

Finding Petroleum

How geophysical contractors could do more
Getting better seismic data for the North Sea
Better subsurface digitalisation
Helping drillers better understand what they
are drilling
Using magnetic and gravity potential field data
Making land seismic 'broadband'
Making land seismic more precise

New Geophysical Approaches, London, April 24 2018

Special report

New Geophysical Approaches

April 24 2018, London



Event sponsored by:



This is a report from the Finding Petroleum conference “New Geophysical Approaches” held in London in April 2018

Event website

<http://www.findingpetroleum.com/event/210a5.aspx>

Many of the videos and slides from the event can be downloaded from the event agenda page.

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New geophysical approaches

Finding Petroleum’s forum in London in April “New Geophysical Approaches” looked how geophysicists can provide more value, better ways to integrate and analyse geophysical data, better ways to do land seismic, and ways to work with potential field data

Geoscientists, their surveys and the survey equipment, could make a lot bigger contribution to the oil and gas industry than they currently do, if their input was more widely used in other parts of the industry such as drilling and field development.

For example, geoscientists could better advise drillers on the pressures of the rock they are about to drill through, enabling drillers to operate at a lower pressure safety margin (i.e. with a smaller gap between the reservoir pressure and the drilling mud pressure), in turn leading to less damage of the reservoir from high pressure mud and better well log readings.

This is one of the points we discussed in our April Finding Petroleum forum “New geophysical approaches”.

We talked about how geophysical companies are still geared up to do what they have traditionally done – find frontier oilfields – when oil companies are now asking for something very different, better understanding of mature fields. The change in positioning is not happening fast enough. There can still be a lot of oil to find in mature oilfields, and it needs good seismic imagery, too.

We also discussed how geophysicists can better work with public ‘potential field data’ describing the natural electrical, magnetic and gravity fields of the earth, and where the anomalies are (where it shows something different to what you would expect), and how that can give indications of the geology.

We learned about the big improvements in land seismic recording, both on the source (vibrator) and recording (nodal) side, leading to higher trace density and much better seismic imagery.

We also heard from a former seismic equipment marketing manager about how the land seismic industry might be moving too fast to follow the road to more and more traces – and there could be less expensive but more sophisticated ways to improve the quality of land seismic recording with no increase in cost – or reduce the cost with no decrease in quality.

Note – many of the videos of these talks, and the slides, are available on the Finding Petroleum website - <http://www.findingpetroleum.com/event/210a5.aspx>

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How geophysical contractors could do more

Geophysical contractors could increase their contribution to the oil and gas industry if they could help oil companies do what they want to do today, mainly improving recovery from mature and onshore fields, said David Bamford, a former head of geophysics with BP

Geophysical contractors could add value to today's oil and gas industry if they could better help oil and gas companies to do what they want to do at the moment, which is mainly improving recovery from mature and onshore fields, said David Bamford of Petromall and a former head of geophysics with BP.

He was speaking at the Finding Petroleum forum in London in April 24 2018, "New Geophysical Approaches".

Some oil majors today are even saying they have no interest in "frontier" exploration, the traditional area of focus for explorers. They are also saying much of the investment in frontier exploration in recent years did not yield very good results, he said.

Meanwhile, some geophysical contractors seem to be betting that the oil price will soon be back to \$100 because of Iran and Venezuela's collapse, so they just need to wait and there will soon be employment for the big seismic boats.

That could be a risky strategy, when you consider how much effort companies are putting into demonstrating that they are now 'energy' companies not oil and gas companies, he said.

Broadband

Geophysical contractors might be able to sell broadband seismic surveys over mature fields, to support further development. Some of the seismic surveys of the UK Contin-



David Bamford of Petromall

ental Shelf "are truly awful at the moment," he said. "There's a lot more scope for good acquisition."

In the UK North Sea, oil and gas companies often seem too happy to accept reprocessing of 10 year old 'megamerged' 3D seismic "as the limits of technical progress," he said, "and I don't think that's true. Although it is certainly better to re-process them than rely on processing done on original multiclient data."

For West of Shetland, Northern North Sea and Central North Sea, there are "very large megamerged surveys" with data over 10 years old.

Modern recording technologies, such as broadband, enable much clearer subsurface images. "I personally don't understand why folk who can offer that are not doing so more assertively," he said.

Also, 3D seismic surveys onshore should be as routine as they are offshore. "The perception is still that it remains forbiddingly expensive," he said.

Seabed

Seabed seismic recording could add a lot of value in today's industry, including areas which have already had one seabed survey, since many earlier seabed surveys had many operational problems, he said.

Seabed surveys can record both P and S waves, generating data which can be used in rock physics calculations. "There are fields in the North Sea where that has happened and the field has been transformed as a result," he said.

Analytics

Geophysical contractors might be interested in subjecting their large data sets to big data analytics. "I have not yet seen anybody who has delivered anything sensible in that arena," he said.

One useful area for the analytics could be improving the velocity model (understanding of the speed of seismic in different parts

of the subsurface, essential data for migration time to depth).

