digital energy journal

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"Factory" drilling in the Permian

Why software automation is different to mechanical automation

Covering the gap between the tech and the engineering / sensor world

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3D visualisation in subsea

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United House, North Road,
London, N7 9DP, UK
www.d-e-j.com
Tel +44 (0)208 150 5292

Editor
Karl Jeffery
jeffery@d-e-j.com
Tel +44 208 150 5292

Advertising and sponsorship sales
Richard McIntyre
mcintyre@d-e-j.com
Tel +44 (0) 208 150 5296

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Cover image: A 3D model of a subsea "dry mate" electrical connector developed from underwater video cameras and imagery by UK company Rovco. Rovco imagines a future where video images from underwater vehicles could be converted into 3D models in real time, leading to big improvements in how the ROV operations could be carried out. For more information see page 19

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How would Google run an oil and gas company?

"How would Google run an oil an oil and gas company" is a question many conference speakers and article writers have tried to answer over the years. We got some hints to the answer from a speech by Greg DeMichillie, director of product management with Google Cloud, talking at the Oslo "Subsea Valley" conference in March 2018.

We would see a lot more machine learning, or attempts to make it work. Mr DeMichillie believes that the current attention on machine learning is justified, not hype. The maths for machine learning has been around since the 1970s, but has never been possible to put into action until now, because the computing power has not been available. Machine learning is letting us solve many problems for the first time.

However "Google Oil and Gas" would probably soon realise that oil and gas data is just not good enough, or available enough, to run many machine learning algorithms. "If you have a corporate culture where data is not shared, that's a cultural barrier to machine learning no software system can solve," he said. He advised that companies should "think about your culture of openness".

Cognite

Mr DeMichillie mentioned Oslo oil and gas technology company Cognite in his talk, telling the audience how Cognite uses Google's "TensorFlow" machine learning framework to build tools for predictive maintenance and for predicting corrosion for oil and gas operator AkerBP.

Cognite is building an integrated data platform for Aker BP's data. The CEO of AkerBP, Karl Johnny Hersvik, spoke at a conference a few weeks previously, the "Moment – the Future of Work" oil and gas conference in Oslo on Mar 15 2018, wearing a T-shirt with "Data liberation front" written on it. The Google Data Liberation Front is an engineering team at Google whose "goal is to make it easier for users to move their data in and out of Google products."

Google has a link to Cognite in that Geir Engdahl, Cognite's CTO, is a former senior software engineer with Google in Canada.

Cognite is owned 72 per cent by engineering and construction company Aker ASA (NOK 44m / USD 5.7m) and 10 per cent by oil and gas operator AkerBP.

Machine learning

Machine learning is getting better and better at working with small amounts of data, he said. "I used to say you need big data [for machine learning], that's less and less true."

For machine learning to work, the training data needs to reflect what happens in the real world. For example, if the data is based on a sample of people which is 80 per cent male, then "it won't reflect the world at large," he said.

The data would also need to include all the things which happen in the real world. A computer cannot use machine learning to predict something it has never seen, in the same way that a human could not predict what a dog looks like without having seen one before.

Machine learning in Google

Google uses machine learning to suggest what replies people should send to Gmail messages, and today "smart reply" is used for 1 in 8 replies sent via smart device, he said. The company has used machine learning to make big improvements to Google Translate, which can be proven by translating a complex literary phrase from English to Japanese and back. Google has used machine learning to control the cooling systems in its data centres, and achieved an astonishing 40 per cent reduction in electricity required.

Google developed an open source machine learning framework called Tensorflow, which any researcher can use, and it developed custom microchips to run on it, which can run AI algorithms 15 to 30 times faster than conventional chips, with 30 to 80 times more compute operations per watt. Google also provides tools for building and training models.

Tensorflow is used by Airbus to analyse satellite imagery, such as identifying whether white clouds in a photo are clouds or snow.

Another application was a company which used machine learning to try to identify ships which were illegally fishing, by understanding tracking patterns in their satellite positioning data, which all ships must transmit. As a result, one small island was able to levy a fine on a shipping company which amounted to a sizeable proportion of its annual state income.

Fractured basement - Hurricane's experiences in the Lancaster field - working with data

Hurricane Energy has drilled 2 horizontal wells in the Lancaster fractured basement field, West of the Shetland Islands, North of Scotland, and expects them to produce a total of 20,000 bopd based on well test results. CEO Robert Trice explained how the company works with data

Hurricane Energy, an oil and gas company based in Surrey, UK, has drilled 2 horizontal wells in the Lancaster fractured basement field, West of Shetland Islands, North of Scotland. It has drilled a total of five wells on the Lancaster field. Based on well test results, it expects the two horizontal wells to produce 20,000 bopd in total, when the field comes into production in early 2019.

Fractured reservoirs have not been given much attention in the UK until now – partly because of the abundant sandstone reservoir horizons, but also because until the mid-1990s there was insufficient technology to confidently exploit fractured basement reservoirs.

Robert Trice, CEO Hurricane Energy, explained the company's work at the Finding Petroleum London forum on Jan 23 2018, "Understanding Fractured Reservoirs".

Geological background

Basement rock is defined as rock which is not from any kind of sediment, i.e. which formed from when the earth was a burning ball of magma and cooled down, 2.5 billion years ago. The initial joints (cracks) in the rock appeared from the initial cooling.

Then the basement below Lancaster was repeatedly buried under more layers of rock, and uplifted, over a long period of geological time. During this period of geological time the basement rock and the associated fractures were subject to periods of flushing by hot and cold water which would have deposited and removed minerals.

Planning the second well

The focus of the talk was on how Hurricane aimed to get a better understanding of the fractures and faults, before drilling its second horizontal well, "7z".

The 7z well was planned to be drilled to the north of the first "6" horizontal well, aiming to penetrate a series of "seismic scale" faults (large enough to show on seismic). It was expected to drill through reservoirs of average porosities of 3.6 to 4.4 per cent. It was expected to repeat the success of the first horizontal well, with flow

Robert Trice, CEO of Hurricane Energy

rates of around 9,800 and similar API of oil. It did turn out to be a good well, as explained later.

But in order to put the drilling plan together, "we had to be confident we felt we understood what was making the reservoir work," Dr Trice said. In other words, the company needed a working reservoir model.

Pressures and drilling

Understanding the subsurface fluid pressures is very important. For drilling, it is important for safety and managing drilling muds, ensuring the drilling mud pushing into the reservoir has a higher pressure than oil pushing out into the well. The fluid pressure also controls how liquids will flow into the well. Fractured reservoirs can show a variety of aerial pressure regimes if associated with pressure sealing faults

The first vertical well was drilled on the assumption that the pressure increase to the subsurface would be hydrostatic, i.e. the same increase in pressure as you would see with a vertical column of fluid, caused by gravity force of the fluids above. This assumption was based on data from other wells in the region, and the geological model.

For the first well, the company was concerned about the drilling mud being lost into the fractures, so it used a 'shear splitting' mud called DRILPLEX, which is designed to block up fractures. The disadvantage of this mud is that by blocking up the fractures, it makes it hard to do well tests or logs.

The results of well logs showed no signs of overpressure in either the basement or overlying clastic rock. "That gave us real confidence in the mud weight and the pressure gradient," he said.

Using this understanding, the second vertical basement well "4Z" was drilled using an experimental tool which made it possible to drill 'balanced' rather than 'overbalanced' (i.e. with the weight of the mud exerting a greater force pushing reservoir fluids back into the reservoir, than reservoir forces pushing on the well to get out).

The drilling was done with a mud with no particulates in it. This has the benefit (from a logging point of view) that it does not build up a 'mud cake' along the well wall. It is basically salty water (a brine). Brine proves "fantastic for data acquisition" but can make it tricky getting tools to the bottom of the hole due to the brines poor lifting capacity resulting in drilling cuttings collecting at the bottom of the borehole

For subsequent drilling, Hurricane anticipates that there will be a normal hydrostatic pressure regime in the reservoir, but no extra "oomph" from overpressure carrying fluids into the well, he said.

Stress models

Understanding the stresses and stress direction was considered important in understanding the fractures. Before drilling, there was a theory that fractures aligned with the stress direction are going to produce more oil.

However studies made after drilling did not support that idea. "Fractures of a variety of orientations flow," he said. "Some of these large aperture fractures which flow have a different orientation."

The indications are that the maximum horizontal stress in the reservoir is NE SW orientated, based on borehole breakout data (analysing the direction where the borehole is breaking into smaller pieces horizontally during drilling).

Schlumberger was contracted to develop a number of stress models, making a map of joints (gaps in the rock layers) which it could see on imaging logs (digital images taken down hole), and showing how they were orientated.

It concluded that again the maximum horizontal stress is NE SW direction.

Dr Trice explained that Hurricane has no definitive stress model for the reservoir but has a working model which it is currently challenging with recently acquired data.

