digital energy journal

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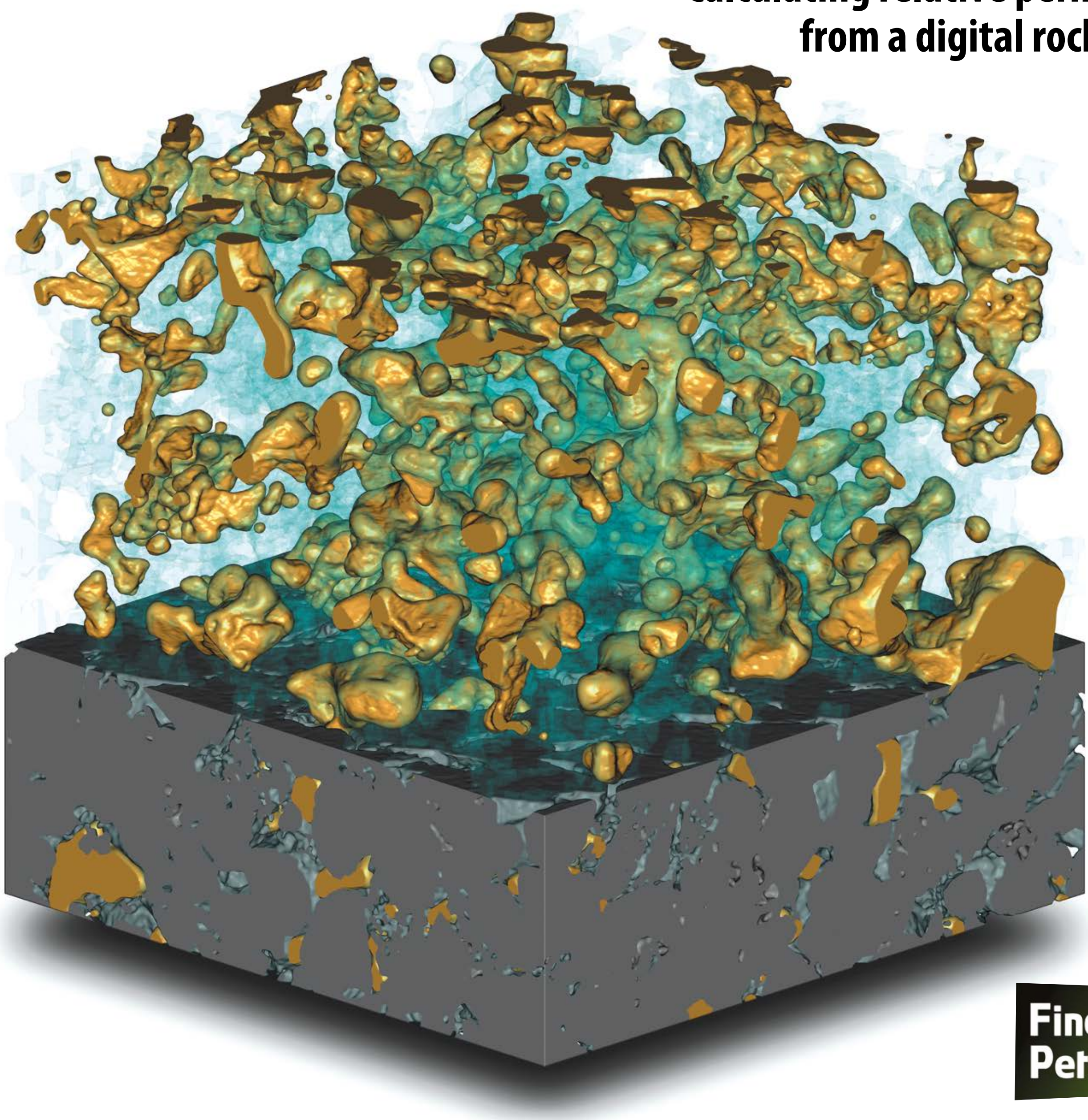
Calculating relative permeability from a digital rock sample



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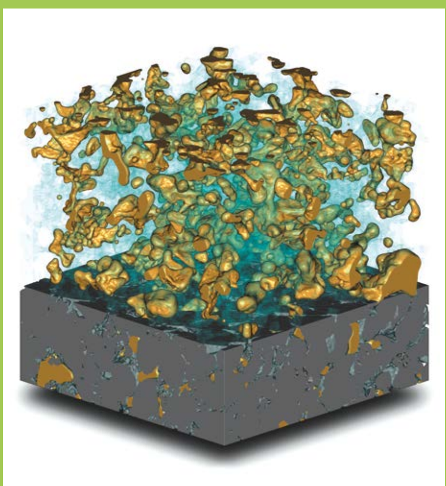

Cover image: Exa Corporation has developed a way to simulate fluid flow through a digital image of a physical rock sample, and use this to understand relative permeability, how multiple fluids will flow through a reservoir, a critical factor to understanding how a reservoir will work. See page 8

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How to get continuous improvement working with technology

Here's a new year's idea for how to achieve continuous improvement in a company activity from working with technology – look separately at your Goals, Expertise, Learning, Modelling, Analytics and Data. It spells a kind of word "GELMAD" if that is any help.

Goals - start with something specific the organisation wants to improve, like drilling non productive time, exploration success rate, well construction costs or operational risk management. The organisational goals should be broken down into individual goals for the experts in the organisation who are going to achieve them. Without goals, there is no development of expertise, and no understanding of how technology can help.

Expertise - the industry experts are the people who are going to learn how to better work with technology to achieve the goals. The oil industry experts are its engineers, geoscientists, and leaders. We develop expertise by understanding our situation, making decisions and seeing if the result of the decisions is taking us towards our goals.

Learning - all of this drives personal and organisational learning, and by learning we work out how to reach our goals. We are learning to better understand our situation, learning how to better work with technology, and learning more about our field of expertise, all at the same time, and the different sorts of learning are undividable.

Modelling - where we use digital technology, it needs to be carefully modelled around what we need, as industry experts. The purpose of digital technology is generally to help us understand our situation, so we know where we are. That's a mixture of factual data and analysed data, all presented in a way which is easy for us to understand, quickly access the most important information, see analysed data where appropriate, and understand how the analytics are made.

Analytics - the rapidly growing ability of computer systems to analyse data in different ways is the most exciting recent technology development. But analytics is only useful if it is 'modelled', or provides something useful to an industry expert, by helping them understand their situation. It is often easier if analytics is kept on a small scale, just aiming to do one specific thing at a time.

Data - for this to work, you need company data which can provide useful insight to company experts, perhaps with some analytics. The data must be available to the various digital systems to work with, and must be complete and good enough quality.

This whole "stack" can be looked at either top down or bottom up. The top down approach starts with organisational goals, and then looks at what expertise and learning would help the organisation to reach them, and what software, analytics and data would help them. The bottom up approach starts with the data you have available, and then looks at how it can be analysed and modelled to provide something useful to company experts, to help them to better understand how to achieve the company goals. Perhaps both bottom up and top down need to happen.

What we see perhaps too much of is companies just focussing on the A - analytics part - or even not focussing on the people part at all, imagining that the future is all about computer decision making and transaction management. There are industries which can seem pretty much run by software - industries which do the same thing over and over again, like retail, supply chain management, insurance, airlines, website hosting, banking and telecom.

But the oil and gas industry is not like that. It relies on geology and reservoirs, which is different everywhere, and relies on topside / surface equipment which theoretically could be standardised but never is. Our industry is too complicated for computer decision making for anything but a tiny piece at a time.

So if we're going to get digital technology to work, it will need to work with our people. This means it provides something people need. And perhaps we have to change our organisations a little to make people want what digitech can offer. We have some ideas how to do that in this magazine.

Karl Jeffery, editor
Digital Energy Journal, London

Data managers need to use judgement

Oil and gas data managers rarely have the resources to keep the company data perfect, so they need to use their judgement on where their time adds the most value, said data management consultant Philip Lesslar, formerly with PETRONAS

In all his years of working in data management in oil majors and National Oil Companies, Philip Lesslar has never seen a team who can meet all the organisational demands, because it would take more staff members and skills than the company is ever willing to pay for. So data managers need to learn to prioritise their work, spending their time on projects with the biggest impact.

"You can't do everything with the time you have - or the resources you have," he said.

Rather than ask how good your data can possibly be, it may be better to look at the minimum standard for data to be workable, he suggested.

Or it might help to look at the specific problem areas, where company staff do not have quality data they need to make decisions. This could be due to a lack of governance structure around data, a lack of standardised workflows governing how data is created and stored, or a lack of an accountability structure for ensuring quality and availability of data.