"If you are exploring, exploiting or doing reservoir management in complex structures, you need to get the [time to depth] migration right," he said.

Integrating data

Another business opportunity for geophysical service companies is services to integrate and manage many different types of data.

For example, on a basin like the Permian or Powder River in the US, companies are drilling thousands of wells, and each well has 6 or 7 well logs. Every state has a cuttings and rock samples depository. Fluid samples are kept. It leads to huge databases. In the North Sea, the UK's Oil and Gas Authority publishes data about several thousands of wells, including several hundred exploration wells, with cuttings, cores, fluids, huge historic data. You could add to that new data, such as broadband seismic, seabed seismic, inexpensive 3D Controlled Source EM, full tensor gravimetry.

The industry is not very good at integrating all this data, so it remains in silos. "Between geoscience and reservoir management and production operations, different data kept in different ways."

Geophysicists could shift their focus from just seismic technology to the whole sub science of integrating seismic and well logs to get at rock physics, which leads to an understanding of lithology and predicting fluids, he said.

From there you can get into a wider range of physical measurements – controlled source electromagnetics (CSEM), full tensor gravity gradiometry (FTG), and get a more profound reservoir description.

Ultimately, you have enough data, control, understanding of the stratigraphy, sedimentology, structural history and rock physics, you can be much more specific about where good drilling targets are, rather than using probabilities.

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Then it is possible to acquire real time data to monitor fields – 4D seismic, fibre optics downhole, electrical methods, real time flow / production data. This leads to the possibility of understanding how a reservoir in production is actually behaving, rather than basing your understanding on a simulation.

“It opens up a huge opportunity for geophysics contractors to augment and change what they do,” he said.

“Too many people see geophysics as [just] seismic interpretation,” he said. “I think we as geophysicists have the domain knowledge of all these technologies actually based on physics.”

There are also business opportunities for independent companies in data management, because many oil companies no longer have

in house staff capable of managing the data, including tidying it up, tagging it, and getting it to the point where someone with domain knowledge can work with it, he said.

North Sea opportunities

In the North Sea in particular, many of the opportunities can be around improving the recovery factor, which needs a lot of technical work. Many fields have only seen 30-35 per cent recovery so far.

There are also around 300 “small pool” discoveries in the North Sea which haven’t yet been developed. Some are very small, but others are 20-30-40m barrels. Perhaps you could “get to know them well enough” to design a development which would work financially, he said.

As an example of work to improve recovery, the West of Shetland has been explored for 50-60 years. “I started getting involved with it again about a year ago, I realised the whole petroleum system story was not understood at all. They knew which rock the oil came from, Kimmeridge Clay, but not when [the oil came to the reservoir]. They didn’t have the data to tell them when.”

“What they did was rely on an academic model of how margins evolve, and it was wrong.”

“You have these models that underpin everything you do, and they were wrong, not even close. If you believe the models, most of the oil was generated before the reservoirs were in place, which is a tricky problem to solve.”

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Digitalisation “comes down to measuring and managing”

Digitalisation basically comes down to measuring and managing operations, says Duncan Irving of Teradata – but doing it in a much bigger way

“As far as I’m concerned, digitalisation is nothing new, it is the concept of measuring and managing your operations,” said Duncan Irving, oil and gas practise partner with Teradata, speaking at the Finding Petroleum forum in London on April 24 2018, “New Geophysical Approaches”.

Today’s digitalisation can be seen as a re-tread of the efforts to control processes, made in many industries in the 1950s and 1960s, he said. But this time, companies are doing it with much more data, much more data processing, and using it to support decision making in more sophisticated ways, such as bringing data from different domains together.

Dr Irving is currently on assignment with an oil major, helping define its subsurface digitalisation strategy. He is a Phd geophysicist who went on to work in IT and technology consulting.

Maturity

The oil and gas industry is still somewhat behind other industries in its maturity in using data, such as social media, retail or banking, he said.

The problem is not a shortage of the right algorithms, such as for interpreting seismic, simulating a reservoir or making predictions about

maintenance. Some simulation algorithms used in modern reservoir simulators were written in the 1960s, he said.

One head of research for an oil company recently said he thought that all of the algorithms that the oil industry will ever need have probably already been written.

The challenge is more getting all of the algorithms into day to day use, or “operationalising” them, he said.

Also, there is still a big gap between what data

scientists are able to do, and what companies have embedded into their organisations as “strategic capability,” he said.

Many companies are doing “top down digitalisation,” perhaps driven by a chief digitalisation officer. “That’s OK, it’s a standard organisational box to put the new transformational stuff in,” he said. “It is not old IT, it is new stuff, it has to have a C level executive giving leadership to it.”

Artificial intelligence and machine learning are buzzwords, but they are “buzzwords for a reason, they have tangible benefit,” he said. The challenge is working out how they fit in at a strategic level.

Large oil company

In January, Dr Irving moved to work for a large oil company, helping it define its vision, and create a strategy and roadmap, for digitalisation in the subsurface domain.

“Really, it is the coolest project I’ve had the privilege of working on,” he said. The work involves many in-depth interviews with IT practitioners, and domain experts, such as “explorationists, well planners, reservoir geologists, field managers, production engineers.”