Modelling fractures, faults and joints

The fractures, faults and joints in Lancaster occur at a number of scales. There are micro fractures, defined as having a trace length less than the diameter of the bore hole, and joints classified from borehole imaging as fractures with a trace length at least as long as the borehole diameter.. Then there is large "seismic scale" faulting, discernible from seismic. Between the two there are characteristics of the fracture system which can be discerned from dynamic well testing, Dr Trice said.

Large scale faults are an important target for exploration appraisal and development. The company wanted to be confident in its fault maps.

The first well was based on a very low density fault map. But this map became richer as work progressed. "I asked my geophysicist to create a map which 10 geophysicists would agree with. In other words, every fault on there really had to be there. We could potentially drill a well through it."

"As we added more data and integrated it, the fault pattern became more confident," he said.

Data gathered during the drilling, and in subsequent well logs, was also used to further develop the fault map.

Both the seismic and the horizontal well logging indicated that the faults are predominantly subvertical (close to vertical).

A map was also made of the joints within the reservoir. The joint classification can be made in a number of ways, such as the orientation (going NE SW), cross joints, orientation at high and low angle, and large aperture joints (over 2cm). A greater than 2cm aperture is the size associated with turbulent flow, and also Karst type reservoirs.

The study showed that there was not any increase in the number of joints when close to faults, or within "fault zones", as some studies of fractured reservoirs elsewhere show.

The bulk porosity (void fraction) is about 4 per cent. Bulk porosity is interpreted as being related to fractures and includes fractures enhanced by dissolving (dissolution) of the rock.

Log studies

Well logs were widely used to get a better understanding of the fractures, faults and joints. It helped that the company's CEO, Robert Trice, had a background as a petrophysicist, so had a great deal of experience working with well logs to 'constrain' or understand the limits of what might be happening.

The most important data proved to be the PLT (production logging tool), which can provide information about the formation fluids.

The data can be integrated with high resolution gas chromatography (analysing gas samples for their content). It gives further information about the permeability and fluid types.

The company also took sidewall cores (rock samples taken from the side of the well bore) while drilling. Before taking the cores, it used digital imagery (known as 'digital image logs') to identify a good place in the sidewall to take the core, and make sure it was not trying to take a core from within a joint.

The position and depth of a given sidewall core is established by running an UBI (ultrasonic borehole imager). Petrophysical analysis is undertaken on the laboratory on the SWC's.

With well logs it as possible to confirm the presence of fairly large aperture fractures, for example one with 40cm diameter, flowing oil. "These things are quite common in the basement and indicates there's something helping the fracture system other than mechanical failure," he said.

Another useful piece of evidence about fracture size was from rock samples which came to the surface stuck to the drillbit. Dr Trice showed one photograph of a rock sample, which looked like a cobble from a beach, worn down by water. It had been choked in a fracture, and indicates that the fracture aperture must have been wide e enough to hold it.

Micro fractures can be clearly seen on the image logs, and by analysing them when "captured" by SWC's it is possible to understand the diagenetic processes (how the rock was formed) through thin section analysis

The NMR (nuclear magnetic resonance) log can be used to get porosity data.

Putting into a model

All of the fracture, fault and joint data was put together in a model, which could then be used in a reservoir simulator, to see how fluids might flow, and then used to plan the drilling path.

Consultancy Golder and Associates was brought in to put together a discrete fracture network (DFN) model.

The model was run in a flow simulator, which showed that the "regional joints and faults are the main contributors to the flow from the fracture system," he said.

Drilling 7z well

The 7z horizontal well was drilled based on this fracture network model and the interpreted seismic,

Based on the model and simulation, the well was expecting to encounter 11 fault zones, and produce at a similar rate to the 6 well, perhaps higher rates.

As the well was drilled horizontally through the faults, the path dropped, finishing up 70m below the start point vertically.

The average fault zone width for this well was 49m, just above the 40m average for the field. Porosities for the reservoir was 3.8 per cent, slightly lower than the field average of 4 per cent. The regional joints ran NE SW, supporting the reservoir model.

"From the drilling data, it looks like we've got a nice reservoir," he said.

Ultimately the well flowed at 15,000 bopd in the well test, with flows limited by surface equipment, and with a high productivity index (a measure of how easily fluids flow into the well).

"So, a very favourable well. The well was suspended as a future producer," he said.

Future development

Hurricane now plans to tie the 2 horizontal wells to an FPSO (a floating production storage and offloading vessel). It aims to keep production levels from both wells at 20,000 bopd, to avoid reservoir damage. Over the first 6 years it expects to produce 37m barrels.

It plans to do interference tests on the wells to try to better understand the dynamic properties of the reservoir.

After that, it will be able to plan a second phase of field development, with more wells, and wells further away.

Kimmeridge - how Permian basin development has evolved

Development in the West Texas Permian basin is arguably going into a third phase of 'factory' type development, with much closer well spacing targeting multiple 'horizons' within the same square mile, said Neil McMahon of Kimmeridge Energy

The Permian Basin of West Texas is arguably now in a very different stage of development to the early days of fracking, with the drilling intensity going to a much higher level, looking more like manufacturing than it did before, said Neil McMahon, managing partner with Kimmeridge Energy.

He was speaking at the Finding Petroleum forum in London on Feb 21st, "Opportunities in Mature Provinces and Super Basins".

Geologists often think they are working in an 'old' industry, where everybody knows everything there is to know. But the way companies are working today does not fit with the old knowledge, he said. "The science is embryonic, our understanding of how oil is generated is embryonic, and how oil migrates is embryonic."

"All my training, all my work, from the early 1990s at BP, I've frankly thrown out the window because it is not that relevant any more to modern understanding of petroleum systems, how oil is generated and how oil is migrated," he said.

Understanding petroleum systems is important because the most important factor in governing whether there will be oil in a reservoir is whether the source rocks were in the right temperature 'window' over geological time, so they would turn into gas or oil.

History

The first phase of development of the basin, starting in the 1920s, could be called the "main conventional phase." It was initially focussed on the Central Basin Platform, the Delaware basin to the West, Midland basin to the East, and the Eastern Shelf.

This was followed by a period just before 2000, when a lot of vertical fracking started to take place, looking at lower quality reservoirs around the big oil fields.

After 2000, horizontal drilling was first tried through the Bakken and Barnett shales. Companies started targeting reservoirs around or below the main fields, which had a lower porosity and permeability.

Increasing intensity

We are now arguably entering a second phase of unconventional development, focussed on the Delaware Basin, Mr McMahon said. Companies are placing wells much more closely together than they have ever done before.

The Delaware basin currently has 16 per cent of all of the horizontal rigs in the US, and so probably 16 per cent of current drilling activity. "That's going to go up and up," he said.

The best parts of the Delaware basin can work with $30 oil prices, with the most stacked pay and best overall economics.

There was a massive ramp of in activity in 2017, with companies going in full "development" mode, after doing all the de-risking of the reservoirs earlier.

To illustrate the pace of development Kimmeridge has used satellite imagery to compare a picture from January 2007 to January 2018 in the Delaware basin, which shows how many more wells, roads and pipelines there are.

US drilling permits often require companies to drill a new well at least every 120 days or risk losing some of their lease, which also adds to the pressure to keep drilling.

Delaware has multiple different formations, which makes it different to formations such as the Eagleford shale play, which is largely a "one formation unconventional play" and now "getting towards mature mode".

Many parts of the Permian have many levels, described as Wolfcamp A upper and lower, Wolfcamp B upper and lower, Wolfcamp C and D. If there are going to be multiple wells into each of those, within the same lease block, this illustrates how drilling activity is going to increase exponentially, he said.

As an example, Energen Resources Corporation is currently targeting many different levels in the "Wolfcamp" reservoirs of the Delaware basin, with laterals all at different levels. The company is planning 16 wells just to go into the "Wolfcamp A" horizon on their lease.

Neil McMahon, managing partner with Kimmeridge Energy

Similarly, Resolute Energy is planning 36 to 48 wells per square mile in its lease in Reeves County, to be drilled over the next 10 years.

"It shows you how the industry is taking these mature old basins and moving them forward," he said.

Tracking source rock

Kimmeridge is making a lot of effort to track which source rock the oil in the reservoirs is coming from, using geochemical methods. "We're coming to the era of the geochemist," he said.

The studies show that about half of the oil is moving vertically (upwards) rather than laterally within the reservoirs, coming from older and deeper source rock systems, going through microfractures rather than through faults.

For example, because the Central Basin Platform is sitting on a high, there is very little Permian age strata which has been in the temperature window where it would generate oil, he said. So the oil can only have come from an older source rock.

This is something "the industry hasn't caught up with yet," he said. "It is a different way of thinking about migration to the standard North Sea approach."

Maana launches "Maana Q" to make it easier to build graphs

Knowledge technology company Maana is making it easier for companies to build the 'graphs' which the computer system uses to compile data together, with the launch of "Maana Q"

US digital knowledge technology company Maana has launched "Maana Q", a system which makes it easier to build the 'graphs' which are used to map and understand company data.

The graph is the 'map' which is built to help the system understand how a company's data fits together – and so gather together data from multiple documents and databases to support decision making.

Because every company has different data, the graph needs to be built by every company.

