digital energy journal

Decision support tools for exploration managers

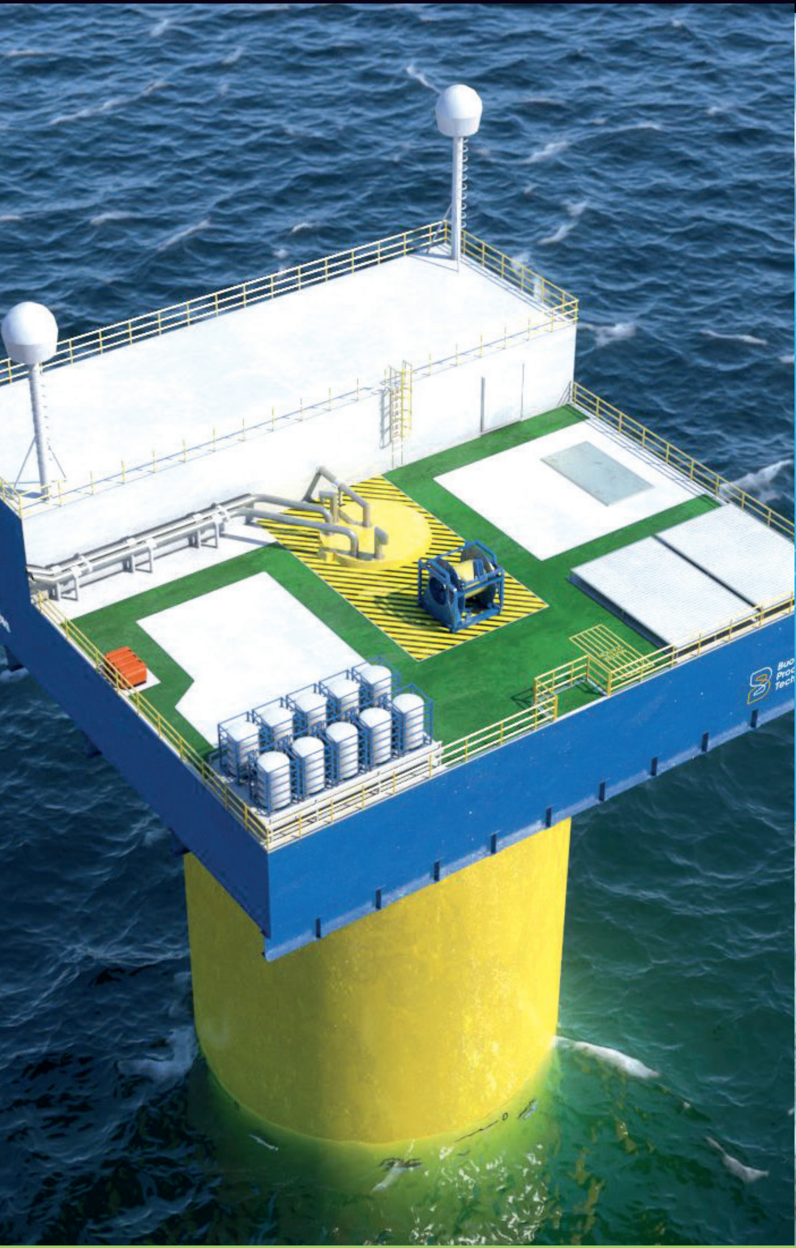
Cognite - putting business data in context