The introduction of digitalisation means that people will change their day to day work, perhaps with computers doing the more mundane parts of their jobs and people applying their knowledge in new ways. Many people are nervous about this, especially older people, he said.

“There is a palpable feeling of transformation across the industry.”

Cloud

The introduction and ubiquity of cloud is one of the main drivers behind the new possibilities in digitalisation, Dr Irving believes.

Oil companies often start with Microsoft’s cloud services, because they are usually using Microsoft Office already, and associated file storage, computational tools, perhaps SharePoint as well. This means that a geophysicist can see SharePoint and their computing tools through the same portal.

So if geophysical technology providers offer their software in the same cloud system as their clients use, whether Microsoft or Amazon, they can also be immediately part of the infrastructure. It is something of a surprise that more geophysical technology companies are not seiz-

ing this opportunity, Dr Irving said.

Outside companies could also offer analytical tools and services on oil companies’ cloud data.

To work with cloud, you need to get your data onto a cloud system, and if you are processing on one cloud and storing data in another one, then data needs to be moved from one to another.



Duncan Irving, oil and gas practise partner with Teradata

Legal issues can “really slow things down moving to the cloud,” he said. For example, if each oilfield has its own legal framework and team, that means that if you want to move data for 30 oilfields in the cloud, you need to get 30 sets of approvals.

Security concerns have more or less gone away. “A few years ago the cloud was so new and so poorly understood, people asked, ‘how could an operator countenance trusting the security?’” he said. “Now, it’s ‘do you really trust your own IT guys with your security? Of course you put it in the cloud.’”

“That one just flipped with no-one really noticing.”

Today, applications should probably be run on the cloud as a first choice. “I don’t really see the need for applications on people’s PCs in the medium term,” he said.

That means that if an oil company has made a decision to move software to the cloud, it changes the way it does business with vendors.

Subsurface digitalisation

Oil companies are exploring many ways to introduce digitalisation to the subsurface world.

Companies want to set up “workflows”, where

people go from one step to another to get a subsurface understanding from subsurface data such as seismic.

To do this, they need a digitalisation “architecture” around their data, to manage how data is brought in, quality controlled, integrated with other data, and then subjected to some kind of analytics, in a suitable timeframe.

Meanwhile, the business imperative is to do everything faster, compressing tasks like “deliver a well plan” in 2 months, where it previously might have taken 6 months.

Companies are also looking to automate many of the data housekeeping and management tasks, for example where data needs to be moved between different packages during a process, such as Halliburton’s software packages COMPASS for directional well path planning and EDM for managing engineering data.

If companies want to work with real time data, for example to support drilling operations as they happen, or even predict what will happen, they need a stronger digitalisation capability, he said.

The ultimate aim is for individuals to be able to blend the insights they get from computer simulation with personal experience, so they can (for example) see what the production is like in fields similar to the one they are about to drill.

People answer questions like that all the time using their own experience, or perhaps looking up reports of past projects which they recall are similar. But it is very hard to do with digital technology, because it would need some kind of predictive data mining capability, he said.

The current way

The way most oil companies operate today could be compared to an old car, with lots of different components which don’t quite fit together, and the need for a human to get it started, understand what is happening and try to diagnose problems.

“We have several applications, poorly integrated. We have to spend a lot of time deciding whether we trust the data from someone else’s piece of the workflow before we can perform our own analysis on it.”

“We have to decide whether we trust the way the data has been reformatted and restructured to put it into the application we are using. And there’s also the time it takes to find the data in the first place.”

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This means that geoscientists end up getting locked into doing specific tasks, not because they are particularly capable of creating value while doing them, but because they know which buttons to push on the software to make it work effectively. No-one else in the company knows how to do it, so they can't move on to any other job.

"This has come out of interviews I've done with some of the operators last year," he said. "Companies want to find a way out of their bind, and find a way to make the most of the abilities of their geoscientific talent."

How geophysicists can add value

There are many processes in upstream oil and gas where geophysicists could add more value in upstream operations, aside from the traditional technical work (processing wavelets).

They could add strategic value to a company, if they could help drillers understand better what they are about to drill to, using a combination of well logs and the logging while drilling data.

This is actually quite a complex data challenge – it isn't easy to integrate different well log data streams in Excel, for example. But you could do it with geophysicists and data scientists working together.

The aim might be to create a really clean master well log with all of the available data integrated, and any bad data removed. In the process, a geophysicist might be able to identify that a certain piece of data is obviously wrong and remove it. Or a geophysicist could advise a driller which data is more reliable.

Geophysicists might also be able to use their geomechanical understanding to advise on the

best way to construct the well. They could also help predict production and what factors would affect it. They could advise drillers on the best targets to go for first.

Once a number of wells have been drilled, geophysicists could advise which ones are most worthy of intervention investment to improve production. If data from all the wells is integrated, it becomes possible to do comparative analytics and work out how to optimise drilling effectiveness.