Maana's customers include Fortune 500 companies such as Airbus, Chevron, GE, Maersk, and Shell. Its "strategic" investors include Frost Data Capital, GE Ventures, Intel Capital, Chevron Technology Ventures, Saudi Aramco Energy Ventures, Shell Technology Ventures, Accenture Ventures, CICC, Eight Square Capital, and Sino Capital.

Explaining the graph

Maana describes the graph as a "digital knowledge layer over the operational data."

To explain it, consider the way that search engines can find a bundle of related data about something you search for. For example, if you search for a movie star, Google will return photographs, data from the Wikipedia page, quotes, movies, social media profiles, and related people. Google does this because it has a programmed 'graph' about information someone looking for might want to find, and where to find it on the internet.

For a business example, consider the different questions a company might want answered about one of its vessels (ships).

If it wants to know the length of the vessel, it can be simply looked up from a database. If someone wants to know the weight of the vessel, that depends on the cargo, so it needs to find the unladen weight and the weight of the cargo and add them together.

If someone wants the current position, that needs to be taken from a live web service which receives vessel tracking data.

If someone wants to estimate a vessels' arrival time, that becomes a much more complex calculation, involving understanding the vessel's fuel consumption strategy, sea zone restrictions, sea routes (since vessels do not always go in straight lines), routes around peninsulas.

The idea is that the company would have a "computational graph", which tracks the different elements of data needed to answer this question, where they are in the corporate systems, and how they should be retrieved and put together.

In this case, Maana calls it a "computational knowledge graph", because it is able to perform computations from different pieces of data.

Another example is how the graph could be used to help drillers better understand a problem. For example, help them understand the problems being encountered at 12,000 feet depth. The graph could be used to extract and store the problems (and depths) mentioned in the drillers comments in the daily drilling reports. These problems could be correlated to geological features depths such as sub-surface salt domes.

The graph could also be used to help put together data about the multiple of different activities being done at the same time in a complex organisation.

For example, an aircraft manufacturer has multiple staff working with different spare parts, and each spare part has data about incidents, mechanical history, design specifications, certifications and more. The graph is a way for the computer to put all the information together so it can be used as a whole.

Another analogy to the graph is a bubble chart, which people sometimes draw, to show how a system fits together, with different components, perhaps tasks, people, and equipment.

The graph software is built using GraphQL, a data query language developed originally by Facebook, which can be used to query multiple different types of databases to get exactly the data the graph wants, in whatever form the graph wants, in one go, thus saving a lot of to and fro.

Build your own graph

The critical component of Maana software turns out not to necessarily be the graph itself, but the capability to build a graph, and how much expertise is needed, and this is what Maana has been focussing on, with the launch of "Maana Q".

Bluntly, it enables people who are less adept with digital technology to build their own graphs.

The idea is that building a graph should be 'self-service'. Subject matter experts and business analysts can build their own tools which they can use to support their decision making, based on all kinds of data in the archive.

This means that the people who will ultimately use the results of the graph are also the people building it, so they can make sure they build exactly what they want.

The ultimate aim is that people have the best possible information from the corporate data systems available to them at the right time, leading to better decision making, says Donald Thompson, CTO of Maana.

Customers often say they are craving the capability to build graphs, but lack the resources in their companies to build sophisticated solutions.

"We're on a continuous mission to lower that barrier of entry," Mr Thompson says.

With Maana Q, "The core ideas haven't changed, how we are delivering them has drastically changed," Mr Thompson says.

Maana has made the improvements from watching how people work with the software, and how the projects work.

With more people able to work on the graph, there is more likelihood that the graphs will be 'kept alive' and relevant to the needs of the technical experts. There is also less likelihood that a graph will end up siloed, only serving the needs of one department but inaccessible to other departments, Maana says.

The new version has been designed to be easier to deploy on the corporate IT networks, with all of the software tools placed in 'containers'.

There is no need to have a more technical person to assemble the bits and pieces, there are components pre-assembled.

Bots

Maana has also been improving the "bots", software agents which continuously run through new data and try to understand it.

For example, if someone takes a photograph for an insurance purpose which is saved on the corporate network, a bot will immediately try to work out what kind of image it is - a photograph, scanned document or diagram. If it is classified as a photograph, a second bot looks at the photo to see if there is something useful in it. For example it might be a photo of equipment, and the computer can analyse the image and look for defects.

There are domain specific bots to try to understand the facts of a specific problem. For example if a driller's comment is about stuck pipe, the bot might try to identify what caused the stuck pipe (Hole Pack-Off, Differential Sticking, Wellbore Geometry) based on other text and data in the graph.

The image processing bot could be used for drillbit grading, automatically analysing a photo of a drillbit to generate a IADC Dull grade score for its quality. You could set up other bots to start whenever a drillbit with a certain grade is discovered, such as a suitability score of the bit to be re-run in hole based on how much hole is left to drill.

Bots can also be used to classify new documents, for example, given a well document is it a mud report, directional drilling report, incident report, or a wellbore schematic?

General use graphs

Maana is also developing general use graphs, which can be used by all of its customers.

It has built a "whole geological domain model," covering geological formations, locations, chemicals. Some companies have built their own statistical models on top of it, proprietary to them, to analyse their own exploration data.

It has also worked with PPDM, an industry standard data model, putting the PPDM model into a 'graph' environment, says Jeff Dalgliesh, director of oilfield digital transformation with Maana.

By doing this, a graph model can turn text based information into structured data – for example a description of problems encountered during drilling, which are only included within a PPDM model as a text based comment, in the Drilling Remarks table. Maana extracts these problems and stores then in the graph as problems that are related to the well.

The Maana software can be programmed to recognise different types of problems and understand their causes. For example, it could spot different geological conditions which tend to lead to stuck pipe, or different weather conditions which tend to be more likely to lead to delays.

Using sensor data to support decision making

UK start-up company Dashboard Ltd aims to help oil and gas companies better use sensor data to support their decision making, filling a gap, as it sees it, between the competencies of automation companies and the technology providers companies

Dashboard Ltd (www.dashboard.net), a UK start-up company headquartered in Exeter, is helping companies make more use of sensor data to support decision making, filling a gap, as it sees it, between the competencies of automation companies and software companies.

Piers Corfield, Co-founder of Dashboard Ltd.

Co-founder Piers Corfield says that most of the companies which make oil and gas sensors are automation companies, with a background in engineering and control, but are not necessarily specialists in data analysis. They have many electrical engineers in their staff, and many legacy products which they are loathe to "cannibalise" to allow a new range of data centric products. Some of the products go back to the days of analogue electrical engineering, so do not lend themselves to the consolidation of digital information for analysis.

To illustrate this, consider how dated many of the user interfaces on automation control systems remain, he says. For example, many of the legacy SCADA control system interfaces are "worryingly counter intuitive, to which he compares many as resembling Windows 3.1."

As a result, oil and gas companies typically use SCADA data to monitor and control their processes, but only a fraction of the data is analised for business intelligence in order to optimise performance, he says.

However the companies which do have expertise with data, the software and consultancy companies, have less background in engineering, so are less equipped to be able to help oil and gas people work with it, he says.

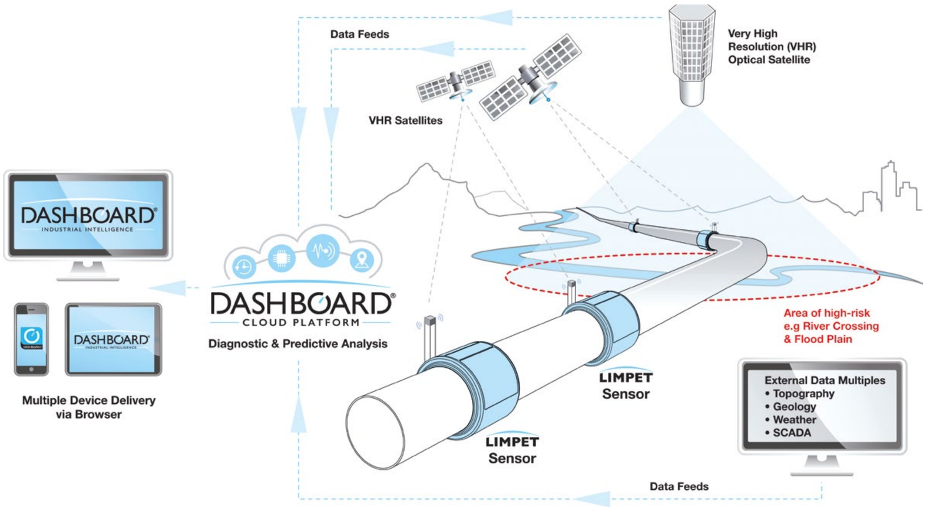
There is a gap to be filled in the middle, using sensor expertise, tech / software expertise and domain expertise, to build useful tools which can help oil and gas people with decision making.

Dashboard makes a range of products involving sensor data and software, including dashboards, advanced visualisation, analytics, digital twins (making a digital model using sensor data) and mixed reality. The company sees itself as an oil and gas "internet of things" specialist.

