Finding Petroleum

How electromagnetics could have changed the drilling sequence creaming curve in the Barents

Fibre optics in wells to record seismic - now competitive with ocean bottom nodes?

Improving workflows for non-seismic data - one data set can help you better understand another

Non-seismic Geophysical Technologies and Non-Conventional Seismic, London, Oct 11 2017

Special report

Non-seismic Geophysical Technologies and Non-Conventional Seismic

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Electromagnetics, well fibre optics and combining data

Finding Petroleum's London forum looked at non-seismic geophysical technologies and non-conventional seismic, with a special focus on using electromagnetics to reduce risk, working with well fibre optics, and combining seismic and non-seismic data

This is a report from the Finding Petroleum conference "Finding Petroleum: Non-seismic Geophysical Technologies and Non-Conventional Seismic", held in London in October 2017

Event website

Many of the videos and slides from the event can be downloaded from the event agenda page.
www.findingpetroleum.com/event/ef071.aspx

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Finding Petroleum's London forum on October 11 2017, "Non-seismic Geophysical Technologies and Non-Conventional Seismic," looked at how companies can work with electromagnetics, in-well fibre optic seismic, and combining seismic data with other types of data.

Daniel Baltar, Global Exploration Advisor with electromagnetic company EMGS, explained how electromagnetics might have been used to get a better understanding of the different risk of well prospects in the Barents Sea – and then showed how the drilling sequence creaming curve might have been changed if EM had been used. This can then be compared to the actual success of the wells, which is now known.

It illustrates that EM data only reduces exploration risk by a quantifiable degree. It also highlights the significant value of the EM negative case Considering the large amounts of money involved in drilling, particularly in the Barents Sea, derisking improvements over the portfolio scale are well worth having.

Garth Naldrett, Chief Product Officer of Silixa presented the company's technology to record acoustics in wells using fibre optic cables, which can be used for (active) seismic and passive seismic. In particular, it is useful for repeat surveys, if the fibre optic cable is permanently installed, and it may prove to be better than ocean bottom nodes (OBN).

Markus Krieger, Managing director of Terrasys Geophysics presented some techniques to use different kinds of data together, for example gravity and seismic. It may be helpful as an intermediate step to use crude or low granularity models, as you try to understand what the subsurface actually looks like.

Perhaps it is better if you don't try to invert all of your seismic (from time to depth) at the same time, but just convert the seismic where you have a good idea of the density / velocity model at that point, for example using well data, he suggested.

Using electromagnetics together with seismic

Electromagnetic data is perhaps best used in practise to de-risk, or get a better understanding, of targets selected from the seismic. Daniel Baltar explained how to do it, with an example from the Barents Sea

Electromagnetic (EM) surveys of the subsurface can directly reveal one thing – material with less resistivity than the norm – and that means salty water. Both hydrocarbons and dry rock show up as high resistive bodies.

Explorers are not looking for salty water, of course. But understanding the salty water can help you understand where hydrocarbons might be, as Daniel Baltar, Global Exploration Advisor for EMGS ASA, explained.

Daniel Baltar, Global Exploration Advisor with EMGS

In this way, EM could have been used to better understand the risk for a number of Barents Sea wells. Mr Baltar explained in his talk what the drilling sequence was based on seismic alone, how understanding from EM could have led to changes in the drilling sequence, and how much could have improved the final result, based on the actual success of the well.

Controlled Source Electromagnetics (CSEM) is a technology to generate an electromagnetic signal, send it through the earth, and see what you receive back, some distance away. Electromagnetics are also used for communications between a mobile phone and an antenna. An EM signal will travel through the subsurface more easily if there is salty water (brine), because it conducts electricity.

The value of EM is based on the fact that it can see something which seismic cannot – i.e. whether there is brine in a reservoir – and then using EM together with seismic to get a better picture.

Reservoirs usually have salty water beneath the oil, pushing the oil upwards against the seal (oil is less dense than water). So if the reservoir space appears to be partly full of something with lower resistivity, that makes it more likely that the rest of the reservoir has a seal and a trap, Mr Baltar said.

Working with just seismic

Seismic itself can tell you about the geometry of the subsurface, and if you have 3D seismic you can interpret amplitude patterns to get an understanding of depositional patterns of the rock. But it cannot tell you anything about the fluid in the rock.