Geophysicists could contribute to efforts to find remaining oil reserves in mature fields. "Who has a sneaking suspicion that in all the seismic data for the North Sea to date, we might have missed something? Or are you happy we found everything there was to find because it was all imaged well?" he asked.

Geophysicists can act as a bridge between different domains, having both the geological understanding and the numerical skills to talk to engineers and business decision makers.

Quality control

Geophysicists can help quality control data from outside companies, ensuring that any seismic or logs lacking the right master data do not find their way into the corporate archive.

Teradata has put together a "forensic geophysics" team for its oil company client, including data scientists, geophysicists, and a data management specialist.

This team was able to combine its skills to make tools for quality assessment of well logs. It used both statistical and geophysics expertise, for understanding seeing how a well log fits with the well logs around it, and whether it shows the

lithofacies (rock layers) you expect.

Some logging while drilling (LWD) data is provided time based, some is provided depth based (this log was recorded at this depth). "It would be nice to flip between the two really seamlessly, we've discovered," he said. Teradata's team built a tool which could do it.

When the diameter of a borehole changes, you expect to see some change in the response of the gamma ray recording. If you don't, it might indicate a problem with the gamma ray, which can then be corrected before you use the gamma ray log for other analysis.

Once the company is satisfied that the well log data is good quality, it can be used for tasks like trying to find bypassed pay, combining the digital tools and data with people's expertise, drawing on drilling logs, well logs, reservoir simulation and the seismic model.

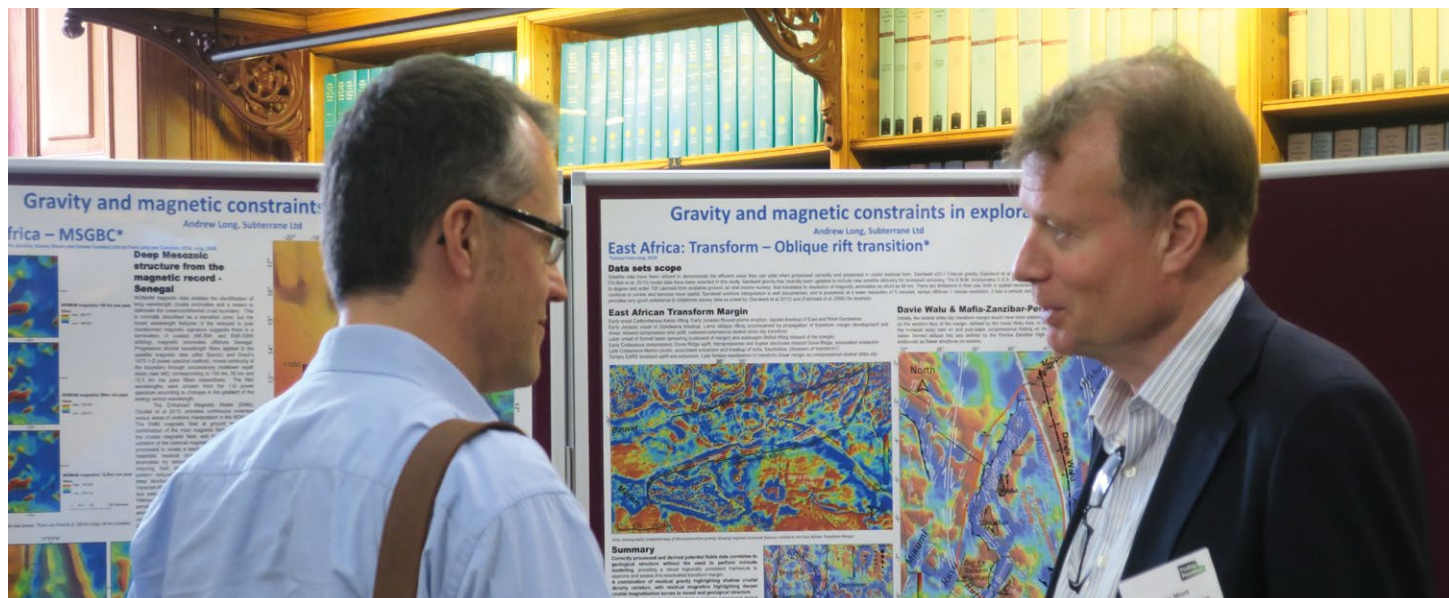
It is not so much "innovative geophysics," but could be considered innovative data management, and a good use of geophysicists, he said.

Silver haired geophysicists

This kind of work might be well suited to so-called silver haired geophysicists, who have many years of experience, and deep understanding of the physics itself, Dr Irving said. "They can provide numerical insight and an understanding of the wider context."

It would mean going to the traditional, earth sciences part of the skillset, and numerical part of the skillset, rather than the ability to work with a certain piece of software or follow a workflow.

"I think geophysics should be the hottest job in the industry. We need to re-invent ourselves as a profession."



Using gravity and magnetic “potential fields” data to determine geological structure

Utilizing gravity and magnetic “potential fields” data, at satellite level is the single, only capable data source that captures the long wavelength components of geological structure and is essential to an interpretation workflow and understanding the evolution and framework of basin exploration. Andrew Long, director of Subterrane Ltd, explained how.