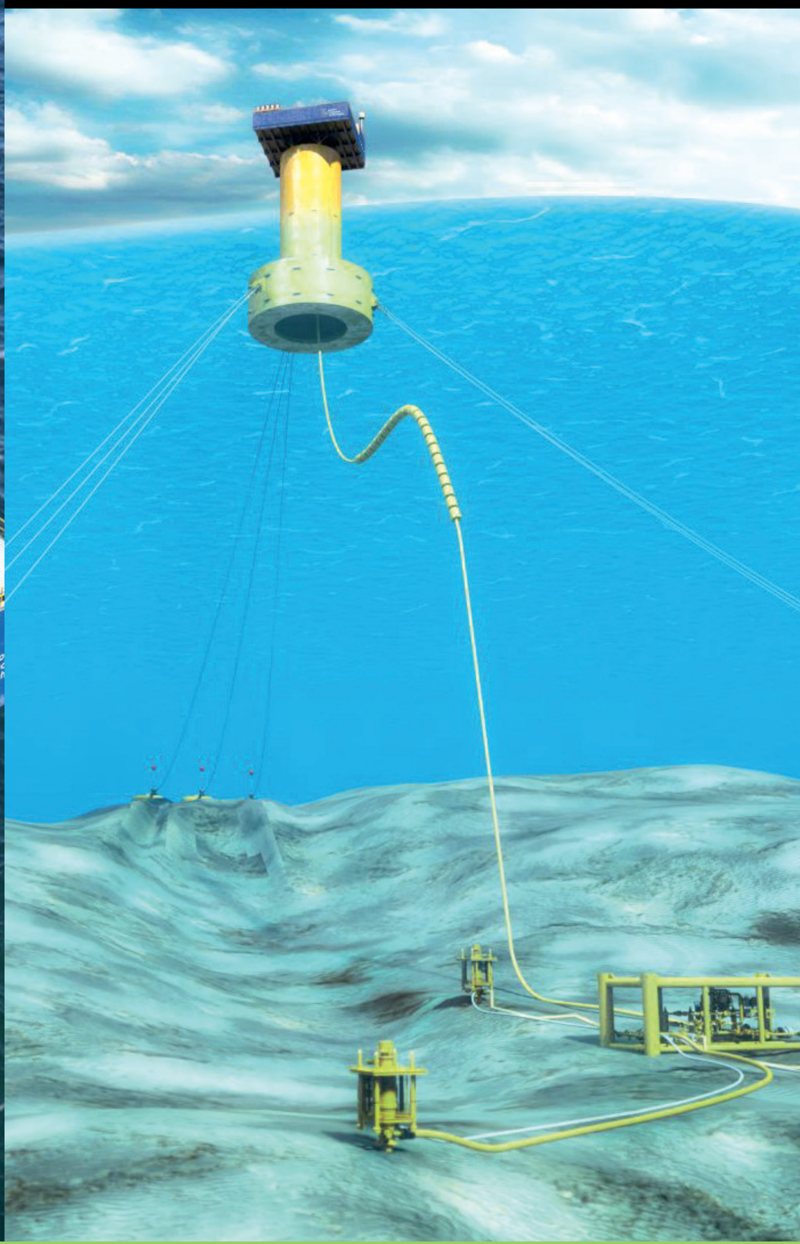
MAN ES - new data collaboration platform

Spearphishing shuts down US gas facility

Well data analytics as a service

April - May 2020





New approaches to developing marginal fields

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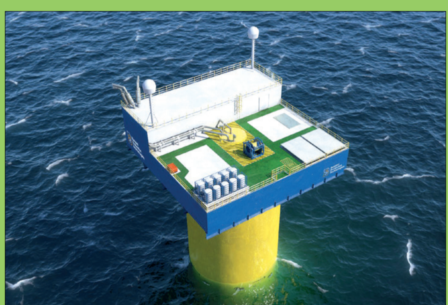


Cover image - The Crondall "Floating NUI"
Crondall Energy, an engineering consultancy based in Winchester, England, has been developing a design for a normally unattended production buoy, which it calls "Floating NUI".
Floating NUI can also be configured as a 'Power and Utility Buoy' supplying power and utilities such as chemicals at the wellsite to support long range or technically challenging subsea tiebacks.

Comment

The organisation-centric approach to tech

Digital technology in upstream oil and gas is turning into much more of a story around organisational issues, rather than technology itself - and big strides are being made in how these organisational issues are being handled, as we found out in our research for this issue.

We talked to Cognite about how they are making big advances in ways to help oil and gas companies handle live sensor data, and now moving to subsurface and drilling data. The ultimate goal is to give decision makers what they need - but you need quite a sophisticated data infrastructure to get there. This can be more an organisational challenge than a technical one (not that the technical part is easy).

We talked to mýa, the new live data integration platform founded by MAN Energy Solutions, about how they are inviting all equipment manufacturers to share ownership and control of their platform, which can gather together and integrate live sensor data from many different manufacturers.