Mr Lesslar is formerly principal consultant, Technical Assurance, Compliance & Technical Assurance, Group Technical Data, Project Delivery and Technology, with PETRONAS Exploration and Production. He was speaking at the Digital Energy Journal forum in KL in October, "Improving the Digital Platforms - Data Management & Quality."

Not well understood

It doesn't help that data management is not well understood in the wider oil and gas industry, with wide misunderstanding on what data managers do, how much work is involved, and why it is difficult to automate.

Many oil and gas people see data managers like a company librarian. But if data management really was simple, the problems probably would have been solved by now, particularly considering how many people with PhDs have been working on it, Mr Lesslar said.

Senior managers and others continually underestimate the complexity of the task. It is common to hear senior managers make statements like "we need to keep all the data," or "transfer

Philip Lesslar, data management consultant

only the data you need", "I want it fully integrated", "we must have quality data".

They say this and then they leave the room. But a data manager can't deliver this without knowing what "all the data", "the data you need", "fully integrated", and "quality data" actually mean in detail, he said.

Sometimes people profess an overconfidence in automation tools to solve the problem, saying that data can be integrated "just by writing some code, he said.

Perhaps data managers should get better at being able to demonstrate the value they create.

They can show that good data management should lead to better decision making, which leads to profit – but then it is hard to assign the profit directly to the data management.

Conversely, if the company makes losses, it could well be due to a bad decision, which could be due to poor data, but it is hard to know for sure.

Activities and data types

Mr Lesslar has a list of 28 different activities a data manager might do, with increasing complexity, from handling tapes and media, through data loading, requirements definition and standards implementation, up to data mapping, quality metrics, data science and machine learning projects.

At the bottom of the list are tasks which can be done as a "data service" from a centralised location, which are highly repetitive – including handling media, scanning, converting data, and basic data cleaning.

Tasks towards the top of the list require much more specialist knowledge.

The full list is available in his slide pack online (see link at end of article).

The list of tasks could be seen as a competency framework, where people gradually work their way up the list so they can do more complex tasks. Data managers should also see it as their responsibility to develop competence to get up the list, rather than endlessly doing data loading.

There are over 100 different upstream data types, across geology and seismic, interpretation and compilations, petroleum engineering, and drilling / production operations (which Mr Lesslar also lists in his slides).

Serving the maximum

One approach is to make sure the work you are doing is helping the maximum number of people.

Perhaps 10 per cent of the subsurface professionals in a company are doing detailed petroleum engineering or production geology studies, such as borehole imaging. These people "will find ways to take care of themselves."

But 90 per cent of staff are doing basic geological interpretation. To do this, they typically need 8 basic well logs – gamma ray, Sonic, Density, Neutron, Resistivity (S, M, D), and Caliper. So it makes sense to focus on making sure this data is available.

Selecting priority wells

A company with 10,000 wells might have 200 to 300 "of active interest" at any time. So the data management work can have more impact if it just focusses on improving data quality for these wells.

You need a process to periodically update the list of "wells of active interest", and an "enterprise dashboard" to track your progress improving the data for them.

A well header can include 40 different attributes. The well ID is a mandatory field, and usually system generated. Therefore it will always be filled. But other attributes such as "date reached total depth" are also important but whether they are entered is a "hit or miss thing," he said.

So you could improve the basic well data by aiming to populate all of these important attributes, and check the data to ensure they are correct.

You could also make sure that the well logs are easy to find, perhaps by putting all the quality controlled well logs in a separate area of the well logs library, all given a quality stamp. Users can often get confused with all of the well logs in the database, many of which are not relevant to them and they have to make sense of all that. "I see that all the time," he said.

Digital Energy Journal's KL conference in October

Because of the diverse nature of data quality improvements, i.e. different data area focus in different wells, it is just too easy to lose track of what has been done over time. Therefore the enterprise dashboard mentioned above, that keeps track of the quality checked data, is really important. This is called the Quality Data Inventory and is essential to ensure that as you always know what has been quality checked and what still needs to be done.

With that dashboard in place, the business will help you define priority wells but you must have that process defined that will ensure you cover all business units and their priorities.

A slide is included in the presentation to explain how this is all optimized.

"All the time you know exactly where you are in the process. Every step of the way you are contributing to better business performance."

You can watch Mr Lesslar's talk on video and download slides at
www.d-e-j.com/video/1911.aspx

Using graph databases in E&P

Graph databases, which use abstract data structures rather than rigid boxed data structures, could prove very useful in E&P, particularly working with complex data sets. Michelle Lim from PETRONAS explained

Graph databases, which store data in a loose structure rather than in rigid tables (as the usual relational databases do), could prove very helpful in exploration and production, particularly working with the large complex data sets, said Michelle Lim, from the Digital Innovation, Strategy and Architecture department of PETRONAS.

She was speaking at the Digital Energy Journal conference in KL in October, "Workforce of the Future: Improving Data Analytics & Knowledge Management."

The word "graph" means "graphical", or arranged in free space (not a graph of the sort where x changes with y).

Data in a graph database is stored as "nodes", and the database understands how the various nodes connect together as "edges".

The more common relational databases store data in tables, like data in a spreadsheet. They are much more rigid.

The development of graph theory is attributed to Euler, a mathematician, in 1736, who wanted a mathematical way to work out whether it would be possible to cross each of the 7 bridges in the town of Königsberg (now Kaliningrad, Russia). He drew a map of the bridges and land connecting them as edges and nodes.

Michelle Lim, PETRONAS

Today, graph theory is used by Google, to show how different pieces of information are related. This enables Google to present a wide range of different information related to the subject you are searching for (shown on the right hand side). For example if you search for Tom Cruise, you will be given different pieces of biographical information, quotes, movies, social media pages, and pages of former partners.

Graph databases are also used by Google Maps directions, to keep track of the different ways for getting from one point to another.

Facebook is also a large graph, where it keeps tracks of all kinds of relationships between people and things. Facebook is looking at ways to develop its social graph for workplaces, to help find the right people within the organisation.

The computer system can understand data similar to how a person would – for example there are certain pieces of data which could be connected to a person, such as their date of birth and their first school. Every company office should have an address

NASA

Graph databases were used to index documents by the North American Space Agency, showing how the different documents relate, she said. This can prove a much easier way to search for a document than by keyword.

In one project, engineers wanted to develop an "up-righting" mechanism for a spacecraft, and they thought it was very likely someone had done this in NASA before, and wanted to see how they did it.

If they were searching through documents via keyword search, it could still take months to find the information, with tens of different terms which might be present in a useful document.

But with the documents connected in a graph, showing how they linked together, it was possible to find the relevant information in 4 hours, a significant cost saving from time saved.

The E&P industry has a similar challenge, with about 100 different data types. "The more information we have, the harder it is to find information, this is our dilemma," she said. "When we have massive amount of data, they are sitting across disparate databases, that makes things even harder."

E&P projects

Graph databases were used in the E&P industry to get a better understanding of well data and oilfields. The data could be visualised with green nodes for the oilfield, blue nodes for wells and purple nodes for the oilfield.

The data can be visualised with wells linked to the oilfield they are in, and wellbores linked to the wells they are in. This immediately provides a different and unusual way to visualise the company's wells, showing which fields are the largest.

This work can also show up problems or faulty data, for example if you have a wellbore which is not related to any well, or an oilfield which does not have any wells in it.

Graph databases could also be used to understand the software applications which the company is using, showing the types of data they work with. The data types are shown as green nodes and the applications are yellow nodes, and the data types are connected with the applications they work with lines.

This will generate a visualisation showing the most important data types, because they are used by many different applications. It can also help you spot where you two applications might be doing the same task because they use the same data types.

There are thousands of different software applications being used across PETRONAS and big savings if some of them can be taken out of use.

The technology might also be helpful in project management, when many different data types need to be bought together to better evaluate options for developing a field.

Graph data can also be useful for more complex data search systems (sometimes known as 'cognitive search') because it makes it easier for a computer to pull data from different data storage systems, and the graph database can better understand how the data connects together.

As the amount of data grows, and there are more different data storage systems, it is getting harder and harder for companies to get the right data together.

The data can be stored in different places – each 'node' in the database can be a separate data store.

Building it from documents

The work of building a graph database for documents would involve taking some of the main topics from the documents, and then mapping how the documents connect together.

Ultimately it could include millions of documents (as nodes) and connections between them (as edges). But you don't have to include all the documents to make a useful graph database – you can start small, say with 100 documents, and then build from there.

It usually requires domain expertise to know what fits together with what. "Humans are always required," she said.