Gravity and magnetic “potential fields data”, where you begin with a data set covering for the most part, the entire globe, can be very useful as part of a geological workflow, if you understand where the data can be used and what it tells you, said Andrew Long, director of Subterrane Ltd, speaking at the Finding Petroleum April 24 2018 London forum “New Geophysical Approaches.”

Potential fields data can be described as “data that has come from the skies”, since much of it is recorded by satellite or airborne acquisition. Most of the satellite recording is by government organisations with data available for public use. You add the detail with airborne acquisition once you know the regional framework.

The basic technology to work with the data has been available for decades, with some methods dating back to at least the 1950s (Sigmund Hammer wrote his gravimeter terrain corrections paper in 1939). But some data sets are becoming progressively more useful since then as resolution and precision improves.

Potential field data has been used in many areas of subsurface exploration, including understanding structures offshore East Africa (where there was sparse seismic data available), understanding tectonics including divergent, convergent and transform margins. It has also been used to understand deep basins and crust dating back to Precambrian times. Similar geological structures have since been discovered in Central America, and the UK and Irish North Sea.

Low resolution coherent magnetic data

A starting point is a limited resolution magnetic data set, the US National Oceanographic and Atmospheric Administration (NOAA)’s Enhanced Magnetic Model 2015, that describes the Earth’s regional crustal field very well.

It is based on a “spherical harmonics

model”, which means it is compiled as a spherical representation, and using harmonics, fitting it to order 720 (30 minutes or limited around 56km resolution), and utilizing aeromagnetic, marine and ESA swarm satellite, amongst other satellite measurements such as CHAMP and ORSTED.

You could use the US National Oceanographic and Atmospheric Administration (NOAA)’s “EMAG2” Earth Magnetic Anomaly Grid data, compiled from satellite, ship and airborne magnetic measurements, however the dataset suffers interpolated noise effects due to kriging, where measurements are sparsely made. A comparison of the datasets’ energy spectra clearly demonstrates this.

The term “magnetic anomaly” refers to the residual magnetic response of a rock or suite of rocks that contain iron mineralization, whether in igneous, metamorphosed or sedimentary rocks.

56km resolution is sufficient to understand deeper crustal magnetisations and aid regional structural interpretation, he said.

By applying conventional processing to the satellite magnetic data, you can get an understanding of the geological structure.

Weaknesses

The biggest weakness with the EMAG2 data is that some of it was recorded sparsely. For example data recorded by ship in the Indian Ocean was recorded with tracks over 100km apart, making it not very suitable for geological purposes.

A lot of the data for the space in between was worked out by interpolation or “kriging” (a more sophisticated form of interpolation based on statistical processes). This artificial interpolation adds a great deal of noise. The data is presented at 2 minute resolution (approximately 4km cells), which is probably much higher resolution than the survey data would justify.

For onshore EMAG data, there is a lot of aeromagnetic data which can improve it, so onshore data can be better.

NOAA has also provided another data set of magnetic data called EMM (Enhanced Magnetic Model) 2015. The EMM field has a lower wavelength, constructed as a spherical harmonics model, he said. This benefits the data’s worth, since the interpolation is based on a weighted sum of observation points.

There is not a great deal of correlation between EMM and EMAG for offshore data, suggesting that the EMAG2 data suffers from noise. However onshore there is excellent correlation.

Free air gravity needs to be corrected

Another useful starting data set is the Sandwell Free Air Gravity, a gravity anomaly map first compiled by Sandwell and Smith in 1997 and version 23 was released in 2014.



Andrew Long, director of Subterrane Ltd

The residual gravity record provides guidance about shallow crustal density variations, and the magnetic data provides information about deeper crustal magnetisation. When you combine them together it can tell you something really in-

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teresting, he said. It can also tell you what is happening over thousands of square kilometres, impossible to get from any other geophysical data source. For much of the world, data from ocean based methods can be very sparse, such as in the Western Indian Ocean.

The free air gravity data can be shown to correlate with bathymetric relief (the depth of the ocean). In oceanic regions, the crust/mantle boundary is shallower and thus the gravity response is greater due to the influence of shallow dense mantle material. It does not correlate with geology or shallow density variation in the crust, he said. It needs to be processed to reveal shallow crustal geological structures for the purpose of basin exploration.

Free air gravity does not tell you much about sediments, and isn't much use onshore.

So it is most useful in the study of geodesy. You can practically use it to make a "local geoid" model for the purpose of levelling and surveying when combined with local gravity measurement.

Parts of the onshore Sandwell data collec-

tion used interpolation or some other infill data, which means in some parts of the world it is not very useful as an independent data set, he said. The Pavlis paper (2012) clearly indicates which areas are lacking, he said.

Combined data sets worth

The biggest value can come when different data types are combined together – including with seismic data, if it is available. Adding potential field data to seismic data can enable geophysicists to get more confidence in what the data is saying and what the structures it shows relate to.

