digital energy journal

New Geophysics Approaches

- Advanced gravity survey technology
- Getting more from mud gas analysis
- Moving subsurface models around using data standards
- Self organising maps on subsurface data

- Predictive maintenance - which equipment you should start with
- Developing a strategy for your sensors
- Working with well DTS data

Finding Petroleum

Opening

What does your dream digital technology look like?

Imagine you could design your dream digital technology by sketching on a clean piece of paper.

Make a hand drawn model or diagram, the way an architect might start designing a building, or an airport designer might make an initial plan for ring-fenced security.

Most oil and gas experts will have developed their own 'metrics' they use to get the understanding they need from a situation – their sketch might show how this metric works. It is probably a long way from what their current software actually does.

For most oil and gas experts, the most important understanding is to get early warning of something going wrong – emerging reasons why they might be drilling in the wrong place, why a drilling project is getting behind schedule, that there is an emerging problem with equipment, or an emerging problem with oil production. The most useful digital technology might help with that.

The software design sketch would cover how the software actually functions, not just what the user interface looks like. The internal logic, how the data would flow and where it would be stored.

The benefit of making software around a model like this would be that the logic would be easy to understand by everyone involved, including the oil and gas experts using it. The logic of a data model could also be clear, so it is easy to integrate different datasets together, or make sure that data which is meant to be secure stays that way.

Designing a digital technology implementation from scratch is not a new idea – some people have told me their company has tried it and nothing changed as a result.

But we live in different times now. There is far more impetus in oil companies to get better digital technology than there was 10 years ago. Also

customers are far less willing to just accept what technology companies want to sell them, which may be some embellishments on their old product, rather than something totally new.

It is getting much easier to build software which closely follows a non technical model, such as low code technologies.

If we were going to design software from scratch, we would probably need to involve the domain expert customers, the software project managers who are going to get it built, and software developers. But they wouldn't necessarily need to be all sitting together all the time. Perhaps software project managers could do the bulk of the design work, as with any other project, and bring in expertise as required.

Digital Energy Journal is exploring ways to help oil companies get the digital technology which will most help their staff, through designing software from simple models like this. Perhaps it could be a forum for oil and gas project managers, perhaps supported financially by companies making platforms, or who have a benefit from good technology. Perhaps it would need oil and gas expert involvement, perhaps it wouldn't.

It would probably need a concise objective (this is what we are designing software to achieve), and a report published afterwards, which is probably freely available for future workshops to build and adapt on.

If you are interested in working with Digital Energy Journal this autumn on such an idea, please let me know.

Karl Jeffery, editor
Digital Energy Journal

Arup Inspection MInteg (AIMTM), a new oil and gas inspection service offered by engineering firm Arup and maintenance and inspection company MInteg Limited. The entire inpection workflow is digitised, which should lead to inspections which are faster, safer and cheaper, with information instantly available. The service will initially be offered in the North Sea, Western Australia and Gulf of Mexico.

What new geophysical methods offer most potential?

Finding Petroleum's April 30th forum in London, "New Geophysical Approaches", explored a range of geophysical and subsurface techniques offering potential to better understand the subsurface, and which methods oil companies and geologists might want to pay most attention to.

We discussed advanced gravity gradiometry measurements, the potential of atomic dielectric resonance (focussed radio waves into the earth), ways to do more with drilling mud gas analysis, how to move subsurface models between software applications using data standards, and machine learning on subsurface data.

One of the most useful technical capabilities in geophysics might just be the ability to integrate multiple data sets, said Dr David Bamford, a former head of geophysics at BP, chairing the event, in his introduction.

David Bamford

To illustrate what is possible by integrating data, Dr Bamford showed a video made by NASA showing earthquakes over the past century on a revolving globe, with the size of a circle being the magnitude of the earthquake. A similar model showed strength and depth of earthquakes, and how they align with plate models. This must have been a very complex data compilation exercise, taking data about earthquakes from the multitude of people recording them around the world over the past century, all in different formats and on different mediums.

The model might be useful in predicting future earthquakes, if you identify that a certain plate boundary has seen no major earthquakes for 50 years, it may be more likely to have an earthquake now.

Similarly, in oil and gas exploration, it is no longer enough just to do a 3D seismic survey of thousands of square kilometres. Getting the understanding we need – such as of petroleum

systems – needs more data sources, he said.

This becomes more relevant as we see oil companies of all sizes looking more and more at parts of the world where multiple complex data sets exist, such as onshore US, Middle East, North West Europe and former Soviet Union. The data has a wide range of formats and ages.

We are also seeing companies which operate in mature areas and unconventional areas getting more interest from investors, compared to companies which only explore in frontier areas, he said.

Meanwhile, seismic companies seem to be making plans on the basis that the oil price will soon rise to $100 a barrel, and companies will just start spending as much on seismic technology as they did in the past, with expensive deepwater, frontier, proprietary surveys. "In my own mind, it is not clear where geophysics is going at the moment," he said.

Making better use of gravity and magnetotellurics

Big advances in gravity sensors, magnetotellurics and data methods are providing a much better understanding of the subsurface, better than seismic in some situations, said Mark Davies of Austin Bridgeporth

Big advances in gravity sensors, magnetotellurics (MT) and associated data modelling and processing make it possible to do far more to understand the subsurface, better than seismic in certain situations, said Mark Davies, CEO, Austin Bridgeporth.

An example was presented of oil and gas exploration in the Muskwa-Kechika, a wilderness area in Rocky Mountains of Northern British Columbia, Canada. It is extremely hard to do seismic surveys in the region, with a total elevation variance of 4.5km, and much of the land inaccessible for big equipment.

But it is possible to do gravity surveys by aeroplane, and the data fidelity from gravity surveys has been much improved by new technology, such as the "enhanced full tensor gradiometry" or "eFTG" systems recently made available by Lockheed Martin.

The system includes twice as many accelerometers as the previous iteration of the technology, known just as "FTG", leading to a signal to noise improvement of around

3.6 based on the FTG. This means that one line of eFTG data has the same noise levels as 9 lines of FTG data with the data stacked together.

Mr Davies showed a comparison of the imagery you get from conventional gravity data, FTG and eFTG, with images of the same region of Gabon. Conventional gravity data could not see any salt bodies, FTG can see just large salt bodies, eFTG could see all of them and a defined basin high.

If you are measuring gravity with so much more sensitivity, you also need to make more effort to get rid of "geological noise" - gravity changes caused by other geological features and changes in terrain. Bridgeporth uses hyperspectral imagery and LIDAR tools to help strip this noise out.

Past exploration in Muskwa-Kechika

Mr Davies explained how, in the period 1994 to 2009, Mobil had drilled a dry well in Muskwa-Kechika, and then realised it

Mark Davies of Austin Bridgeporth

was because its gravity correction placed the reservoir in the wrong place. It re-drilled 2 years later and hit the reservoir.

In 1994, Mobil had acquired seismic, full tensor gravity gradiometry, magnetic gradiometry, LIDAR (using laser imagery to understand the shape of the terrain), and hyperspectral imagery (analysing the colours in photographs). All the data had been integrated to model a carboniferous reservoir structure at about 4km depth.

It missed the reservoir initially due to an

error in the "Bouger correction" – a way of correcting a gravity reading. It adjusts for the terrain, the height it is recorded, and the geology at the surface, as shown in the geological map of the region.

Above the reservoir, there were carbonates shown on the geological map, so the gravity correction would be made based on this. But there were actually clastics beneath the carbonates.

In another part of the survey area, there were clastics on the surface, so the geological map would show clastics, and you would correct for that, but there are actually high density carbonates beneath it, so you end up under correcting.

When the study was done again with greater data fidelity, including FTG gravity data, and a more complicated shallow earth correction based on LIDAR and hyperspectral imaging, the location of the reservoir structure moved to a different location.

You can see that the initial well hit the edge of the reservoir structure and the drillers tried to move towards the reservoir but didn't manage – but when the prospect was re-drilled 2 years later using new data, it hit the structure directly and it was hydrocarbon bearing.

Long wavelength gravity

One criticism of FTG was that it did not measure "long wavelength" gravity information, where there is a big variation in gravity reading, as accurately as a conventional gravity system.

So it was not so effective when recording gravity over a region with big changes in gravity, such as a mountainous region.

But conventional gravity data, because it takes an absolute reading of gravity rather than look for variance in gravity, does not have this problem.

The problem can be fixed using software and algorithms, making it possible to gather both big and small changes in gravity in the same survey system, rather than have to put together data from different systems.

Lockheed Martin has also developed a "Gravity Module Assembly", for directly measuring gravity within the FTG system.

Now, "When we run the depth models, we have the entire gravity data set to work with," he said.

Integrating with magnetotellurics

Oil companies want an independent data set to verify what the gravity is saying, and seismic was tough to gather in the difficult terrain of Muskwa-Kechika. An alternative is magnetotellurics (MT) which measures electrical currents in the subsurface.

There are ultra long wavelength changes in magnetic fields in the earth due to interference from solar radiation, and shorter period changes from lightning storms in tropical regions of the earth, with energy bouncing around the troposphere (up to 6-10km above earth). Different types of rock show up differently in a MT survey.