A by-product of the work is that a company's sensor data is more shared and more exposed, creating a holistic view of what is happening across the company, rather than keeping data in silos. This can sometimes show up areas of the business which are less well instrumented, Mr Corfield says.

The company has a mission statement of "helping people make better decisions faster", developing products around the idea that "technology is there to empowered humans, do the drudgery, repetitive stuff, free up a human to do something more interesting – usually process improvement," Mr Corfield says.

If the outputs from analytics "can't be put into the head of a human," or the human decision maker does not act on it, all the efforts are totally wasted, he says.



Dashboard's pipeline telemetry system

About Dashboard

Dashboard was founded in January 2015, and looks at the oil and gas, utilities, mining and infrastructure sectors. Co-founder Piers Corfield has been a founding director in three previous start-ups, covering wireless communications, electronic document management and mobile communications. Pete Stirling, co-founder, has a background in advanced engineering, having worked in a number of industry sectors including aviation and defence.

The company's technical authority for pipelines, Alastair Maclachlan, is former senior pipelines consultant with BP.

The company has 14 investors from the oil and gas industry, including from Shell, Schlumberger and BP. It has a Shell and Schlumberger representative on its board of directors.

Pipeline telemetry

One of its first products is a pipeline telemetry system, which uses sensor data and machine learning to create a computer model of flows through a pipeline, so operators have an in-depth idea about what is happening between the flowmeters. It can use this understanding to spot if the fluids a flowing in a different way to expected, which may give early warning of a leak or damage to the pipeline.

The company's business model is centred around an OpEx utility computing approach, where pipeline operators pay per km per month inclusive of the hardware, whilst the company seeks to work with customers to identify which sensors should be integrated and what systems should be built.

This system is being adapted to run on subsea pipelines as a virtual multiphase flowmeter, giving companies better insight into how fluids are flowing through their pipelines.
It could also be used to spot underground leaks.

Dashboard is also looking at methane leak detection technology, working together with a laser scanning (LIDAR) based technology under development at Bristol University, UK. It may be possible to fit the device on a drone. This would create new ways for oil companies to understand methane emissions across entire facilities, a subject fast becoming a critical one for the industry.

When automation isn't mechanical

Automation isn't necessarily about replacing people's jobs with machines. It can also be about automating processes with software to put the right information in front of the right people to help them do their jobs better. We interviewed Peter Zornio, CTO of Emerson Automation Solutions, to find out how it works in industry today

When most people think of 'automation' they think of automating machines, to do mechanical jobs, like robots.

But to Peter Zornio, CTO of Emerson Automation Solutions, perhaps the more interesting applications of automation today are where software automation helps people to do a better job.

One of the best examples of this, one we are all familiar with, is Google Maps' capability to suggest routes to us, and make use of all kind of dynamic information to do this, such as changing traffic congestion or public transport delays.

Mr Zornio says – this is not a computer telling us what to do next, but a computer guiding what we are going to do, and alerting us when something has changed so we should do what we normally do differently (such as a traffic jam 30 minutes away on our usual route). The software has all kinds of analytics and expertise happening in the background to provide us with the most useful information. The process could also be called "decision support".

Today's automation tools can also help workers acquire knowledge faster, by providing them with what they need to know, for example guiding them about upcoming problems with a piece of equipment. It can provide access to information onto mobile computers – making data freely and securely available wherever it's needed

You can differentiate the various types of automation by talking about "physical automation," where a robot does a mechanical process and "software automation", where a software tool is making your work easier or better. For example, autonomous cars are physical automation.

The oil and gas industry does have some mechanical processes which could benefit from physical "programmed" automation – drill rig operations, dynamic positioning of vessels, automated streamer positioning on seismic vessels, programming a drone inspection along a pre-planned path, or a system to inject chemicals when certain decisions are made. These are important, but only a small part of the overall industry. Working in the oil and gas industry, whether in exploration or production, is far more about making decisions based on relevant, real-time information. So many tasks come down to someone making the right decision, for example with anything associated with reliability and maintenance.

Mr Zornio manages Emerson's automation technology strategy and standards.

Synthesis

Computers have many strengths compared to people, but the one strength people have compared to computers is 'synthesis', the ability to put together many different pieces of information and working out a pathway forward, Mr Zornio says. Computers cannot do this as well, but are improving.

Google Maps understands its limitations putting information together, which is why it often suggests a number of different routes you might like to take. There could be other information which even Google doesn't have, for example that you prefer buses to trains or like quiet roads. Or you might know that a rail replacement bus is often unreliable and don't want to take Google's first suggestion.

Similarly, a good system for an equipment repair engineer might give a number of different explanations for a fault, and the engineer can use the explanations together with other knowledge she may have to decide what to do.

The more sophisticated the computer system, the more confident it can be in its suggestions.

Consider the way that doctors work, Mr Zornio says. They may have computer tools which can help interpret specific results or scans, but only a doctor can synthesise the available information and make a diagnosis, computers are nowhere close – yet.

Or consider the challenges with autonomous cars. A human driver will see two 5 year olds playing with a football by the road and know to drive more carefully. A computer will see a road and obstacles in front of the car, but not have the experience to be more aware of children. But the computer can still provide value.

Peter Zornio, CTO of Emerson Automation

Industrial experts can use computer information to know that something may be close to failure. But only a person can work out the best path forward when taken in consideration with other information. How critical is that equipment in the current situation? If there is other planned work going on next week, perhaps it would be OK to risk things for a few days and change the component while the other work is going on. The decision requires 'context', also something which computers are very bad at compared to people. Computers are far stronger when they only need to work with the information right in front of them.

Keeping equipment autonomous

An interesting trend is that companies are proving much keener on keeping decision making about autonomous machinery made within the equipment or plant itself, not over a distance.

For example, Emerson is the main automation contractor for Shell's recently launched Prelude Floating LNG vessel.

All the control systems for the LNG equipment are onboard the ship itself, so there is no dependence on satellite data connection for core operations.

Similarly for autonomous vehicles, all of the decision making for controlling the vehicle is onboard the vehicle itself.

Onboard decision making is faster, and seen to be more reliable.

There can be remote monitoring, however, for autonomous cars and for the Prelude FLNG.

"It is the exact same thing for oil and gas as you would find in autonomous cars". Today, people don't want critical functions to be dependent on an internet connection, he says. "People want the first level of control on the ground".

However, there are appropriate remote monitoring services that can offer important data for decision making. There can be remote companies studying how the algorithms work and evaluating how well they work – for example autonomous cars have companies like Google continually fine-tuning their algorithms, perhaps finding ways to improve how the machinery operates.

You could also have software in the cloud which helps people manage their work, for example storing photographs taken in an inspection to be shared. You can have remote systems for managing equipment reliability or sensor data about equipment health so you can predict potential problems and prevent unscheduled downtime.

Top quartile

Emerson has done some analysis into how oil companies compare in their operational performance. It found that the top quartile of companies tend to have both higher reliability and lower maintenance costs. Emerson found that top quartile performers spend half has much on maintenance compared with average performers and operate with an incremental 15 days of available production each year. They also spend 20 percent less on production-related expenses.

This is partly because typically about a quarter of companies are now active in using condition based maintenance, Mr Zornio says. This is tricky to do, but means that companies can get a sense of when something is going wrong, based on actual condition, before it does. So where other companies will change the oil every 8,000 hours, or whatever the manual says, a company with condition based monitoring might see that it only needs to be changed after 12,000 hours.

Confidence in the guidance

One of the biggest factors differentiating stronger and weaker companies is that for stronger companies, the staff have more confidence in the guidance that the computer offers, and so are more comfortable acting on it, and spend less time gathering their own data.

For example, many companies rely on Emerson's new suite of software solutions (from its recent acquisition of Paradigm) that provide improved modelling and better targeting for drilling, which will help them maximize recovery from reservoirs.

Mr Zornio is careful to say that the computers are providing guidance rather than rote instruction.

In the oil and gas industry there are still people who say they want to inspect equipment in person rather than trust what a computer says. Sometimes they are right. But still one of the biggest hurdles in getting a computer based monitoring system used is persuading people to accept what the computer says, he says.

Improving the performance of your equipment can be seen as trying to lose bodyweight, in that there is no big secret to it, but lots of tools that can help; provide you are willing to do the hard work to make it happen, Mr Zornio says.

FPSOs and unmanned platforms

In February 2018, Emerson announced it had completed a $90m automation project for BP's "Glen Lyon" FPSO (floating production, storage and offloading vessel) West of Shetland. Emerson serves as main automation contractor. The project is expected to ultimately produce 130,000 barrels a day.

The contract covers 5 years and includes remote monitoring and predictive maintenance technologies, as well as support.

The systems should help BP improve reliability and availability of the equipment on the FPSO, optimise production and reduce operating costs. BP will also use Emerson's simulator tool to train operators and engineers on 'real world' scenarios before doing it on the real thing.

Emerson provides similar services for Clair Ridge, another 'mega project' from BP in the North Sea. It also manages the fiscal metering systems on all of BP's North Sea assets, generating data for accounting, custody transfer and taxation purposes.