The confidence can be further increased if you use two completely independent data sets of a potential field, since a regional seismic line is not going to give you any information about the fault trace's strike off the line of the 2d section.

Mr Long showed a comparison with magnetic data and "residual gravity" data. Residual gravity shows how gravity for that part of the world differs to what you would expect if the earth was smooth and layer cake geology, given the crustal density variation. The results show "there's something there [which] we can correlate to the

structural geology," he said. This is beyond fabric.

East Africa, and beyond

Mr Long demonstrated how the data could be used to get a better understanding of East African geology, integrating potential field data with other types of data. (A video of the presentation can be viewed online).

The data looks so much more convincing when you put it in to the context of broader regional geological structure, he said.

One example is from a gas field offshore Tanzania, which had been mapped out from 3D seismic, with transpressional structures.

The gravity and magnetics data could be used to show the closure in the structure, the main fault which separates oceanic crust from deformed continental crust. There is compressional deformation on one side and an extensional regime on the other.

Mr Long showed other examples of the regional geological structure from Central America and the North Sea. This needs to be handed over to an academic research group, he said. I am seeking interest and a commercial partnership.

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Improving land seismic technology

Land seismic recording technology is seeing big developments, with better imaging being achieved from Vibroseis sweeping over a wider range of frequencies (broadband) and higher trace density, supported by new, lighter, nodal receiver technology. Andy Bull from INOVA explained

There is an increasing demand from oil companies around the world, particularly in the Middle East, for better seismic imagery onshore – and this can be achieved by more lower and higher frequencies in the vibrators, and more receivers.

Andy Bull, VP of Emerging Technology with INOVA Geophysical, explained how the changes are happening, speaking at the Finding Petroleum forum in London in April 24, “New Geophysical Approaches”.

The term “broadband” is often used, meaning having seismic over a wider range of frequencies, in other words adding in signal at the very low and very high ends.

Richer data can also be gathered by using longer offsets (longer distance between source and receiver) and more channels (higher trace density). Enormous data volumes are created.

There are also options about whether the recording sensors should be cabled or standalone (nodes), or a mix (hybrid).

There is a common belief that onshore seismic is very expensive.

However, if the price is calculated per trace, taking into consideration that much more recording is being done now than 20 years ago, INOVA calculates that the cost per trace has actually reduced by a factor of well over 200 since the 1990s.

“We’re delivering a huge increase in value compared to what’s been happening in the last 20 years or so,” he said.

What is possible

Mr Bull showed some examples of what sort of seismic imagery can be generated with modern onshore broadband seismic.

The first example was from Canada, with a relatively shallow target, imaged with high frequency seismic and a mini-vibe truck. There were short intervals between receivers. The seismic image shows some “really nice content at the higher end,” he said.

For low frequency data, Mr Bull showed an example from the Middle East, using an 80,000 lb vibrator, together with a 26,000 lb mini vibrator, over the survey area, with sweeps starting at 1.5 Hz.

INOVA developed a custom ‘sweep’ for this project, where for the first 6s the frequency was gradually increased from 1.5 Hz to 6 Hz, and then the last 3s went quickly from 6 to 86 hertz, so 9s sweep altogether.

“That is now used as a standard production sweep in that particular part of the Middle East,” he said.

Improving the vibrators

There has been a lot of work going on to improve the vibrators.

“In order to get these low frequencies, we’ve had to re-engineer the hydraulic systems that drive these vibes, to get the vibe sweeping and responding correctly,” he said.

“We’ve developed a much longer stroke length to increase the force at these low frequencies,” he said. “A vibe today will generate almost double the low frequency force that you may have been used to 5-10 years ago.

“We’ve also completely re-engineered the base plate mechanically, making it much stiffer. That helps with distortion, generating broadband force and helps with repeatability.”

Another focus area is reducing engine noise, both to comply with noise regulations, and to reduce the amount of noise which is recorded.

“There’s a lot of new technology out there which provides quieter, more fuel efficient engines,” he said.

Work is being done to improve the controllers, the “brains” of the Vibroseis, so they are better able to control harmonic distortion and subsequently allow more fundamental force to be generated.

“There now seem to be a trend towards what we would call unconstrained simultaneous source, which is basically, ‘put as many vibes as you can into the field’”, he said.

“They are all shooting single source, single sweep. Get them to shoot as quickly as possible unless they are too close to each other. That is a very high productivity method.”

Recording systems

Higher density shooting (with more recording devices per unit area) nearly always pays off, in terms of getting a better image, he said.

Today’s onshore cabled recording systems



Andy Bull, VP of Emerging Technology with INOVA Geophysical

can handle over 200,000 channels in real time, recording continuously, both digital and analogue.

Digital MEMS (micro electro mechanical systems) sensors can now provide better results at high frequency and low frequency, because they are directly measuring acceleration and have particular performance properties that lend themselves to broadband recording.

There is something of a trend away from large vibe fleets towards single vibes and as

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many source locations and receiver points as possible, he said. However whether the best way to increase trace density is to have more sources or more receivers “will depend from job to job”.