One thing I like about both these companies is that they are well funded, and by funders who are looking for something from the project other than direct financial returns. Public data for Cognite says that it is 62 per cent owned by engineering giant Aker (which also owns 49 per cent of Aker BP) - and Aker BP is making good use of Cognite for its own purposes. mýa was launched and initially funded by MAN ES, a subsidiary of Volkswagen, and grew out of a desire to serve not only its own customers better but helping to drive collaboration and knowledge sharing between the users as well as other OEMs.

This matters because building these data platforms takes a lot of engineering time and expertise. The tech industry can have an unhealthy fetish for small start-ups, which don't have the resources to take on big tasks like this, or if they do, need to quickly give returns to their investors, which can imply a need to seek some control or monopoly power, the last thing any platform customer wants.

We talked to two interesting US data science companies, Validere, focussing on fuel specification data, and Lone Star, focussing on well head data. What is most interesting about both these companies is their business offering, providing data integration and data science based insights to customers as a service. "We employ the data scientists so you don't have to".

1st Subsurface, based in the UK, has a similar offering for oil and gas exploration managers. The company integrates and indexes publicly available exploration data. So the data it provides is not unique, but the collating and indexing system is. 1st Subsurface employs a number of former exploration managers, so they know exactly what oil and gas subsurface professionals are looking for when planning their fields.

We also have stories about projects which make it much easier to work with subsea monitoring data, alarms data, analytics on sensor data. We have a story about how a company which develops easy-to-install-and-use enterprise asset management software is beating the world leader in the sector.

Outside the world of data integration, we report on the enormous ways the oil and gas industry has changed in how it approaches the 'energy transition' - moving faster than nearly anybody anticipated - with our reports from the Aberdeen Subsea Expo forum in February. We report on some of the big developments in business approach and equipment which companies are making to make it more viable to produce marginal fields.

It is no secret that many in the industry expected faster progress with digital technology. Mhairidh Evans, principal analyst, Upstream Supply Chain with Wood Mackenzie, said that "we expected to be a bit further down the [digitalisation] journey than we already are". Hopefully some of the developments in this issue can help us make progress.

Karl Jeffery, editor
Digital Energy Journal

1st Subsurface – the *TROVE* decision support tools for exploration managers

UK subsurface consultancy 1st Subsurface provides the TROVE decision support tools for oil and gas exploration managers based on public data, and a knowledge of what exploration managers would find most useful.

1st Subsurface, a UK consultancy specialising in subsurface management, exploration and asset strategy, is providing public subsurface data 'curated' in a way to make it most useful to exploration managers.

It is able to do this because it has many staff members who are former exploration managers themselves, and so know exactly what exploration managers look for.

Managing director Mike Cooper is a former subsurface manager with E&P companies Lundin and EnQuest. In these roles he had responsibility for subsurface aspects of a number of oilfields in the Central North Sea, West of Shetland and Northern North Sea.

The 20 employees include "a bunch of former exploration managers from North Sea companies," Other companies formerly employing his staff include Maersk, Taqa, Centrica and Talisman.

The company works exclusively with released public information – and as a result is able to sell its entire curated TROVE "Knowledge-Bases" to all customers. Databases are structured datasets whereas we refer to TROVE as a KnowledgeBase as the various analytical tools, dashboards and required graphs are built in.

The employees spend time searching and indexing data from wherever they can, including from industry press, competent person reports (CPRs), academic publications and filings with regulatory authorities. All data is indexed back to its source, so there is an audit trail.

One particularly good source of data, on the UKCS, are public relinquishment reports, which are put together when a company relinquishes a certain block and provides what it knows about the block to the regulator.

Supplied as a spreadsheet

All of the data is compiled into enormous spreadsheets, which are available to purchase for permanent use.

For example, all the Central North Sea fields and discoveries data is sold as a 3.21 Gb spreadsheet.

Customers can pay extra for subsequent updates, with an annual charge of around 30 per cent of the initial cost per year. Companies can also just keep using the initial spreadsheet without paying for updates if they wish. "The advantage of annual renewals is simple – there is diminishing value in out-of-date information" Mr Cooper states.

"Everybody has got Excel, knows how to use it, Mr Gates maintains it, and everyone can take the data and manipulate it," he says. It is "like having your own oil and gas Wikipedia on your desktop."

