
Avinga Pallangyo, Finance Administration, Future Energy Publishing
Ken Armitage, MD, GeoDirk Ltd
Allan Induni, Geoscientist
Alexandra Kenna, Managing Director, GEOSERVE Limited
David Bannister, Marketing Manager, Geotrace
Chris Boot, Business Development, Getech
Norman Hempstead, Director, Hempstead Geophysical Svs
Suzanna Bailey, Hewlett-Packard
Paul Muscat, director for energy and utilities industries in UK, Hewlett-Packard
John Brennan, HP
Martin Hodge, Data Processing & Time Imaging Geophysicist, IExST
Ravi Chandran, Director, Kalki Consultants Limited
Mike Leach, Workstation Technologist / Business Development Manager, Lenovo
Rebecca Clare, Business Development Manager, Lenovo
Nick Grealy, Director, No Hot Air
Mark Enfield, Managing Director, P.D.F. Limited
Robert Parker, Consultant, Parker
Adeola Akin-Odidi, Principal Geophysics, Petrofac
Vincent Sheppard, Chief Geophysicist, Petrofac
John Hother, MD, Proneta
James Page, BDM, PVE Consulting
Josh King, Analyst, RAB Capital
Simon Fleckner, Graduate,
Kes Heffer, Director, Reservoir Dynamics Ltd
David Sendra, SubSurface Manager/ Petrophysicist, RSI Geophysical Ltd.
Keith Holdaway, Principal Solutions Architect and O&G Domain Expert, SAS Institute
Dominic McCann, Director, SAS Institute
David Webber, Seismic Operations Supervisor, Sceptre Oil and Gas Ltd
Paul Day, Director / Consultant, SCGIS Ltd.
John Moses, Seabed Geosolutions
Glyn Roberts, Director, Spec Partners Ltd
Richard Lee, Sub-Surface Data Technologist, Sub-Surface Data Technologist
Frank Eisenhower, Operations Manager, TGS
Sean Akinwale, Business Development Manager, TGS Geophysical Company
Nigel Quinton, Head of Exploration, Tower Resources plc
Jay Sahota, Lead Geoscientist, Tullow Oil
Alec Robinson, President & CEO, Valient Energy
Peter Lancaster, Director, Valioso Ltd
Rana Wallwork, Technical Analyst, White Rose Energy Ventures LLP
Ben Couzens, www.CV.Couzens.biz
Andrew Zolnai, Consultant, zolnai.ca

What did you enjoy most about the event?

"The variety of breadth and depth of topics being presented, as well as the time given to Q&A"
Peter Lancaster, Valioso Ltd

"Opportunity to meet a cross section of various industry stake holders"
Sean Waddingham, CGG

"Variety of topics and exposure to information outside of normal day-to-day work"
Dominic Davey

"Some mix of disciplines albeit heavily geophysical"
Kes Heffer

"It was interesting to hear about things from the data analysis side of things, ie from those 'outside' the industry and to see some applications of the technologies"
Adeola Akin-Odidi, Principal Geophysics, Petrofac
Geodirk – using geology to understand seismic

By integrating geological understanding with seismic processing, you can get a much better understanding of the subsurface, which can lead to fewer dry wells, said Geodirk’s Ken Armitage.

Ken Armitage, CEO of UK company Geodirk, has developed a methodology and computerised system for understanding seismic data taking geology into account, which he believes can make a big impact in avoiding dry wells.

Using geological understanding in seismic interpretation can “at least double the information available from post stack seismic,” he said.

He presented the method and system at Finding Petroleum’s April 13 2015 London conference “Transforming Subsurface Interpretation”.

The method uses computer tools to analyse for geological ‘shapes’ (such as faults and thrusts) in the seismic data.

A geologist can look at this geological picture and see if it makes geological sense. The picture with “geological sense” means that she can see how the subsurface could have ended up with these features, based on what might have happened over geological time.

In geology, if a geological story looks roughly correct, it probably is correct, he said.

The geologist can work out how the rock might have been deposited, and how it might have changed since deposition (diagenesis).

“It is necessary to build something which a sedimentologist and structural geologist can agree is a sensible picture;” he said.

Once you have a sensible geological story, you can process your seismic data in the usual way, taking into account the rock properties you expect from the geology.

You can put the model in reservoir modelling software such as Landmark and Petrel. Then people from all disciplines can have a look at it and check it makes sense to them.

The end result is that you should have a model you feel surer of, which can be used to better make drilling decisions, he said. Instead of having a fat bell curve with lots of possibilities of what the truth might be, you have a narrow one.

Usually the geological interpretation is only done after the seismic interpretation has been finished, he said.