Another approach gaining ground is the idea of deploying sensors semi-randomly, rather than in a regular grid. The idea of using randomly placed sensors to generate a seismic image builds on image processing technology ideas known as “compressive sensing,” he said.

Any further increases in receiver density will probably all be achieved with latest generation nodal technology, because increasing the number of cable channels means increasing the crew size (since the crew is mainly handling cabled equipment). Many companies feel that the crews have got as large as they would like them to, he said.

Generation three equipment

Inova is now providing what it calls “Generation 3” nodal equipment, developed with Netherlands-based sensor technology company Innoseis.

It has a recording device which weighs only 650g, and so feels more like a sensor

than a node. It has a long battery life. With a lower weight, the manual work involved in deploying the device is much lower, so less people are needed, and the human risk is less.

INOVA modelling shows that the latest nodes enable a crew to achieve the same productivity but with significant reduction in field personnel when compared to a cable system – or if the crew count is the same, you can achieve a step change increase in receiver line productivity.

It is important to consider the data management system as well as the node, to get data out of the sensor. You have to see it all as a system not just a node.

All nodes or a mix?

Rather than deploy the system entirely in nodes (no cables), some companies are looking at doing a hybrid with some of the system on cables. You would use nodes on the parts of the survey area harder to reach with cables, such as cities or difficult terrain.

This means contractors can stick to what they are used to for part of the work, and use the nodes to supplement it. They can also do their traditional quality control

methods on the cabled seismic. “It potentially simplifies things for contractors,” he says.

Alternatively you could have many nodes with a sparse cable array between them. The cabled recording can still provide real time quality control.

Real time communication

One idea which was popular a few years ago was for communicating land seismic recorded data continually to a base station over wireless communications (as it would if the devices were cabled) – rather than storing the data on hard drives on the devices themselves, to be downloaded later when the devices are retrieved.

The biggest purpose of this was to enable quality control of the data as you are recording it.

But this facility comes at a high cost, with a requirement for wireless communications infrastructure, extra people and more hassle, Mr Bull said. And companies might not necessarily do much with the data.

If you have a high enough receiver density, you should be able to handle whatever noise you have comfortably.

Finding
Petroleum

Land seismic – from brute force to precision

It is technically possible to get much higher fidelity in land seismic surveys, or get the same quality survey as we do now but for lower cost – but the main factor missing is equipment suited to the real physics of land acquisition, said Bob Heath

Too often, the priority nowadays with land seismic surveys is just maximising the number of channels and sources, said Bob Heath, a former vice chairman of SEG’s Technical Standards Committee, and whose career included being International Marketing Manager for a number of land seismic equipment manufacturers.

Maximising channels and sources should be considered a “brute force approach”. It suits the larger manufacturers because they get to sell more equipment. But there are more sophisticated ways to get a higher fidelity recording at possibly far reduced cost, he said.

He was invited to speak at the Finding Petroleum forum in London on April 24 2018, “New Geophysical Approaches”.

Another reason which necessitated the gradual move towards the “brute force” approach over recent decades may be the reduced numbers of people with appropriate scientific expertise, particularly physics, working at oil companies, manufacturers and contractors, Mr Heath said, himself a former physics and astrophysics student.

Seismic contractors must of course focus on the signal to noise ratio of the data they wish to record, this is what they are selling. But high quality data could be acquired with less source and receiver effort than is presently used. This requires a better understanding of the physics of sensors, recording systems and sources.

Geophysical contractors, effectively encouraged by oil companies who also may lack the requisite understanding of underlying physics, often just buy the technology with the lowest cost per channel, or whatever their competitor just bought, with little regard whether this allows them to optimise data quality with less equipment. The result has been ever more equipment often doing ever more of the wrong thing.

Instead, companies could offer equipment with better monitoring capability. For example, geophones can sense information about their condition, and whether they have a good ‘plant’ in the ground while the digitisation process could be more attuned to how seismic energy disperses.

It is also possible to fit sensors to source

vehicles (Vibroseis) to calculate and record what exactly is being sent back into the earth, rather than just using a poorly calculated ground force as a proxy. The improvement which comes from a better understanding of Vibroseis would also enable impulsive sources to be developed which might compete with vibrators.

Quality driven acquisition

Another idea is quality driven acquisition (QDA), where the quality of some essential aspects of the data are monitored in real time, allowing adjustments to be made to the source and receiver effort.

Just as there is no point in coming back with data so poor it cannot be interpreted,

it is also costly to acquire data with more SNR (signal to noise ratio) than is really needed. QDA, based around appropriate hardware, allows adjustment of field effort according to recorded quality.

This is not a new idea – AGIP (now ENI) was doing this in the 1990s, he said. “Quality driven acquisition came to a halt simply because [in the 1990s] there wasn’t the processing power in the recording truck. That is a problem nobody has any more.”

“If you want to radically reduce the cost of land seismic to get it to the absolute minimum, these are the sorts of things you have to do. There are no other choices. Simply acting as though ever more source and receiver effort is the only answer simply ignores basic physics and economics.”

Many other industries have mastered the ability to change what they are doing as the situation changes, ranging from the military to hospitals, he said. “It is not difficult, we just don’t do it.”