Subsurface data analytics is changing

The way oil and gas companies are approaching subsurface data analytics is changing, with more focus on the quality of data and data preparation, and companies often building their own software rather than buying it, said Jane McConnell of Teradata

Oil companies are putting more focus on the quality of data, and getting data preparation right, before they do data analytics, said Jane McConnell, Practice Partner - Oil and Gas at Teradata, speaking at the Digital Energy Journal Kuala Lumpur conference in October, "Improving the Digital Platforms - Data Management & Quality."

Companies are often building their own analytics tools, rather than buying software to do it, so they can put data together any way they want. "The way people are interacting with this kind of data is changing," she said. "It is not just fixed workflows."

Important 'rules' for getting analytics right are to get the right people, the right platform, work with 'good enough' data management, to be 'agile', and to get business buy-in, she said. It is important to understand why subsurface analytics is different in many ways to analytics in other industries.

Good quality data

Analytics needs good quality data, which means that the data needs to be well managed.

This probably means that the industry needs to move from manual data management to more automated methods, she said.

The industry has long employed a large army of data managers moving files to wherever they are needed and do necessary conversions along the way, for example to export seismic SEG-Y data into Landmark interpretation software.

But along with this way of working comes a habit of fixing problems with the data just before the data is needed, rather than fixing problems with the data stores behind it, she said. Also the manual methods can be error prone.

For analytics to work, the systems need to be able to retrieve data from the company data stores in good quality.

Jane McConnell of Teradata

Teradata has seen many data science projects in oil companies where the analytics was well underway before someone realised a major problem with the underlying data, such as half of the data is in one unit of measure and half is in another, she said. As an example, "we had people working with weather data - half of the data had the wind speed in metres per second and the other half was knots,"

So people working with analytics end up spending endless time trying to resolve problems or fill gaps in the core data stores.

It doesn't help that the people who originally created the data, and understand it, are often not available to help.

Data lake

One desired end goal is described as a 'data lake', where all the data which analytics systems might need is readily accessible.

A data lake is not a physical data store, but more an architecture, where all of the data stores are available to the analytics systems, she said.

Many people have got the wrong idea about a data lake, thinking that if they just copied their data into a single file store, "as if by magic good things would happen," she said.

For this reason, some people are turning away from the term data lake, using the term "discovery lake" instead.

The analysis company Gartner has described three types of data lake. One is the 'inflow data lake', where you bring in data from multiple sources together to one place, such as a dashboard. The second is the 'outflow data lake' where one set of data serves multiple different applications. The third type is a "basic data lake" which is a starting point, with some controlled data management.

Data preparation

There is never enough time to get perfect data, so it is useful to define the minimum quality data which is acceptable for what you want to do with it, rather than try to get it perfect.

In this sense, subsurface data work is different to financial data, and most traditional data management work, where everything has to be absolutely correct at any point. Subsurface data work is more experimental.

Most successful data science projects just focus on one or two specific areas, rather than cover the whole company, she said. You may want to build a data lake for trying to solve a specific problem, and make sure the data is just good enough for that.

However, as the industry sees more successful data science projects, it is probable that it will want to do more and more of it. This will increase the need to bring in structured data governance processes. It will also increase the complexity of the data preparation work, so create more room for error.

Master Data Management (MDM) means setting up processes, governance and standards for managing the critical data of an organisation, making it available from a single point of reference.

"I can't think of any oil companies that do MDM beautifully," she said.

Spending time on MDM, across the company, is a good way to improve data management and to be better organised.

Build not buy

Until now, the upstream oil and gas industry has mainly worked with purchased software packages, which include data management, visualisation and analytics tools in the package. Data preparation work has mainly been in accordance with the requirements of the package. This could be called "buy not build".

Part of the reason for this is that corporate IT departments typically did not have much understanding of the petrotechnical and engineering domains, so it made sense for oil companies to use software developed by oil and gas service companies, such as Landmark and Schlumberger.

But this approach is not best suited to the analytics era, where data scientists want to put together different types of data in new ways to gather new insights from them. The data stores within software packages are usually in formats which only that software can understand.

It would probably be better to take a "build not buy" approach, making analytics tools as you go along, and building tools to get data to them in the right format. Data engineers can write code to run data pipelines, including tools to split files, move data and run data quality checks.

There is an open source project to develop software to automate the flow of data between software systems, which Teradata is involved in, called Kylo. Kylo builds on Apache NiFi. NiFi is short for Niagara Files, a previous name of the software, when it was developed by the US National Security Agency.

Kylo can be used to define the jobs you want to do with data such as split or check files, and schedule jobs and check for problems.

Many oil and gas companies have data stored in a range of old file formats, which they think can only be read with special software. But there is a surprising amount of open source software tools and scripts available which can work with old file formats, she said.

The important point is that "we need to move to a place where data is not held away from us by the software vendors and applications companies," she said.

This philosophy was adopted by the team setting up the "Diskos" National Data Repository in Norway, where there was a view that data could only be stored in non-proprietary formats.

Why subsurface is different

Subsurface data is different in many ways to data from most other industries, and it is important to understand these differences if you want to do data science with it, she said.

Subsurface data analytics includes a lot of measurement data, which is not found in other industry sectors. There can be very complex jargon and data structures.

Petrotechnical and engineering software systems are usually built around the specific needs of the subsurface domain. In this sense, they are different to oil and gas business IT, which is similar to business IT in other industries, she said.

So oil and gas business departments have long been doing analytics with the same software that other business departments use, such as Tibco Spotfire, but the petrotechnical world has been limited to what it can do within the subsurface software environment. And it has not been very easy to do analytics which involve bringing petrotechnical and business data together.

Another issue is that much subsurface data management work evolved out of work to do records management, looking after physical items such as tapes, printed well logs, fluids, seismic tape. The culture is around making sure the original data doesn't get lost, rather than finding ways to move forward, she said.

Rules for analytics

When doing subsurface data analytics, the first rule can be to get the right people. The best people are described as "T shaped," having both depth (being very good at one narrow aspect of E&P) and breadth (understanding how it all fits together). For data science projects, you want data scientists who have in-depth data science skills, but also who understand the broader oil and gas domain. And you will need subject matter experts who have in-depth skills for their domain, but also understand the broader analytics approaches.

The second rule is to work on the right platform (software system). The E&P industry typically works with linear workflows, where data is worked on with one application in one department, then sent on to another application in another department, and these methods have evolved over time.

But this means that some data types have never been put together, because the traditional apps don't have a way to do it. Trying out new ways to put data together is usually a big part of analytics work.

Analytics also often involves looking deeply within data to see if there is something worth looking at further, which is not something which can be done easily if the data can only be accessed via an application.

The third rule is to work around "good enough" data management – doing the minimum amount of work to be able to answer the business question you want to answer. This might mean storing data so you can just pull out the piece you want, such as individual seismic traces, or well log data just for a specific depth level.

It helps if data is "profiled" so people can get an idea of what it is, without having to load it into the right software system to understand it.

The fourth rule is to be "agile", or focus narrowly on what the goal requires. The industry can so easily get stuck into "waterfall" rigid step by step processes which take years, rather than going as fast as possible to answer the specific question.

"If you have a business request for a piece of work, do that piece of work, make sure the value is delivered, don't turn it into a 10 year project," she said. Small projects can be better – people working quickly to see if they can achieve some specific outcome which is useful for the business.

The fifth role is to get business buy-in. If you want to make changes across silos of the business, you need business support at level which the various departments will both listen to, which might mean "C" level. Otherwise you can't escape out of any silo. One idea is to have a C level "chief data officer" who guides the company on things to stop doing or start doing.

The chief data officer might also try to stop people using software tools which are very difficult for someone else to work with, such as Excel and PowerPoint. They can also ensure continued governance on the data and continued data quality improvement. Dashboards can be a good way to drive data quality.

Companies are increasingly forming "asset teams" where people with different disciplines work together on business problems – rather than in the old days where one department works on data and throws it over a wall to the next one – geophysicists do their seismic interpretation, reservoir engineers do their simulation.

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.