The MT technology was developed in the Second World War. It was initially very laborious to acquire and interpret data. "You used to spend 3-4 days to acquire one point. You had to get up in the middle of the night, switch over the frequencies that you were measuring, then go back to bed," Mr Davies said.

But between 1980 and 1997, the acquisition technology was made much smaller, so it can be carried to the field by a three man team.

With today's technology, the magnetometer is put in a 6 inch deep trench, 2m in length. There are diodes placed in little holes. It is left for 24 hours. There is no other environmental impact. This means that the technology can be more popular with environmental groups and regulators than seismic surveys.

The MT data was used together with gravity data, to build a 3D model of the reservoir, with longwave components from gravity and magnetics to understand the base of the model, and topography, geological maps and hyperspectral data to understand the surface geology.

In the region of the Thunder-Cypress well in Muskwa-Kechika, there was legacy seismic data available, which had been reprocessed a number of times. Some steeply dipping thrust sheets had been imaged.

If you overlay LIDAR data, you can see that some of the thrusts line up perfectly with topographic features. The MT data could additionally help tell you the angle of the thrusts, and show up synclines, anticlines and faults. Some of the results were better than the results from seismic.

Bridgeporth acquired 5 MT lines altogether, 2 of 250km, one 270km, the others "a bit shorter", total 3,500 points. It took less than 3 months to acquire. The costs were around $6.7m, "a drop in the ocean compared to the seismic that we're currently planning."

Next year, Bridgeporth will take an eFTG survey of the region, add in more MT lines, and then shoot seismic when it is sure of the structures.

Mr Davies was asked if anyone was integrating the various data sets in an integrated way, rather than converting each one separately to depth and then combining them together. "That's the holy grail," he replied. "Many companies say they do it but do they really? Not really," he said.

Delegates at the New Geophysical Approaches event in London on Apr 30

Assessing ADR

Atomic Dielectric Resonance (ADR) technologies, a form of focussed radio wave, may be able to help understand the subsurface. So far the results look interesting, although some are sceptical. A key point of discussion was around the depth resolution achievable.

Atomic Dielectric Resonance (ADR) technology sends focussed radio waves vertically into the ground, records the reflected response, and analyses the data to try to get an understanding of the subsurface.

The reflections from the subsurface can be recorded and analysed for their energy, frequency and phase.

The technologies have been proven to work over short distances – it was used to test out a folklore story in Scotland about a horse and cart stuck in a concrete railway viaduct from 100 years ago. (Google horse in a viaduct in Scotland" for the story). The technology is also used by Chevron in the US to track subsurface water.

The question is whether they can work over longer distances.

The technology is being developed by Scottish company Adrok (among other companies around the world). Adrok asked Dave Waters, a geologist with UK consultancy Paetoro Consulting UK, to help them assess the results.

Speaking at the Finding Petroleum forum, Dr Waters pointed out that many different variables affect exactly how different radio waves will interact with solids. We think we understand it, when we see how the path of light is blocked and imagine that radio waves would be blocked by the ground in the same way.

But solid material, at an atomic level, contains a lot of space, and the barriers to light we imagine solids might have, are perhaps not as great as we think. We can see that X-rays, which are higher frequency electromagnetic radiation than invisible light, can penetrate the human body. But perhaps also radio waves at much lower frequencies can also penetrate solids. It is a function of the wavelengths of the light and the size of the objects encountered, a bit like how small waves on the sea have little effect on a large cruise liner.

When a radio wave meets a barrier, it can be reflected, transmitted or absorbed, and which of these happens depends on multiple factors related to the electromagnetic energy (wavelength frequency, intensity) and the barrier (chemistry, physical microstructure,

thickness). So it may be possible to find wavelengths which are a size which interact with molecules and chemical structures, and pass through it.

Dave Waters, geologist with Paetoro Consulting UK

Experiments with electromagnetic waves to penetrate the subsurface have been going on for over 100 years, including being used to estimate glaciers in the 1920s. They were used on aircraft and spacecraft in the 1980s and 1990s, with directed radar pulses sent over an area, in a technology called SAR (Synthetic Aperture Radar).

There have been research studies using the technology to study shallow subsurface geology, with some successes in Scotland, the North Sea and Egypt. The same technology was used by a probe on a Mars rover which detected what is believed to be a liquid lake under the South Polar ice cap, looking 1.5km deep. The technology has also been used in medicine, mining, geology, archaeology, geothermal, as well as hydrocarbons.

After LIDAR was invented, using directed lasers to understand the shape of objects, researchers were interested in using directed radio waves in a similar way.

ADR has some similarities with ground penetrating radar (GPR), but GPR uses much shorter wavelengths – typically centimetres, which don't penetrate the ground so easily, so usually used for shallow subsurface. Also GPR is not usually looking at the relative permittivity. ADR is trying to focus intense rays, typically 40cm wide at most.

Developing the technology

Adrok was founded by Colin Stove in 1999, who had been previously working with remote sensing and SAR. He has been doing research on ways to make the radio waves

go deeper into the earth, without about 25 patents issued.

The Adrok system uses electromagnetic waves in the 1 to 100mhz band, which is usually used for radio broadcasts. But the waves are specially created to try to give them more power to penetrate the subsurface, using directionality (keeping all the energy focussed in one direction), and coherence (all the source signals have the same wave form, frequency and phase difference).

Adrok has observed that the penetration is greater, the lower the frequency of the radio wave.

Attention is being focussed on the shape of the wave, including combining different frequencies of waves to form directed packets of energy in a fixed pulse and fixed phase relationship.

The wave is multispectral (having a range of different frequencies), in order to capture more response. There are two synchronised waves in phase, which illuminate the subsurface in a narrow converging cone. There is a longer wavelength "carrier" wave which gets more depth, and shorter resonating waves within it – their aim is to enhance as far as possible the vertical resolution.

The surveys are effectively 1D, recording responses at different times, corresponding to different depths.

In a typical survey, 17 different curves will be recorded, 14 looking at various aspects of frequency and reflectivity, and the consistency of these responses, 2 looking at estimating the dielectric constant, and 1 curve looking at the number of harmonics in the frequency response. It is difficult to use just one parameter to identify lithology unambiguously – so Adrok uses curve combinations to help.

The system can be calibrated by shooting it over wells where well logs are available.

Dr Waters anticipates making a kind of 'genome' workflow which can be applied to compare and characterise measurements of calibrating well pairs over a particular interval of subsurface, and then applied to help with predictions elsewhere, where no wells exist.

The tool can be carried in a backpack, so can go anywhere a person can go. The field work is typically done in a few weeks, and processing is more time consuming, taking a few months. But the overall cost is a fraction of seismic, Dr Waters said.

Relative permittivity

One aim from the data analysis is to get insights into the relative permittivity of different layers of the subsurface, and use this to identify the material.

Many rocks have similar values for dielectric constant, typically between 4 and 12. For hydrocarbons it is typically in the range 1-2, and for water it is 80-81. The dielectric constant also varies with temperature, so it could be used to detect steam, useful for geothermal wells. It may be possible to ultimately discern the rock type, porosity and pore fluids in this way.

Relative permittivity is about how polarised a di-electric material becomes when sub-

jected to an electric field. It can be calculated from the recorded ADR data, applying Maxwell's laws.

Case study

Dr Waters was invited to review results of a 2017 test project supported by UK government agency Innovate UK, giving a geologist's perspective, rather than a theoretical physicist's perspective, and exploring the results for objectivity, auditability and repeatability.

From analysing the results, the system proved to work better sometimes than others, he said. It could see some points where there is a big change in the rock, (dielectric contrast) such as bands of carbonate. Seeing hydrocarbons proved a bit harder. Without a big dielectric contrast, "the non-uniqueness of subsurface responses can be an issue."

Similarly it could 'see' where there was a big change in fluid saturation or porosity.

Sometimes there were "blips" which happened to coincide with hydrocarbon bearing reservoirs, but it may be just a coincidence. Where there are near-surface zones of high-water saturation (e.g. deep soils), it can also sometimes affect results, and where possible these are best avoided.

"I'd argue subsurface geology is seen by ADR techniques but not all subsurface geology," he said.

"It readily sees high water content. Purely lithological changes are sometimes discernible. Detecting hydrocarbons in a known reservoir is trickier but also feasible."

It might be most useful in onshore surveys where lithological and structural variations are limited, he said.

The data sets might be appropriate for AI techniques, if they can spot patterns without necessarily understanding what they mean. "This is a young technology – it is under development," he said.

Geoprovider – finding more from mud gas analysis

Data from "mud gas", gas carried to the surface in circulating drilling mud, can provide many insights into the geology. Geoprovider of Stavanger is developing ways to do more with it

Oil companies routinely report data about mud gas – gas which enters a well during drilling and carried to the surface in circulating drilling mud.

But they could perhaps get a lot more insights into the subsurface from this data than they currently do, according to Stavanger / UK company Geoprovider.

Geoprovider has developed a methodology for working with gas data from drilling mud, including quality control of the data, assessing the data, analysing it and finally interpreting it.