Emerson also has executed a $17m automation contract for Premier Oil's "Solan B" platform, one of the first oil platforms in the North Sea designed to be unmanned (most of the other unmanned systems are gas only). The systems for managing gas are a simpler than oil, without the complex separation processes, and so unmanned equipment is much easier.

Methane leaks

One automation topic of growing interest to oil and gas companies is how to manage methane leaks.

There is a backstory here that oil companies want to make a persuasive argument that gas is a much greener fossil fuel for electricity generation than coal – and a number of NGOs have claimed that the methane leaks are so high in the gas production process that is hardly true. Methane is a much more potent greenhouse gas than CO2 (although typically will only stay in the atmosphere for 8 years).

Gas can leak through gas-driven controllers and pumps, equipment leaks and seals, well venting, among other sources.

Straightforward gas sensors, which are fitted as standard on offshore platforms as safety equipment, can also be used to check for fugitive emissions. They will show that the gas concentration in the air is higher than it should be, or rising. Their use can be followed up with manual gas sensors which people can carry to find the leak more precisely.

Ultrasonic leak detectors can be used in relatively quiet facilities, covering around an acre (4000m2) of land. They can hear the sound of a leak.

For longer pipelines, computer modelling can, to some extent, provide an alternative to regularly spaced leak detectors. Emerson recently acquired a software company called ESI which has technology to make a computer model of the pipeline and calculate how flows should change along the pipeline, due to friction and turbulence. The flow can be measured every few km or longer if needed. If the measured flow is different to how the model predicts the flow should be, that can be taken as an indication of a leak.

Understanding flows using modelling is similar to a technique doctors use, when they want to work out if an artery is clogged without opening up the artery. They inject a dye in some part of your body, and monitor how the dye is flowing around your body, and compare that with how the dye would flow if no arteries were clogged.

Honeywell – supporting decision making in operations with better data

Staff in oil and gas operations need to make many decisions. Better data can help them make these decisions. Dan O'Brien and Bart Winters from Honeywell share some ideas on better ways to do it

By Dan O'Brien, marketing director, and Bart Winters, product manager, Honeywell Connected Plant

The oil and gas industry can significantly impact production and profitability when it has the ability to make fast, smart business decisions.

Oil and gas industry facilities must operate not only at desired capacity, but also at optimal efficiency. This requires a clear understanding of current operating conditions and performance, as well as the ability to detect undesirable process conditions and equipment issues before they occur, and then to systematically address them as part of a continuous improvement process.

Also, experience has shown that upstream operators can avoid critical asset failure, unplanned shutdowns, and improve bottom line results by implementing a connected asset performance management strategy.

Companies are able to use advanced data analytics to predict failures of critical pieces of equipment.

All of this needs data. So there needs to be systems for streamlining data collection, validation, surveillance and notification processes from field systems and engineering applications.

It also requires an integrated operations platform delivering both operational intelligence and field system and engineering application integration for improved operational performance.

What digital transformation means

For most industrial organizations, digital transformation means the following.

Access to key operating data.

Understanding operational models, KPIs, metrics, and performance characteristics to detect deviations between expected/predicted conditions and actual.

Event detection, prioritization, notification and workflow to take pro-active actions and intervene in time to minimize negative impact and eliminate surprises.

Visualization and analytics to promote awareness, increase insights, and accelerate decision-making.

Today's business challenges

Important questions for today's operating companies include:

How does your business currently measure productivity?

How do you make operational and asset decisions?

What types of decision-support tools do you use?

How are process and equipment data used to make informed decisions?

How quickly is real-time asset information available?

How do you track results based on asset performance monitoring?

Operational objectives

Oil and gas producers have a critical need to ensure essential safety procedures perform as designed, alarms are well managed and enforced, well performance is instantly available, and collaboration through remote operations is a reality.

The goal is to improve production and, at the same time, reduce the need for onsite personnel, which is particularly important when moving into higher-risk environments.

Specific operational objectives for upstream firms include the following:

Deploy online, continuous monitoring and exception-based alerts for process performance, equipment, and controls.

Capitalize on increased data availability across the enterprise.

Put data into context so as to compare assets to determine similar conditions or behaviour.

Bart Winters, product manager, Honeywell

Implement tools for process and reliability engineers, enabling visual data exploration to decrease reliance on complex machine learning algorithms to solve problems.

Establish collaboration with both internal and external subject matter experts (SMEs).

Critical factors for results

Every upstream organisation has identified critical factors for optimizing its business results. They can include:

Production certainty – upstream firms seek to eliminate surprises in their production planning. They are focused on achieving more efficient and effective asset operations while reducing safety risks, increasing uptime, and making best use of resources. Well performance monitoring and data acquisition are essential for reducing production downtime and improving safety via faster identification of integrity issues.

Asset reliability – due to the criticality of upstream assets, it is important to identify potential failures and service requirements as early as possible. With the availability of real-time information regarding the health of production equipment, companies can shift away from older maintenance techniques toward condition-based and predictive maintenance methods.

Agile remote operations – managing a large amount of geographically distributed assets is a vital task for energy producers. Operators must be able to turn wells on and off as determined by production demand, however, there is concern about deploying humans to areas that are less than hospitable. At the same time, they have a requirement for integrated operations management applications providing an overall view into what is happening across all their production assets.

The mark of a successful operating company is its ability to reliably meet production targets and shareholder expectations. For example, this might require tools providing accurate information on whether an oilfield is producing at the level predicted by reservoir engineers, wells are producing the right mixture of oil and other products, production equipment is healthy enough to maintain uninterrupted operations, and the operator is receiving the right production allocation.

A connected ecosystem

Due to increasing competitive pressures, oil and gas firms are seeking to move beyond traditional operating strategies to a fully connected and flexible automation ecosystem – one that uses a constant stream of data from connected operations and production systems to learn and adapt to new demands.

The result can be a more efficient and agile production, less downtime, and a greater ability to predict and adjust to operational changes.

The automation industry is now leveraging the Industrial Internet of Things (IIoT) to deliver solutions comprising smart connected assets, enterprise integrated automation, secured cloud-based data and advanced analytics. These solutions employ real-time plant data with advanced software, analytics and plant process models to enable operational improvements and increase reliability.

For example, the latest cloud-based Supervisory Control and Data Acquisition (SCADA) systems allow multiple SCADA servers to operate as one within a single asset or across the enterprise, and enable seamless global access to points, alarms, interactive operator control messages and history. They can be used to operate production assets remotely, rather than sending technicians into the field for manual intervention.

Key to implementing a connected automation ecosystem is the use of a cloud-based, multi-asset model "Digital Twin". The digital twin unifies existing data silos into a virtual entity, federates data across different applications and edge devices to drive end-to-end integration, deploys process simulation technology beyond current scope of process design, and utilizes the cloud to overcome maintainability issues and enable third-party expertise.

Better decision making

Thanks to recent developments in real-time process performance monitoring, upstream operators have become significantly smarter and more responsive.

Problems that caused them to be less efficient or productive – and that went undetected for weeks or months – are now visible and resolvable quickly and proactively, and decisions that used to take days can be made in hours.

For operating companies, the avoidance of downtime and suboptimal performance, coupled with better efficiency and agility, and lower maintenance costs, can be worth millions of dollars per year in terms of reduced unplanned capacity loss and fewer lost profit opportunities. Leading automation suppliers like Honeywell now offer connected asset performance management solutions that employ data from process and asset measurements to enable digital transformation, and in doing so, support key decision makers. They provide real-time digital intelligence through advanced process and event data collection, asset-centric analytics and powerful visualization solutions, turning plant data into actionable information to enable smart operations.

Dan O'Brien, marketing director, Honeywell

The new technology is designed to dramatically simplify data access and connectivity. It supports digitalization by standardising work processes, applying high-skill resources to high-skill tasks, providing a single version of the truth to enable process intelligence, reducing missed opportunities, and accelerating response.

By taking advantage of advanced digital twin technology driving the most effective monitoring, analytical, and predictive capabilities, process engineers can implement around-the-clock monitoring of plant data, and ongoing operational health checks and recommendations to close performance gaps.

AspenTech – optimising plant with simulation and data patterns

Optimising oil and gas plant using simulation and pattern spotting requires careful effort to make sure you are guiding people, not instructing them, and making sure your software is very easy to use. We talked to AspenTech about how the use of the technology is progressing

Oil and gas companies have been talking for many years about using data analytics and simulation techniques to work out how to optimise plant operations and maintenance activities.

But actually doing it is very difficult in practise, when you have a range of different equipment of different ages, and with different cost structures and objectives. Companies have staff with different amounts of understanding about how the field operates, and different levels of comfort and competence with technology.

Perhaps the biggest areas computer systems can contribute is in making computer simulations of the actual plant, which can be used to guide decision making, and from scanning large amounts of sensor data, to spot for useful patterns. That's easy to say but very hard to do. One of the biggest areas of market interest is analytics systems for large compressor systems, which are very expensive, can be very troublesome, and can take out an entire production environment when they fail, and there isn't space or money to keep a spare available,

Ron Beck, Energy Industry Director, Aspentech

says Ron Beck, energy industry director of oil and gas equipment optimisation company Aspen Technology ("AspenTech").