The data can be provided via geographic information system (GIS), but then people's ability to work with the data is only as good as their GIS skills, Mr Cooper says. "In our experience, most people can do basic tasks in GIS, but they can't necessarily write the SQL code to investigate complex enquiries."

For example, if you want to do a task like search through all the North Sea oilfields to find fields with Jurassic reservoirs, containing oil, and which are currently in production, that is a data manipulation task most people would find easier in Excel than in GIS, Mr Cooper says.

1st Subsurface describes itself as an information management company, since it collates vast amounts of data but does not, yet, develop software.

Hubs

A pillar of 1st Subsurface's approach is building tools to help exploration managers work out the best locations for hubs in the North Sea.

Mr Cooper strongly believes that the future of field development will be about picking the right production hubs, taking into consideration the number of fields nearby which can feed into them, and predictions about how long fields will keep producing and how long assets will be in operable condition.

"Hub analysis is the future of mature basins like the North Sea," he says.

"There are over 1000 discoveries across the North Sea that have not been developed. The UKCS map shows 2400 prospects and leads, while we drill only about 20 a year."

Some observers ask the question, "if we can't develop what we have already found, why are we looking for new ones?" The answer is that using analogues found in TROVE, significant new finds will be made, some in large stratigraphic traps or re-thinking non-conventional plays, Mr Cooper says.

The reason that many discoveries are unsanctioned is usually, of course, because of their small size. But if you group together fields with the same sort of hydrocarbons which are in close proximity, you can design new concepts for hub developments.

"The future of the North Sea is hub-based, it has to be, it is the only way we're going to be able to move so many stranded resources forward," he says.

"The quest is to find economic projects, rather than reporting technical successes."

The hub analysis tool is also useful for people considering buying or selling oil and gas fields, if they can be better advised about other available discoveries nearby, how big and how far away they are, and what they contain, this adds incremental value.

Indexing

The core work is entering all available data about oil and gas fields, which makes it possible to search for oilfields according to many different parameters.

For example, for every drilled asset in the North Sea, data (if available) is entered about subsurface factors such as resource/reserves size, geological age, oil density, pressure, temperature, depth etc. Data is also entered about operational factors such as asset age, operator, project status, water depth, distance from the hub location etc.

This builds up a database which an exploration manager can use to search for fields with certain parameters.

Many countries provide databases of oilfields in their own territorial waters, but 1st Subsurface's database can be used to search across national boundaries.

So you can see data for UK, Norway, Denmark, Germany, Netherlands, Ireland and the Faroe Islands, on the same map – including every oilfield, gas field and discovery ever made, covering 1500 fields and discoveries. It is possible to look across the North Sea in its entirety, including all the way to the Barents Sea in the north. "This might be the first time anyone has been able to show this with such a level of technical subsurface detail," Mr Cooper says.

For example, you can see all the gas condensate fields in the North Sea, or every field which goes into the Forties pipeline, or all the unsanctioned discoveries without maps being truncated at international boundaries.

You can see every discovery / prospect within 30 to 200km from any chosen point in the North Sea, sorted by (say) size, fluid type and pressure regime. This would be useful if you are considering tie-backs to a hub, or where future hubs should be situated.

You can see fields in terms of current remaining reserves (updated Quarterly) and the ultimate recovery, so a measure of how mature they are. This gives a useful pointer to how long they are likely to act as a host for tieback opportunities.

Value from analysis

The analytic tools in TROVE can reveal insights about operations which are not revealed on public data. Here are some examples.

People might be interested to know the remaining reserves for a certain region, and what stage of "maturity" fields and hubs in that region are in – early, mid-life, late life, decommissioned etc.

You can look at all the production profiles, and extrapolate trends, to predict how long the oilfield looks like it will be operating for, with both oil and gas, and so predict cessation of production, and estimate ultimate recovery and recovery factor.

Estimates of tanker requirements for the entire North Sea, or how much the ultimate recovery will be from a field for recovery factor determination. Individual companies will have this data about their own fields, but when the infrastructure involves a number of fields connected to a pipeline system, it is a different situation.

"We can combine all of that into one view, for somewhere like the Brent province. You can see there's a lot of fields which have either been abandoned or are late in life. There are very few that would be called greenfields."