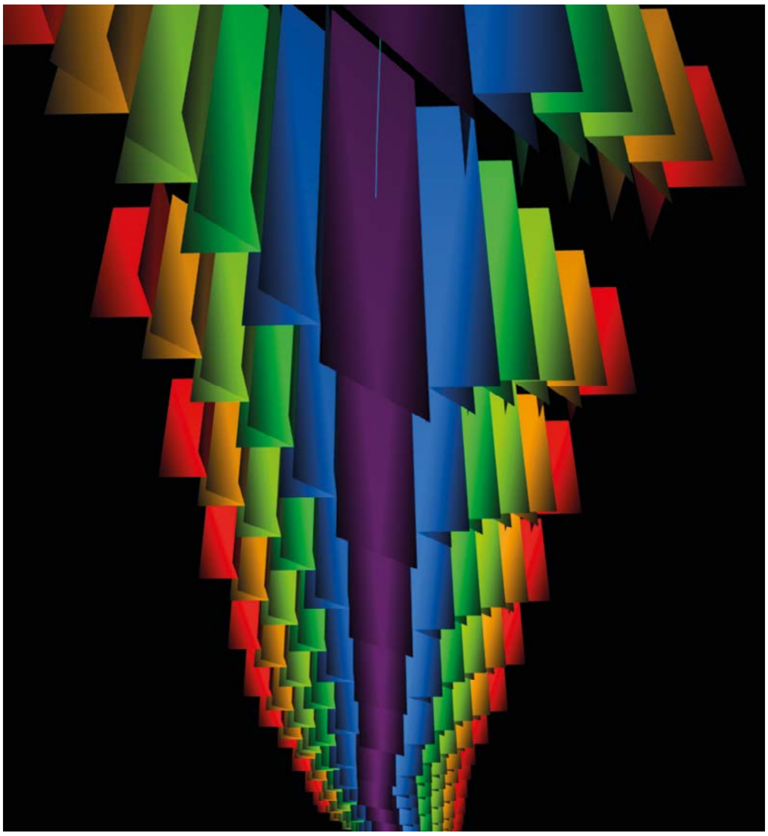
"The task of production engineers is to maintain production targets. Historically this has meant mainly surveillance, seeing what production currently looks like. Access to reservoir simulations will give them a better understanding of why changes in production rates are happening," says Indy Chakrabarti, 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



The Paradigm K reservoir simulator

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.

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 over-simplified, 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.

Indy Chakrabarti, senior vice president of Product Management at Paradigm

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 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."

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."

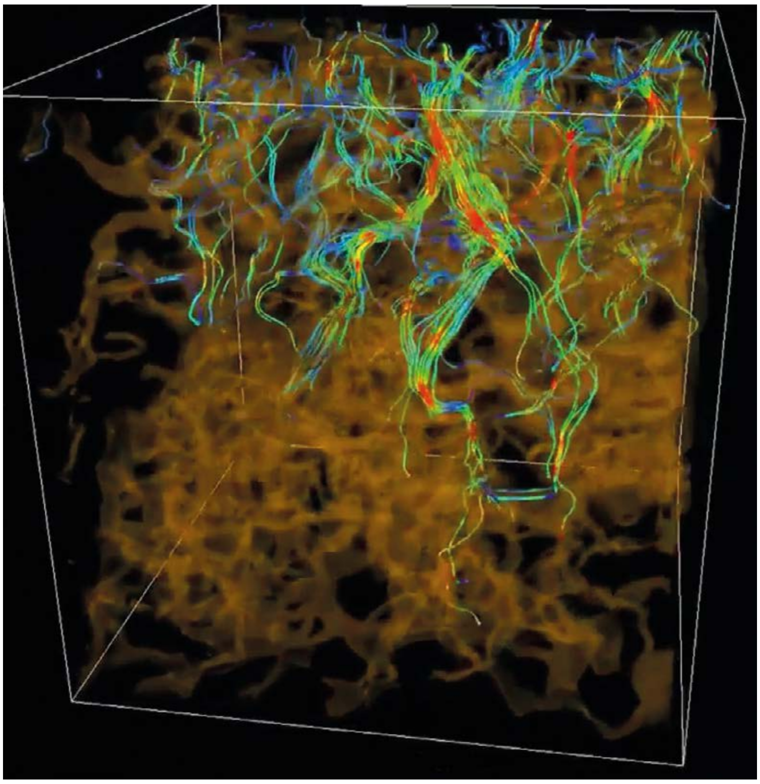
Evolution of technology

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 filled with water filling their pore spaces, and hydrocarbons percolate in there over time and push the water out.



Simulating flow of different fluids through a rock sample

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.

A longer version of this article is published as part of the Petromall Insights Nov 2017 report "Can we squeeze more value from reservoirs in production from better use of data?" You can download the full report free at **bit.ly/reservoirPIQ4**

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 the 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 in 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.

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

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.

A longer version of this article is published as part of the Petromall Insights Nov 2017 report "Can we squeeze more value from reservoirs in production from better use of data?" You can download the full report free at **bit.ly/reservoirPIQ4**

Analysing fracs using a pressure gauge and bridge plug

Reveal Energy Services, a Houston company spun out from Statoil, has developed pressure-based fracture map technology to evaluate the frac half-length, height, and asymmetry. The technology is based on a pressure gauge and a bridge plug on a monitor well, and some clever data analytics

Reveal Energy Services, a Houston company spun out from Statoil, has developed pressure-based fracture map technology to evaluate the frac half-length, height, and asymmetry. The technology is based on a pressure gauge and a bridge plug on a monitor well, and some clever data analytics. The technology was originally developed by Statoil.

Companies can confirm whether the stimulation treatment is producing the planned fracture dimensions to improve treatment design and well lateral spacing decisions. The system also provides insight into the fluid system so you can understand where the proppant goes, in addition to insight into the perforation clusters, diverter effectiveness, and depletion boundary.

The frac evaluation is equivalent to other methods of evaluating fracs, such as microseismic analysis, fibre optic monitoring and electromagnetic imaging, says Sudhendu Kashikar, CEO of Reveal Energy Services.

The company has done an analysis and comparison of this technology with other methods, using a variety of completion variables, including fluid design, proppant size, perforation designs and diverter types, he says.

With this method, it is possible to validate the completion design on every well you frac, not just a small sample. There is no disruption to operations, or large numbers of oilfield personnel

The technology has already been used in over 2,000 frac stages in the US and Canada.

The technology costs about 20 per cent of the costs of legacy diagnostic technologies, such as microseismic and electromagnetic frac monitoring systems, and even lower if larger volumes are involved.

How it works

The system works by using the stress effect that fracking a well has on a neighbouring well, which has already been fracked, and is full of fluid.

To explain it, we will call the well being fracked the 'treatment well' and a nearby well used for monitoring the 'monitor well'.

A pressure gauge is placed at the wellhead of the monitor well. The monitor well should only have one stage isolated and affected by the work on the treatment well. This is achieved by placing a bridge plug below the last stage fracked in the monitor well, isolating the fracs in the previous stages from the pressure gauge.

Then, when you create a new frac in the treatment well, the new frac creates a stress field in the rock around it, which leads to a pressure response in the monitor well. Over the short term, because everything is stable in the subsurface, the increase in pressure in the treatment well will lead to an immediate and visible response in the monitor well.

The bigger the new frac is, the higher the pressure response in the monitor well.

The clever part of it is how you use the pressure data to get fracture geometries, Mr Kashikar says.

Different sized and shaped fractures in the treatment well will drive a different response in the monitor well. For example, if the fracture is 600 feet long and 50 feet high, or 400 feet long and 100 feet high, the response in the monitor well will be different. The 3D stress field created by the two geometries listed above can be quite different and will result in a different pressure response.

The distance between the new frac and the observation frac is taken into consideration in the modelling.

For the system to work, the maximum distance between the treatment and monitor stage is around 1500 to 2500 feet (457m to 762m). The company is working on extending that range.

Other data

The technology has been further developed to provide information about how far the proppant has gone out into the rock and where it went.

The company can also do analysis of perforations so an operator can improve cluster spacing decisions with the highlighting of fluid distribution within a stage. The perforation technology offers a clear understanding of pumping rate effects on fluid distribution.


Sudhendu Kashikar, CEO of Reveal Energy Services

You can also look at other changes, for example, using hybrid gels to support proppant rather than slickwater (chemicals added to water).

You can also get data about the effectiveness of diverter (chemical or mechanical) agents used to make a temporary block in parts of the well and stop a 'runaway' fracture.

Reveal Energy Services' diverter technology can quickly analyse and determine if a given diverter drop has been successful in stopping the growth of this 'runaway' fracture. The studies show that sometimes diverters can actually make a problem worse, somehow accelerating the growth in the largest fracture.

Some clients use the data to test out different diversion techniques in the same well. "They can get feedback in near real time on what technique did or didn't work," he said. "They can also try different materials or different quantity of materials."

Data model

Behind the technology is a 3D stress model, which computes what kind of pressure response might be expected in the monitor well and how much a new fracture in the treatment well will increase the pressure in a facture in a monitoring well. The computer model then uses observations from multiple fracs and determines the geometries of the newly created fractures by comparing the predictions with the observations.

The system does not require any calibration and is insensitive to rock properties such as Young's Modulus and Poisson's Ratio. This is a result of the unique formulation and setup of the stress models.
The model is set up as a force balance problem, monitoring how the force being imposed on the treatment well is being balanced by an increase in pressure in the monitoring well.

