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INSIGHTS

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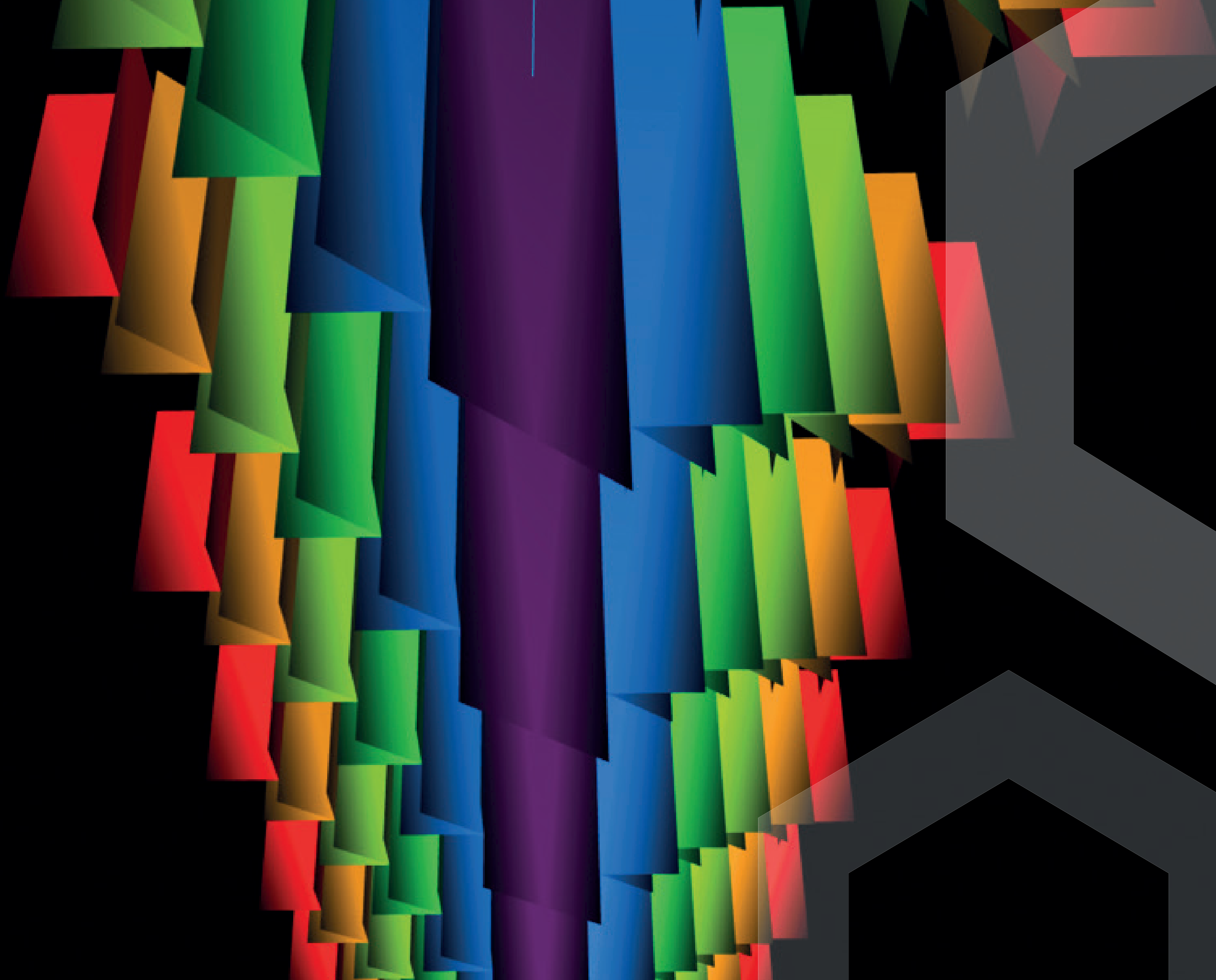
Can we squeeze more value from reservoirs in production - from better use of data?



Time to treat reservoir simulators with more scepticism?

Using changes in gravity and subsidence on the seabed

Working with repeat seismic recorded on the seabed

Using fibre optics in wells for measuring seismic

Rock relative permeability from a digital rock sample

Petromall

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Can we squeeze more value from reservoirs in production - from better use of data?

The understanding that oil and gas companies have of reservoirs in production is a basis for multibillion dollar decisions and could hardly be more important in the overall success of the business. Is there room for improvement in how they develop this understanding?

The oil and gas industry's understanding of reservoirs in production is the basis for multibillion dollar decisions which affect everyone in the industry.

The valuation of the company, the remaining life of a well or field, sizing of new production facilities, decisions about where to place infill wells, and whether to do workovers or enhanced oil recovery schemes, are all based on the company's understanding of its reservoirs in production. A better understanding of reservoirs could also help maximise hydrocarbon production and minimise water.

The industry has made great advances in improving recovery over recent decades, from having a better understanding of the reservoirs and how to extract more from them.

But it may be possible to improve recovery even more, if more different types of data could be used in better ways to understand reservoirs, and more people could contribute to the understanding. This might mean having reservoir data systems which are easier for people from different disciplines to work with and access, than the current complex reservoir simulators. This report explores ways it could work.

There is plenty of published material about new subsurface survey techniques, how geoscientists develop their static (one point in time) geological models, how reservoir engineers get a better understanding of reservoir properties in specific points of the reservoir, and reservoir simulation software available on the market. We can call this bottom up information to understand a reservoir.

There is also plenty of published material about successful wells and dry wells, production rates, and companies which over-estimated their resources or production and let down their shareholders. We could call this top down information to understand a reservoir.

Between this bottom up and top down processes is something of a black box. How do oil and gas companies take this bottom up and top down information to build and improve their understanding of the reservoir? Yes, we know they use reservoir simulators, but these are still something of a black box, only understood by the people who use them.

Some people we talked to think that reservoir simulators, and their predictions, should be treated with a little more scepticism. The alternative ways to understand reservoirs, based on observed data, do not give a complete picture either, but should perhaps be given more weight, with the raw data more widely shared.

Understanding of oil and gas reservoirs can only become more critical in future years. When operating margins are tight, making the right decision becomes more important. With mature fields, predictions need to be made about how much life is left. Often we have drilling, field development, operations, asset sales, tie-backs to new wells, enhanced oil recovery and decommissioning all taking place in the same field at the same time. Perhaps in future we will also have CO_2 injection, for permanent storage and enhanced oil recovery.

And there are plenty of new technologies being developed which can help understand reservoirs in production - including 4D seismic techniques on the seabed and in wells, measuring changes in gravity and subsidence on the seabed, understanding multiphase flow from analysing drill cuttings, studying interference between wells, better ways to integrate and simulate data, enabling production engineers to access reservoir data, and preparing better geological models for reservoir simulators. The industry needs to make sure that all the information generated from these technologies is not wasted.

Integrating and analysing multi-physics - the key to improving production?

We have many technologies which can acquire data on the dynamics of petroleum reservoirs - if we can integrate this multi-physics and analyse it as one, our production predictions might take a great leap forward

By David Bamford

Hindsight is a wonderful thing and looking back one can see areas of our everyday and working lives that technology has transformed.

One of my over-used examples is the weather forecasting that we see now hourly it seems on TV.

Many years ago I visited the UK's Met Office in the hope of learning something about prediction success and instead discovered that their forecasting apparently consisted of 1st degree level physics, some IBM 360's strapped together, and data from a few meteorological stations scattered up and down the UK and out in the Atlantic.

The resulting analyses didn't lead to very good predictions and I left assured that the best forecasts were based on either "tomorrow will be pretty much like today" or "tomorrow will be pretty much like the same day last year"!

Consider what we see nowadays - satellite and airborne imagery: radar, thermal etc, even probabilities quoted. Sometimes we may be sceptical but the forecasts are much more reliable now.

Closer to our working lives, consider the impact the advent in the mid 1990's of 'regional' or 'exploration' 3D has had our exploration success rates, our exploration prediction accuracy. Who would think of exploring without it nowadays?

For a while I have asked myself when and how we will see the same impact on reservoir management?