You can map trends in pressure and temperature, oil column heights, porosity, permeability, across multiple fields, or multiple fields of a certain geologic age.

You might want to know which fields have the closest analogues to the fields you are looking at, or where the best discoveries are in a certain part of the world.

Companies considering buying an asset can find out more about the assets around it. During an asset sale, exploration and subsurface managers get overwhelmed by the sheer amount of detail in the specific asset's data room. But they will probably not have time to assess all surrounding opportunities there might be for future growth, Mr Cooper says.

Some interesting observations emerge, for example that explorers in one country's waters have found fields at two different geological ages, but explorers in the neighbouring country have only discovered fields of one age, so may be missing out.

In another example, from analysing data from the oilfields in the Gannet complex, it becomes clear from interpreting the production data that the platform is at its limit for water handling, Mr Cooper says. To produce more oil via the Gannet platform, requires reducing produced water either by water shut-offs or increasing water handling capacity (maybe hydrocyclones, possibly subsea separation).

Comparison to other analysts

There are a number of analyst companies active in the oil and gas industry, but they usually provide their insights in terms of finished reports or presentations, rather than making their interpretation available for scrutiny, Mr Cooper says.

But having the basic subsurface numbers, graphs & extrapolated decline curves means that exploration managers, commercial managers and field development planners can assess the quality of the forecast for themselves.

Independent assessment of future production forecasts using consistent analytic techniques offer the most up-to-date and unbiased and systematic reserves estimates.

Other sectors

TROVE databases also cover LNG, renewables, pipelines and terminals, gas storage, energy storage, and CCS (carbon capture & sequestration).

You can also find out about pipeline and terminal status, relevant to a field development and strategic area plans.

The wind farm database is useful to offshore oil and gas companies looking to use renewable electricity to provide power for oil and gas platforms, or generating power from gas offshore, and exploring only transporting the power to shore, via a power cable.

"The company also provides TROVE KnowledgeBases for over 100 countries around the world. It has indexed data covering the whole of the African continent, the entire Mediterranean and the whole of offshore Europe, offshore North and South America including the Caribbean & Gulf of Mexico, and Oman to Myanmar. The company's approach to Future 'Wells to Watch' is an innovative approach for both E&P operators and the supply chain. Enabling planners to instantly see worldwide not only the when and where, but what the project entails and who to contact, is every business development managers dream!" Mr Cooper says.

TROVE may soon be able to link in data from other analysts – for example a data set about company share price, executive renumeration, so you can see how it compares with booked reserves & resource, is a possible near-term development. Such metrics would enable investors to assess the intrinsic value proposition for a company.

Cognite – a business putting data in context

Cognite, based in Oslo, has built a business putting oil and gas data in context – working closely with Aker BP – starting with production, now moving to subsurface and drilling data

Cognite, based in Oslo, has built a business putting oil and gas data in context, starting with production data and now moving to subsurface and drilling data.

Cognite works closely with oil and gas operator Aker BP. The two companies have a common shareholder, Norwegian engineering giant Aker, which owns 62 per cent of Cognite and 49 per cent of Aker BP.

Aker BP makes good use of Cognite tools for its own purposes, and the two companies have a common vision about how they want to make better use of digital technology.

The core philosophies could be described as "liberating" and "contextualising" data. Cognite defines liberating data as taking data out of the proprietary data formats and software systems which restrict its wider use, and putting it into standard formats and structures.

"Contextualising data" means connecting data together in a way which makes sense for others.

The term "contextualising" probably needs more explaining. Perhaps this analogy is helpful. Chips, tartar sauce and deep fried fish, by themselves, don't mean very much. But if you put them together you get a classic British dish which means a lot to British people.

Similarly, there's a limit to what you can do with seismic data and well log data by themselves, but if you connect them together in the right way, a geophysicist can get great insights into what is happening in the subsurface.

Cognite has built a business offering around the process of liberating and contextualising customer data, finding out what domain experts need and giving it to them, and achieving concrete results for customers, such as a reduction in specific costs or time.