"By setting this up as a force balance problem, the underlying problem becomes fairly insensitive to rock properties," Mr Kashikar says. "There's only one place the extra pressure can go, and that's into the monitoring well."

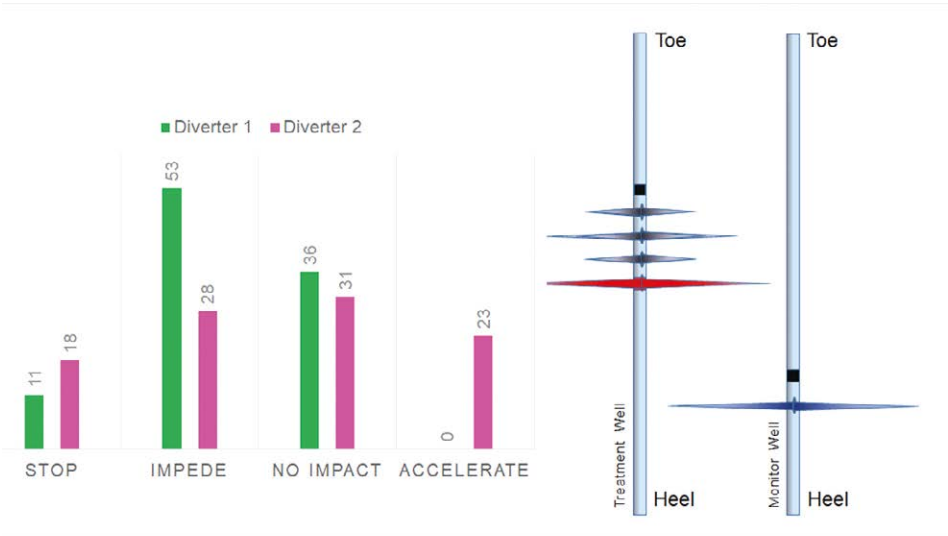
Technology development

Statoil developed the technology after finding that none of the available techniques for understanding fracs were cost effective to deploy on a large number of wells, Mr Kashikar says. These older techniques also needed additional equipment and people on the wellsite.

This meant that the industry was typically monitoring fracs on a few pilot projects, and assumed the results were similar on all wells.

Statoil challenged its R+D team to come up with a technique which would allow them to monitor a much larger number of wells, so they could quality control the fracture geometry when they moved to "factory" mode.

The research project started in 2015, with methods tested on actual wells in the Bakken and Marcellus, comparing results with microseismic and electromagnetic analysis.



In this example of Reveal Energy Services technology, the monitor well, far right, evaluated diversion effectiveness for two diverter types. Diverter 1, the better choice, stopped dominant fracture growth in 11 percent of the drops, impeded growth in 53 percent, and had no impact in 36 percent.

The technology was spun out into Reveal Energy Services in mid-2016, and the company has continued to develop the technology. It has so far been used on over 2,000 frac stages, with between 20 and 90 frac stages on each well.

Many clients have undertaken cross validation studies, comparing the results from Reveal Energy Services with results from other methods, and "so far, every study has shown that it is as accurate as any other method," he says.

The pressure-based fracture maps have been generated from work in Canada and in the US in the Bakken; Permian Basin's Midland and Delaware Basins; Oklahoma's Woodford Shale; Eagle Ford; and Marcellus and with projects starting in Colorado.

Understanding digital and security competency

The Malaysian Oil and Gas Services Council (MOGSC) has a project to better understand the competencies needed to do oil and gas jobs, focussing initially on ICT and security skills.

The Malaysian Oil and Gas Services Council (MOGSC) Competency and Training Working Group (CTWG) has a project to try to better understand the competencies required to do different oil and gas jobs – and which competencies are useful for a variety of different jobs. The project is focussing initially on ICT and security skills.

The study is led by Dr Jeffrey Bannister, a consultant with Orbitage. Dr Bannister also works extensively with the telecom industry. Telecoms are similar to oil and gas, in that it is very technical but also in many cases very traditional, and gone through a number of major transformations, including the current 'digital transformation', he said.

He was speaking at the Digital Energy Journal forum in KL in October, "Workforce of the Future: Improving Data Analytics & Knowledge Management".

Challenges

Companies often find that they need people with digital skills very urgently, so they rush to fill gaps rather than developing longer term plans.

Companies often find that graduates do not have the right digital skill sets, perhaps because there is not very good communication between industry and academia about what skills are needed, or graduates have theoretical knowledge but not practical knowledge. Companies complain that new graduates are ready for training, but not ready for work.

But on the other hand, companies are often too narrow when they specify what they need, saying they need someone who can do a specific thing, not the broader competencies.

It can make sense to define a set of competencies as the minimum someone would need to be able to do a job, rather than describe what the person currently doing the job can do, he said.

Often jobs are split (so 3 or 4 people doing one job) or combined (2 or 3 jobs become one), as the amount of work goes up and down. Sometimes there are competencies which companies sometimes need, but they say they don't actually need it right now.

A "competency" can be defined as a mix of knowledge, skills, behaviour and attitudes required to successfully perform a task, he said.

Roadmaps

The MOGSC project aims to build "roadmaps" or competency frameworks for organisations to follow, so they have a path to improve their overall organisational competency. Improving competency means understanding what your staff can currently do, and so where the gaps are, and if they are best filled by recruiting people who have those competencies, or by training existing staff.

Because there are so many different jobs in the oil and gas industry, the project team are aiming to define the digital skills used in a variety of different roles, rather than specific competencies for specific job roles.

This will also make it easier for staff to transfer from one role to another, because the organisation will understand that the skill they have can be used in many different roles. "We can say, 60 per cent of the skillset you have here is applicable to this role here, you need to top up this part."

It should help avoid people getting into a situation where people's skills are thought to be only suitable for the specific job that they are in. This means that people can't progress anywhere unless their boss leaves. Sometimes people in this situation just get fed up and leave the company, he said.

Once competencies have been defined, they can be used by many different companies – so it makes sense that the work of defining them is done by an industry association, rather than individual companies.

Assessing competencies

Companies want to be able to measure how well certain staff members have a certain competency – which means that it cannot be defined too vaguely.

Although if it is defined too narrowly, or with a long list of different competencies required to do a job, it can be very hard to find someone who has them all.

Assessing competency can be much easier for practical skills, Dr Bannister said. Take welding for example. A welder has a certificate which shows that they have had rigorous training and assessment in welding. He is assessed on every welding task he does. If the weld is good, the test is passed.

Dr Jeffrey Bannister, Consulatant with Orbitage

But more academic and theoretical skills are typically tested in an exam, or online multiple choice test, and only a certain number of correct answers is needed for a 'pass'.

Sometimes course trainers are explicit in telling students, they are not there to be trained in skills they will need in the workplace, they are there to learn how to pass the exam.

It may be better to test ICT skills in a similar way to how the welder is assessed, such as by asking people to configure a firewall or demonstrate that they can analyse data.

Learning from telecoms and IT

The telecom and IT industries have already done a great deal of work defining competencies in digital and security skills, which is something oil and gas might be able to make use of, he said.

One Malaysian organisation, CCPS, has developed a model showing different roles as a tower of blocks. Where the same skill is used for different roles, the block stretches across different towers. Each box has a description of what performance outcomes someone should be able to achieve to demonstrate they have competency.

This framework sets a common language between HR, learning and development, and technical teams. It can make it easier to identify which skills are easy to find among new recruits, and where it makes sense to train the existing workforce. It can also help communications between HR and technical departments, if technical people can just point to the skills they need as one of the blocks.

MOSGC has taken on three areas of this framework into the oil and gas industry, covering IT (databases, software development and analytics), IT security, and IT data communications and networking. Each area has the same fundamental, transferrable skills, of basic networking and basic computer operating.

MOSGC is circulating it around the oil and gas industry to get feedback on how it can be adapted for the industry and where bigger changes are needed and where the gaps are, he said.

HR / technical communications

One challenge is the quality of communications between technical staff (who are often working on today's problem and finding they don't have people to do the necessary tasks), and HR people (who have the role of finding people who can do the tasks and help them develop skills).

Typically, the HR people will not understand the technical domain. They ask technical people what skills they need. The technical people come back with a list of skills which HR people do not understand, which they have to hammer into a plan or a training course.

The training course can often mean someone in HR just passing on the list to a 'usual suspect' training provider and ask them to make a 2 day program. The end result is often unsatisfactory.

One common problem is when the company gets a new HR manager, who wants to improve the way the company manages skill developments. This person is typically not technical, so feels more comfortable with the so-called "soft skills" training, such as leadership and communications, so this is tackled first. But the technical part does not get tackled well at all.