Partly this is because reservoir engineering or, more precisely, reservoir simulation has remained pretty opaque to me, an art I have described as similar to the building of Chartres Cathedral or perhaps the Grand Mosque at Córdoba - built and re-designed over decades, even centuries and as in the case of the latter, filling now a completely different purpose to that which it was designed for.

But we now have, as reviewed in this Petromall Insights, several technologies which can acquire data on the actual dynamics of petroleum reservoirs.

But.... the trick we have not yet mastered is how to integrate this multi-physics and then analyse it as one.

If we can do this then our production predictions will take a similar Great Leap Forward to the weather forecasts most of us see every day!

David Bamford is a former global exploration lead with BP, and former non executive director of Tullow Oil and Premier Oil

David Bamford

Working with technology

The approach of writing this report is to try to find out how the oil and gas industry actually works with reservoir data today - and explore how it might be improved.

We did not find any people who currently work at oil and gas companies willing to speak on the record, but many of our interviewees formerly held senior roles in oil and gas company reservoir departments.

We also spoke to seven companies who are developing technology which can be used to better understand reservoirs in production. We did not focus too much on their technology itself, but focussed more on how companies work with their technology. How oil and gas companies make a decision to use it, and how they work with the data which is generated.

This report has two sections. The first is on better ways to gather data about a reservoir in production. We look at Octio, which gathers gravity, subsidence and seismic data from the seabed; Seabed Geosolutions, which gathers seismic data from the seabed; Silixa, which puts fibre optics in wells which are used to record seismic; and Exa Corporation, which can model multiphase flow through a reservoir, from a piece of drill cutting or core analysed in a CT (tomography) scanner.

The second section looks at better ways to work with reservoir data. We look at iRes-Geo, which has developed a workflow for preparing high resolution geological models for reservoir simulators; Kes Heffer of Well Dynamics, who studies flow interference data, and Paradigm, with software to help production engineers work with reservoir models.

The reservoir simulator

The reservoir simulation starts with a static picture of the reservoir, developed by geoscientists, with models generated largely from interpreting seismic data, mapping them against well data and anything else available.

The reservoir simulator makes a computational model of how fluids would flow in this reservoir model, with the pressures, different fluids, rock properties, fractures and wells taken into account in the computation.

Reservoir engineers aim to continually improve their simulations by using revised geological models made by geoscientists, adding more live data, and making other tweaks until the predicted production 'history matches' the actual production.

They can calibrate the reservoir models across the whole of the reservoir, not just for individual wells, looking at the entire volume of the reservoir.

They want to get correct data for the reservoir depths, surfaces, faults, net to gross (total 'pay' footage divided by total reservoir footage), porosities and lithologies.

The dynamic flow simulation also takes into account that the pressure in the reservoir will drop as it depletes, leading to reduced flows, meaning lower production through the wells.

Over time, the reservoir simulator should show you parts of the reservoir which are not draining into the wells, and so are targets for infill drilling.

But many of our interviewees expressed private doubts about reservoir simulators. It isn't possible to know for sure how good they are. In theory, the closer the simulator is to reality, the more likely it is to be able to predict accurately. But in practise, if you don't (and can't) have a good understanding of the subsurface – the geology and fluid flows – then more investment won't give you better predictions.

Two interviewees raised the issue that the reservoir simulation is usually based on statistics, probability and various empirical (observed) equations. Techniques to get a more understanding from seismic have much improved in recent years, including understanding rock physics, and the reservoir simulations do not get the benefits from them.

Also, the geological model often needs to be simplified (reduced in granularity) in order to make it possible to put through computation simulation. This can remove a lot of the detail which is required to make it accurate.

For example well logs might show up small thin barriers or layers within a reservoir, 1-2m thick. When the reservoir model is reduced to cells with a resolution of tens of metres for a simulation, they would disappear from view.

Some lithologies such as carbonates can be very difficult to simulate, because there can be big variations in the porosities and structures, with so many complex caves or erosions and fractures at different scales and directions.

There could be information you don't know which reveals why the reservoir project actually has a negative net present value (NPV), when your calculations show it as positive.

Observed data

The only alternative to reservoir simulation is to work on actual observation of the reservoir and there is no perfect way to do this either – just repeat seismic surveys, gravity or subsidence surveys. These are expensive and usually only cover a small area. Or you can try to get more insights from well data or analysis of rock samples from drilling.

But observation data might be able to directly answer questions such as where untapped areas of the reservoir might lie. For example, if you have subsidence sensors over the reservoir, and 90 per cent of them show that the ground beneath them is compacting slightly, the other 10 per cent of them show no subsidence, these 10 per cent may be above a section of the reservoir which is not draining into the wells.

Data management

Another issue is how all of the dynamic reservoir data should be managed. At the moment, most companies use the reservoir simulator as a kind of data management system. All new data is ingested somehow into the simulation. It can include everything you know about the reservoir including geological interpretations, stratigraphy, sedimentology, porosity and permeability, core data and well log data (such as saturation).

But that doesn't provide much confidence that the company gets maximum insights from the information available.

For example, someone might make a useful observation about an injection well seeming to have a close relationship with pressure in a production well, indicating that water breakthrough to the production well is not far away.

The right decision might be to choke down that production well.

But if instead the information is just passed to a reservoir engineer, to ingest into the reservoir model in its next re-run, the production engineer might not get to learn about it.

We have not seen any single software system capable of managing all of the various information about reservoirs in production – with all information at different granularity, different time scales, and about different parts of the reservoir.

You might remember the big promises of around 2006 of the 'digital oilfield', seeing the oilfield as something of a living being, with wells all in the perfect place, the flows all perfectly extracting the maximum amount of hydrocarbon for the least investment.

Perhaps a more useful data management concept is the 'digital twin' idea which is being developed by many engineering companies for topsides equipment. This is a digital copy of what is happening in the real world. Or to express in another way, it is all of the company's information about real world operations put together in an integrated format so it is easy to work with.

A subsurface 'digital twin', developed along similar lines, would not be a simulator at its core, but a way to gather all of the company's understanding of the reservoir, in a workable format, from one place. It is available for everybody involved with the reservoir to work with, and easy to use. Any simulations for predicting the future could be viewed by drilling down into the model, rather than being the core of the model itself.

Author's acknowledgements

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OCTIO – measuring gravity, subsidence and seismic on the seabed

OCTIO of Bergen provides services for recording gravity changes, pressure changes (an indication of seafloor subsidence) and seismic from the seabed – all useful ways to get observational data on reservoirs in production

Reservoir monitoring and subsea surveillance company OCTIO, based in Bergen, Norway, provides gravity and seafloor subsidence monitoring. The technology is currently being applied in 7 oil and gas fields in Norway. It also makes and operate subsea passive seismic recording devices.

The gravity and subsidence monitoring technology was developed internally by Statoil, and pioneered at the largest field in Norway, Troll. It was then taken over by OCTIO in 2013, with an aim to achieve a wider rollout of the technology. OCTIO's daughter company Gravitude has been surveying Norway's Ormen Lange field, the second largest gas field in Norway, since 2014.

Gravity

The gravity data can be used to better understand gas production, because once gas is produced, the space it previously occupied is usually filled with water, leading to a higher gravity reading, because water has a higher density, says Martha Lien, CEO at OCTIO Environmental Monitoring.

This way, you can spot a section of the field which is not communicating with the rest of the field (the fluids are not moving, in other words), because there won't be any gravity change there.

Gravity data is gathered in dedicated surveys, in which gravimeters are deployed sequentially at a set of locations on the seafloor, situated above the producing reservoir.

By recording gravity on the seabed, the accuracy is "orders of magnitude" better than recording it from vessels or from the air, Ms Lien says, since the recording is much closer to the ground and at stable conditions.

Oil companies use the data to improve their reservoir simulations. "In our experience, our data is used directly to improve the reservoir modelling, to enhance the confidence in the predictions of future production, and eventually to take better decisions, like placement of additional producing wells" Ms Lien says.

Gravity data and seismic data complement each other nicely for interpretation, as the former provides good quantification of mass changes while the second maps accurately the extent of the area affected.

The gravimeters used by OCTIO Gravitude are sensitive to a few microgals change, which is a billionth of the normal gravity field on the earth's surface, or the gravitational field between two people half a metre distant.