Mud gas data is collected for nearly all North Sea wells, said Trym Rognmo, project leader for advanced mud gas and well studies with Geoprovider. The Geoprovider methodology

Trym Rognmo, project leader for advanced mud gas and well studies with Geoprovider

has been tested on data for around 500 wells, mainly in Norway but some in Denmark and UK.

The biggest part of the work can be getting the data in a digital format, assessing and 'conditioning' it, steps which could all be considered part of quality control.

Many wells still only have their logs in paper format, so these have to be digitised. Some mud samples are still physical, with companies sealing a sample of mud and drill cuttings in a can and sending it to a laboratory.

The analysis work starts by looking for signs of a "show" - hydrocarbons in drill cuttings or cores, which must of course be higher readings than the background level. Gas shows are analysed in a graph chromatograph, to find out the presence of different gases such as methane.

Analysis work can involve looking at the gas ratios (the ratio of one gas molecule to another), looking at how strong the various shows are, and indications of where there might be seals in the reservoir, because the gas flows on one side of the seal are different to on the other side.

The composition and volume of any gas you

find can tell you where the gas has come from - gas which comes with oil is usually much heavier than gas directly from a source rock, he said.

The data can be integrated with other data sets such as seismic or petrophysical parameters when interpreting it.

Quality control

The quality control work involves understanding different factors which might lead to a change in the mud gas reading.

For example if the drilling is overbalanced, with a heavier mud density, less gas will enter the well bore than with normally balanced drilling.

The ability of drilling mud to absorb gas varies with temperature. So if the drilling mud changes in temperature as it flows to the surface, for example for a deep sea well with mud coming from subsurface through cold ocean, that will impact how much gas comes out of the mud.

Another factor is the quality of the systems on the rig used to analyse the mud (chromatographs), and if they were calibrated and used

correctly.

Data assessment

One way to assess the quality of well data is to compare the total gas recorded with the gas detector, and the sum of the measurements of individual gases from the gas chromatograph.

The "total gas detector" will record CO_2 and other gases which the gas chromatograph won't detect, which you need to correct for, he said.

The data can be considered good quality if the readings are +/- 20 per cent of each other. "A lot of the vintage wells will completely plot outside of this," he said. "The majority of wells we have been working on are from the 70s and 80s."

The poorer quality data can still be used, but with a higher uncertainty assigned to it.

The larger the carbon number of a gas molecule, the higher the critical point of the gas, the temperature at which it will 'degas' from a drilling mud.

One study was made by Weatherford in 2009, injecting gas into drilling mud at the surface, and seeing how much gas came out of the drilling mud as it circulated back to the surface. It found that nearly all the methane injected into the mud was produced. But ethane had about half as much produced as injected, propane about a third, and so on.

The rate of penetration of the drilling can also affect the mud shows. If the rate of penetration is increased, the data for a certain change in depth will be recorded over a shorter time interval, which usually leads to calculations showing an increase in gas concentration for drilling over that interval.

Gas readings are recorded in time, so needs to be projected to convert it to depth, and there can be errors there.

The hole diameter will affect the gas concentration, because the smaller the hole, the less gas can penetrate into it.

A coring task will involve reducing the circulation while the work is done, and so creating less cuttings, also leading to an abrupt change in mud gas concentration. In one example, the gas concentration suddenly changed from 8 per cent to 0.5 when a core was drilled, because the circulation was slowed down and there were no new cuttings.

There was a second core drilled in the same well, with no obvious drop in the gas data – although at this point, the well was drilled into a gas cap, he said. The third core also shows a drop in gas concentration.

Another factor to take into account was the changing practise of recording gases in different years.
In the 1970s, people recorded butane and pentane but not the specific isomers. In the late 70s they started recording pentane (C5) and it wasn't until the mid-90s companies started to split both butane and pentane into isomers.

Isomers are molecules with the same formula but a different structure. For example there are two isomers of butane, they are both C4H10, but one has the carbon atoms in a line, the other has 3 in a line and the 4th branching off the middle one.

Another factor to consider is the use of oil based muds, which can reduce the interaction between the formations and the well bore, as a kind of blocker. They can also contaminate the gas reading.
Mr Rognmo showed data from a North Sea well using an oil based mud called XP 07. "This mud is a red flag for us, we've often seen this one contaminates mud gas data," he said.

You can spot contamination by looking at the mixture of gases above, in the overburden, which acts as a kind of gas separator. Typically the lightest components will penetrate first (C1), followed by C2, C3 and so on. If you see first methane (C1) and then iC5, that might indicates that something is adding iC5 into the well bore, such as an oil based mud.

There isn't a good way to correct for contaminations other than removing the parameter, but if you are aware of them when you do data anlaysis, you can end up with a better result, he said.

Interpretation

One useful piece of interpretation work is to look for seals. If you see changes in gas signatures from below a certain depth, that indi-

cates a seal, which gas is unable to penetrate through.

You can analyse how the level of gas changes with depth. A big change with depth is an indication of low permeability if the lithology and drilling parameters stays the same.

You can also get a sense of permeability by looking at the ratio of methane to a heavier component. If it is sandstone, which is quite permeable, the ratios between all components will stay the same. But with a tighter formation, the larger molecules can't penetrate as well as before, so the ratios will change, showing an exponential increase between C1 and C2+ . You can get an indication of good permeability, medium, low or tight, in this way.

If the drilling has been done in overbalanced conditions and with oil based mud, it can be quite hard to determine where the gas shows were from looking at gas data. It can be more useful to look for changes in the gas composition, showing you where the seals and impermeable rock is.

Geoprovider did this analysis on a Barents Sea well drilled by Equinor using water based mud in overbalanced conditions. Even though a core was taken in the reservoir, the excellent conditions in the well allowed for the gas-oil contact to easily be identified.
There were increased gas readings in the gas zone, reports of staining on cuttings, and then above it, sands with a different level of hydrocarbons.

The gas "signature", the mix of gases you see, can be different in zones containing oil, gas and inert gas.

The signature will change as oil gets heated and starts to crack (big molecules into smaller ones). It will change when hydrocarbons start migrating, with smallest and lightest molecules leaking off. If a trap is filled with different oils you get a completely new signature.

If there is an interval with no obstacles to flow, all you would expect is the lightest gas components to move towards the top. If there is a break in this pattern, that indicates something is stopping the flow, he said.

Wider analysis

The data can be very useful when multiple wells can be studied at once.

In Quadrant 35 of the North Sea, Geoprovider gathered data from 59 exploration wells, drilled between 1987 and 2017. It is quite a mature area, containing a deep cretaceous basin and a Jurassic play. There have been recent discoveries in the Quadrant, so it is quite "hot" in Norway, Mr Rognmo said.

Geoprovider modified a thickness map of the Jurassic (Millennium Atlas, 2000) play and the study were based on data from the 53 wells which penetrated it.

It presented the wells on a map, with the size of gas shows in the well mapped as bubbles. A bigger bubble represented a bigger show. There was colour coding of pink being wet gas, green being oil, and dark green being residual (heavy) oil, detected from staining on drill cuttings.

Only two wells had strong residual oil shows. They might lie on an oil migration pathway, not in the accumulation themselves, he said.

Another well had clear gas shows in an upper section, but some smaller "blip" gas shows which might easily be missed.

Another project was to plot wells with shows above the Jurassic. They mainly show where the Jurassic is thinnest, as you might expect, but there are some showing where the Jurassic is thick (250 to 500m). These shows also correspond with discoveries made in cretaceous sandstones.

The shows could be an indication of the amount of sealing – a good seal means no hydrocarbons migrates vertically, so there are most likely no shows above the seal.

However another explanation could be that as the Jurassic gets thinner, there is accumulation space to deposit cretaceous sandstones forming a reservoir, so there is more space for the trap.
The Jurassic and Cretaceous were thought to be independent, but perhaps this was not the case.

The data can be used to help improve the "common risk segment maps" which oil companies make, assessing their risks of having source, charge, trap and seal. For example you can say your risks of a seal are 75 per ecnt or 50 per ecnt or 25 per cent. The map can be improved as more data is added.

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Moving subsurface models around using data standards

Energistics' RESQML standard makes it much easier to move subsurface models between different software applications. This is particularly useful if the software is cloud hosted, as it increasingly is today. Energistics' Dave Wallis explained further

Energistics' RESQML data standard makes it possible to move data subsurface data and models easily from one software system to another.

Conventionally, you move data between software packages by exporting data from a database in one application, perhaps doing some data configuration, and then importing it into another one. It can be very labour intensive, to the point where the challenges of moving data around prevent people from doing it at all.

Energistics RESQML standard is designed to

Dave Wallis from Energistics

enable subsurface models to be easily exported from one system and imported into another.

It works with all types of subsurface models and data sets apart from raw subsurface data such as seismic. It includes rock structural data, fluid data, reservoir simulation grids, time lapse data (how the reservoir changes over time). It can handle all the steps from seismic data interpretation to reservoir simulation, and ultimately provide a way for data to be archived.

The data could also be shared between asset

teams within one company, and between oil companies. Metadata can be added so you can keep track of the pathways which data has been on before. "If you get a set of data, you want to know who touched it before, whose fingerprints are on it," said David Wallis, senior advisor with Energistics.