The analytics systems are also popular for optimising gas lift, reducing slugging, and reducing failures on drilling, he says.

A completely automated situation is many years away, so you will always need staff who understand the equipment operation and typical problems. They will combine the guidance and suggestions from the computer system with their own judgement. "An oilfield is very complex. You can't just set it all off to run automatically," he says.

AspenTech is based in Bedford, Massachusetts, and promises to help oil companies keep their equipment running reliably and at its limits, focussing on oil and gas, chemicals and refining sector.

Alaska gas lift

AspenTech was recently involved in a project on the North Slope of Alaska, looking for the best way to optimise oil production using gas lift injection. The project involved selecting the right option from a range of possibilities.

The cost of replacing equipment in Alaska North Slope can be three times as expensive as doing it anywhere else, because of the high transportation costs, so there is a need to try to get more out of old equipment.

The study observed that there was a big problem with inefficient gas compressors. If they don't run at maximum efficiency, they pump less gas into the reservoir.

AspenTech built a simulation model, running on real data, of how the compressors were operating and how they could run more efficiently. The simulation model is now used in Alaska, providing guidance to the (human) compressor operators.

If any of the sensor data is missing, the computer system can often make 'synthetic' data, based on looking at other data from the same period, to fill in the gap.

This project saved $3m in the first month, just by advising staff how to make small adjustments to how the equipment is operating, Mr Beck said.

Scanning data for patterns

In October 2016, AspenTech acquired a San Diego company called Mtelligence Corporation (known as "Mtell"), a company which makes software tools which aim to predict when equipment failures will occur, so companies can be prepared or find ways to avoid the failure, for manufacturing companies. It makes tools which can be used to understand early "failure symptoms" and their root cause.

The Mtell software can 'ingest'' large amounts of data, including perhaps two years of historical data, and all the current data from sensors on equipment.

If you tell the software that certain faults occurred during the past two years, the computer can look for the data patterns associated with that fault, which might include indications of something about to go wrong which could be seen several months before.

The system can then scan current data for the same patterns and indicate if the same fault looks likely to emerge again. "We call those 'intelligent agents' – an agent is a pattern of data that the system is watching for," Mr Beck says.

The system understands patterns of abnormal operation, which is called "abnormality agents". It also understands the patterns of normal operation.

Often, failures are caused by a change in operating parameters which happened several months before, but it is very difficult to work out what change in operating parameters led to what problem.

For example, operating a piece of equipment at a higher pressure will, over a number of months, lead to a problem of fluid breakthrough into the compressors, but you are not aware of anything until the fluid breakthrough causes equipment breakdown.

With the help of the analytics software, you can recognise the patterns, and then decide to reduce the operating pressure of the equipment.

The system can sometimes have as much as 10 different "failure modes" or "abnormality agents" which it is scanning the data for.

Sometimes, the system observes a change in data patterns, but does not recognise the pattern. In this case, the activity can be categorised as "to be determined".

Pilot projects

AspenTech has run around 30 pilot projects with different customers, to try to build confidence in this pattern spotting ability.

In the pilot, it asks a client to supply a sample of data which contains some specific equipment faults. Then it asks the client to supply another sample of data, to see if the computer system can spot same faults emerging in the second sample.

"We've done that in 30 pilots over the last year, and been successful in 30 out of 30 pilots," Mr Beck says.

In one example, a customer was told, that they would see a problem with a compressor in between 80 and 87 days. The customer did not believe it. The compressor then went on to fail after 83 days, Mr Beck says.

The company recently announced a major purchase by one of Italy's largest refineries based on one of these pilots.

Guidance not instruction

It is important that the recommendations made by the software are presented as 'guidance', rather than instruction, Mr Beck says. The computer system can only ever know a small part of the full context of operation.

The equipment operating staff can use the recommendations together with whatever other goals or understanding they have to make a decision about what to do.

For example, the computer system may advise about an emerging risk, but the human operator may decide the risk is worth taking, bearing in mind it may be much cheaper to do maintenance during a scheduled shutdown in a few weeks' time.

"It is making concrete suggestions, 'change the operating pressure of this system in order to avoid this problem," Mr Beck says.

Also, staff might not be comfortable making a change just on the basis of a recommendation from a computer system. "You're dealing with large amounts of equipment, operating oilfields where if you make a wrong decision there's an implication," he said. "People aren't just going to make wholesale changes without a comfort factor."

Making it easy to configure

AspenTech has been putting a lot of energy in trying to make its software systems easy to set -up and work with. Whether people can quickly get up to speed with a system is a major factor in the success of the implementation, he says.

Building software tools which subject matter experts and 'end users' can configure themselves is a major part of AspenTech's approach. "Our strategy is fundamentally to empower companies and empower users," he says. "If you empower people, innovation will happen faster."

Ideally, people should be able to access data without having to be an expert data scientist, or need years of experience working with these pieces of equipment. They should also be able to do it on tablet computers, or when working outside, using gloves.

The software interfaces are designed to be as fluid as possible, like software on mobile phone apps. They can be quickly reconfigured into something else.

The company also tracks how people are using the software, and which parts of the software they are using.

AspenTech uses 'personas' in its product development, an idea of what a typical customer might look like – including what their objectives might be, and their inclination and ability in learning a new piece of software.

To get a better understanding of how younger people work with technology, AspenTech recently hired 200 college graduates, accounting for about 14 per cent of its total workforce, because it wanted people who had grown up with new technologies.

The company also provides a wide range of online training materials, including e-learning systems and YouTube videos.

Nexen VP - improving the "mindset" of the North Sea

North Sea oil and gas companies need an improved mindset, more collaborative and also more disciplined, says Mike Backus, VP operations with Nexen UK

Mike Backus, VP operations with Nexen UK, believes that the North Sea oil and gas operations needs a "new mindset", which is more collaborative, focussed on promoting good behaviours, whilst also disciplined and focussed on reducing waste.

Mr Backus believes that companies should drop their obsession with confidentiality as a pathway to competitive advantage. "I believe, confidentiality [should only go] into the licensing round. Once we've got past that, why aren't we more open, honest, and transparent with ourselves, peers and contractors? I think we are hugely behind other industries from a behavioural standpoint," he said.

One of the most frustrating elements is commercial behaviour. "We come up with good technical solutions and it falls apart on a legal or commercial level," he said.

A lot of "misalignment" can form, within an organisation (when different departments have different goals) and externally, when one company wants to go ahead with a project but it has joint venture partners who don't.

The oil price crash has led to a "relentless focus on efficiency, a bit more financial discipline and cost control," which will probably be sustained even when the price rises, he believes. There have been some accusations that the industry is already starting to go back to the previous ways of operating once the oil price goes up, although "I personally haven't seen that."

The oil price crash has led to job losses and difficulties in organisations. But it has also led to a "a lot of rallying, people helping each other. Crisis can make people unite," he said.

The word "collaboration" is so overused it has become something of a joke, but there is more of it around, he said.

Suppliers

One culture Nexen would like to change is the idea of pushing the supply chain to get lower prices. "A lot of organisations take a 'cut to the bone' approach," he said. But "If the suppliers go out of business, the oil companies are no longer viable companies.

The company has been putting contracting strategies together in new ways. For some strategic relationships, it has signed 10 year contracts, which saves both suppliers and buyers a lot of time deciding which supplier to work with every year.

Nexen has also been looking for ways to get 'small pools' into operation, small oilfields which are too small to have their own production infrastructure.

Mike Backus, VP Operations with Nexen UK

The company asked 25 individuals who work for Nexen suppliers to discuss together ways they can reduce the costs of development. "We said, come back in 3-4 weeks and tell us what you can do. They came back in consortiums offering different operations models, with open ended ideas."

The business models lead to suppliers taking more risk themselves, and putting together integrated teams, "so a slightly different commercial mindset. It appears to be unlocking some opportunities for us," he said.

Mr Backus was asked if he thinks the current lower supplier costs are more structural than cyclical. Some people are saying half structural, half cyclical, but "I think it is more skewed to the cyclical side," he said – in other words when the cycle changes, and equipment is in demand once more, perhaps only 25 to 30 per cent of the current cost reductions will be sustained.

Cultural beliefs

Nexen has established 6 "cultural beliefs" which it wants everyone in the company to follow. These are "be bold, be the best, do it right, results matter, safety first, step up, value feedback, win together."

Nexen is firm that its employees should either "get on the cultural bus or find another home."

To try to get the culture changes to stick, it has developed "focus recognition cards." These are a physical card which colleagues can give to each other, when they see someone demonstrating behaviours which fit with the cultural beliefs. The cards are given personally to the recipient, and can then be pinned up on walls. "This program has taken off like wild fire and hasn't cost anything to do," he said. "It has actually stuck."

Marginal gains

Another approach is looking for small marginal gains, which can all add up to a large difference. One inspiration for this is the Sky Cycling team, where one small gain was achieved by transporting bedding and mattresses, so cyclists could sleep in their 'own' bed every night, leading to better sleep and better performance next day.