"Our clients maintain a reservoir model, and pick a few parameters within the model which determine mass changes," says Hugo Ruiz, Vice President G&G at OCTIO. "By choosing the values of these parameters that better fit the observed gravity data, they reduce significantly the space of possibilities of these parameters and hence the uncertainty in their models."

The data can be used to monitor movement of a gas-water contact, quantify water influx from aquifers, map hydrocarbon depletion, identify compartmentalisation, map reservoir properties like compressibility away from wells. The economic value of information arises from identification of infill well planning targets, avoiding water break-in to wells, or improved hydrocarbon reserve estimates that allow a better planning of pipelines and resources.

Subsidence

OCTIO Gravitude's method for measuring seafloor subsidence is based in measurements of changes of water pressure at the seafloor. As gravity monitoring, it is based on periodical surveying.

When hydrocarbons are produced, the reservoir compacts and the seafloor experiences some degree of subsidence, Ms Lien says. Changes of seafloor depth above the field are compared with measurements away from the field, to provide calibration. In this way, we obtain 2 mm accuracy in subsidence throughout the field. There is no other technology that can reach to such level of accuracy.

Subsidence data provides a map of reservoir compaction as it is being produced. You can also see lateral differences - if one part of the reservoir has more compaction than another, it tells you that there is a compartment of the reservoir that is not being depleted, and an infill well needs to be drilled there.

Hugo Ruiz, vice president G&G, Octio

The subsidence measurement can be important for installation safety. In extreme cases, subsidence can damage the platforms sitting on legs on the seabed.

Gathering data

The usual workflow begins with a feasibility study, modelling the expected gravity change and subsidence to occur. The objective is to determine where these measurements will help reducing the uncertainty in the modelling, and hence provide better decisions during field development.

Typically 20-120 gravity / subsidence measurement locations are selected in a survey, marked with semi-permanent concrete platforms on the seafloor. The gravity and subsidence measurement equipment is placed sequentially over the platforms during a survey, with the help of an ROV (remote operated vehicle). This way, measurements at different surveys, which can be one to three years apart, are gathered at exactly the same position.

The instrumentation used by OCTIO Gravitude includes 3 gravity meters and 3 pressure meters. The data from the sensors is sent to the ROV, and further to the vessel, where its quality is analysed in real-time. Each reading takes about 20 minutes.

Stations are placed both above and around the hydrocarbon field, with the stations placed around it used to provide calibration. The data is corrected for tides and other oceanographic effects.

The data from gravity and subsidence meters is delivered to the clients usually as a gravity change or subsidence map, and support is provided to include this new data optimally in the reservoir simulation.

Case studies

On the Troll field, 4D gravity data saw a rise of 2 m in the gas water contact in the period 2002 to 2009. That couldn't be detected with time lapse seismic.

On the Mikkel field, gravity surveys have been performed since 2006 to monitor water production into the reservoir, because there were concerns about hydrate formation. The monitoring showed lower water influx than expected into the reservoir, which lead to a significant change in the estimated gas volumes in place. This, in turn, helped with long term planning of pipelines and resources.

On the Midgard field data has been gathered also since 2006, helping to monitor the reservoir draining patterns and aquifer support, the fault distribution and compartmentalisation. It was possible to see that one segment of the reservoir was underproducing, with faults acting as barriers to the flow.

The reservoir model could then be updated to include a sealing fault, and a new well could be drilled in the undrained part of the reservoir. This became the most producing well in the region.

The devices were used on the Ormen Lange field to help make decisions about installing compression facilities and infill wells, where there were uncertainties about compartmentalisation in the reservoir and early water breakthrough to the production wells.

On the Statfjord field, subsidence monitoring was used to look for undrained compartments and study aquifer properties. The data was also used to calibrate the geomechanical model.

Passive seismic

OCTIO provides also seismic sensor arrays – which can be used to image the reservoir using active seismic surveys, but also for passive microseismic monitoring.

Passive monitoring can be used at drill cutting and waste water injection wells, to make sure it is not causing any formation damage that can eventually cause waste to leak to the surface.

One oil company customer injects waste water and drill cuttings back into an oil well 1000m below the seafloor, which is much less expensive than shipping it to land. It uses one of OCTIO's systems to monitor the injection of the fluids. The passive seismic system can listen continually and check if the injection is creating any cracks in the subsurface, which would indicate that there could be waste escaping from the target formation. It can also detect any possible fault re-activations.

OCTIO's systems can be used to monitor well drilling operations. In such projects, the sensor array is used to precisely position the drill bit with respect to the geological data of the area. Any small crack developed during the drilling is also detected in real-time, and this provides additional safety to the drilling operation. This service has the commercial name of OCTIO DrillWatch, and is especially suited for areas with thin overburdens, like the Barents Sea.

The key features of OCTIO's seismic systems are their robustness and flexibility. Small sensor networks can be deployed for specific applications at the beginning of the production of a field, and then expanded to larger areas and even a full reservoir monitoring system if required.

The data can be collected and pre-processed on an offshore platform, and then sent to land for further processing.

Seabed Geosolutions – recording seismic on the seabed

Seabed Geosolutions places seismic 'nodes' – small devices - on the seabed, which can be used for repeat ("4D") seismic recording, with better resolution than conventional towed streamer seismic

Seabed Geosolutions, a company with offices in Houston and Massy amongst others, places seismic 'nodes' – small recording devices - on the seabed which can be used for repeat or "4D" seismic recording.

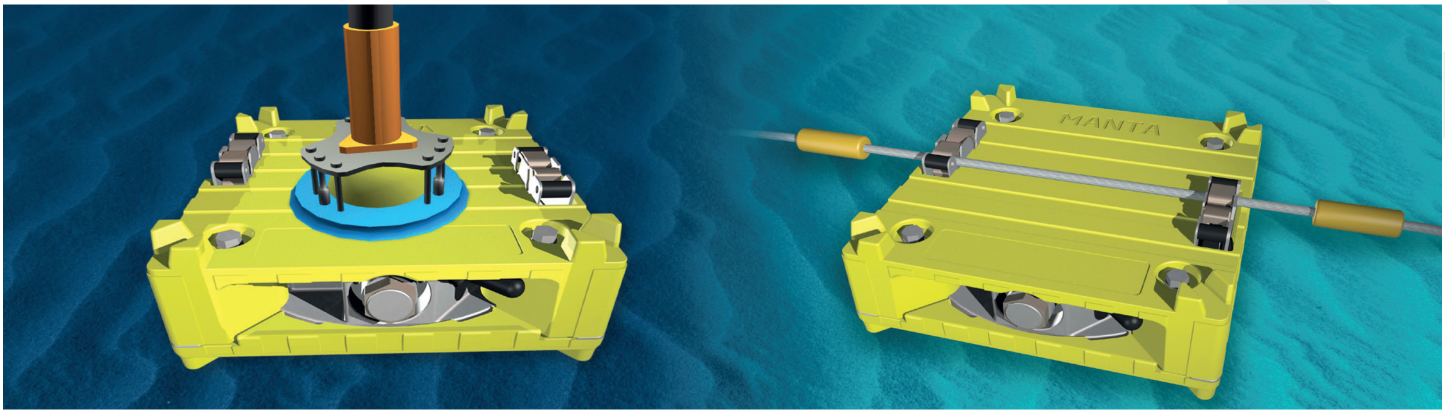
Ocean bottom nodes (OBN) are considered a better seismic acquisition technique than conventional towed streamer because fuller azimuth illumination of the subsurface (looking at it from more different directions) can be obtained, leading to a better understanding of the reservoir and overburden structures. This gives you better definition of the overburden and reservoir properties, including seismic anisotropy, depth and geological structure. The seismic amplitude response of the reservoir can give additional information about the rock properties, "net to gross" and possibly porosity.

After a few years of production, there may be changes in the seismic response on repeat seismic surveys due to the changes in reservoir fluid and/or pressure which could show up in amplitude attributes, or "time-shifts" (changes in the seismic velocity leading to changes in the two-way time of the reservoir). This can help indicate where the hydrocarbon production is coming from or where injected fluids are flowing in the reservoir and provide valuable input to decisions on reservoir management such as drilling further infill or injector wells.

Conventional towed streamer seismic provides only 20-30m resolution of the subsurface at typical reservoir depths which might not be enough to resolve the entire reservoir, the company says. Seabed Geosolutions' broadband seismic technology produces higher resolution images because of wider bandwidth acquisition and lower noise content.