If you trust the integrity of the processes the data has been through before it reached you, you can work with the data without wasting time doing more checks on it, he said. Checking data takes a huge amount of people's time, particularly if they have to look at data, and tidying up problems.

The system is completely vendor neutral, for every part of every earth model.

The latest version of RESQML, version 2.0.1, was released in December 2016.

Energistics has 110 members, including E+P companies, oil field service companies, software companies, system integrators, cloud providers, regulatory agencies. It sees itself as a custodian of standards created by the industry, rather than a body which writes standards.

The three main standards are WITSML, for moving drilling information between and operator and subcontractors; RESQML, for moving earth model data; and PRODML, for moving production data.

In 2016 Energistics created a standard technical architecture for all of them, so oil companies could easily bring together data from production, reservoir and drilling. It also developed the Energistics Transfer Protocol, to move data round quickly. It adapted a protocol developed by NASA for sending data in and out of space.

Amazon and Microsoft have recently joined, because they recognise how the standards can help transfer data into software systems hosted on their cloud, Mr Wallis says.

RESQML demonstration

Energistics conducted a live demonstration of transferring subsurface data via RESQML at the SEG (Society of Exploration Geophysicists) 2018 Annual Meeting in Anaheim, California, in October 2018, at the exhibition stand of the Society of HPC Professionals, basically transferring earth model data across different software applications. The whole demonstration took 45 minutes.

Real data was used, for the Kepler field, jointly operated by Shell and BP, in the Gulf of Mexico. It followed a real geo-modelling workflow.

The process began with a Kepler static model on Emerson software (Roxar RMS), which was updated with static software also owned by Emerson (Paradigm SKUA).

The data was then exported to IFP Beicip OpenFlow to generate additional properties. All of this time, the data was stored on AWS (Amazon) cloud.

Then the data was moved to Schlumberger's Petrel software, using Schlumberger's "DELFI" platform, which runs on Google Cloud.

Then the files were moved back to AWS for mapping new properties to the model on Paradigm's SKUA. Then a simulation was run using the "IMEX" software from Computer Modelling Group, running on AWS. Finally, time-lapse results were viewed on Dynamic Graphics' CoViz4D software on AWS.

At each step, the data in RESQML was read into the application, modifications were made on the model, and the resulting updated model was exported back in RESQML. Metadata was also added at each stage, keeping track of what had been done to the data, who did it, and with which software application.

The data transfer included wells, trajectories, static and dynamic reservoir arrays for one of the reservoirs. The trial was fully pre-prepared and tested, to make sure it would work.

Moving data between applications is necessary because there is no single application which can do everything oil companies need, Mr Wallis said. And the need to move data between software applications looks likely to increase with more "boutique applications" being developed to do specific tasks.

Having the data standard might make it possible to make data models which would otherwise be too time consuming to make, because of the effort exporting and importing data.

There is an interesting project emerging called "Open Subsurface Data Universe" with a number of subsurface data service companies discussing ways to move subsurface data around, he said.

digital energy journal

Self organising maps on subsurface data

Self organising maps is a useful machine learning technique to help get a better understanding of subsurface data, by helping you pick out patterns which might identify geological bodies, from spotting patterns in seismic attributes. Tim Gibbons, Managing Director of geoscience sales company Hoolock Consulting, explained

Self organising maps is a technique which can be used to pick out geological bodies on seismic data, on the basis that there are similarities in the seismic attributes (pieces of data derived from seismic data) in different locations of the geobody.

Working this out manually, or with standard computational techniques, is very hard, because there are hundreds of different seismic attributes you can calculate, you don't know which ones are important, and the match is not exact, and some attributes give fairly random data.

The technique uses Principal Component Analysis to determine which attributes are most important (in terms of having the biggest influence on other attributes), and then which areas of the seismic section have a close match of seismic attributes.

You can do this analysis without necessarily understanding what the individual attributes mean, but just on the understanding that there are geological reasons which will cause a change in some of the attributes.

So in this way you reduce a large data problem to a manageable problem, thereby helping you understand subsurface features, providing a better definition of reservoir geometries and improving correlation in difficult strategic environments. It does in no way remove the need for a geoscientist – they are still needed to interpret the results.

A detailed explanation of the Self Organising Map (SOM) technique is beyond the scope of this report (although there are plenty of explanations on the internet). But this is the essence of how it can be used in subsurface exploration, as Tim Gibbons, Managing Director of geoscience sales consulting company Hoolock Consulting, explained.

Mr Gibbons presented a non oil and gas example of where Self Organising Maps is useful – working out which countries are most similar.

Special report from New Geophysical Approaches event

Tim Gibbons, Managing Director of Hoolock Consulting

There are many standard pieces of data available about countries, such as life expectancy and infant mortality. But if you have 30 different data points about 180 countries, it is very difficult to work with. But the SOM technique can crunch the data to show that (for example) Thailand, Ecuador and Mexico are similar in their data.

If you had only two or three variables, you could visualise them in a 2D or 3D graph to see if there is any obvious relationship. But with more variables than that, it gets very difficult to visualise.

The Self Organising Map technique is similar to a technique geologists have been using for years, using log crossplots to determine the lithology at each depth in a well.

Self Organising Maps "works well with the types of data that we've got and the randomness of a lot of that data. It works very well with seismic attributes," he said.

This is a form of machine learning which is called "unsupervised" – it is done with no idea what the answer is, and does not require any person to 'train' the algorithm. It is basically just looking for patterns in the data, and leaving it to an expert to interpret what those patterns might be.

It is possible to bring in other types of subsurface data into the analysis, such as gravity and magnetics. The only criteria that the co-ordinates (x, y, z) uses the same system, so the samples are taken from the same place.

Working with just one attribute can cause problems. For example, a geophysicist might say, because these three points have the same seismic amplitude, they must have the same rock properties.

Mr Gibbons presented an example showing why this is not always true, with a seismic image showing three different wells which had been drilled into a formation with the same amplitude, and one of the three turned out to be dry. It would have been impossible to know that just on the basis of amplitude data. But an analysis of multiple attributes picked out features which were present in the two producing wells but not the third dry one.

As the seismic amplitude is a function of impedance contrast, which is a product of velocity and density, and velocity varies on a lot of different parameters so If 2 parameters change you may end up with the same impedance contrast but you don't necessarily have the same geology, he said.

Over 150 different seismic attributes can be calculated from any seismic volume. 150 is too many to deal with, but they come in families relating to different geological features, for example instantaneous attributes are very good for unconformities and geometric attributes are very good for structural attributes like folds and faults. So you can reduce the number of attributes you want to examine based on what you are looking for.

In one example from the Norwegian Sea, the SOM picked out 4 distinct layers, which could be highlighted with colours. Another example showed how the analysis could show faults much more clearly.

Mr Gibbons showed a series of examples from an onshore US 3D seismic survey to demonstrate the impact of changing the inputs and parameters

With an analysis based on just the top four attributes, you could just about pick out a channel and faults. With the top seven attributes the channel and faults were clearer. But with 10 attributes, the result was not as good. So too many attributes can be worse than too few.

Another question is how much data to put into an analysis. Mr Gibbons showed results just working with data from just below the channel and just above it, so a lot less data, and it shows a clearer image of the features.

You can choose to only run the process on a certain subset of your data. This is called 'harvesting'.

Mr Gibbons showed an example of a self-organising map which was "harvested" in four different quadrants of the image. The channel only exists in the top left quadrant, and the image harvested on the top left quadrant shows the channel much clearer. The images harvested in the top right, bottom left and bottom right quadrants don't pick out the channel in anywhere near as much detail. One image could not show the channel, just the boundary around it.

Further examples were shown with varying input parameters such as the neural learning rate, initial neighbour distance and number of neurons. However, the impact of changing these was much less than seen in any of the previous examples.

The software system was developed by a specialist geophysical software company.

Developing a sensor strategy

Our digital strategies are based on data gathered from the humble sensor, yet often very little thought is put into them. For example, there might be better ways to use "edge computing", where processing is done perhaps within the sensor itself, rather than sending all the data.

By Jane Ren, CEO, Atomiton

The role of the humble sensor is to obtain our data. It is an often neglected but key component of modern industrial systems that feed data to the controllers, monitors, and other operational technologies running the facility.

Oil rigs can have tens of thousands of sensors. Sensors serve many important roles in the oil and gas sector from monitoring downhole pressure and temperature, measuring inlet and outlet pressures on pumps, measuring oil, water and hydraulic fluid pressures. There are a wide variety of sensor types available, with new and improved versions coming along continually including temperature, motion, position, presence, vision, force, flow, and chemical composition.

Research & Market predicts that the global oil and gas sensors market will reach $9.4 billion by 2023 from an estimated $7.4 billion in 2018 at a CAGR of 4.81 percent.

This growth can be attributed to the increasing demand for sensors due to capacity addition in the refinery sector and the growth in the IoT sector.

There are 33 families of sensors, including acoustic / sound, automotive, flow / fluids, optical / imaging, electrical / magnetic, proximity, radiation, navigation, force / density, chemical, pressure, speed / acceleration, thermal, pressure.