HR people ask technical supervisors to do periodic 'appraisals' of their staff, but the value of these is questionable. "I was with the CTO of a large organisation recently, and he said, let's be honest, by the time I've got to the 8th or 9th appraisal that morning, number 10 is not going to have much thought put into it. The further in there we go, we get less effective."

You can watch Dr Bannister's talk on video and download slides at
www.d-e-j.com/video/1907.aspx

CISCO – making your "internet of things" easier to manage

Computer networking giant CISCO has developed an 'internet of things' platform called Kinetic, to make it easier for companies to manage complex networks of sensors and the data they generate

CISCO, a company best known for computer networking equipment, has developed a product called Kinetic for companies to manage complex networks of sensors and other 'internet of things' (IoT) devices.

The service is most beneficial for companies which have thousands of different devices, and want a way to reduce the headache of setting the devices up, managing the policy of what data they want and where they want it, running appropriate software on the devices, and then actually moving the data.

The service is provided as a mixture of hardware (Cisco routers) and software running on cloud services.

You can immediately set the whole system to a default setting, where your sensors and other devices provide standard data to cloud hosted software, ready to be fed into your various software applications. You can then use this default setting as a starting point for configuring the system to do exactly what you want.

For the oil and gas industry, Cisco provides a starter kit, as a "default blueprint" to get you going. It includes a default way to extract data, and cloud hosted applications which can receive the data on a daily, weekly or monthly data.

The oil and gas industry uses many different "internet of things" devices, including acoustic sensors, temperature sensors, fibre optics, gas leakage monitoring and equipment health monitoring.

Apart from oil and gas, the system is used in city management (including lighting and parking), manufacturing (monitoring machines, energy, inventory and deliveries), transport (including traffic lights and 'connected car), and retail.

Theresa Bui, director of IoT strategy with CISCO

The service is offered following Cisco's acquisition of Jasper, a company which makes a cloud based 'internet of things' service platform, in March 2016. It is used by over 16,000 companies.

Working with well data

One oil and gas industry customer uses the system to gather and work with well data.

It has thousands of wells worldwide, all fitted with different sensors, generating data in different formats, and with different "application programming interfaces" (APIs). This meant that gathering and managing the data involved a great deal of manual work. It was very difficult to build a centralised system for understanding the whole 'fleet' of wells, and do any data analytics.

The company wanted to get visibility in near real time of what was happening with the wells, and wanted it all automated, so it would not require the data to be formatted by an engineering team before it could be used.

The oil company had four different business units who wanted to work with the well data and do different kinds of analysis on it.

They wanted statistics for individual wells, and aggregated information about multiple wells, and the ability to do big data analytics.

CISCO installed a new router on each of the customer's sites, which connected upstream to the various sensors on the rigs, and downstream to the cloud hosted software. From there the data could be distributed to the software systems of the business units who wanted to work with it.

Setting up the system

When setting up your IoT system, you need to determine what data you want to receive from all of your sensors, and where this data should go. This is called creating data "policies".

For example, if you have 32 sensors on a well, you might want sensors 1-10 to send data to SAP hourly, and send data from another sensor once a month.

A company might want its business partners to see some of the data but control exactly what they can see.

It is much easier to set up a system if your sensors are more standardised, generating data using the same data model, says Theresa Bui, Director of IoT Strategy, CISCO.

Various options are available for connectivity, including cellular, and a new satellite communications options, and Narrow Band IOT (NB-IOT), enabling communications between devices over cellular communications bands.

Three modules

The CISCO Kinetic software has three core modules – gateway management, edge processing, and data control.

The "gateway management module" is for adding new devices or "gateways" to the system, making sure the network can extract the data it needs from the device in some kind of standard format, enabling fast set-up of a sensor (in minutes rather than days, the company says), and enabling remote management of the device.

The "Edge & Fog Processing Module (EFM)" is for managing processing on the "edge" or in the "fog" – terms which basically mean doing processing near to the device itself.

This means that data only needs to be communicated to the cloud when there is something to actually say. An offshore drilling platform can generate 16 terabytes of data a month, Ms Bui says, and companies probably won't want all of that data going to the cloud.

It also means that the system can be programmed to do something immediately something happens (for example shut a piece of equipment down if a shaft is rotating too fast), rather than send the data to Houston and get an instruction back.

In the jargon, the system is "pushing policy back to the device".

A third "data control module" does the work of aggregating data from all of the devices, and can be used to set your policies for where the data goes, and who gets to see the data.
The software modules can run on CISCO's networking infrastructure.

Security

To keep the system secure, all the components of the system need to be secure. This can include making sure manufacturers are making their devices secure, making sure any applications running on the device are secure. Also making sure that the movement of data is secure, and the storage of data, such as in a cloud server, can't be tampered with. It also includes establishing who is responsible for what.

ARI now managing 'half US oil and gas vehicles'

US vehicle fleet management company ARI reports that it is currently providing vehicle management services for 135,000 vehicles in North America, about half the total vehicle fleet

ARI, a company based in New Jersey, USA, reports that it currently provides fleet management services for around 135,000 oil and gas vehicles in North America, about half the total oil and gas vehicle fleet in North America. A typical US oil and gas company will have between 1,600 and 4,000 vehicles, ARI says.

Altogether the company now manages over 2 million company fleet vehicles worldwide.

The service offering manages vehicles from purchase to disposal, including financing the purchases, vehicle maintenance, certificate renewals and driver training programs.

Vehicles can be fitted with various telematics systems, monitoring seatbelt use, taking tight corners, engine idle running, all of which can be used to help companies make sure vehicles are being run as safely and effectively as possible.

ARI has developed a range of data tools which help companies work with the data to minimise the cost of running their vehicles and maximise the value they can get out of them.

It provides condition monitoring and preventative maintenance services tailored for vehicles who spend the lives on rough and dirty roads, as oil and gas vehicles often do.

This should lead to reduced downtime for the vehicle. Downtime can often mean the driver is unable to work, as well as losing the use of the vehicle.

ARI can provide standardised and robust systems to manage all vehicles in a company's fleet in the same way, says Jim Spera, oil and gas sales manager at ARI. This service can prove most useful after a company acquisition, because the acquisition will usually include the company's vehicles.

Tracts - using software for title management

Tracts of Houston has developed software which promises to cut billions of dollars from the cost of determining who has rights to the land you want to drill on

Tracts, a company based in Houston, has developed software to help manage the complexities of who owns the rights to the land you would like to drill on.

The company estimates that oil companies spend between 2 and 8 billion dollars a year "running title", or working out who has rights to what.

The software might be able to halve this cost, says Ashley Gilmore, co-founder and CEO, by making it much easier to manage the complex documentation and calculations.

Mr Gilmore sees the software similar to how the first accounting software in the 1990s enabled accountants to do their jobs faster and more accurately, and enable people who weren't accountants to do accounting.

A "tract" of land is defined as a piece of land with one owner, or one group of owners, which does not need to be further sub-divided. That is to say, the same owners own all of the piece of land.

Why it is complicated

To understand why the process is so complicated, consider that in the US, onshore oil and gas is privately owned, usually by the landowner, but sometimes the "mineral rights" are sold separately to the land.

The typical "running title" work process starts when a geophysicist picks a spot which he thinks might be suitable for drilling. Then he asks the company "landman" to go and find out if the land has been leased already by another oil company, or is available to lease.

Before you can drill, you need to negotiate a royalty with the owner of the executive mineral rights.

If you fail to do this, or negotiate with someone who turns out not to be the rights holder, you can lose 100 per cent of the revenues to the actual rights holder, when he appears.

And to determine who the rights holders are, sometimes you have to go back through the deeds to the point in history when land was first given to a private owner by the government, and follow all transactions since then, including how property was passed on following a death.

When people die, sometimes they mention in their will who the ownership of both land and minerals should go to, and sometimes they don't, Mr Gilmore says. Sometimes land will be split, so someone will give half of a tract of land to someone but retain ownership over the minerals for the whole thing.

There is also a complex system of rights, such as "executive right, right to bonus, right to royalty, ingress." The executive right controls all the other rights. So if you have a "right to a royalty" you can't do anything with it without the "executive right".

A 1 per cent executive right is different to a 1 per cent royalty right. A 1 per cent royalty right must be traced back to its specific executive right in order to be leased.

The "executive rights" need to be connected with the other rights. There are also leasehold rights, including "overriding rights, lessor royalty, working interest".

If the landowner is a different person to the mineral rights owner, you may want to discuss with the landowner additionally.

Tract can have as many as 100 'instruments' – different legal documents – and processing each instrument can cost $75 to $100.

To add to the complexity, companies are usually in a race with other companies to be the first to sign a lease to drill on that piece of land, Mr Gilmore says. Sometimes people sign leases before they prove that the person they are talking to is the owner.