“Working out geology at the same time as doing seismic interpretation can be quite daunting to think about, which is probably why nobody has in the past, or made much progress with it,” he said.

Reducing dry wells

The oil and gas industry really needs to improve its exploration success rate, he said, as it is reported to have dropped from 25 per cent to 15 per cent over the past few years.

“Exploration is a small part of E&P cost, but there's still a significant amount of waste;” he said.

“Investors and oil company owners are telling us we've got to solve this problem. Stop getting money to spend wastefully on dry holes.”

Finding more reservoirs

With methods such as this one, it should be possible to accurately target much smaller reservoirs, he said, including fields which have many layers of reservoirs and seals.

“We are moving to a situation where we've got to start looking at interbedded sediment, not just massive sand and massive shale.”

“All the big easy structural traps seem to have been found,” he said. “We've got to find the missing ones and do it with less risk.”

With better subsurface understanding, you can also find ways to reduce water production, and extend the production life of the facilities, he said.

Permeability and porosity

Mr Armitage did an analysis of dry wells, and found that one of the biggest causes is poor predictions of porosity and permeability (“poroperms”), he said.

A reservoir needs to have high porosity and permeability, and be sealed by a rock with low porosity and permeability, he said.

In order to make a good porosity / permeability estimation, you need to know about the rock types – which means a geological understanding, he said.

There are 30 or 40 different geological reasons why porosity and permeability might change moving across horizontally, he said.

Some areas of subsurface have a mix of rock fragment sizes, from very fine clastics to much coarser clastics. This all means a difference in rock properties, which will mess up your seismic processing if you don’t know about it.

About 60 per cent of rock does actually have predictable properties, he said. For example 60 per cent of all shale sediment will compact in a similar way due to the weight of rock above it.

So rock in many areas of the world has interchangeable properties, including the Gulf Coast, Norway and some of the North Sea, he said.

The way the rock compacts will drive its density, velocity of seismic waves through it, porosity and permeability.

But there’s also a 40 per cent probability that it will have different properties, which will mean that the calculations will provide the wrong result, he said.

For example if the rock has had non vertical stress on it, or pushed up from below by salt. “That will stop this process working.”

But some rock will compact at faster rates – including chalk, and material made of coarser grains. This will lead to a higher than expected loss in porosity.

So if you don’t do a geological analysis, your work will only be accurate 60 per cent of the time – when the rock is deposited in a standard way, he said.
If you have a reservoir model built up using cells, you can make sure that the geological model you evolve from the seismic is sensible, for every single cell, he said.

“It could mean going through the laborious tasks of figuring out all the things that could make geology change - then filtering the data for its presence of absence.”

“Geology is giving us surprises, and therefore poroperm surprises.”

**Dong case study**

In one example for oil company Dong, a lithological understanding was built into the seismic interpretation, including water, anhydrides and dolomites.

There were also volcanic rock in the subsurface volume being studied, which is hard to spot.

The target reservoir was actually beneath the source rock, with everything over pressurised, he said.

**Computer system**

With Mr Armitage’s method, the seismic interpreter could access a standard database of rock properties, which can be used to calculate seismic velocity, porosity and permeability taking geological factors into consideration, such as rock type and compaction rate.

Then you work out how this would change if various seismic shapes or geological attributes were present, such as faults.

You could also add in factors such as temperature and pressure, and how these might impact porosity and permeability. None of this information is available directly from seismic.

You can develop databases of rock properties which have undergone similar compaction and transformation (diagenesis).

“We basically bundle all the lithologies into different families of behaviour,” he said.

“This is where you need processing power, because you've got to filter the seismic data and shapes,” he said.

“You've got to make this as objective as you can and minimise subjectivity.”

“It only takes one project to enable an asset team to be expert in how this works,” he said. “It is 1000 different applications fitted together in one system.”

Some of the computer processing tasks might take 4-5 days to run on an older PC, but with today’s workstations it could be done instantaneously, with the results checked in real time, he said.

**Background**

Geodirk’s processes were first developed in the early 1990s by oil companies who found that they did not have a good idea of the velocity of seismic data, with rock imaged by 2D seismic. “We tried to make a geological way of working out seismic sequences,” he said.

Mr Armitage was involved in early work to develop algorithms to try to spot various geological ‘shapes’ in the data, for example looking for signs of non-vertical stress, inversion (something pushing up from below) and faults.

When 3D seismic was developed, much better predictions of velocity could be made. But the velocity still isn’t made accurately enough to predict porosity and permeability, he said.