Each of these sensors has multiple 'classes' - for example the company counts 224 different classes of pressure sensor, such as downhole, tactile sensor, pressure gauge and piezometer.

Then each of these classes has multiple models - the company counts over 12,500 different types of piezometers, vibrating wire, pneumatic, titanium, and more.

Many of these will be analogue rather than digital. They can be wired or wireless.

Edge computing
Edge sensors

There is a new breed of sensors that are now available that can combine the function of a sensor with local processing power.

These devices, called smart or edge sensors, can merge disparate data into streams of actionable information and allow assets to be monitored and optimized from anywhere in real time.

Edge computing allows you to collect and process the data from sensors where it is being generated, rather than sending it back into the cloud. It is critical to impacting business operations in real time.

Sensors and edge computing are closely tied together.

Edge computing provides real-time analysis of data, reduces data that is sent back to the cloud (thus reducing bandwidth required and cost) and lowers costs related to operations.

These sensors facilitate the accurate and automated collection of environmental data with less erroneous noise amongst the accurately recorded information. Another benefit of smart sensors is that they have built-in gateways and software to securely send the data to the cloud in a form compatible with cloud platform service providers.

Five steps

It is vital that a company's sensor strategy is aligned with its IIoT ambitions to deliver the raw information for data analysis. Instead of focusing on attributes of individual sensors in isolation it is essential that every company develop a well-planned strategy for their sensor network.

There are five essential steps that companies need to go through to create a scalable sensor strategy. Determine business needs, define their data requirements, consider standardization, understand your own specific applications and decide how to integrate everything within their digital architecture.

Business needs

The process begins by gaining a full understanding of the need for sensors and what they are used for. Within the oil and gas sector there are a myriad of reasons that sensors are utilized.

One reason may be to retrofit existing equipment or systems, such as pumps, generators, valves, or equipment like welding machines that were not originally designed as smart machines. By retrofitting this equipment with sensors, they can become self-aware, self-diagnostic, and collaborate with other equipment without requiring
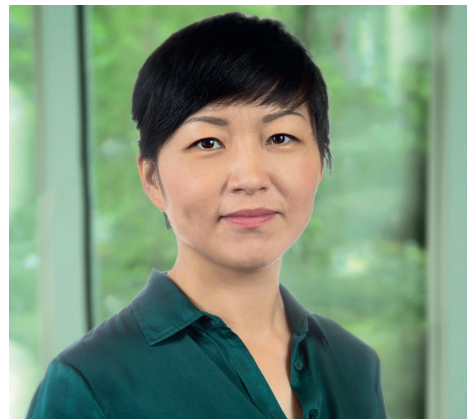
Jane Ren, CEO of Atomiton

a significant upgrade and budget to do so.

Another reason to leverage sensors is the vast geographic distribution of many of the sector's assets, which are often remote or not easily accessed. Product wells, pipelines, gas storage facilities may require significant manpower to gather data, or simply be difficult or hazardous for personnel to access. Sensors may also augment human capabilities in sensing, such as detecting gas leaks, pressure imbalances under the well, tank overfill risks, and do so more quickly and safely than humans.

Defining data requirements

Although having sensors covering every facet of production offers tantalizing rewards, it does come with challenges, particularly the amount of raw data they generate. A typical offshore oil platform generates between 1TB and 2TB of data each day. Most of this data is time-sensitive, pertaining to platform production and safety. In many cases it is not data that's lacking, it is analyzing it in real time and applying the results to improve functional and business capabilities.

Sifting through, analyzing and managing this scale of data can be significant work. As part of your sensor strategy, you must define the data you need, and how often you need it. In defining the necessary data, start with the end results, by answering the question - what is the need for the business?

The requirements will change from business to business. It may be that asset data such as locations of moveable assets, functionality, performance, availability of the assets, tank levels, stress, load and fatigue of materials and energy

use are core to your business's performance. For others it may be activity or process data; pipeline flow, mixing or heating of product, usage such as fuel consumption, status such as fabrication progress through cutting, welding, fitting, non-destructive testing; safety of personnel such as excessive extension or tilt.

Most likely you will need multiple types of data, and by starting with the business needs you can understand what data brings more intelligence that you can analyze to impact operations.Consider the timing of data as well. What is needed in real time, what is needed at intervals (and at what intervals), and what can be sent straight to the cloud for later scrubbing and additional analysis. The value of the right data, streamed continuously or at specific intervals, provides operational intelligence when needed, and where needed.

Take for instance gas meter reading. If the meter is read once a month its only real use is for billing information. However, if the meter is read every hour then it supplies product flow information, providing operations with actual intelligence when needed. In drilling operations, you may need data on the position of the drill bit every minute, or you may decide you only need data in the cases of deviation.

Defining the data needed helps you understand the types of sensors and the numbers of sensors required. Don't forget to consider the bandwidth needed for large amounts of data being sent to the cloud and the associated costs.

Consider standardization

One of the drivers within the oil and gas sectors aimed at reducing cost and complexity is standardization. When faced with the huge selection of sensors that are available in the market it may be prudent to standardize on some aspects of your sensor strategy.

Do you want to standardize on the sensor vendors? Perhaps you could select sensors that use the same transport and communications protocols. Or, you could decide that all sensors need to have a minimum battery life or use only a specific amount of power. Depending on the environment for your sensors, you may require ruggedized, weather-proof, or other industrial-specific types of sensors.

Knowing your application

Nobody understands your business like you do. Domain expertise is a vital commodity when it comes to defining your strategy and understanding the applications. Ren explains that the applications used to deliver insights must be determined, in order to understand how you want to leverage the data from the sensors. Your sensor applications may be broad-based or functionally-specific.

As an example, a broad-based sensor application might be a GPS sensor on a moveable asset like a crane or forklift. This GPS data can be used for an asset management application, an intelligent fuel application, or a project tracking application. A function-specific application is when sensors are used for only a specific, designated purpose, such as measuring the position of a steam valve in a system.

Integrate with digital architecture

To be able to handle data effectively requires the right data architecture that is built on a foundation of understanding the business requirements. Oil and gas operators must make sense of ever growing and more complex data volumes that are collected from a variety of sources in various formats: a task that traditional data infrastructures struggle to manage effectively.

The sensor strategy will become a part of the organization's overall digital architecture that spans from the enterprise to operations. Sensors sit at the edge of operations, as part of operations technology.

Assessing the need, data, standardization, and applications will help you build a reference architecture that defines the selection, deployment, access, data gathering, monitoring, management and security of sensors. For oil and gas companies driving digital innovation and transforming their business, it becomes a part of the overall enterprise strategy.

digital energy journal

How do we get distributed temperature sensing data out of our wells?

Recovering downhole distributed temperature sensing (DTS) data (from fibre optic sensors), accurately processing it and making it available for use anywhere within a global enterprise infrastructure, can be challenging for wells located in remote locations.

By Andy Nelson, senior software engineer at independent global completions service company Tendeka

Understanding the relative contribution to production by different zones at different times in the wells' life, and whether production is dominated by a single zone, adds value to planning future wells.

Tendeka's initial implementation in 2016 was for a multiphase development across 12 coal seam gas wells for a major producer in the Surat Basin, Australia.

As the wells were in a remote and extreme environment, the first obstacle to overcome was to secure and maintain power and connectivity.

Minimal communication infrastructure and at least six-hours driving time from the nearest manned location capable of providing support, proved problematic.

Fluctuations or power outages can have a direct impact on the effectiveness of the data and subsequent analysis, and ultimately the value of the DTS installation.

The first DTS units deployed in the field provided limited connectivity options.

Typical collection required someone physically visiting the site and downloading the data via the application to a laptop computer and then returning that data to the office domain at some later time.

The only method provided by the DTS vendor to retrieve the collected data was via a proprietary Windows desktop application.

Communications solution

To provide a working communications solution, each well was equipped with either local gas-powered electrical generators or solar-powered units capable of running the DTS units and a modem for extended periods without human intervention and, in the case of solar-generation, throughout the hours of darkness and times of inclement weather.

Tendeka personnel connected each Sensornet DTS unit to a GPRS modem.

Using the telecom carrier's infrastructure, a hardware-based virtual private network (VPN) was established between the modem and cen-

Andy Nelson, Senior software engineer at Tendeka

tralised servers, thus securing the remote connectivity solution from outside intrusion.

The modem was then connected directly to the DTS unit via a serial communication port. A tunnel capable of linking a COM port on the DTS unit over potentially any distance to the server in the data-centre was also established.

Data recovery

Having set up the physical connection, the next task was to recover the data.

DataServer software was set up to continuously poll for new DTS measurements as they

became available. Once recorded, the measurements would be retrieved from the DTS instrument and copied to the server.

A second server operating in the data-centre was installed with software responsible for managing the DTS data.

This software is alerted to new DTS measurements being saved and then proceeds to import those measurements. A workflow process of validating the data was the first step in the import process.

Each file is opened and checked against pre-configured rules to determine if the data is coming from the expected well site. For example, the DTS measurement data contains details about the well, such as a name or unique identifier, which must be validated before data can be imported.