Ocean bottom node surveys have traditionally been more costly than towed streamer seismic surveys depending on the geometry of the acquisition. Seabed Geosolutions are continually reducing costs as they focus their efforts on operational innovation and efficiency enhancing technologies such as their Manta® system.

Seabed Geosolutions have developed a containerised solution for efficient deployment of ocean bottom nodes either by ROV or by wire.



Manta® ocean bottom nodes are designed to seamlessly deliver improved geophysical illumination with flexibility for dense source grid, full-azimuth and long offset surveys.

"It is a case of trying to acquire data as efficiently and cost effectively as possible that gives the understanding you need to make sensible business decisions," says Hemang Shah, Seabed Geosolutions' Area Geophysicist for Europe, Africa and the Middle East.

Seabed Geosolutions' ocean bottom nodes run on batteries that last approximately 75 to 120+ days. Therefore, they cannot be kept on the seabed running permanently. It is possible to have ocean bottom sensors on cables which are powered from the platform and left permanently on the seabed. This has been done in a few places around the world, including the Norwegian field, Valhall. These permanent systems allow repeated surveys at lower cost, but with a significant initial capital outlay compared to OBN surveys.

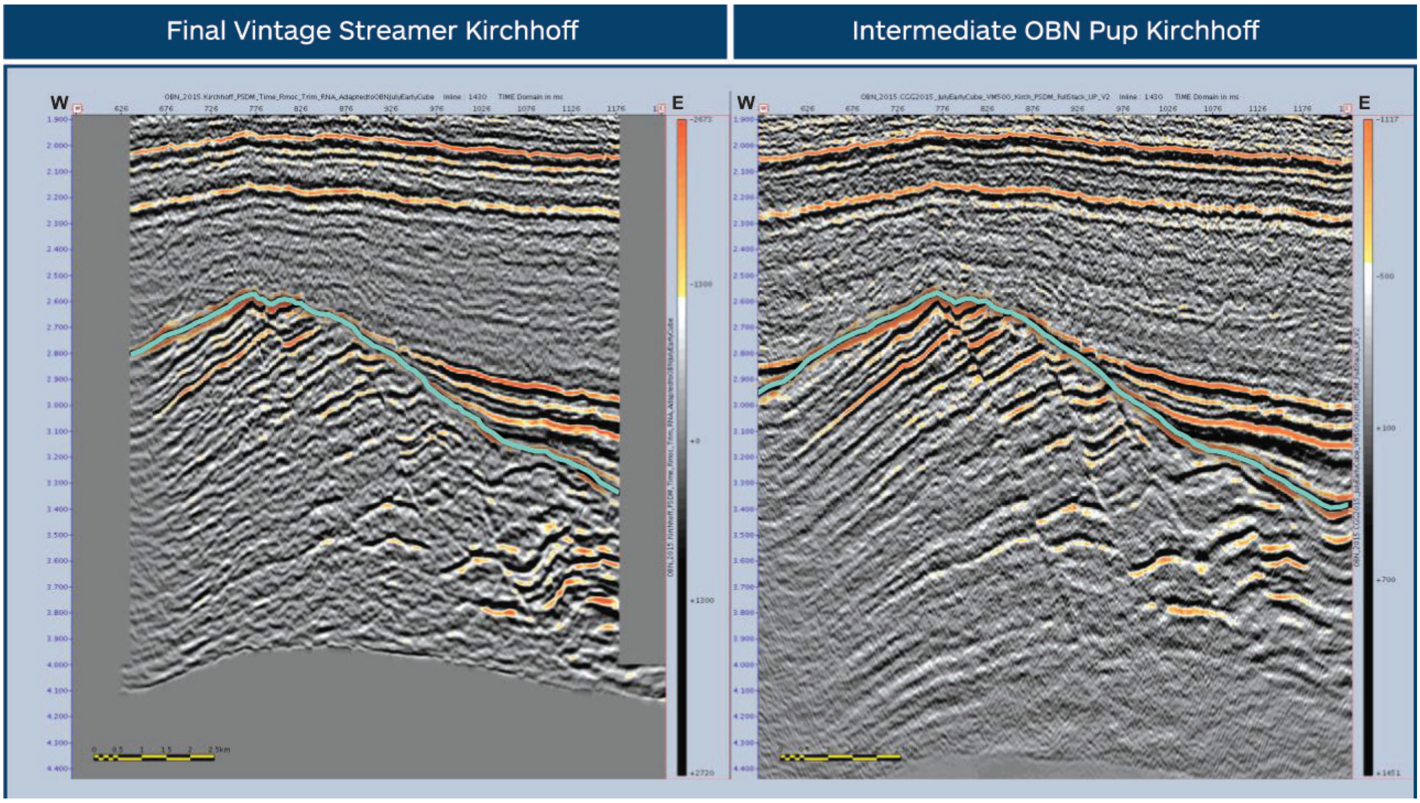
Companies will typically perform repeat seismic surveys every 1-2 years depending on reservoir seismic rock properties, but 5 years is probably too long, noting oil wells typically have a production life of 10-20 years, he says.

Alwyn North Field

One example of using ocean bottom nodes is in the North Sea Alwyn North Field where Total presented a paper about its experience at the EAGE Conference in Vienna in June 2016 with subsequent follow-up results at the EAGE Conference in Paris in June 2017.

The field, which is subject to significant faulting, is located on the Western side of the Northern Viking Graben, has three stacked reservoirs, from the Middle Jurassic, Lower Jurassic to Triassic, and Upper Triassic. The first two reservoirs have seen a recovery factor of 55 to 60 percent, but the Upper Triassic had only produced 15 percent, and therefore, was a focus for production optimisation. It is a tricky reservoir of low net-to-gross with thin sand bodies of lateral extension from a few to hundreds of meters. The sands have low porosity and permeability.

The EAGE Conference paper presented in Paris in 2017 confirmed that OBN gave better imaging and attributes than the vintage towed streamer, and thanks to the wider bandwidth and improved signal-to-noise ratio, a better description of static reservoir geometry was obtained leading to an improved understanding of the dynamic characteristics. The results can be used as part of a dynamic simulation, leading to better correlation with well data, and improved infill well selection.



Results from Sparse Ocean Bottom Node on the Alwyn North Field - from Acquisition to Joint PP-PS Imaging, Brunelliere et al, EAGE Conference (2016) highlight clear improvements on both faults and lithology in the OBN data versus streamer data.

Silixa – using fibre optics in wells to measure seismic

Silixa uses fibre optic cables in wells for seismic recording – so it can record data from within the reservoir and around it, getting a high resolution picture of wells in production

UK company Silixa records seismic data using fibre optic cables installed permanently in wells – so it can get a seismic recording from actually within the reservoir and near to it, so getting a high resolution picture of wells in production.

It takes advantage of the fact that the light flow through a fibre optic cable is perturbed (changed) by changes in the sound around the cable, so it can act like a microphone.

If there is an active seismic source, such as a vessel airgun, the seismic response at the well can be recorded. It can also record passive seismic (where there is no active source – such as noise made by subsurface fracturing).

The same fibre optic cable can also record pressure and temperature in the same way, because the light flow is perturbed by changes in temperature and pressure.

Silixa aims to make it possible to get higher quality seismic at lower cost – and generally make 4D seismic more widely available and more frequent. Silixa's customers typically do repeat surveys every 6-12 months, rather than every 2 years, as usually seen for other types of 4D seismic, says Garth Naldrett, chief product officer of Silixa.

Improving technology

The technology is gradually shifting from being something for 'early adopters' to being accepted as a real alternative to conventional geophone technology, Mr Naldrett says.

The progress has been led by advances in instrumentation – measurement performance, signal to noise ratios and repeatabilities.

This means that a fibre cable in oil wells

can "see" for miles laterally (to the side).

The system can also 'see' better than conventional seismic where the reservoir is below salt, because the seismic does not have to pass through salt twice (down and up) in order to see the reservoir.

It is possible to use the fibre optic cable to record pressure, temperature and acoustics at the same time. So the same cable can be used for both production surveillance (using pressure and temperature to monitor changes

Working with the data

Silixa aims to give data to oil companies in the most easy to use possible format. Production data might be delivered in PRODML format, and seismic data in SEG-Y format.