"It will astound you how many ideas are in you organisation which haven't come to life," he said.

One 'marginal gain' was achieved from training hundreds of employees in basic oil and gas finances, so they would understand where most money is spent producing a barrel of oil, which will help them make better decisions relating to costs.

Education

Mr Backus was asked if he thinks that the current university education programs are fit for purpose. "Engineering programs give you very little training on behavioural strategies- I don't know if that's something you need to build on," he said.

People say that "10 per cent of what you do in working career is from academia, 90 per cent is what you learn on the job. I don't think there's a structural change that needs to happen."

Westwood: oil price "dependent on OPEC"

Also in the SubseaExpo plenary session, Andrew Reid, CEO of Westwood Global Energy Group, said that whether the oil price stays healthy enough still largely depends on OPEC – because if OPEC members do not continue the production cuts they agreed with each other, the industry will go back into oversupply. And it is quite possible that they will not maintain the production cuts. "You need caution on how this plays out."

Factors pushing the oil price up include OPEC cuts, Chinese import increases, global consumption growth, decline rates of existing wells.

Andrew Reid, CEO, Westwood Global Energy Group

Factors pushing it down are increasing efficiency of US shale operations, possible production growth in Libya and Nigeria, and suspensions of OPEC cuts, he said.

Existing wells may decline production faster than expected because many operators have been 'sweating' them, trying to get as much out of the ground as possible, to try to break even in lean oil price times. But this can destroy the reservoir quality.

However US shale costs may increase, as companies start needing to buy new equipment rather than being able to use old oil equipment.

The offshore industry is still in a 'challenged' market, which indicates that costs are unlikely to increase.

Currently there are 200 well heads ("Christmas trees") being ordered per year by the industry, where manufacturers have capacity to build 600, he said.

The industry will be reliant on 'final investment decisions' (FIDs) coming through.

"2018 could still be quite a tight year – it is not a gangbusters recovery," he said. There's "still a high degree of vulnerability in the market."

Renewables – built on oil and gas

Tim Cornelius, CEO with Atlantis Resources, a leading tidal power developer, said that oil and gas companies are currently the biggest investors in renewables, speaking in the SubseaExpo Aberdeen plenary session

The marine renewables market has benefitted from the slump in the oil and gas industry, with yard rates and vessels very low. Vessels which formerly cost $65,000 a day are now available for $14,000 to the renewables industry, he said.

This is led to an "unbelievable reduction" in cost of installing renewables, such as £120 to £130 per MWH for offshore wind. This means that offshore wind is "rapidly approaching subsidy free", after being £350 / MWH not so long ago, he said.

A lot of renewables technology has been developed in Scotland, and a lot of it is similar to oil and gas technology, he said, such as the use of jack-ups in installing wind turbines.

Also, tidal power, which Atlantis focusses on, can be considered "wind technology subsea," he said.

It is highly predictable, which is important for investors. You can be 95 per cent sure of electricity generation capacity for 25 years in advance.

Tim Cornelius, CEO with Atlantis Resources

Another change is that capital expenditure for wind is becoming as big as for the oil and gas industry, which means that wind can compete head to head with oil for contracts with suppliers, rather than just fill in the gaps where facilities are not in use for oil.

Consider that the fabrication yard in Nigg (Aberdeen) employed 2,000 to 3,000 people on oil and gas projects 10 years ago, now a large proportion of those people work in marine renewables, he said.

Viper Innovations – fixing subsea cable water ingress

One of the most common problems with subsea power cables is water ingress to the insulation – which conducts electricity away from the cable and 'steals' the power. Locating the leak so the cable can be replaced is expensive. Viper Innovations has a system to make it easier

One of the most common problems with subsea power cables is water getting in through the plastic insulation and touching the conducting cable. Because salt water conducts electricity to a small degree, it can 'steal' power from the cable – so there is less power available to serve the subsea equipment.

According to Peter Alexander, business acquisition manager at Viper Innovations, water ingress to subsea cables is a case of when not if, as the insulation around the cable gradually weakens over time. Water ingress to cables is the biggest cause of subsea faults.

Damage can also be caused by marine life, particularly in warmer climates. This can gradually push connectors apart.

Until now, the only resolution to the problem is to run electrical tests on different sections of the cable, the same as you would with an electrical problem in your house. But doing it subsea involves fiddly work with a remote operated vehicle (ROV), and can even cause more damage to the connectors. Cables can be tens of kilometres long.

Viper Innovations has developed a system to make it easier. It involves installing a subsea electronics 'node', called V-SLIM (Viper's Subsea Line Insulation Monitor) along the subsea power cable when it is first installed. The power cable does not need to be cut within the V-SLIM, because this might cause more potential for breakage and complete power outage.

Peter Alexander, business acquisition manager at Viper Innovations

The resistance is monitored using wire coils, measuring the resistance of the insulation between two points. If there is any water ingress, the resistance of the insulation over that length will reduce.

Any problems are communicated back to surface along the same cable that is being monitored.

This means that if there is a problem with insulation resistance somewhere along the subsea cable, it is possible to find out exactly where the problem is, so only that part of the cable needs to be replaced. You also get plenty of early warning about a problem emerging, so you can fix it at the same time as other maintenance work.

You can add in more units as the subsea network grows, like plugging in another 4 way plug board into an existing 4 way plug board, Mr Alexander says.

Insulation resistance recovery

Viper has also developed an intriguing and secret technology which it says can 'fix' damaged insulation, by changing the flow of electricity through the cable. The service is called "V-LIFE".

The company will not disclose how it works, aside from saying it uses "electrochemical and electrokinetic phenomena" to increase the resistance between the cable and the seabed, and it "forms a precipitate at all points of failure to reverse the effects of sea water ingress."

It can be activated by installing a "V-LIFE" box on your subsea cable power system. You will need to pay Viper for a software runtime licence before the system can be activated.

The system is not guaranteed to work, but Viper says that if it fails to stop the insulation problem, you can just stop paying your subscription. There are 50 systems in use globally, some going for over 5 years, in the North Sea, West Africa, Australia and South East Asia.

The company can give you advice about the likelihood that it will work, based on your answers to a questionnaire.

The SubseaExpo Technology Showcase

Generating power on the seabed, improving diving simulation and better underwater vehicle navigation systems – interesting technology presented at SubseaExpo's Technology Showcase in Aberdeen in February

Austin Asuquo, Department of Naval Architecture, Ocean and Marine Engineering with the University of Strathclyde in Glasgow, has done a Phd thesis into better ways to generate power on the seabed based on the difference in temperatures between two fluids.

One thermoelectric module can generate 13W of power from fluids with a 100 degree temperature difference. This temperature difference is plausible on the seabed, where you have very cold sea and very hot oil. The thermoelectric module is a solid state device which can operate with very low maintenance.

If you have 10 modules, you can generate 130 watts, enough for critical subsea infrastructure. That's enough to power a multiphase flowmeter, or a temperature and pressure meter. If there were more modules, it is possible to imagine generating power for equipment such as a blow-out preventer control pod.

With more subsea power available, it might be possible to build better safety devices. For example could the Deepwater Horizon disaster perhaps have been prevented with more sophisticated monitoring on the seabed, shutting in the rams when it was clear there was a problem, Mr Asuquo said.

Diving simulation tools

DiveSource, in partnership with a specialist simulator development company PaleBlue, recently launched a dive control simulator which can be used for competency and safety training, including helping divers practise dives before doing it for real.

Pale Blue is a Stavanger company which specialises in making graphical simulators of the 'real world', including for diving, offshore drilling, engineering and construction,

Simulators have been used for many years by aviation and military, and are starting to be introduced into oil and gas, says Sarah Hutcheon, managing director of DiveSource.

There is an instructor workstation. The instructor can set up both normal operations and emergencies.

The various roles simulating simultaneously can be a diving supervisor, vessel operator, and diver. They can do a full rehearsal of an actual dive project.

Everything is recorded, and students can get a debrief at the end about how they did.

There is a virtual reality tool for actual divers, where they can see a view in their headset similar to the view they would get while diving. They can use their hands, and show their hands in the headset view with a glove. The computer can simulate doing the actual task.

So you can recreate an entire subsea worksite based on CAD models.

Companies are still proving hard to convince to buy it – partly because it is something very new for the oil and gas industry, she said.

Better underwater navigation

Nortek UK has launched a new generation of Doppler Velocity Logs for underwater vehicle navigation, a device which can be attached to an Autonomous Underwater Vehicle (AUV) to help it understand its location.

The main navigation system for AUVs are inertial navigation systems, which work out their position using accelerometers. But these can 'drift' over time, so the Doppler Velocity Log gets it back on track.

The Doppler Velocity Log utilises the Doppler effect, the change in frequency of a wave recorded by a receiver moving relative to the wave source, to make a measurement. The underwater vehicle is moving, and the sound wave bounces off the seabed and back to the vehicle.

The new device from Nortek is lighter than previous versions, so there is less for the AUV to carry. It has improved synchronisation with the inertial navigation system. It also has improved capability to detect the seabed.