During import, any errors or data discrepancies are flagged in an alerting system to a human operator so that the data can be manually checked. The alerting system also notifies operators if the DTS unit appears to be offline, if the data coming back from the instrument is corrupt, or if the modem communications are down.

Having imported the data, the application man-

Modem connects to DTS unit and telecom carrier

DTS unit periodically records temperature measurements from well fiber

Telecom carrier provides VPN connection

Server connects to modem via telecom carrier VPN and downloads DTS data via vendor application

Main application imports data following established rules

Authorized users and systems can access data from anywhere in the world via secure connections

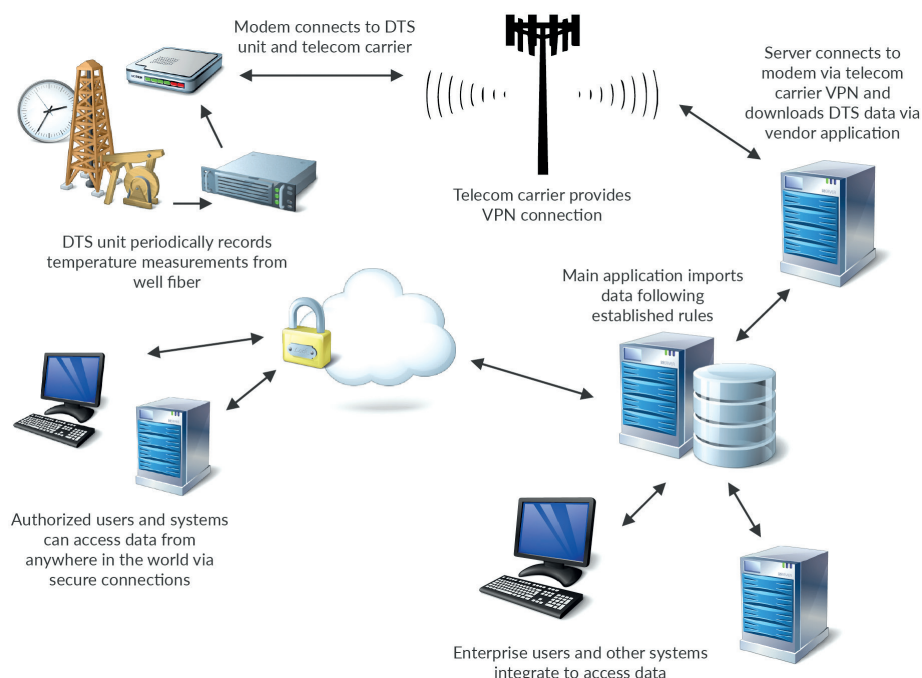Enterprise users and other systems integrate to access data

Figure 1 shows the architectural data flow.

ages data security and access to both human operators, using Tendeka's FloQuest analysis and modelling software, and automated systems.

The system has an application programming interface (API) that offers a representational state transfer (REST) interface to allow third-party systems, with the appropriate authorisation, access to the data, analysed results and alert status.

The initial solution monitored 12 wells in Australia but has subsequently been scaled to monitor more than 100 wells with another customer in South Asia utilizing the same solution and similar infrastructure.

Subsequent projects have been deployed using existing DTS vendors for the instrument boxes. Each deployment changes depending upon the infrastructure needs of the well.

Data analysis

The data was analysed, along with other data from sensors across the sandface to the wellhead, by Tendeka's own FloQuest modelling and analysis software.

This uses proprietary algorithms and intuitive interfaces to seamlessly integrate multiple data sources into clear visual outputs.

The same methodologies can be used beyond just DTS data. The ability to manage data automatically and process it by handling it at source and then bringing it into a cloud-based solution, means that more data can be processed to its potential value.

digital energy journal

Value from predictive maintenance

Predictive maintenance systems can provide better value where they can predict specific failure modes occurring, rather than where they need to predict a slow degradation of a component. We interviewed Ron Beck and Lawrence Schwarz from Aspen Technology to discuss further.

There are many components in an offshore oil platform, in your house, in your car, which degrade slowly and unpredictably. Suddenly, a tile falls off your roof or a chain snaps.

These are probably not the best places to use predictive maintenance software – because, even with massive amounts of data, it is very hard to predict. And even if you did have a prediction, such as "30 per cent change of failure in the next 6 weeks", it is very hard to make a decision that would prevent the problem.

But where predictive maintenance software can provide much more value is in spotting specific failure modes occurring – where something specific is actually going wrong, where there is often a seemingly unrelated cause in a complex system that you can predict, and if you don't fix it now, it will get worse until it stops your operations.

Saras refinery

AspenTech, one of the world's biggest industrial equipment maintenance software companies, provides a case study to illustrate how big this value can be, based on its work at the Saras refinery, in Sardinia, Italy.

The refinery handles 300,000 barrels a day. It has its own 575 mW IGCC power generation plant.

The refinery deployed AspenTech's "Mtell®" software which can identify the failure "signatures" which precede asset degradation and breakdowns on a subset of equipment, including looking at condition data and process data.

The data analysis covered 52m pieces of sensor data. The team looked at 163 data quality issues, including bad data and missing data.

They also cross referenced the work order history of the four assets, covering 340 prior work orders. The maintenance history covered 17 problem classification codes.

From the patterns learned, the system was able to identify a future valve temperature failure 39 days in advance, and a valve replacement due to an instrument failure, 25 days in advance. It could also predict a number of seal failures 24 to 45 days in advance. There were no false positives.

And the failure patterns provide operators information on the cause, so that changes in operations can be made to alleviate or prevent the issue.

Now, Saras plans to implement the software across the refinery.

Diagnostic software

Following a similar idea, oil and gas companies might want to use predictive software when they would like to be able to spot problems happening in advance on specific pieces of equipment, said Ron Beck, marketing strategy director with AspenTech.

The software is perhaps less easy to quickly implement on highly complex pieces of equipment, such as blow out preventers or complex drilling systems, where failure modes can happen differently every time, he says.

"A blow out preventer is very complex so it probably will yield to this kind of analysis but maybe not until we apply it in several test cases to understand which of many different information types are the strategic ones that influence incidents," he says. It is actually a complex thing to diagnose. There are geophysical

Ron Beck from Aspen Technology

factors, oil characteristics, flow assurance factors, the infrastructure conditions, and environmental factors external to the system, and the process itself. There is so much domain expertise required in understanding a blow out preventer, that that would yield best to a different approach, hybrid modelling, which we are also working on for future software.

In contrast, the many compressor trains and gathering systems in production environments fail because of factors "upstream" of the actual equipment, so these ideally yield to today's analytics and AI based analysis approach

And on a rig, for instance, it would be the downhole drilling tools themselves, high value and prone to damage, that would also yield to this analysis.

"Where machine learning and AI excels, he said," is where there are many streams of data, monitoring many parameters, but where people don't have the capacity or team of data

scientists to analyse all this data we are creating and discover the important, subtle patterns to predict what will happen," he said.

Studies show that most failures are not due to equipment wear or age, but process factors inherent in the systems, he says. When plants and oilfields are run hard, infrastructure condition often responds to these process factors.

It is already being proven that prescriptive maintenance systems can replacing scheduled maintenance on whole classes of equipment, such as pumps, compressors, motors, heat exchangers, separators and more

When considering deploying analytics, people are inclined to tackle their most difficult equipment problems, but this is not necessarily where analytics can most easily offer the most short term value, he said.

"It's a matter of choosing where to apply this, where there's a significant dollar benefit, both in terms of the cost equipment being down and the cost of lost production, and also the proven ability of these systems to handle it.

The systems can be called "prescriptive maintenance", because they can prescribe the reasons something is going to fail, so that remedial actions can be taken – this differentiates the terminology from "predictive maintenance," predicting what is going to happen.

Working on individual compressors and pumps can be "a more productive place to start – than trying to understand the entire rig itself," he said. "Why not start with the [problems] that are definitely solvable."

Better than planned maintenance

Studies show that only about 15 per cent of equipment failures are linked to factors which could be prevented by planned maintenance, he said.

And when companies do maintenance on a fixed schedule, such as a pump overhaul every 2 years, this can also create failures, "you interfere with something that's operating well," he said.

So the most useful contribution the software makes, he says, is to help people understand why something might be about to fail. "The why is really the most important thing," he says. "Unless you know why, you really can't do anything about it."

This can be more important than simply seeing a trend or being able to calculate a probability.

If the analytics tells you something is going to fail in 60 days, that doesn't necessarily drive any change in behaviour, you could still just let the object fail. But if you understand better what is going on, you are in a much better situation to make decisions to change operating strategy to protect your asset integrity.

With the 'why' information, engineers have what they need to make a choice – for example to change the temperature or try to work out why fluids are making it into the gas stream.

"That's really one of the jewels of this, the operator can understand not only that something is going to happen but why, and take actions that can avoid the occurrence from happening," he says.

Training on data

The AspenTech system looks at multiple streams of data, including processes upstream of the critical equipment. It does a range of analytics on the data, looking for patterns which may be indicators of a failure.

The machine can be trained on historical data – and then can identify if there is a failure happening.