When oil and gas explorers want to understand the hydrocarbon potential of part of the world, they generally start by interpreting seismic to build a structural and geological model.

They use this to try to understand whether there might be a reservoir (an accumulation of hydrocarbons), a seal (which stops hydrocarbons leaking), and a trap (an arrangement of the reservoir and seal which does not allow leaks). All of these factors need to be present to produce oil.

Then they estimate the amount of oil by calculating the gross rock volume, saturation and expected recovery. A combination of the estimate of the amount of oil (the prize) and estimate of the risk leads to a decision about whether to develop the field.

It is very hard to do successfully. In the Barents Sea, 106 wells have been drilled, but an analysis by the Norwegian Petroleum Directorate showed that about 95 per cent of them did not turn out to be economically viable, and only 10 per cent had more than 100m barrels of oil equivalent (with 200 to 300m boe minimum field size in the Barents Sea).

One oil company did an analysis of the reason behind 120 of its dry "wild card" wells, and found that 45 per cent of them turned out to have no seal on the reservoir, and 30 per cent had no charge, a pressure force pushing oil into the reservoir. So there were no fluids in the reservoir.

In another example, Mr Baltar showed a graph of volume predictions of fluids in reservoirs made in Norway, comparing the predicted volumes with the actual volumes. There is so little correlation, essentially it shows that companies cannot make predictions at all, he said. Nearly all the predictions are over-estimates.

At the same time, records show that most of the really big discoveries ever made were originally underestimated in size. So you can't just dial down all of your estimates, in case you leave large reservoirs behind thinking they are too small, he said.

CSEM in more detail

The ability of CSEM to image a reservoir is a function of the area of low resistivity (= the area of the briny water volume), the thickness, and the level of resistivity (= the concentration of the brine).

If a reservoir is entirely filled with hydrocarbons, or there is just a small volume of briny water, then it will not show up in the EM data.

But if the EM data shows low resistivity in the same place as your reservoir, it might be telling you that the reservoir is entirely filled with brine (no hydrocarbons).

If the reservoir is nearly all full of brine but with a small amount of oil on the top, then the oil will be hard to see, so it will look like a field full of brine on the EM data.

But if you have a reservoir part filled with oil and part filled with brine, the reservoir will show up as having a higher resistivity than if it was filled with brine, but not the same resistivity as the surrounding rock.

This is how EM can provide more insight into your target reservoirs.

Five Barents prospects

Mr Baltar presented an example where CSEM was used to help evaluate five prospects in the Barents Sea, named Korpjell, Blåmann, Gemini North, Koigen and Kayak.

Korpfjell was in the most bid on block in the previous license round in Norway, with "real fights" between companies to gain access, he said.

Blåmann and Gemini North were close to already known discoveries, which put them higher in the ranking (lower risk).

Koigen and Kayak were considered more outliers.

Kayak is cretaceous, the other four, Koigen, Gemini North, Korpjell and Blåmann are lower Jurassic, in rotated fault blocks.

The planned drilling sequence, based on the understanding described above, was Korpfjell, Blåmann, Gemini North, Koigen, and Kayak.

When using CSEM you would probably drill in the order Blåmann, Kayak, Koigen, Korpfjell then Gemini North.

Mr Baltar explained in detail how this decision would have been reached. The description is difficult to cover in this written account, but you can watch it online together with the illustrations, on the Finding Petroleum website. http://www.findingpetroleum.com/event/ef071.aspx

As it turned out, Koigen was a dry, tight reservoir (no hydrocarbons). Kayak was a reservoir with about 20-50 million barrels of oil and may turn out to be an economic discovery. Blåmann was a small gas discovery, Korpfjell was a small gas discovery and Gemini North was a small gas discovery. So in hindsight, a better drilling sequence may have been Kayak, Blåmann, Korpfjell, Gemini North, Koigen.

So the CSEM would have correctly pushed Korpfjell down the drilling sequence, incorrectly raised Koigen and Blåmann, but perhaps most importantly taken Kayak, the prospect which might be economic, from 5th to second place in the drilling sequence.

So overall, CSEM would have improved the likelihood of success.