Sometimes oil companies will ask Silixa to get involved in interpretation of the data – Silixa's knowledge of the way the instrumentation records data can be useful for that.

Other times oil companies want to feed it into their workflows, and different companies work in different ways. Sometimes they work with independent seismic processing companies.

One customer, an oil company in Qatar, had been operating a field for 10-15 years, and finding that whenever it drilled new wells, the well performance wasn't meeting the simulation prediction.

This led the asset manager to say, the only way we can improve the reservoir model is capturing more data from the field – leading to a decision to use distributed temperature sensing, feeding back into reservoir and production models.

Subsea wells

A next step might be subsea deployment of the technologies (installing fibre on a subsea well, where the well head is on the seabed, not on a platform).

Statoil did some surveys and found subsea fields had typically 10-15 per cent lower recovery than conventional wells. That could be attributed to having fewer wells, fewer entry points to the reservoir and a lot less data.

"The value case in a subsea field development is much more extensive," "The well costs are higher. You really want to optimise well and reservoir performance," Mr Naldrett says.

Exa and BP – get relative permeability from a digital rock sample

Exa Corporation has developed software together with BP to model flows of multiple fluids through a digital image of a physical rock sample, and so find the relative permeability, a critical factor in understanding the reservoir

Exa Corporation, a company based in Massachusetts, USA, has developed a way to simulate fluid flow through a digital image of a physical rock sample without losing any resolution, working together with BP. The technology is provided as an online software product called DigitalROCK.

The simulation solution was co-developed with BP, during a 3 year technology collaboration agreement.

It can be used to understand relative permeability – how multiple fluids flow through a reservoir, and the forces they will make on each other.

Exa claims that this is the first predictive computational solver for relative permeability for oil and gas.

Relative permeability is the resistance to flow for a mixture of fluids – for example a certain reservoir might allow water to flow through much more easily than oil. It is different to absolute permeability, which is the reservoir's overall resistance to flow.

The relative permeability can be used to understand what ultimate recovery can be achieved from the reservoir (a function of how much oil will be left behind in the pore spaces and never flow to a well). It can enable an understanding of how this can be changed with an enhanced oil recovery technique or water flood.

The basis of the study is a 3D CT (computerised tomography) scan of a small piece of core or drill cutting. Clients can take a scan image themselves, and upload it to Exa's online software, to run a simulation.

Exa is a simulation software company, specialising in computational fluid dynamics. It also serves the automotive, aerospace and aviation industries.

Exa provides purely software, provided over the cloud. You can upload a 3D CT image, and start running flow analysis, getting results "in a relatively short time."

BP agreement

Exa has been developing its flow simulation technology for a "couple of decades", and realised it might be helpful when used together with pore scale imaging.

The company met BP in 2014, who were trying to solve the problem of relative permeability simulation. BP had done digital rock scanning, but not simulating multiphase flow.

In May 2017, Exa announced it had signed a multiyear "commercial agreement" with BP to provide its DigitalROCK relative permeability software.

BP said that the capability "will help engineering teams to make more informed decisions on wells, production facilities and resource progression, including enhanced oil recovery."

"The ability to generate reliable relative permeability information directly from digital scans on a much faster time-scale than laboratory testing, and to gain insight into the underlying pore-scale dynamics, provides substantial business value during appraisal, development, and management of our reservoirs," said Dr. Joanne Fredrich, upstream technology senior advisor at BP, in a press release quote.

"We plan to deploy this technology across our global portfolio. After a three-year program of cooperative development and testing, our extensive validation studies are drawing to a close."

BP uses the software as part of its "Digital Rocks" program, and the technology has been used across BP's global portfolio including fields in Angola, the Gulf of Mexico, the North Sea, Egypt, Azerbaijan, the Middle East, India, and Trinidad and Tobago.

BP's Digital Rocks team includes experts in 3D imaging, fluid mechanics, numerical modelling, computational physics, high performance computing, rock physics and reservoir engineering. The technology is implemented in its Centre for High Performance Computing (CHPC) in Houston.

Replacing physical cores

Until now, the only way to understand how different fluids will flow through a rock sample is to do a physical test in a laboratory, with a piece of core sample and test reservoir fluids, under similar pressure and temperature to the reservoir conditions.

Aside from the expense of setting this up, it means that you can only test a single core sample once, and so it is hard to make comparisons. You can't find out how the results might be different with for example a higher pressure water injection. Also lab results can take a year or even more.

Evolution of technology

Oil companies have been scanning rock samples in tomography scans and using the scan to model flow for about a decade now. The difference with Exa's technology is that it does not simplify the rock geometry at all for the modelling.

Other companies have made a model of pores from the scanned image, which can be good for analysing porosity, or single phase flow, but does not necessarily tell you how multiphase flow will travel through the rock, says David Freed, vice president oil and gas at Exa Corporation.

Flow in real oilfields is nearly always multiphase, Dr. Freed says, with oil and gas, oil and water, water and gas, or all three. Having just one fluid is "extremely rare" (except if it is water).

Reservoir rocks nearly always begin with water in their pore spaces, and hydrocarbons percolate in there over time and push the water out.

With Exa's software, the simulation is made without simplifications to make the computer model easier to compute. Its simulation technique uses the full geometry of the pore space.

In the simulation you can see oil and water moving within the pore space, and see how pockets of oil are getting trapped. There is a short video on exa.com website illustrating this.

The flow simulation takes into account the conditions which the reservoir is under, and how the results will change for different conditions.

Using the data

The data about relative permeability can be used as part of reservoir models, used for example to make decisions about where to place wells, and design enhanced oil recovery techniques.

Unless you understand the way different fluids behave then any predictions made by the simulators will not be very accurate. This includes simulations of how injection water will push oil out of the pores and increase recovery.

The data can be used to work out the end point – how much oil you will actually be able to produce from the reservoir, or in other words how much oil will stay in the pores at the point when no more oil is flowing to the oil wells.

The recovery factor of reservoirs varies greatly, from 20 per cent to 60 per cent, and this is the major factor in the return the company gets from the investment in building the oilfield.

The reason not all of the oil is produced is because some of it is left behind in the pores, trapped by capillary forces.

The data is also useful if the company is planning any water or CO2 flooding.

The water relative permeability also tells you how much water is being produced, something which operators also care about, because it is expensive producing and handling that water – and it also occupies topsides capacity.

And it is also important to be able to predict water production, so you can make sure your topsides capacity is able to handle it.

Oil companies are experimenting with surfactants (soaps) in injected water, which reduce the surface tension of the fluid mixture – so changing the flow conditions. With Exa's technology, you can get a sense of how a surfactant will change the hydrocarbon recovery, before you do it.

Carbon capture

The technology could also be useful when planning CO2 enhanced gas recovery / enhanced oil recovery projects, such as using CO2 in coal seam gas fields.

CO2 has been observed to reduce the viscosity of oil, and reduce the amount of gas which stays in coal seam pores, thus increasing oil and gas production.

But the precise mechanics are not very well understood, and detailed predictions of what CO2 flows will lead to what improved oil and gas flows are hard to make. This means there are no hard numbers available to justify making an investment decision about a carbon capture and storage project.

By getting an understanding of relative permeability using software like Exa's, it would be possible to get a much better idea of the return of investment in such a project, and whether it might make sense to do a pilot project. It would also help compare different options.

iRes – Geo: Improving understanding of reservoir behaviour using seismic

UK company iRES Geo Technology believes there is room for improvement in how the oil and gas industry develops reservoir simulations from seismic data – and has developed its own software process to do it

UK company iRes-Geo Technology believes that there is room for improvement in how the oil and gas industry develops reservoir simulations from seismic data, and has developed its own workflow to do it as a one button software process.

Jim Farrington, senior geophysical advisor with iRes and previously a geophysicist and geologist at an oil major, says that one of the issues which has "plagued the field" until now has been that reservoir engineers' primary objective has been to "get a good history match," their time trying to match their models with new data as it comes in (production data, well logs, 4D seismic, fluid analysis), and they do it in a 'patch fix' manner

"It isn't geologically realistic," he says. "It gets worse and worse – the whole thing snowballs. It is increasingly difficult to get a good result."