Errors in detecting the seabed can be due to being too close to the bottom, being too far away (so it can't be seen), a soft bottom (so no return signal), or a slope on the bottom, so different beams return different results.

The seabed in 3D

There are many developments to help companies understand the seabed better in 3D. We heard from Rovco, Whitecap Scientific and Shell at Aberdeen's Subsea Expo in February

Subsea services company, Rovco, is looking to change the future of subsea survey and inspection, by using imagery from high specification subsea machine vision cameras for 3D modelling and Artificial Intelligence applications.

Based in Bristol, UK, Rovco was launched in September 2016. Iain Wallace, chief technology officer with the company, was formerly an autonomy and robotics analyst with SCISYS, where he developed autonomous capabilities for space rovers, and was a technical lead for European Space Agency and UK Space Agency projects.

"Controlling a ROV is a highly skilled job, but also the sort of task which, in theory a computer could do better than a person, if it can make better judgements about how to use the various thrusters to get the ROV in the right position and do the task," Mr Wallace says.

"There are many stages between a human controlling a subsea vehicle and a computer controlling an autonomous one – one of the intermediate stages is for the computer to perceive where everything is in 3D, the same way that autonomous cars can do."

Rovco is currently developing technology which manipulates images from its own prototype subsea cameras, to recreate the subsea environment in full live 3D. Even enabling 'impossible views' of the operation as someone would see it looking from any side, so you can see both the subsea vehicle and the equipment it is working on, while its software further analyses asset condition.

"The computer can tell you where the ROV or AUV is from extrapolating backwards from the position of the camera, which can be calculated using the position of the fixed subsea infrastructure as a reference point. This is quite a demanding computer application, because the 3D image would need to be created at the same time as it is recorded," Mr Wallace added.

"This 3D image would also enable more people to get involved in subsea operations, something which is much harder when the only information available is displayed on a screen, on-board a vessel which the operator is watching. For example, with our system there could be an expert on subsea asset monitoring the data and images from their own office, rather than on the vessel.

"Ultimately, it may be possible to have totally autonomous surveying / inspection, where a computer controls the subsea vehicle to complete a required task in general terms with some human input. For example inspecting a pipeline and informing the operator of any emerging problem. This would use 'machine learning' tools to interpret the video and determine whether there is a problem or not.

"Surveying can be very tedious work, capturing hundreds of hours of video, which someone has to watch, and then make a list of possible problems identified, such as free spans, point loads or exposed cable.

"A more basic benefit of the real-time image manipulation is that it can be used to generate a live 3D model, which is then used for taking measurements. Another application is monitoring the changes happening from one year to the next, using difference modelling."

Rovco has sent out Tweets linked to an image of a 3D view of a pipeline, which you can see online at Twitter.com/Rovcosubsea

Rovco has secured funding from UK government agency, Innovate UK to experiment with live 3D inspection, in conjunction with the ORE Catapult and using their dry dock. This summer they will be proving the accuracy of their system by laser scanning various subsea assets before submerging and verifying with their prototype cameras and live 3D system.

White Cap Scientific

White Cap Scientific Corporation of Newfoundland is also developing technology for 3D underwater inspection.

Sam Bromley, managing director of Whitecap, notes that there are many intermediate stages between video imagery from subsea vehicles (as we have today) and generating live 3D images from video. For example there could be an automated system to scan the video and detect something which doesn't look right, for human follow up.

The company has experimented with using 2 subsea cameras side by side, and then showing their images on a VR headset with a different camera image projecting to each eye, so people can get a 3D view.

The computer can also automate the task of stitching together different video fragments, for example if the company would like a continuous video along a pipeline.

The video images can be processed so they are only recording something "persistent in time". So a fish swimming around the subsea infrastructure is automatically erased from the video, he says.

To make the computing load of generating 3D images in real time easier, it is possible to do it in lower resolution, just aiming to make something which people can recognise.

Shell – subsea laser scanning

Shell was involved in what is thought to be the first use of laser scanning on the seabed, with a project in September 2015. The project was presented at Subsea Expo by Alan Holbrook, subsea engineering consultant with Shell, together with colleagues Lee Blinco from Subsea7 and Neil Manning from underwater laser (LIDAR) specialist 3D At Depth.

The work was to disconnect 3 wells, with 1 well being reconfigured to send its production though a different line to the Gannett platform, and the other 2 being permanently blanked off.

The seabed had a "congested worksite" with different pieces of protection equipment.

Other alternatives for doing the survey were acoustic metrology, photogrammetry or some kind of hybrid.

Acoustic metrology (acoustic measurements) means doing the survey by acoustic energy seeing what bounces back, but this was thought to be difficult with so much metal in the area bouncing back acoustic energy.

Photogrammetry is using photographs for surveying. But this would require "longer vessel time," and was "relatively expensive," said Lee Blinco, senior project surveyor with Subsea7, which was involved in the project. So laser scanning was chosen.

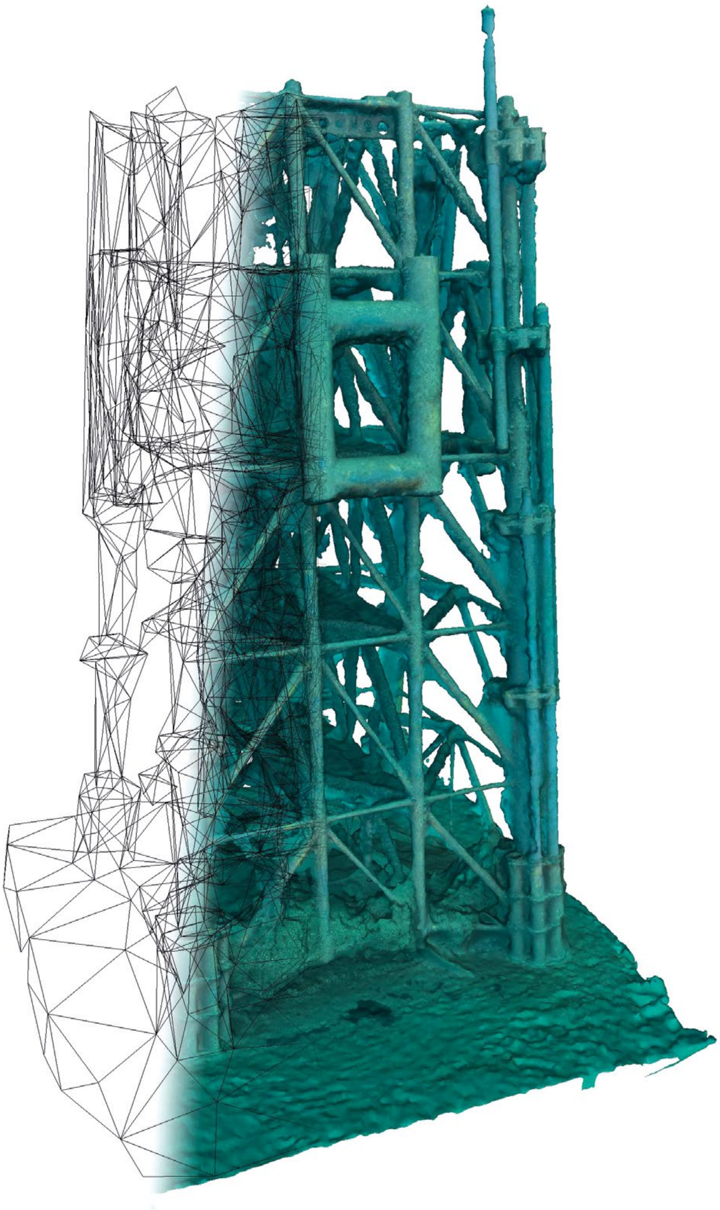
The actual subsea work was done with divers. They could be given detailed drawings before they had to do the work.

This is the world first Subsea LIDAR by saturation divers. (It is called saturation diving because divers allow their body tissue to have inert gas dissolved in them to saturation. When the diver decompresses when coming to the surface, this gas can form bubbles which may block blood vessels. Divers have a "bell", a pressure vessel, which they can go into for resting between work, without having to let themselves decompress.

Divers were used rather than ROVs because of the complexity of the project, which required access to awkward places.

Using the imagery

The laser scan image could be used together with a normal camera image. The camera image made it easier to understand what exactly you are looking at, while the laser scan image brings in technical accuracy, useful for making measurements and getting a detailed understanding.



Rovco develops a 3D visualisation of a subsea jacket based on video images

The imagery proved very useful for planning. Instead of having to guess whether or not a subsea dredger was required, the imagery made it "pretty evident" that one would be required, Shell's Alan Holbrook said.

The imagery was used to check a design for the new "spool", the short length of pipe which was to be plumbed in to connect the well with the new pipeline. As it happened, the initial spool design (made before the 3D imagery was taken) proved to be incorrect – so without the 3D model, the company would have wasted a large amount of money taking the wrong shape spool to the site and trying to install it.

Overall, the costs saved using laser scan is 10 per cent of the overall authorised expenditure, Mr Holbrook said.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