There is some granularity to interpretation, Mr Baltar says. People who look for a yes or no tool probably have expectations too high as what exploration technology can do.

You can't say every single resistor will be a successful reservoir or every single non-resistor will be unsuccessful. EM doesn't mean your evaluations will be perfect, just that they will be better.

Silixa – well fibre optic for recording seismic

Fibre optic cables, placed in oil wells, can be used for seismic recording. The technology has recently advanced in sensitivity, and can now be equivalent to using Ocean Bottom Nodes (OBN), said Garth Naldrett of Silixa

Fibre optic cables can be used as listening devices, because acoustic energy (sound) creates a tiny change in strain on the cable, in the same way that acoustic energy creates a tiny change in strain by vibrating our eardrums.

This change in strain can be converted into data by sending light pulses through the cable. The light pulse is changed and reflected by the change in strain. At the end of the cable, the light pulse can be analysed. From knowing where the light pulse was along the cable when the change happened, you can know where the sound was the loudest.

This way, a fibre optic cable in a well can be used to record seismic energy, replacing a geophone hung in the well on a wireline.

Because the recording is made actually within the subsurface, rather than on the surface or seabed, the seismic energy does not have to travel so far from the source to the receiver (recording device), leading to a clearer (less noisy) signal.

If the fibre optic cable is fixed in the well, it means that comparing repeat seismic recordings (3D seismic) is much easier, because the position of the recording device is exactly the same each time.

The actual measurement is slightly different to a geophone – a geophone measures velocity of ground movement, whereas a fibre optic measures changes to strain. However the recording for both is very similar, Mr Naldrett said.

The seismic can be recorded with a wide 'aperture', because you can record for the entire length of the well at once. There is no need to move the wireline up and down the well as you are recording (as you might with geophones on a wireline).

The system is sensitive enough that it can be used to record music, from the way that the music sound waves changes the light pulsing through fibre.

The seismic can only be recorded in one direction (the strain of the cable), unlike conventional streamer seismic recording, which can record in 3 directions. Although one approach is to have a helically wound fibre optic cables, which mean that the sound can be recorded in many different directions. This approach was used on the Otway CO_2 sequestration project, described later in this article.

Background

Silixa has been developing acoustic fibre optic technology since 2007. It made a step change improvement to the technology in 2012-2013, upgrading instruments and its sensing system. It is about to launch a new system, using a new fibre optic cable designed to reflect light in a stronger way, providing a much stronger response.

There are already about 5,000 wells around the world with fibre optic cables installed in them, because it has been installed for monitoring pressure and temperature in wells since the late 1990s. These can be used for acoustic recording.

Gart Naldrett of Silixa

In 2016, Silixa received an Institute of Physics award for its work on seismic imaging in wellbores.

Applications

As well as imaging the subsurface, you can use the system to evaluate the cement around the casing, checking how good the cementing is and where the top of the cement is.

In the US, the fibres are used in unconventional wells to understand how the proppant is working, or to do production profiles, understanding which reservoir intervals the well fluids are being produced from.

It can be used to monitor gas lift optimisation, or check for leaks in any tubing strings.

Working with it

The technology is based around fibre optic cables an eighth of an inch diameter installed in a wellbore, either permanently outside the casing, permanently in the annulus between the casing and production tubing, or temporarily inside the production tubing (on wireline or slickline).

The fibre can be packaged inside a metal tube, or within a wireline, for protection.

If it is being installed outside the casing, it can be strapped to the casing as it is run into the well. The cable can be brought out of the well by wrapping it around the casing hanger and taking it out through the tree.

On the surface, the cable is plugged into an optical interrogator unit. For onshore wells, the interrogator can be installed in the equipment room. For offshore wells, it can be on the platform. The interrogator generates light in very short pulses, and analyses the light pulses which come back. It can interrogate a fibre which can be tens of kilometres long.

The system can generate terabytes of data every day on some projects. But the data can be handled offshore, it does not all need to be sent home.

The fibre optic cable can typically last 10-15 years in wells – cables installed in the early 2000s on wells are still being used. The fibre optic cables can manage high temperatures and pressures.