The cost to revolutionise the land exploration industry to make it viable with \$60 oil is little more than the cost of a major three month survey. And it’s not science fiction; much of what is needed is to bring together a number of already-existing loose ends. “The company which accomplishes this will dominate land seismic for decades to come”.

Note: Bob Heath can be contacted on rgheath@btconnect.com

Finding
Petroleum



New Geophysical Approaches

New Geophysical Approaches event, London, April 24 2018, Attendees

Hugh Ebbutt, Director, A T Kearney	Richard McIntyre, Sales Manager, Finding Petroleum	James Thadchanamoorthy, CFO, NRL
Jonathan Minnitt, Business Development Manager, Aker Solutions	Jeremy Berry, BD Director, GCA	Mike Rego, Independent Consultant, PetroMall Ltd
Geoffrey Boyd, Field Development Consultant, Antium FRONTFIELD	Nick Cameron, Geological Advisor, GeolInsight Limited	David Bamford, Petromall Ltd
Maria Mackey, Energy Sector, AWS	Geoff Marsden, Processing Geophysicist, GM Geophysical	David Sendra, Associate Consultant, Petrophysical Consultant
Simon Berkeley, Director, Berkeley Associates	Thomas O'Toole, R&D Geophysicist, Halliburton	John Clure, Managing Director, Phoenix Hydrocarbon Resources Ltd
Steve Callan, Sales / Marketing / Business Development, BGP Marine	Norman Hempstead, Director, Hempstead Geophysical Svcs	William Davie, Director, Precision Impulse
Nick Pillar, Manager of Geophysics, Canadian Overseas Petroleum Ltd	Geoff Chambers, Sr Geophysicist	Colin More, Prospect Geoscience
Rory Scott-Russell, Director, CaribX	Neil Simons, Consultant	Mark Rees, Managing director, Rees Onshore Seismic Ltd
Chris Matchette-Downes, MD & Owner, CaribX and MDOIL Limited	Abdulmohsin Dolaijan, Consultant	Martin Smith, Business Development Manager - Operations, RPS Energy
James Andrew, Business Development Mgr EAME, CGG	Mike Hibbert, Independent Consultant	Mike Larsen, Business Development Director, EAME, RPS Energy
Micky Allen, Consultant	Andrew Clark, Chief Commercial Office, Innoseis BV	Keith Holdaway, Advisory Industry Consultant: Global O&G, SAS Institute
Peter Farrington, Consultant Geophysicist	Andy Bull, VP, Emerging Technology, Inova Geophysical	Robert Heath, Consultant, Seismic & Oilfield Services Ltd
Richard Walker, Consultant Geophysicist	Naohiro Yoshino, Geoscientist, JAPEX	David Eastwell, Geoscientist, Spectrum Geo
Dan Kunkle, Director, Count Geophysics	Kai Gruschwitz, Senior Geophysical Advisor, Lukoil	Andrew Long, Director & Founder, Subterranean Ltd
David Boote, DBconsulting Ltd	David Peel, Technical Director, Lukoil	Phil Houston, Founder / CEO, TalEng
Stephen Norman, Business Development Manager, DNV GL	Anne-Mette Cheese, Exploration Geologist, Lukoil Engineering, London Branch	Duncan Irving, Practice Partner, Oil & Gas, Teradata
Brian Donnelly, Consultant Geophysicist, Donnelly	Artem Kotenev, Lukoil Overseas UK Ltd	Peter Roberts, Business Development Manager, Tessella
Martin Riddle, Technical Manager, Envoi	Chris Morgan, Managing Director, Lynx Information Systems Ltd	
Karl Jeffery, Editor, Finding Petroleum	David Buddery, Consultant, Neoseismic Ltd	
Avinga Pallangyo, Conference Organiser, Finding Petroleum	Helen Turnell, Principal Consultant, NR Global Consulting Ltd	

What did you enjoy most about the event?

<p>“ The sense of networking. ”</p>	<p>“ INOVA presentation. <i>Brian Donnelly (Consultant Geophysicist)</i> ”</p>	<p>“ Presentation by Andrew Long, and the final two presentations by Dave Bamford and Robert Heath. <i>Mike Rego (PetroMall Ltd)</i> ”</p>
<p>“ DB's perceptive summaries and insight. <i>Nick Cameron (GeolInsight Limited)</i> ”</p>	<p>“ Chance to meet old friends. <i>Bob Heath (Seismic & Oilfield Services Ltd)</i> ”</p>	<p>“ Interesting and entertaining speculation about the future plus excellent update on land seismic acquisition. <i>Richard Walker (Consultant Geophysicist)</i> ”</p>
<p>“ Insight into the winds of change blowing through the industry. <i>Geoff Marsden (GM Geophysical)</i> ”</p>	<p>“ A lot of dialogue, people were engaged. The question and answer sessions were very informative. ”</p>	<p>“ Opportunity to hear overview opinions. ”</p>
<p>“ Talks by David Bamford and Dr. Duncan Irving. ”</p>		