Sometimes reservoir engineers introduce 'fudge factors' to try to get their reservoir models to work, such as saying a large area of the reservoir contains high porosity material, or "parameter scaling factors", or baffles in the model (walls obstructing flow).

Also typically reservoir engineers, geologists and geophysicists work on their own with different data and models, even if they are all sitting on the same floor of the same office. There is no easy way to integrate the data together from different disciplines, or even create an integrated visualisation of the data, he says.

And the seismic data is underutilised, he believes. "People use it to pick the top reservoir, base reservoir, some important faults, that's more or less the end of the story," he said. "Beyond that, [they develop] the reservoir model using statistical approaches."

Observation, simulation and intermediate

There are two basic pathways to achieving a greater understanding of your reservoir's performance and locating remaining oil – an observation based approach (making decisions based on what you can see in 4D seismic) and a simulation based approach (making a reservoir model and simulating production / injection; data from which you then use for decision making).

The 4D seismic approach is "something we are involved with very heavily," he says. "If you can afford it and have the resources and time, that's the ideal approach." You can do 4D analysis and interpretation on your data, and don't necessarily need to build a reservoir model.

For example, you can use 4D seismic to track the change in position of the gas cap or water front, or understand changes in strain.

Jim Farrington, SVP, iRes – Geo

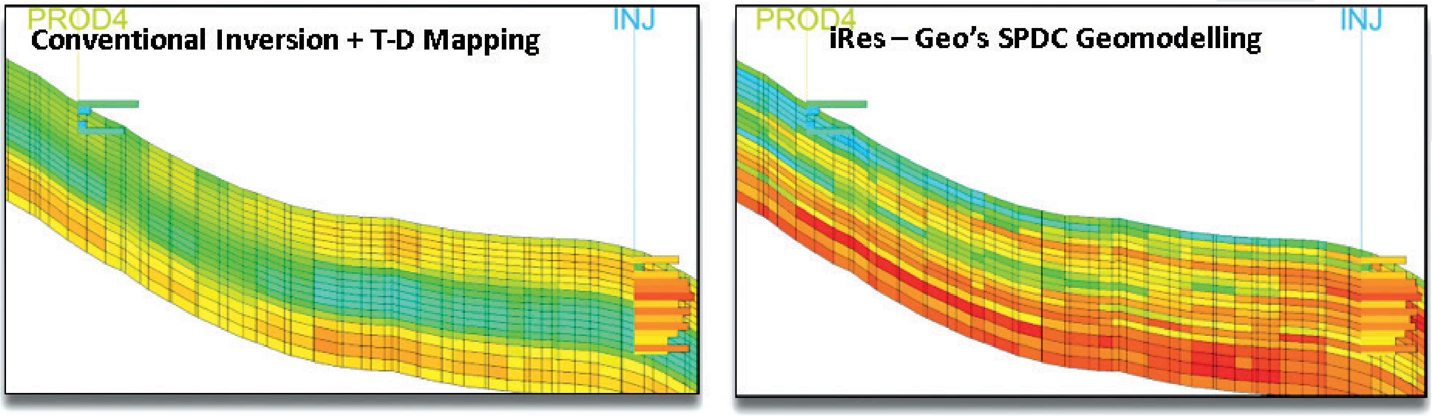
iRES - Geo has proprietary software which can optimally generate 'reservoir snapshots' from 4D seismic data, showing how the reservoir has changed over time due to production.

If you want to build a reservoir simulation model, it needs to be as geologically realistic as possible, and leverage all the available data, while providing a good history match.

Reservoir models can be populated with both static parameters (from 3D seismic) or dynamic parameters (from 4D).

Reservoir modelling workflow

iRes – Geo has developed cutting edge reservoir modelling technology; "Single Pass Data Casting (SPDC) Closed Loop Reservoir Modelling," this uniquely allows reservoir models to be generated incorporating all the geological realism contained in the seismic data. It involves integration of seismic,



Comparing conventional seismic inversion and well log mapping (left) with IRES-Geo's Single Pass Data Casting (SPDC) Closed Loop Reservoir Modelling (right). Note how much better the IRES model matches the well log data (with production well in green on the left, and an injection well in blue on the right). The iRes-Geo model captures much more of the complexity of the actual subsurface, and allows a higher resolution reservoir model.

petrophysical and geological data,

The entire workflow can be run with a single button press. "That's our philosophy and it's generated a lot of interest," Mr Farrington says.

Customers usually provide an initial reservoir grid, with accompanying petrophysical and geological data.

iRes - Geo takes the seismic data, sampled at regular time intervals such as every 2, 4 or 8 milliseconds, and maps it onto the reservoir grid with no loss of data integrity.

The next stage is to bring in petrophysical data, and define the relationships between the seismic data and the static / dynamic reservoir parameters, so you can integrate the petrophysical data. The company has its own artificial intelligence (AI) software to derive the petro-elastic models. AI can be used to make models which are nonlinear and interconnected, which better reflect real life, rather than using the standard calibration approach; curve – fitting through clouds of data points. "We've seen a significant uplift in reservoir parameter modelling results using this AI approach," he says.

IRES also has a different approach to working with velocity data. The standard approach to reservoir parameter inversion using seismic data is to use a velocity cube to convert the resulting reservoir model from the 'time' domain into the depth domain, the physical domain we live in.

The velocity data used is generated as a by-product of the seismic processing flow. "It is this selection of velocity field which has always caused trouble," he says.

iRES - Geo has developed an alternative 'dual-inversion' technique, where inversion for velocity is done at the same time as the inversion for the desired reservoir parameter.

This populates the reservoir model at the initial grid scale with reservoir parameters located at the correct depth, with no need to upscale or downscale, everything is at the same resolution. "You lose data resolution – you introduce error every time you upscale and downscale," he says.

The final stage is to take the resulting reservoir models and use them to generate 'synthetic seismic cubes', working out what seismic response you would have if the reservoir model was the target of a seismic survey. If this synthetic seismic cube closely resembles the recorded seismic, this is an indication of the accuracy of your reservoir model.

Otherwise you can iteratively tweak parameters in the reservoir model until you get a closer match between the synthetic and observed seismic data.

The output of the SPDC workflow can be input into any standard software, such as PETREL for geological modelling or Eclipse reservoir simulator.

Clients and partnerships

iRes-Geo Technology was founded by Dr Yi Huang, a formerly Lead Reservoir Geophysicist at Statoil.

iRes - Geo is working with Petrobras in Brazil, aiming to do a research project.

It is looking at proposing a pilot project with Chevron in 2018, and working with Suncor.

iRes – Geo also works with Napesco in Kuwait, providing general G & G services and more advanced, specialised 4D seismic services.

iRes – Geo has also entered into an agreement with PSS-Geo, a geophysical service company based in Stavanger and Oslo, specialising in 4D seismic processing.

In August 2017, iRes - Geo announced a partnership with Stingray Geophysical, a company that manufactures fibre optic based permanent reservoir monitoring systems.

These fibre optic systems can record seismic across a wide bandwidth, are cost effective, low maintenance and light weight, which makes them easier to place on the seafloor. They don't need big electrical supplies and have a good signal to noise ratio. Their fundamental advantage however is the high repeatability of the 4D monitor surveys.

In the short term however, they are expensive, so are usually only used on the parts of the reservoir requiring further study, such as complex areas of the reservoir, or the crest, with reservoir modelling and simulation covering the rest of the reservoir.

There is work going on in the industry to try to reduce the cost of 4D seismic, perhaps by reducing the amount of data being recorded, or the number of geophones, Mr Farrington says.