The analysis is usually done by measuring the strain on 10m lengths of fibre – and then move the length of fibre being analysed 25cm along (so find the strain between points 10.25m and 20.25m).

For the microseismic, you don't need to even put anybody offshore, you can manage the survey and gather data from onshore, if there is a means of communicating the data.

Comparison with OBN

Many customers have been comparing fibre optic seismic with ocean bottom nodes (OBN), devices which are placed on the seabed to record seismic.

Individual OBN receivers have a higher sensitivity than fibre optic seismic. But fibre optics have a compensating advantage in that they can record over a much bigger area, the equivalent of a bigger array of nodes, Mr Naldrett said.

The fibre (DAS) systems also don't need as big seismic sources as OBN. This means you can run the source from a normal supply vessel, rather than needing a dedicated seismic survey vessel. This in turn means you can do repeat surveys more often (every 6 months rather than 2 years, or have a survey whenever you need it). "If there's a vessel in the area we can say, shoot past and shot some lines."

Fibre optic seismic can also be cheaper than OBN, considering that OBN needs a vessel and robotic equipment to place the nodes on the seabed and retrieve them every time it is used.

Case studies

Mr Naldrett presented a case study of how the fibre was used on an oil well in China, installed by BGP. The paper was presented in more detail in EAGE 2016.

The fibre optic cable was installed in the well bore on wireline, and the source was from dynamite.

The subsequent seismic images were compared to images from surface seismic.

The first set of data back from the well had a lot of noise in it, because of the dynamite shot creating a lot of movement on the surface, and the slap of wireline cable against the borehole. But it was possible to take the noise out with a little bit of processing, leading to something similar to the surface seismic images, Mr Naldrett said.

A second case study was a survey BP ran in Trinidad, using fibre optic cables which had already been installed in the wellbore. BP was also doing an OBN survey, and wanted to compare the well bore fibre images with the OBN images.

The results showed that the imaging was much better from the fibre optics than the ocean bottom node – and also the two seismic images had a good correlation. This success persuaded BP to run more fibre optic surveys, Mr Naldrett said.

A third case study presented was for Valhall, in the Norwegian area of the North Sea. There were 2 wells equipped with fibre optics for seismic recording. The first well had 1260 receiver 'channels' down a 1260m length of fibre. The second well was a bit deeper.

There is quite a lot of noise on the data but it was "easily removed," he said.

There was a gas cloud above the reservoir, which was causing difficulties in imaging the reservoir with nodes on the seabed, but it could be done with fibre in the wells.

A fourth case study was from wells from the UK sector of the North Sea, with surveys shot using both fibre optics and ocean bottom nodes. The results showed that the images were similar, but the fibre optic image had a better resolution, Mr Naldrett said.

Microseismic and unconventionals

The system can also be used for microseismic monitoring (listening for sounds not created by an artificial source).

One application is monitoring the caprock above the reservoir. If there are any cracks in the caprock then they can be 'heard' by the fibre.

This can be particularly relevant on unconventional wells, which are filled with pressurised liquid to frac them – you want to make sure you are not fracking the caprock and allowing all of the fluids to leak out.

You can see a microseismic event on both P and S waves. You can calculate the distance of the event from the cable, from the difference in time from when the P wave and the S wave arrives.

If you have two receiver arrays you can accurately position the event in 3D, he said.

The system can be used to monitor the fracking itself. Mr Naldrett showed the fibre recording for a treatment for an unconventional well, which had 2.5 hours of fracking. From the data, you can see the pressure being ramped up, the proppant concentration being ramped up, and the microseismic events occurred. The recording was made 500m from the well in an adjacent borehole.

There were a "few hundred" microseismic events, mostly quite close to the borehole, with fractures further and further into the reservoir as the treatment continues.

There is also another response on the cable, as a result of pore pressure or rock forces on the cable, about 45 minutes after the fracking starts.

You can also see a fault being reactivated close to the monitoring well.

CO2 sequestration

The system was installed in a CO2 sequestration well in Australia, part of the Otway research project. The aim was to try to monitor how CO2 was entering the subsurface.

The data was recorded at a 700m offset and beyond, with a 650 Hz range of frequency sweep.

The research team wanted to compare the fibre optic recording with a conventional geophone array. They found that the geophones needed to be placed in 11 different positions, to get the same length of the well as the fibre optic, which can survey the entire well at once.