Cognite's approach to liberating and contextualising data could be seen as having multiple horizontal layers – the raw data sources, the data integration layer, the data contextualisation layer, the data 'enablement layer', doing processes such as data engineering, machine learning and low coding, and the top layer, uncovering data for every application via APIs, (application programming interfaces, the means by which different software systems can be connected).

The business offering is packaged as "software as a service"- software which is made available by subscription via cloud hosting.

The company has grown from 34 employees in Oslo in 2017 to over 300 employees now, based in Oslo, Stavanger, Austin, Houston, Palo Alto, Tokyo, Vienna, Milan, Helsinki and Dhahran.

More on contextualisation

Just like in real life, "context" for data is not a single thing, it depends on the beholder or the person using the data. Different domain experts might want to see the same data placed in a different context, based on the job they do.

For example many different departments of oil and gas companies want to know production rates, but they use the data for different purposes – predicting cashflows, reporting finances, or establishing if there is a problem with the well. Each of these departments 'contextualises' the production data in a different way.

For contextualising large amounts of varied oil and gas data, we need a multi-layered process, where 'raw' data (which could be anything from live sensor data to documents from the corporate archive), after being 'liberated', is placed into simple intermediate data models, and then built up into more complex models which give specific domain experts what they need, contextualised in different ways.

The intermediate data models can combine data from multiple sources in different ways, such as putting data together based on geophysical relationships, or connecting data based on a knowledge graph or entity map of how different pieces of information relate.

The core building block of the contextualisation process could be described as "simple data models". If the data model is simple enough, you should be able to re-use it in multiple places.

A data model could be re-used across different industries – for example a data model for a turbine developed for oil and gas could be used in power generation.

If it is possible to re-use data models or components of them, it can make the process of building a data contextualisation 'system' for a certain industrial process much faster.

Some data already arrives contextualised to a certain degree, for example an old reservoir model is itself a large amount of contextualised data. The sensor data from a piece of equipment, such as a gas turbine, may arrive with multiple streams integrated together, which is a form of contextualisation. There is no need to strip away all of the context before you start putting it back again.

Systems for handling live or "operational" data, such as sensor streams, are different to systems for handling other types of data, such as documents, models and data archives, which Cognite calls "planning" data.

But the same philosophy of data handling can work for both – you need to find ways of getting data from where it is stored or generated, to a format where people can use it to make better decisions.

In this definition, in upstream oil and gas, production data is largely operational data, subsurface data is more planning data, and drilling data is a mixture of both.

Expose to other systems

Cognite does not need to make all of the actual 'apps' which people use to do their work on. It can also provide a useful service 'exposing' contextualised data to other apps, using standard APIs.

It works with some specialist analytics companies, which use data science to try to find interesting insights from the data.

There are also business opportunities for small companies who want to build tools to work with the data to provide useful services.

Cognite also encourages its customers to develop their own applications using the data.

Not many people in a company want to work with raw data itself – but they are happy to work with tools which make it easy to work with.

Subsurface data

Subsurface data can be contextualised in different ways. The obvious way to do it is by grid co-ordinates, so everything we know about the subsurface is mapped to a certain grid position.

But this method does not work for all subsurface data, because not all subsurface data has precise geographical co-ordinates – such as electromagnetic survey data, or gravity.

Digital Energy Journal spoke to Dr Carlo Caso, senior director of product management - subsurface and drilling, with Cognite, who has a role overseeing the strategy and "roadmaps" of the Cognite Data Fusion core components and applications, covering exploration, field development and drilling.

He has a PhD in geology, and then worked for Schlumberger for 7 years in subsurface and drilling software technology, including working with Petrel, probably the most used oil and gas geoscience software.

"There are many different ways to contextualise the data," he says. The challenge for Cognite is to "provide the standard tools to relate the data."

Dr Carlo Caso, senior director of product management - subsurface and drilling, with Cognite

One particular challenge, he says, is finding ways to work with software models which were created using old software versions. You need to either find the legacy software which was used to create the files, or find a way to work with the old code directly.

There have been a number of efforts to build 'port to port' connections between different subsurface applications, connecting one system with another. "This is extremely painful, I don't recall any successful project," he says. Different software packages follow different logic in how they handle data, and it can be very hard to work out what that logic is.