For example it can spot a 'signature' in the sensor data indicating that there are fluids in the gas stream going to the compressor, which will cause a compressor failure if not fixed shortly.

Note the computer system still requires people who understand the various systems to make a decision – it does not remove the need for expertise. But it is looking at patterns which happen too quickly, or which involve too much data, for a person to work with, Mr Beck says. "It is providing indicators and signals that someone knowledge able can make some sense of." Also of value is that the expertise needed is not that of a hard to come by data scientist but rather an experienced operator.

If the system sees an anomaly pattern it hasn't seen before, it raises flags, which an expert can look at, to determine if it really is an anomaly.

If the pattern can be diagnosed, it can be added to a register of things which the machine 'knows' about.

Machine learning can be used to spot different signatures, and AspenTech uses "a lot of machine learning tools," says Lawrence Schwartz, chief marketing officer of Aspen Technology.

Some generic machine learning platforms struggle with the technical complexities of (for

example) data from a compressor fan blade if they aren't combining machine learning signals with domain expertise.

The more data you can "ingest" about a system, the better it is. On the other hand, the false positives which often emerge on new projects can cause a lot of damage, leading to people to lose confidence.

Wells

AspenTech's technology is also being tested in well monitoring. On older fields, typically some wells will become unproductive. It could be due to some kind of blockage in the well, hydrates or wax.

If you are running a field with 500 wells, it is helpful to have some indication that a well is plugging, so you can do something before it happens to prolong its life.

This would in today's world require data to be gathered about fluid flow within the reservoir, which is also a difficult technical challenge. Machine learning based prescriptive tools adds immediate value in predicting these costly events.

Another area is downhole equipment, where companies can use measurement tools worth over a million dollars. Having indication that something is starting to go wrong with the drill string, which might lead to a loss of the equipment, and perhaps wrecking the hole, is very helpful.

Data sharing

If data can be used to improve reliability of operations – should it be shared, to the benefit of everybody, or do companies have a competitive advantage in keeping it secret?

Sharing data can help everybody operate more reliably, improve safety, which everybody benefits from. So should companies agree to share data more widely?

Data sharing is still "a very interesting point," Mr Beck says. If a company was putting in a new facility, perhaps it might make sense to pay a company which has the same compressors in operation for many years, to have access to their performance data if it could be used to spot trends.

Having more data available to more workers leads to the question of how the information is used in the company or the broader industry. If it is not kept open or ownership shared, there is the potential that someone could end up owning all the information about equipment

performance, and so control over a vital part of the recipes needed to keep equipment running smoothly.

Products

The technology at AspenTech was originally developed at MIT in the early 1980s – the name ASPEN is an acronym for "Advanced System for Process Engineering ". Early products included process simulation software HYSYS and chemical plant wide simulation software Aspen Plus.

The company's "Fidelis Reliability" software can generate a comprehensive list of "bad actors", problems which lose you revenue. You can do analysis to determine the impact of these problems, including reduced asset utilisation, or reduced equipment effectiveness.

The company's "Aspen Mtell®" software can make an analysis of past sensor data, maintenance / work order data, and problem data, to try to spot signatures of problems building up, which could be used to identify problems emerging in future.

Some companies use Mtell and Fidelis together, so they can analyse signatures of problems and generate a plant wide understanding of them, Mr Schwartz says.

Perhaps PCs are better for hazops

Perhaps the humble PC could actually be more appropriate than a tablet computer for use in hazardous environments such as offshore oil platforms, says HMI Elements

Tablet computers are easy to transport around, and can be easily passed from one person to another, and can be cheaper than a fixed PC. They can be easily used by people counting inventory and doing asset maintenance as they work.

But there are also some disadvantages of using them in hazardous environments compared to the PC, says UK / US company HMI Elements, which makes PCs, keyboards and wi-fi access points which are intrinsically safe.

It isn't possible to use any peripherals with tablets in hazardous environments, because plugging in any USB drive, charger or network cable would void the hazardous location certification. Normally, only wireless communication can be used.

The small screen of a tablet can also make it difficult to work with software and data, the company says.

Tablets can also more easily get lost or damaged, or moved somewhere and used in the wrong way. Tablets could also pose a safety risk, as operatives may be walking around site whilst looking at the device and trip.

Also there are challenges securing tablet computers with "TPM" type encryption, which is now required in some high security locations.

There are certain aspects of tablet functionality that are also not up to a hazardous computing standard; for instance, tablet screens are not sunlight viewable and could overheat in direct sunlight (sunloading), leading to failure when it is needed most.

Tablets also struggle with limited processing power and screen real estate, meaning combined application use or overhead is prevented.

Also, if companies need to purchase tablet computers specifically configured for the requirements of a specific location, rather than be able to buy tablets in bulk, they are no longer cheap.

So for work which is always done in the same location, where it is helpful to look at larger data, and larger processing power is needed, a fixed PC, perhaps with a touch screen, might still be the best option, the company says.

For example, mud logging, MPD, MWD/LWD, directional drilling, EDR, rig floor, tongue control, CCTV, plant refining process, heat exchanger, cracker units, platform processing and offshore.

Fixed PCs can have a certified fixed network connection, which can often provide a more reliable network connectivity than wireless, the company says.

"Whilst the use of tablet in a hazloc area seems a good idea on the surface - who wouldn't love more convenience and affordability? – they are simply not up to the standards required in a hazardous area and adds credibility to the old mantra "cheapest is not necessarily the least expensive," the company says.

"Perhaps one day there will be a portable solution that will stand up to the tried and tested reliability of a fixed workstation, but that day is yet to come."

HMi's customers include National Oilwell Varco, Canrig, Halliburton and Baker Hughes.

New HMI at OTC

At the May 2019 Offshore Technology Conference, HMi exhibited its latest PC for hazardous operations, the "1301-Z1".

It describes the computer as "a rugged PC that leads its class with extreme usability and toughness, combined with beautifully engineered design. Slim and lightweight with a super-bright 19", 1,000 NIT display the HMi 1301-Z1 is stunning and suitable for Zone 1 areas."

Using abstraction to improve software projects

Most things in real life happen at multiple abstraction levels, but digital technology still mainly operates at a single, very low level of abstraction. How would oil and gas digital projects improve with better use of abstraction? Digital Energy Journal co-organised a forum in Athens to explore the subject.
Based on ideas by Dimitris Lyras, director, Lyras Shipping and founder, Ulysses Systems

Outside the computer world, we see nearly everything in our lives at multiple abstraction levels. We don't think about it in this way, but that is because it is obvious.

We can see our own lives at a high abstraction level – such as our long term goals. We can see our own lives at a low abstraction, or high granularity level – as a succession of tiny thoughts and actions.

An architect operates at a high abstraction level when thinking about how a building will look like on a city's skyline or how it will feel like to enter. An architect operates on a low abstraction / high granularity level when making plans to pass on to the civil engineers who will make the building.

We see nature at a high abstraction level when taking in a landscape, and see it at a high granularity level when understanding the different biological processes which happen.

A politician explains how the world works to people in a high abstraction level. Our political beliefs are abstracted models of how the world works – the big things we

Dimitris Lyras, director, Lyras Shipping and founder, Ulysses Systems

need to get right in order to have a society which functions well.

Computers themselves only function at a very granular / low abstraction level, following a series of rigid instructions to move bits around. We use programming languages and user interfaces to add more abstraction, so we are doing something a little more like what we do in the real world

as we manage objects and transactions, and communicate.

But this abstraction does not extend very far. Take two big examples of how digital technology is used in upstream oil and gas – to help identify oil reservoirs and to keep equipment in good condition.

Our subsurface software will follow specific instructions and processes as we go from raw seismic to geological models. But it rarely does much to support the highly abstracted work which petroleum systems specialists need, to identify whether we have a succession of circumstances across geological time which would lead to a reservoir in that specific location – including a seal, charge and source rock.

The ultimate goal of subsurface experts is to work out the likelihood of oil being in a certain location, which they do with petroleum systems modelling, which they do with fairway analysis, which requires a geological understanding, which they do from a reservoir model, which they make from integrating interpreted seismic with other subsurface data, which requires integrating data, which requires processing data. This describes the various digital steps in levels of decreasing abstraction. Today's digital technology focusses on the lower end (data processing and integrating).

Our asset management software will manage large databases of part numbers and maintenance tasks, and put together a maintenance schedule. But it won't do much to tell a maintenance engineer what they really want to know, such as what the cause of a certain problem is, what the wider impact on the business will be if a certain task is delayed.

Also consider issues of software acceptability in companies. It is common for digital project managers to complain about 'users', including the complaint that the users to not engage much in the software development discussions but complain later complaining that it doesn't help them. But perhaps the cause of this is that the software is not being designed to support the mental models which domain experts actually use.

A geoscientist is focussed on identifying where the viable reservoirs are, and a facilities engineer is focussed on identifying which maintenance tasks are the most critical. They use a range of mental models in pursuit of these complex goals. If the software is not designed around the way that they think through a problem, the software is not helpful to them.

Software built at a higher abstraction level could help people to do far more, since it more closely matches the mental models which people who make decisions actually use, or gives them support that they really need. In other words. The software can support the key processes that need to be performed by the company.