A long offset was used to try to understand how the seismic was changing further away from the wellbore (how far the CO2 was moving). Fibre optics can be better than geophones if you have a long offset, because the increased density of the recording array is much more important.

Terrasys – workflows for non-seismic data

Terrasys Geophysics of Hamburg, Germany, is working out better ways to use non-seismic data together with seismic data, leading to big changes in the final subsurface understanding

Terrasys Geophysics of Hamburg, Germany, is working out better ways to use non-seismic data together with seismic data.

It is much more than just using data from one method together with data from another method. One method can help you better understand the data from another method, said Markus Krieger, managing director of Terrasys Geophysics.

For example, if you can use gravity to get a better understanding of the density of a body, that can be used to get a better understanding of seismic velocity (since it is related to density), and so do a better time to depth inversion on your seismic.

To illustrate this, Mr Krieger showed the results of a seismic inversion made from just seismic, and a seismic inversion interpreted with the help of gravity gradiometry data. The gravity data was used to better define the base of the salt, which in turn was used to upgrade the velocity model, and improve the seismic inversion. The whole image was much better.

But it is very easy to get overwhelmed by the complexity of using multiple types of data which appear to be telling you something different. It may be helpful to work with simplified models.

If you have a team of interpreters with different specialist skills, it helps if they all communicate a great deal with each other to try to build a common picture, he said.

One of the most important points is to rate reliability of input data types, because if that is not done correctly then advanced techniques would lead to misleading results, he said.

Limits of seismic

A good starting point is to observe that seismic methods, while useful, do have limitations, so you do not get the full picture, he said. Seismic methods represent a limited subset of earth model parameters.

In a typical seismic image, there are areas where there might be something but you are not sure. Some horizons can be seen clearly, but in other areas there's definitely room for improvement in understanding, he said.

The solution can only be to either upgrade the seismic or replace it with non-seismic methods, recorded either on ground or airborne, which can deliver complementary parameters, he said.

Data analysis first

Terrasys usually recommends to start with looking at the data itself before trying to bring in interpretation.

If you have a magnetic intensity map, you might see broad regional variations, or change in attributes. This can help bring out interesting features which might be worth looking at more, similar to looking at seismic attributes.

One useful approach is to calculate the second vertical derivative, i.e. how fast parameters appear to be changing as you change vertically.

Mr Krieger showed a Bouguer gravity map showing a salt structure with low definition. If you look at the second vertical derivative, you can usually see the outline of the salt much better. You can see the steepness of the salt flange, and usually the highest density contrast.

You can use methods like this to define your regional structure, or get a better feeling for it.

Simple models

You can build simple models of how you think a volume of subsurface looks, for example by simplifying it into two structural bodies with two respective densities. "This does not work in every case but in general helps reduce the number of parameters," he said.

Or you can define a background density based on seismic horizons, and then have independent 3D structures within it (for example for structures inside salt).

This can be a good way to work with different data sets. For example if you have gravity data and seismic data of a volume containing a salt dome, you can use the second vertical derivative of gravity for an initial model to delineate the shape of the salt, and then use that to work with the seismic.

Stepwise joint inversion

Non-seismic data can be inverted jointly to a unique subsurface model in different ways, often guided by seismic and geological constraints (also called "boundary conditions").

This can be done iteratively, e.g. if the "new" velocity model (based on density variations) leads to updated horizons from seismic processing. These are used for the next inversion, and so on.

In most cases non-seismic inversion successfully focuses on areas of weak seismic imaging, e.g. in zones of steep geological features.

It is important to use all available information, which is sometimes hidden. But you need an uncertainty value for every data type in the inversion.

"We ask our experts, the clients, how sure you are for example about the cretaceous density or the thickness in this or that structure? How much variation from your best guess you would accept? You have to spend effort."

There might be some parts you are more sure of than others, for example if you can see there is very complex allochthonous salt, but you are not very confident in the lower boundary of the floating salt. In such a case the inversion can focus on this part, and the inversion results can also give you information on their reliability (or model uncertainty).

Summary

To summarize, costs could be significantly decreased by considering non-seismic techniques, starting from data acquisition up to joint interpretation, while simultaneously, modelling can be reduced, he said.