Kes Heffer - looking at well interference

Kes Heffer, a former head of reservoir description at BP's Sunbury Research Centre, is exploring how well interference – the amount that rate changes in one well affect other wells – can help better understand reservoirs

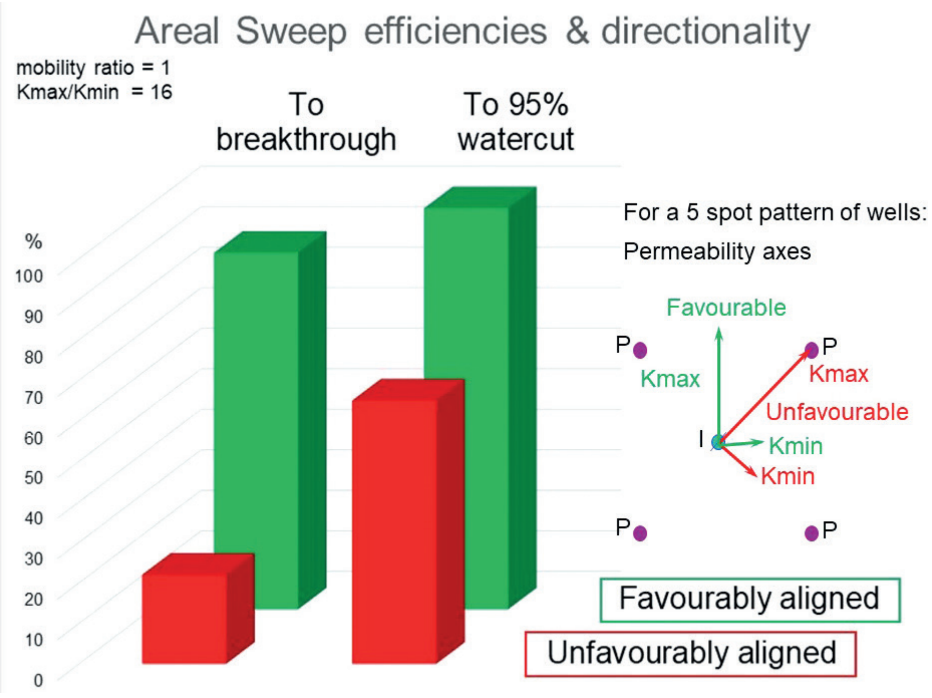


Figure 1: The orientation of well pattern relative to permeability directionality can change oil recovery by tens of percentage points. It has long been known that directionality (anisotropy) in permeability has a large influence on areal sweep efficiency and therefore oil recovery. The above laboratory results for a five-spot well pattern (Caudle, 1959) demonstrate the sensitivity, whether at water breakthrough or at a more advanced stage with 95% watercut.

Kes Heffer, director of Reservoir Dynamics Ltd and Honorary Fellow at Heriot Watt University, has been studying how fluctuations in flowrates at different wells in a field, including injection wells, can correlate with each other. This is a form of "well interference".

Mr Heffer previously spent 30 years working at BP, including as head of reservoir description at BP's Sunbury Research Centre.

Well interference testing can be a good way to understand how much the reservoir geology is connected to allow fluid flow between the wells.

For example a high level of interference between a water injection well and a production well, means that an increase in injection pressure leads quickly to a measureable increase in pressure in the production well.

If such interferences are not roughly equal from an injection well to different neighbouring production wells, then injected water may be flowing preferentially in one particular direction, which might be directly towards a production well.

The data from well interference testing can be used to help calibrate reservoir simulation models.

Reservoir simulators and physics

Prediction of production from a field requires a reservoir model of some sort. Generally, but particularly for fields at the exploration or appraisal stage, where production history is limited to a few well tests, the model used is a simulator that incorporates the geology and calculates fluid flow on a grid basis.

To account for the uncertainties in reservoir geology, reservoir engineers often run the simulations many times over with different input parameters drawn stochastically from the ranges of probability distributions. Because of the uncertainties, for a more mature reservoir you want to make use of the large amount of historical production data to update the parameters of the simulator: this is called "history-matching" of the simulator.

However this is not always a simple or quick procedure. "Workflows are speeding up, but in the worst cases, by the time a history-match of production data up to a cut-off date from several months back was achieved, the model no longer matched newly acquired data, and the cycle started all over again", recalled Mr Heffer.

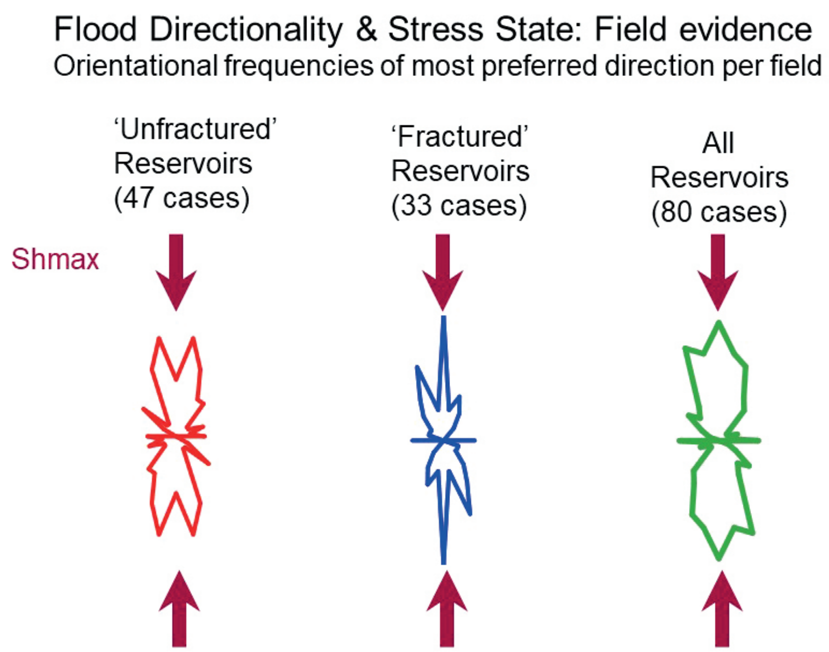


Figure 2: Frequencies of preferred directionalities of floods relative to local orientation of the major horizontal stress axis (Shmax): there is a strong bias towards Shmax for fields that would not be conventionally labelled as "fractured" as well as for those which are more obviously fractured.

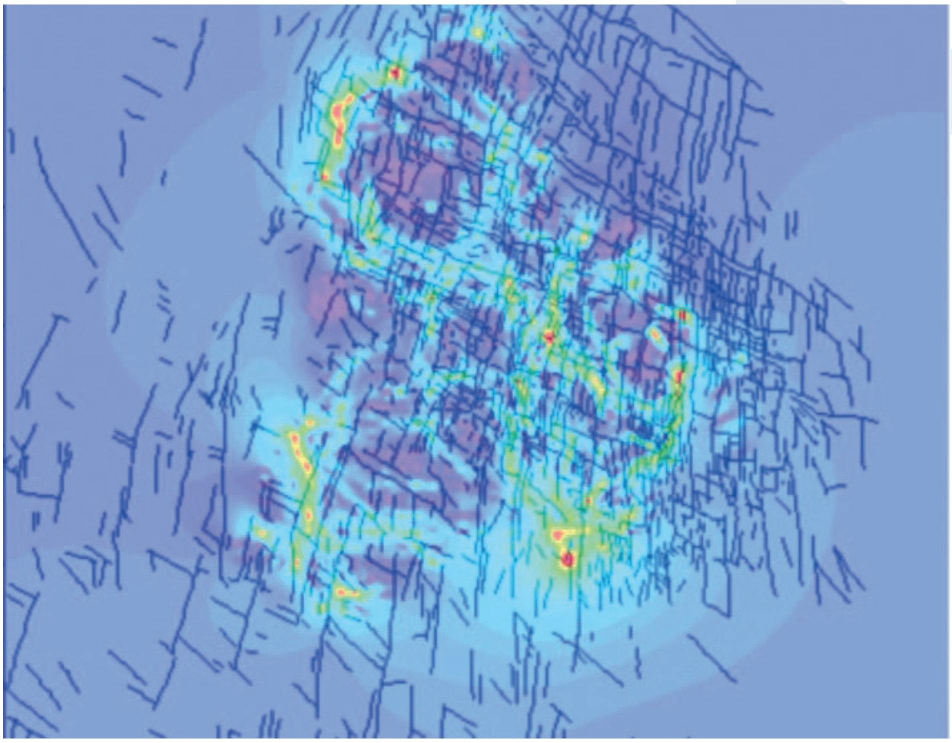
The unwieldy nature of simulators leads some operators to make predictions with a much simpler model, decline curve analysis, which extrapolates just historical production data semi-analytically.