To explore how software projects could be implemented with better use of abstraction, Digital Energy Journal co-organised a "Software for Domain Experts" forum in Athens on May 8. (see www.bit.ly/SF-DEAth6) . This article is based on ideas presented by our opening speaker, Dimitris Lyras of Lyras Shipping and Ulysses Systems.

End goals and nitty gritty

The end goals of the software user – such as geologist looking for oil – could be considered a high abstraction level in the world of software development – while a low abstraction / high granularity level work could be looking at the nitty gritty of how to make software work.

Perhaps in order to get software developers to be able to focus more on the end goals, we need to make the nitty gritty part of the software development much easier.

Software will always have a lot of highly granular processes – this is what software can do much better than people can, handling complex lists of part numbers, tasks, elements of a subsurface model. But you want all this to converge upon what people need and how they make decisions.

Currently, most of the work in software development is at the nitty gritty end, preparing documents about the scope of work, including use cases. Then designing the data models or data storage structures, and

putting them in a database.

Then you design the system for inputs and outputs to the database and any data processing, and build the user interface. Programmers develop the bits of the software that are described by the specific use cases without understanding the entire process the software needs to support.

And the user experience rarely feels like more than inputting and outputting data in a user interface.

The core data models are very hard to change subsequently because the software is built around them. So typically the data models only see small changes such as the addition of another attribute.

The logic in turn is not structured and acts in isolated batches. The whole structure becomes very complex and nobody understands the entirety of the logic. This means that no-one knows what will happen when a new change is made, the only approach is to test and see.

And testing is not necessarily comprehensive because the logic is unstructured. The whole set up ends up very fragile.

An alternative approach might be to start with an understanding of the specific goals of the company and its individuals, and what they need to do or understand to achieve them. This could be drawn just with lines on a white board. Then you progressively add in more granularity, until you have a model with enough detail to run on a computer. Then you give it to a software developer and ask them to build software which exactly follows this model.

Or perhaps you use 'low code' software platforms which generate software directly from a model with no further coding required. But note there currently no computer readable way to persist what people need and how it should work.

If you have a data store, then it can be incorporated into your overall model, but without the data store being central to the model. This way it is much easier to understand what the impact of any changes to the data store might be, or what happens if you move it. You can trace exactly how one change in functionality will affect another area of functionality.

To do this you need to understand the high level processes the software will need to support and not just a linear process de-

scribed in the development use cases.

Data security regulations

To illustrate why you might need to move data or change the logic, consider the evolving data privacy and security requirements, being introduced around the world. Such as in the European Union, where the European Union Agency for Network and Information Security (ENISA) has a remit to certify the security of software.

This is a "staggeringly huge" problem, if we have software which has evolved over decades and is not fully understood by anyone, said Dimitris Lyras, director of Lyras Shipping and founder of software company Ulysses Systems, in his opening talk to the Athens conference.

Too much software written today can be hard for even the person who wrote it to understand, let alone any regulatory agency.

But if software was constructed on a more abstracted level, you could easily see what the impact would be of moving a data store to a different location to the rest of the database, and how to build a system to verify that only authorised people are accessing it.

This abstracted model can be shown to any regulator or compliance body, who can quickly see that the data is physically stored somewhere secure, and there is a system to monitor who accesses it.

"We can present the critical parts to certifying bodies in an abstraction not in detail," he said.

Maintenance software

Maintenance software packages, for shipping and oil and gas, will typically include databases of equipment and spare parts, and make a schedule of work, but with no understanding at all about the impact on the wider business, such as what happens if a maintenance task is delayed.

But in order for a software system to know if that was important, it would be necessary to connect the systems for planning maintenance work with systems for understanding which pieces of equipment are most critical, or which have the biggest impact on the overall business if they break down, something which no software does (including oil and gas software). So you need to document all the processes that are affected by the software.

There are many maintenance management software products on the market, usually known as "asset management", made by major companies such as Microsoft and SAP, which do what computers do best, creating a schedule of maintenance work for someone to follow – but with no connection to wider goals of the business, such as the ability to tell you the impact of a delayed spare part delivery. It is not possible to prioritise maintenance without knowing the link between the maintenance tasks and the main shipping processes.

Asset management software has to do a great deal of heavy lifting, the sort of work software does well, such as maintaining complex databases of different items and making a schedule of which tasks to do, which takes a lot of computation. But it is not linked to anything else a computer is doing. There is no understanding within the software of (for example) how the risks change if the maintenance schedule is changed.

Today's asset management software doesn't usually take into account how the parts relate to the equipment manufacturers, or the full specification of the part which you might need to buy the part from an alternative supplier. As a result, people may enter compromised data in the system, leading to worse decision making.

The software does not help much with diagnosis and fault finding, a big element of maintenance work, which requires understanding different causes and effects. A maintenance engineer does this modelling in their head. Maintenance engineers also need complex mental models if there is a need to postpone or adjust the maintenance plan, working out what is possible to do without wider problems.
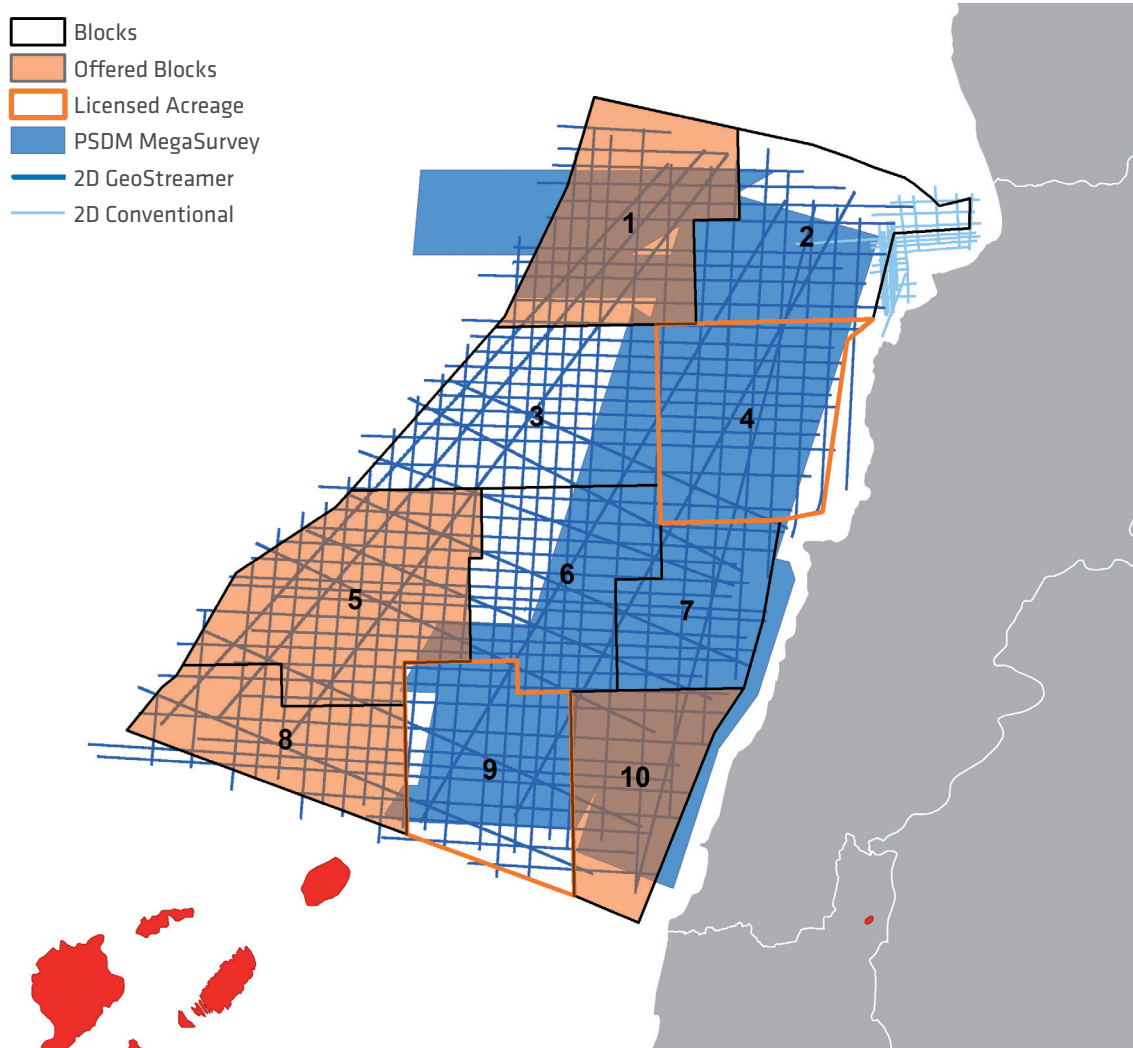
Maintenance engineers also need to know about spare parts. It is common for identical parts to be given different part numbers, partly because suppliers want to force customers to buy from them, rather than be aware that an equivalent part can be purchased less expensively elsewhere. But it is not satisfactory for customers to simply go along with this, their engineers need to carry mental models which understand what a spare part actually does or its technical specification.

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