Oil companies tend to watch one another very closely, and when one company is successful, others will try to lease land nearby.

After a certain period of production (typically 30 days), companies are forced to release production reports to government, which makes them public. Estimated Ultimate Recovery must also be reported. Sometimes companies will try to delay production so they have more time to acquire neighbouring leases, before other companies pile in.

Courthouses around the world have been gradually digitising themselves, making it possible to find deeds and other legal documents much more easily. So they can be accessed online rather than sending a landman to a courthouse. This makes it easier to obtain the documents, but the complexity of working with them remains.

Electronic notes

The first service the software provides is an electronic notetaking system.

It is usual to see many landmen working with handwritten notes, as they visit courthouses to see records of who owns what.

Handwritten notes are very error prone, and mean there is work typing the data into a computer system afterwards.

With Tracts, the landman can enter documents just by scanning them or photographing them.

The Tracts system creates 'notecards' noting who owns what, which are then integrated with any other notecards in the system.

Calculations

There are many other software packages which can be used to gather and store land related data, but what makes Tracts special is its mathematical tools for doing the calculations, and tracking which "executive" connects to which "right," Mr Gilmore says.

The software needs to track between 12 and 18 types of data at any time, such as geographical co-ordinates, mineral types, and time. There are also relationships between the various factors. It rapidly gets too complicated to handle in a spreadsheet, even with multiple worksheets.

It can take a landman several weeks just to calculate who owns what.

With the Tracts software, every time new information is entered into a new electronic note card, the software recalculates interest payable to different parties, updates reports, and places the document in the right spot in the title chain.

Once you have gathered all the documents for the tract, the software can generate the necessary reports, an "ownership report", "chain of title" and "run sheet," which can all be passed digitally on to the title attorney.

Then, instead of giving the attorney just a USB stick full of pdfs and a spreadsheet, and a requirement to re-do the calculation, the attorney can get everything worked out, ready to put the contract together.

Reviewing the work later is just a process of checking the right data was added into the form.

Mr Gilmore also believes that his company's software development team might be more equiped than an oil company in-house IT department in putting software together.

"Our team isn't a bunch of random coders from different teams – it is made up of focussed computer scientists capable of theorising complex concepts – so they can solve real world problems," he said.

Tracking effectiveness

As the bonus, the software can also be used to track the effectiveness of all the parties or companies you are contracting to help, such as lawyers, brokers and independent landmen.

"You can see which ones are the most cost effective for you, and which ones are making the most mistakes, and compare that to their day rate," Mr Gilmore says. "This is something which oil companies have never been able to do in the past."

The company

The company has been developing software since 2015, and currently has clients, ranging from mineral buyers to E+P companies. In January it raised over $1m venture capital funding.

It can be challenging selling the software, after many companies have struggled in the past with adopting new software, and say "we just bought new software why should we buy more". Perhaps it is hard to see how much money is being lost with the manual methods, he says.

However the company is seeing lots of interest from companies in the Permian Basin. We have also seen a lot of interest from mineral buyers.

How Lloyd's Register helps oil and gas

Risk based inspection, supporting in-house technical experts, and helping get new technologies adopted – some of the ways that Lloyd's Register is helping the oil and gas industry

Lloyd's Register (LR), a compliance, risk and technical consultancy company working in the shipping and oil and gas industry worldwide, is developing a number of interesting services for the oil and gas industry, including supporting risk based inspection, and helping demonstrate that new technologies are fit for purpose.

"Risk based inspection" is a method of optimising the amount of inspection or the timings of inspections you do (for example of a piece of offshore equipment), based on a judgement of whether the inspection is needed.

Oil companies spend a lot of money on inspections which do not find anything wrong, and which can themselves be disruptive to plant operations. Some of this money is wasted, but not all, because there is a risk that something could have been wrong or that equipment was degraded more – or less – than expected. The question is to try to get better at spotting the unnecessary inspections in advance or in planning inspection activities in the least disruptive way.

Risk based inspection is all about how to do inspections "at a cost which makes sense", says Richard Nott, head of Offshore and Global Projects with Lloyd's Register. "We look at ways we can do inspection in a more effective way."

But it is a task which involves expert judgement, someone to take responsibility for it, and also knowledge about failure modes, so you can make a good assessment of whether the inspection is needed or can be more effectively programmed.

LR employs experts who work for many different clients in the same sector, and sometimes different types of equipment for the same client, and so is able to gather a large amount of understanding, allowing fully informed decisions to be made.

The judgement can be supported by a large amount of analytics work, to assess the likelihood that something is going to be close to failure, based on past experience and advanced engineering techniques. In this way, Risk Based Inspection might be considered "technology supported decision making."

Not all clients assess risk in the same way, and their risk policies can be used to adjust the software's suggestions.

The service could be improved if oil companies were more comfortable about sharing data between each other, because then the analytics supporting the decision making process could be even better.

The oil and gas industry has been sharing safety data for about 10 years – but now it is looking at sharing more of its data (such as maintenance). "That has been a revelation," Mr Nott says.

LR also offers a similar service to make decisions about the right time between regular maintenance work, called RTAMO (Real Time Adaptive Maintenance Optimisation).

The system can share knowledge developed by different operators about the best time intervals between maintenance tasks. If the time interval is too short you waste money doing unnecessary maintenance, but if the time interval is too long, your risk of a component failure, and subsequent downtime, is higher.

Both services help the industry meet its challenges of trying to expand activity while maintaining lower costs. The true identifier in cost savings is in the way inspections are prepared and how inspection programmes are deployed to avoid the disruption that can be caused to plant operations – especially if a plant has to suffer downtime to enable the inspection to be carried out, which can be costly on a number of levels.

"There will be focus on making the most effective use of people," says Mr Nott. "We help give confidence in new technologies to an industry which can be very traditional in some areas of operations and also in its outlook."

New technologies

LR also helps the industry to figure out where different technologies can provide more value and where they can be used safely.

For example it is looking for ways companies can do more with drone technology, which "has more applications than we might currently appreciate," says Phil Edwards, director of consulting.

Until now drones have been seen in the industry as "a bit of a toy", but the industry is waiting to come across a useful solution at the right price.

LR is also looking at Additive Manufacturing (3D printing), and recently issued the first component certification for oil and gas use of an additively manufactured product.

After the oil price crash, clients are proving more open to technology driven solutions, Mr Edwards says. And we are experiencing a strong "joint industry projects" focus, where companies collectively join together to develop new technology and new solutions and pooling the costs through new Joint Ventures. We are also seeing M&A activity on the rise which is indicative of a new industry model evolving for a changing energy mix.

About Lloyd's Register

Altogether, LR's contribution to the oil and gas industry could be described as helping companies to do more with their in-house technical experts, supporting them with its own.

"We work in technical partnership with clients," says Phil Edwards, director of consulting.

The company's work in energy could be put in 3 service groups – consulting, supporting operations (compliance) and low carbon power. It has a breadth of scope, including solar, wind, tidal and wave energy, nuclear power generation, and oil and gas (onshore and offshore). It has a specialist focus on subsea and pipeline surveys through to everything above the water line.

The company has a major technology and innovation core at the heart of its business which is helping industry to drive through new change with the advancement of applications such as Virtual Reality training, Additive Manufacturing and Unmanned Aerial Systems for internal and external inspections.

Its range of software products is changing how clients are able to achieve better decision making through predictive risk-based maintenance programmes. Lloyd's Register's stance on Industry 4.0 is helping better control the maintenance of operating plant and infrastructure, minimising risk to the environment, to a company's reputation and to the people that work the equipment every day. It also acquired Senergy, a company specialised in subsurface oil and gas analysis in 2013.

LR recently moved its Aberdeen operations including the acquired Senergy business into one site at the new Kingswell Prime Four business park in Aberdeen – it previously operated across a number of different sites around the city.

DNV GL launches cyber security recommended practice

DNV GL has published a "recommended practice on cyber security" for the oil and gas industry, looking at "operational technology" – such as control and automation systems

The recommended practice addresses how oil and gas companies, together with system integrators and vendors, can manage the cyber threat.

The recommended practice is the result of a two-year joint industry project, involving Shell Norge AS, Statoil, Woodside, Lundin Norway, Siemens, Honeywell, ABB, Emerson and Kongsberg Maritime, with contributions from the Norwegian Petroleum Safety Authority from a regulatory perspective.

It is based on IEC (International Electrotechnical Commission) 62443 cybersecurity standards for industrial automation and control systems. It also takes into account HSE requirements and the IEC 61511 functional safety standard.

The benefits of implementing the standard should be a reduced risk of cyber security incidents, cost savings for operators by reducing resources needed to define requirements and follow up, cost savings for vendors and contractors because they can have standardised design requirements from operators, and audits for authorities and internal auditors can be simpler due to common requirements, DNV GL says.