An additional uncertainty in reservoir simulations that is often neglected is that of the physics of reservoir behaviour: the standard conventional model physics essentially incorporates only conservation of mass (balance of fluid flows and density change at each grid-point) assuming empirical relationships between fluid velocities, pressures, and fluid saturations. But over and above these, Mr Heffer maintains that "Geomechanics is playing a large part in fluid behaviour".

This is particularly in terms of important preferential directionality. Figure 2 shows the plentiful field data that supports this statement: the direction that fluids move through the reservoir appears highly correlated with the orientation of the local stress state in the rock.

Despite this, the only general recognition of induced changes to the rock structure in most simulations is through an assumed constant compressibility in the pore volume, which does not reflect any directionality.

Incorporating more complex geomechanics directly in a "coupled" reservoir simulation can mean a big overhead in computer time, and also requires that reservoir engineers, who build the models, are familiar with the concepts of geomechanics, Mr Heffer says.



Further analysis of flowrate correlations reveals linear features that overlay particular faults, implying that those faults are especially important to the geomechanics and fluid flow in the reservoir.

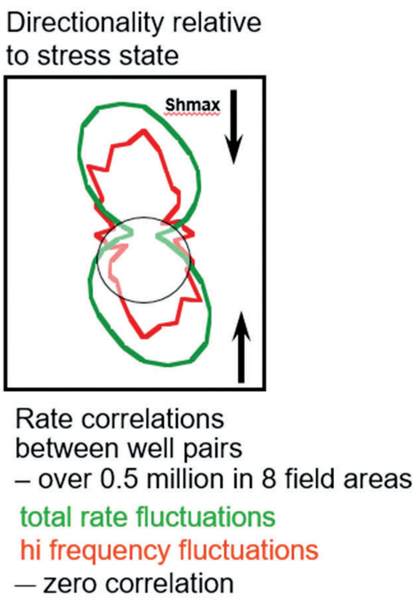


Figure 3: Data from several fields show that correlations in the fluctuations in flowrates between pairs of wells, plotted as a function of the orientation of the line between the wells, also show a bias towards Shmax (green curve). In fact the correlations are negative on average between wellpairs that are separated along the minor horizontal stress axis, orthogonal to Shmax: this is completely at odds with conventional reservoir engineering. The bias towards Shmax persists when the flowrate time series are detrended (filtered to remove low-frequency trends – red curve).

Using well interference data

The level of interference between wells can tell you something about the permeability directionalities of rock. Mr Heffer analyses interferences in terms of correlations in flowrate fluctuations because, unlike pressure measurements, rate data are readily available. As with waterflood breakthrough data, flowrate correlations show a strong bias towards Shmax (figure 3).

In addition to overall stress-related directionality, Mr Heffer has found that the flowrate correlations can be further analysed to pick out particular major faults, implying that those faults are key geomechanical features and potentially strong flow paths across the reservoir.

Given that flowrate correlations are related to the stress state of the rock, one can turn that around and interpolate stress orientation between measurements in a more detailed map across a field using rate correlations: that has been done on one large field to reveal that high watercuts in wells are associated with locations where Shmax is parallel to known faults.

The flowrates used in studies have generally been month-by-month data, as routinely reported to authorities or partners; day-by-day data has also been used on one field, which allowed changes to the correlations through the field's life to be followed: those made sense in terms of changing stress states.

A surprising finding from the studies was that flowrates can be correlated over large distances across a field. This ties in with the concept that a reservoir is at a geomechanical balance, possibly even before the first well is drilled: a small extra force, such as from a rate change at an injection well, leads to changes throughout the reservoir. The well interference data can be combined with whatever other information you have from the reservoir, such as fault data or measurements of stress state.

Permeability directionality is often a consequence of fractures in the reservoir, and Mr Heffer is currently working to develop a method of extracting both permeability and fracture density distributions across a reservoir.

There are a number of other geophysical methods which would be complementary to these analyses, such as shear wave interpretation or microseismicity, which can also be sensitive to fractures, although they are not always available, Mr Heffer says.

Paradigm k – a new cloud-based system for production engineers

Oil and gas E&P software company Paradigm has developed a cloud-based system for production engineers that provides well surveillance data, reservoir simulations, and online collaboration capabilities.

Oil and gas E&P software company Paradigm has developed a cloud-based software solution for production engineers called Paradigm k, to help them perform reservoir simulations and production surveillance analysis.

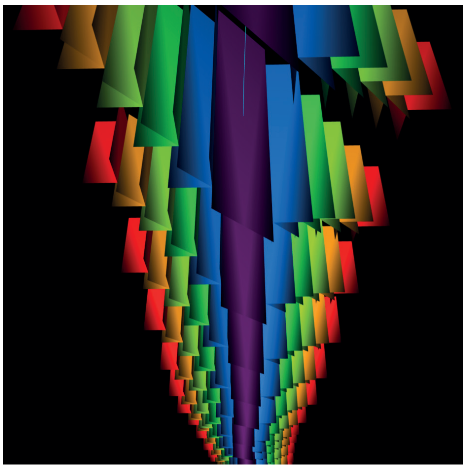
"The task of production engineers is to maintain production targets. Historically this has meant mainly surveillance, seeing what production currently looks like. Access to reservoir simulations will give them a better understanding of why changes in production rates are happening," says Indy Chakrabarti, senior vice president of Product Management at Paradigm. "It is a merger of subsurface and surface workflows coming together."

The system can be used by production engineers to test different plans for in-fill wells, and predict how much oil they might produce. They can investigate reasons why a well is not achieving its target production, or predict what might happen if you change the choke size or do an artificial lift.

The software can 'ingest' surveillance data from well flowmeters and sensors. This data can be used to update the reservoir model.

The software also supports collaboration, making it possible to share what you are doing at each well with your colleagues, as well as the results of those activities.

Paradigm sees this evolving into a knowledge base around wells. For example, someone might post that they are planning a workover for a certain well, and someone else notes that the same well was worked over a few years ago and sends details of the outcome.



Paradigm k can predict fluid flow in complex fractured environments, in minutes – and without time consuming setup.

There are no software requirements to get started – you can run it from an existing reservoir model, or take whatever inputs you have. It is hosted on Amazon Web Services.

Paradigm is initially offering the product to customers involved in shale oil and gas, where the modelling complexity can be most acute, particularly when modelling fractures.

"Paradigm can offer data management as part of the service, or oil companies can manage the data themselves. Oil companies are increasingly paying attention to their sensor data, and historian software systems for storing it, Mr Chakrabarti says." "We can tap into those systems."

Until now, production engineers have basically had two options if they wanted to understand their reservoirs: Either oversimplified, seeing the reservoir as a tank of hydrocarbons with no complex geology, or performing full-scale reservoir simulation, which production engineers often find challenging, Mr. Chakrabarti says. "That process is onerous, and as a result, limits who can do it".

And the majority of reservoirs in the world still do not have numerical simulations, Mr Chakrabarti adds.

Production engineer decision making

The role of the production engineer includes daily monitoring of the well (often referred to as 'production surveillance') to see how individual wells are performing, whether injection systems seem to be helping, and whether the company is on track to achieve its production goals.

Production engineers also have to make more long-term decisions, such as whether to install artificial lift. Experienced production engineers might be able to understand well behaviour merely from

Indy Chakrabarti, senior vice president of Product Management at Paradigm

observation. However, using Paradigm software can help them put numbers behind their ideas, in order to compare production improvements against any extra costs.

The data can be stored in different ways, including with data historians (typically used for production surveillance data), relational databases and models.

A different kind of simulator

Paradigm has developed a different kind of reservoir simulator for Paradigm k, which uses the full resolution of the available geological information, while running much faster.

Standard reservoir simulators divide the reservoir into tiny 3D boxes, and model the parameters for each box individually. This is a computationally intense process which also requires simplifying the geological model into boxes.

The Paradigm k simulator, on the other hand, looks at the entire geology without simplification, and then uses equations to calculate the flows. This means that it does not require any reduction in resolution to run, and can provide a simulation within minutes, Paradigm says.

Tests show that the outcomes of the simulator are very similar to those from a more sophisticated simulator, in much less computing time.

This semi-analytical simulator has been used on unconventional reservoirs, which have fractures which are very difficult and time-consuming to numerically simulate.

"You don't have to build a simulation deck for a production engineer," he says. With this software, "We can represent the fractures and the full complexity."