Instead, following the philosophy outlined above, you can try to abstract the useful elements out of the data, and put them in context, to create a "data fusion layer". Then this data fusion layer can be used as a basis for re-using the data somewhere else much more easily.

Cognite is part of the "Open Subsurface Data Universe (OSDU)" project, set up by a number of oil majors to define a standard framework for subsurface data.

Dr Caso sees OSDU as complimentary to what Cognite is doing. "We are aligned with the philosophy and objective," he says. The APIs which Cognite makes, to allow other systems to integrate, can work together with OSDU's framework.

Similarly, Dr Caso sees the Energistics RESQML standard, as standard way to store reservoir model data, as very helpful to what Cognite is aiming to do – because it puts data in a format which makes it easy for other systems to work with it.

Top down approach

The approach of building data liberation / contextualisation 'systems' could be described as one which is developed both "bottom up" and "top down." Both need to happen at the same time.

The 'top down' approach involves talking to company domain experts about how they work, what data they use for their work (whether analysis or decision making), and then building models which put together data in this way, perhaps automating some of their work.

For example, you can talk to an expert in rotating machinery to find out what data they find helpful from the machinery in telling them if any faults are emerging, and then see if you can build systems to put that data together for them.

Ideally you can have a feedback loop in place, where you are continually improving the data collection and the algorithm, to give more to the domain expert.

"It is not easy or done in two days, but at least its scaleable," says Dr Caso. Once it is done, it can be used many times over.

In some cases, the 'top down' ways of working with the data would be defined by the client themselves. For example, if a company wanted to build a warning system which would tell crew on a drilling rig that they need to evacuate.

The drilling company would need to very carefully define what data 'picture' would lead the computer system to issue this instruction and how exactly it would work, because it would be very expensive if the warning system gave bad advice – telling people they did not need to evacuate when something dangerous was happening, or telling people to evacuate when the situation was safe.

To take some learnings from the Deepwater Horizon disaster, there was a complex data picture relating to drilling mud loss which the crew mis-interpreted. It may be possible to develop a digital system which could put all the relevant data in context and then give the right advice.

Many of the difficulties encountered are usually relating to data quality, or data "wrangling" – putting data into the format you need. "If we go to the root of this we can build a system that can handle it," Dr Caso says.

If you just contextualise data bottom up, you may end up with data put together in ways which are no use to domain experts. But if you only do it top down, you may find yourself trying to build tools from data which is not available.

Bottom up - data modelling and prototyping

The "bottom up" approach can be described more technically as "data modelling and prototyping", taking available data, finding ways to contextualise it so it is useful for how people want to work with it.

Cognite's process involves gradually exploring what can be built, seeing what data could be ingested into a system, making models, and finally connecting it to live data and deploying it.

There is machine-learning powered inference that suggests how data should fit together, which can then be validated by a human being (typically Cognite can match from 70 to 99% of data automatically based on pre-trained algorithms, the company says).

Cognite has developed a number of small tools or "microservices" to improve the data.

For example, there are tools to match together data with different time series. One data stream may give data once per hour, another has data every minute. The gaps can be filled by interpolating.

MAN Energy Solutions – new data collaboration platform

MAN Energy Solutions has launched a platform "mýa" to enable integration of live data streams from sensors on engines, turbines and any connected equipment, which will be spun out in an independent company.

MAN Energy Solutions (MAN ES) has launched a digital platform "mýa", to share, integrate and distribute streaming data originating from sensors on equipment such as engines.

The mýa platform will form the offering of an independent company, with other companies, including competitors, invited to join and share ownership.

MAN Energy Solutions makes a range of oil and gas equipment including compressors, steam turbines, gas turbines, reactors, flare gas recovery and subsea compression. It also serves the marine, power generation and process industry sectors.

The purpose of mýa is to act as a broker of live data, a data collaboration platform, facilitating the integration of data streams from different sources, regardless of the manufacturer of the equipment, enabling a view of the total ecosystem with inter-relationships and dependencies.

In one example, equipment associated with engines can include pumps, fluid monitors, generators, compressors, turbines and emission controls.

Sensor data comes with a time stamp, time series data,(the time the data reading was taken.) Sensors on different pieces of equipment might record data at different intervals and quantities, but are typically time stamped. mýa can align all the time stamps, so you know what all the sensors were recording at a single point in time. This is essential if you want to analyse the data together and look at a complete view of the combined system.