Also, by following the recommended practice, companies should not need to spend so much time developing their own internal standards.

"Aligning our Operational Technology cyber security approach to IEC 62443 enables us to learn from and contribute to industry knowledge and capability," says Julie Fallon, Senior Vice President Engineering, Woodside, in a press release quote. "The recommended practice provides practical guidance on applying the standard to oil and gas."

Examples of hacking into industrial control systems include the Stuxnet computer worm, thought to be developed by the American and Israeli governments, which forced Iranian centrifuges to speed up and damaged its nuclear program, and stories of pipeline systems being hacked, via a CCTV system.

There have been reports of hacking into vessel dynamic position systems (including hacking the GPS signal). Also control systems can sometimes be updated from shore, so that is another pathway.

The document is 58 pages long, and online at dnvgl.com/cybersecurity-rp

Operational technology

The document focuses on operational technology (OT), such as control and automation systems, which are used in oil and gas production sites.

The cybersecurity focus has traditionally been on information technology, such as office IT infrastructure. But there is an increasing trend for networks on production sites to be connected to wider corporate networks, so they can be monitored and controlled remotely. But this increases vulnerability, DNV GL says.

Managing operational technology threats requires both oil and gas operational domain competence, as well as general information security competence.

Of course, the level of the threat depends on how much communications is going on. Cybersecurity can be simplest when companies are just taking data from production systems into corporate systems, because the data is just moving in one direction.

If companies are using remote or centralised control rooms, then cybersecurity is harder, because these control rooms must be able to alter critical offshore systems. It gets harder still if you have vendors being able to access and perhaps control their equipment on the plant, going via the corporate systems.

It includes advice about how to authenticate users. It covers system architecture, risk assessment, worse case scenarios.

It includes what you should do during different stages of development, such as FEED (front end engineering and design), production and operation. And what people in different roles should do.

It shows how the network should be set up, and who should do what at different stages of a greenfield project. It also has safety advice such as not to use USB sticks.

It can be used throughout the lifecycle of a project, providing advice on the different threats. The standard also advises how cybersecurity should be handled when you have many different companies involved in design or operating a piece of equipment, or many different company departments involved, with hand-offs between different project teams.

The document explains in detail how to set up a so-called "demilitarised zone" or 'perimeter network' is a midway zone between the internal networks and something else (usually the internet), as a small isolated network. From the outside, you can only connect with what you can see in the DMZ, and from the inside, you can control what you do and don't put into the DMZ. This is particularly important when you might want to allow companies from outside the corporate network to access control systems, for example to monitor equipment they have manufactured or update control system software.

Putting into practice

The right approach could be described as "defence in depth", where you have a number of different barriers and checks to stop problems, but are still able to continue with your business, says Graham Bennett, VP and business development manager for oil and gas in the UK.

You can have a 'risk based approach', where you assess the risk of a certain business relationship, and adjust levels of control accordingly.

So perhaps the most important step companies can make is to make sure the relevant people are aware of the changing risk environment.

The document is more of a "recommended practice" than a standard, showing how to run oil and gas automation systems so they can't be hacked into easily.

It is intended to be a live document, not a one-off, perhaps updated every 6 months.

It is important to test safety systems have not been corrupted. Some hackers have realised that if they corrupt a safety system, which are used very infrequently, it might take a while before anybody knows. For example, if you put a flaw in an anti-lock breaking system (ABS), it will only be apparent when there is an attempt to activate it.

Viewport3 Ltd – from subsea images to 3d models

Viewport3 of Aberdeen creates 3D models from static photographs – these can be used, for example, to make accurate 'point-cloud' 3D models of subsea infrastructure using images or video

Viewport of Aberdeen uses imaging and software technology to create 3D digital models of objects from flat image files. It is used, for example to use data from subsea or topside projects, to make 3D digital models of infrastructure which allow reverse engineering and analysis to be completed.

To understand how the technology works, imagine a number of photographs taken of an object from different angles. Images are then manipulated by the software to make a 3D model of the item.

In the oil and gas industry, the flat images might be taken as frames from a video feed. The video or images could be taken from a camera on a helicopter, drone, or subsea vehicle. The process usually negates the need to ship additional hardware offshore or integrate new hardware to a subsea vehicle.

At least 3 images must be taken from different angles to make a 3D model, but more images make the model more dense and accurate. A video feed with the camera panning 360 degrees around the object is a great starting point, but the company recommend relevant personnel are trained by the company's lead imaging personnel, in order to maximise the end result.

The virtual replications can be processed in a few hours in some cases, after the images have been transmitted back to base. The photographs don't need any special equipment to take, so if the object is easily accessible, the photographs can be taken by the existing offshore staff, using the best imaging equipment available to them.

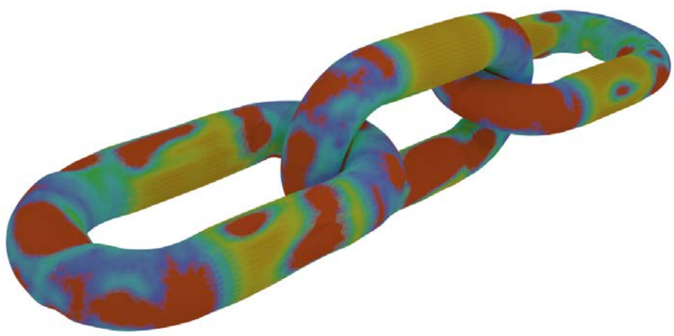
This means that the process can react much faster than laser scanning when such laser hardware is not already available on site.

Mr Harvey worked on the idea for the business after working as a subsea inspection engineer with Subsea7, seeing workers struggling to understand the equipment they were working with, which led to problems with intervention work.

The software solution he developed brings together a number of different image manipulation products. Work is currently going on to bring more automation to the image processing.

Using it

So far the technology has been used in a range of different applications, both subsea and topsides.



An image of a mooring chain taken with static photos, converted to 3D, and colour mapped to make it easier to see the condition of the metal

In the subsea world, operators have to plan complex subsea intervention work on underwater structures and assets, using divers or ROVs. Sometimes the project personnel don't have a clear understanding of what the structure actually looks like. With the ability view the hardware as a 3D model, personnel can get a much better understanding of the subsea geometry in question.

The 3D models can also be used as an input for 3D printers, for simple viewing of the subsea equipment. This can be easier to engage with and understand than viewing the model virtually.

These models make collaboration more effective, particularly when non-project personnel need to be brought up to speed.

The virtual model can also be used as a basis for reverse-engineering tasks. The models can be compared to previous scans or CAD data and a deviation map or report can then be issued. This can provide information on how an object is moving, changing shape or even corroding over time. Reverse engineering also allows CAD versions of the geometry to be provided, in a format the customer can import directly into their preferred systems.

The models can also be used as a basis for making measurement and alignment checks on the object or objects.

Outside the oil and gas industry, Viewport has used its technology for special effects for movies, online animations, and surveys of buildings, archaeological and heritage sites.

Viewport3 provides imaging training courses to help customers take better images and hence improve the detail of the final output.

"We've gone from something that looks 'nice and pretty' to something very technical which is very easy to use and incredibly deployable," he said.

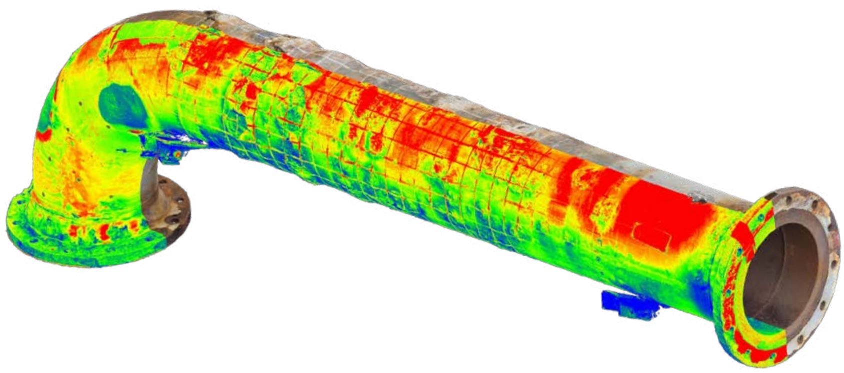
About Viewport

Mr Harvey spent 7 years working in subsea inspection at Subsea7, after graduating in mechanical design and offshore and ocean technology.

The company was founded in February 2017 together with partner Richard Drennan, also from an oil and gas background.

The company is now looking to engage with industry and determine the best value uses for this technology, which is becoming more widely-used by operators the world over.

The company was recently awarded incubator membership of Subsea UK.



A 3D model created from photos and videos