However, a diligent feasibility test, appropriate interdisciplinary communication, a correct application of each method, and adequate tools for results evaluation are mandatory for successful integrated interpretation projects.

Finding Petroleum: Non-seismic Geophysical Technologies and Non-Conventional Seismic Attendees

London, October 11, 2017

David Roberts, Consultant, 3-DMR

Christian Bukovics, Partner, Adamant Ventures

Christian Richards, Sales Manager, AustinBridgeporth

Bernard Wayne, Chief Geophysicist, Azimuth

Joe M Boztas, Director/Interpreter, Boz Seismic Services

Tony Bourne, Potential Fields Geophysicist, BP

Robert FE Jones, Director, Caithness Petroleum

Robert Kennedy, Commercial Director, Caithness Petroleum Limited

Nick Pillar, Manager of Geophysics, Canadian Overseas Petroleum Ltd

James Andrew, Busines Development Mgr EAME, CGG

Micky Allen, Consultant

Peter Farrington, Geophysicist

Richard Walker, Consultant Geophysicist

Grahame Grover, Convolve

Ian Newth, Director, Count Geophysics

Stephen Norman, Business Development Manager, DNV GL

Brian Donnelly, Consultant Geophysicist, Donnelly

Lodve Berre, Senior Geoscientist, EMGS

Charles Thomas, Senior Vice PResident Africa & UKCS, EMGS

Izebrand Huizenga, ExxonMobil

Robert Warren, ExxonMobil

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Daniel Baltar, Global Exploration Advisor, Fox Geo Exploration

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Geoff Marsden, Processing Geophysicist, GM Geophysical

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Clare Smith, Geoscientist, Hansa Hydrocarbons

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Neil Simons, Consultant, Independent

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Peter Allen, Consultant, Layla Resources

Jon Wix, Lloyds Register

Kai Gruschwitz, Senior Geophysical Advisor, Lukoil

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Robert Parker, Consultant, Parker

Johnni Cestari, Perenco

Simon Russell, Senior Geophysicist, Perenco

Vincent Sheppard, Chief Geophysicist, Petrofac

Mike Rego, Independent Consultant, PetroMall Ltd

Henry Dodwell, Consultant, PetroVannin

Joshua May, Sales and Marketing Manager, PGS

Allan McKay, EM Processing and Interpretation Manager, PGS

Dave Forecast, Sales Supervisor, Polarcus

Iain Buchan, Polarcus

Colin More, Prospect Geoscience

Jon Nicholls, Business Development Manager, Rock Solid Images

Lucy Macgregor, Chief Technology Officer, Rock Solid Images

Martin Smith, Business Development Manager - Operations, RPS Energy

David Webber, Seismic Operations Supervisor, Sceptre Oil & Gas

Tom Martin, Director, Shikra Consulting

Garth Naldrett, Chief Product Officer, Silixa

Glyn Roberts, Director, Spec Partners Ltd

Phil Houston, Founder / CEO, TalEng

Markus Krieger, Managing Director, TERRASYS Geophysics

Stefan Hossfeld, Geologist, TERRASYS Geophysics

John Weston, Tecnical Director, Tridevi Energy & Resources

Gareth O'Brien, Geophysicist, Tullow Oil

Alastair Bee, Westwood Global Energy

Jake Berryman, Senior Geophysicist, WyeDean

What did you enjoy most about the event?

Chance to meet people.

The relaxed pace on questions was good.

Informal work-shop provided a better technical understanding of the technique.
Geoff Marsden

That there are other techniques than seismic!

Very interesting technical content.
James Andrew (CGG)

Opportunity to network and the EMGS workshop.

The talks.
Robert Kennedy (Caithness Petroleum Limited)

Learning more about EM technology and interpretation.

Technical content and Q&As.
Abi Mirkhani

Excellent presentations and useful case studies.
Richard Walker

Stimulating discussions and networking.

Thought provoking presentations and open forum for discussion.

Developing understanding of unfamiliar technologies.
Mike Rego

The focus on CSEM technology and the afternoon workshop.
Jim House (GeoSeis Ltd)

Good networking and update on the latest technologies.