Integration and visualization of well fibre optic data

Dynamic Graphics is developing computer tools which can help display acoustic and temperature data, gathered from fibre optics in wells, together with other reservoir data, such as seismic and production data.

Dynamic Graphics Inc (DGI), a company specialising in data visualisation and analysis, has developed a computer tool to display acoustic and temperature data, generated from fibre optic cables in wells, together with all of your other reservoir data and models.

This should make it easier for oil and gas companies to work with well fibre optic DAS and DTS data, to understand what the data is showing, and how it relates to what else is happening in the surrounding reservoir.

“My experience is that a lot of data is being captured but not used to its full capacity,” said Jane Wheelwright, Technical Application Specialist at DGL, speaking at the Finding Petroleum forum in London on Apr 13, “Transforming Subsurface Interpretation”.

Also, “a key thing is not looking at a well in isolation but getting an understanding of what else is happening in the reservoir,” she said. “The results are more powerful when they can be integrated with other data. It gives a far better understanding of what is happening with a well.”

Displaying it

Dynamic Graphics provides two ways of displaying well fibre optic data. Firstly the temporal downhole view, where the temperature or acoustic data for the well can be visualised together with any other well and reservoir data, at any specific point in time.

This enables the data to be viewed at different points in time with other time varying data – so, for example, you could see a 4D seismic survey from a year ago, together with the acoustic data from the well at that time.

Another way is the ‘waterfall’ display where you see how the data recorded from the well is changing over time.

“The capability to see both these displays is very useful, they complement each other,” she said.

“You want to have capability to integrate with existing data, quantitatively and qualitatively, and be able to back interpret and cross plot the information.

CoViz 4D

Ms Wheelwright showed a view of a mature offshore oilfield using Dynamic Graphics’ CoViz 4D software, with many different data sets available.

By looking at the field at different points in time, you can see how the status of each well changed, and the history of the field. You can see the various fluid flows, with oil, gas and water in different colours.

“As water is injected and oil produced, changes can be seen,” she said.

On the same view, you can see a 4D seismic data set, a geological model, and a reservoir simulation, drawn from other software packages (in this case Seisworks, Landmark Nexus, and RMS).

The CoViz 4D software has a Global time slider which amalgamates all the time steps from each file, so you can see the correct status of all the data loaded at different points in
You can look in detail at any part of the field. For example, you might want to look at data from a producer and injector well pair.

With temperature data, you could see a thermal slug moving up the well in real time.

You can see well temperature data together with the well completion data, because elements of the completion could be causing a change in temperature.

If you have production data together, you could see (for example) that the temperature rose after the well was shut in.

You can see where valves were open and closed.

“There are wide ramifications in using this technology,” she said. “It gives quite unique data and information for the reservoir management team, and it allows for understanding what is happening in a reservoir and optimising decision making.”

Fibre optic cables can measure acoustics and temperature by understanding how they change the flow of light through the cable. One cable can provide many different sorts of data.

DAS (“Distributed Acoustic Sensing”) is a way to use fibre optic cables in wells to make an acoustic (sound) recording of what is happening in the well.

This can be used to spot problems (for example damage to a component), and also to record seismic data from inside the well.

DTS (“Distributed Temperature Sensing”) is using the fibre optic cable to measure temperature at all points in the well.

Fibre optics are already used to replace production logging tools, as a means of understanding which zones in a well are providing most of the oil, and to spot flow leaks inside the well.

The systems are also used to monitor for restrictions in the well bore (which can cause the fluid flowing past them to make a sound). It provides information about completions. It can be used in fracking, to monitor how well the fracking is going.

Oil companies need the data to work out the best way to frack a certain well, and the best way to optimise hydrocarbon recovery.

The data generated by DTS (temperature) is much smaller volume than the DAS (acoustic) data. Most DAS files are larger than 1 TB, which makes them very hard to work with. “A key issue is to reduce the size of data files,” she said.

The DAS data is currently usually provided in HDF5 format, which can be imported into CoViz 4D.

View Jane’s talk on video at www.findingpetroleum.com/video/1289.aspx
INTEGRATE / VISUALIZE / ANALYZE DATA IN CONTEXT WITH COVIZ 4D

INTEGRATION

of multi-disciplinary data, including reservoir simulation, 4D seismic, seismic attribute extractions, structure model, and production data.

HYDRAULIC FRACTURING

monitored using microseismic data. Event locations, error bars, and focal mechanisms are visualized in 4D in relation to the surrounding geologic model, well locations, and surface infrastructure. Treatment curves are also integrated into the display.

SEISMIC

amplitude values are sampled into both a reservoir simulation grid and well log data, enabling statistical analysis and comparison of diverse datasets.