Mýa does not store any of the data, only meta data (such as the volume of data handled). All data is owned by the asset owner unless agreed otherwise, and any data collaboration is controlled via contacts and agreements.

In this way, mýa could be seen as a plumbing system for data from different systems and different partners.

Right now, if an oil and operator wants to work with sensor data from equipment from different manufacturers, it is really difficult. This could be analogous to the hassle of having to go to a street stand pipe to collect your drinking water in the 1800s. mýa is the equivalent of making drinking water available to you on demand through a tap, together with gas, which can be combined to make hot water, in your house, provided with a standard fitting you can easily connect your boiler to.

From its own products

The initiative of mýa, originated in the digital department of MAN ES, which was building "tools" to monitor and maintain the performance of products such as large engines and turbines in operation in the field, and recognised the need for data collaboration and standardisation, across industries such as marine, power plant and oil and gas refinery applications, where its products operate today.

Dr Alan Atkins, CEO of mýa Connection GmbH.

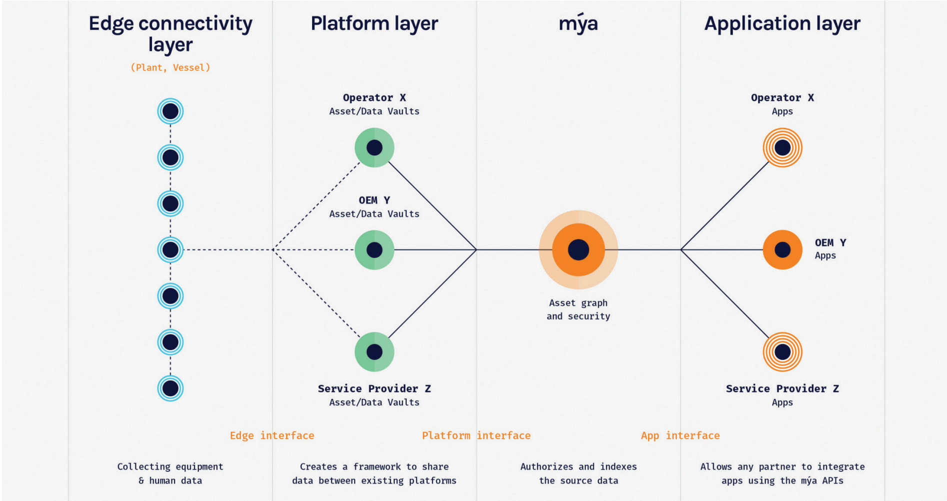
MAN ES has its own asset performance platform, MAN CEON, which powers MAN PrimeServ Assist, a solution to optimize operational performance of equipment in service.

This means that the investment MAN made into developing a parallel platform for its own purposes, is now being made available to others.

Today if you use MAN´s PrimeServ Assist you are actually using the mýa service, which is operating in the background.

Inviting others

MAN ES is inviting other manufacturers, including competitors, to take ownership and join the board of mýa. It is ultimately seeking to have 5 to 10 owners, and thousands of members OEMs and asset owners alike, from all types of industry, not just engine or turbine related. "The aim is to give the control totally



to the non-profitmaking organisation," says Dr Alan Atkins, CEO of mýa Connection GmbH.

Companies who are competitors to MAN ES might say, "We would like to join but we would also like to have a say in what's being done." By being one of the founders, this is absolutely possible and encouraged.

Discussions are ongoing with major equipment manufacturers who work closely with MAN, and also with competitors.

The costs of running the platform will be shared by the founders – but Dr Atkins emphasises that these are not so high – the organisation will only develop the basic functionalities. It will just administer the service and ensure uptime and security. "Applications" and analytics, will be developed where required by the members and third parties as required.

If companies decided they did not want to stop working with mýa at any time, they would not lose access to any data streams, just the integration service which mýa provides.

MAN ES has formed a new company, mýa Connection GmbH, as the vehicle to move forward, with the intention to form a separate independent non-profit making organisation during 2020.

Setting up mýa as a legal entity proved quite complex, including managing some anti-trust issues involved with having competitors working together. But now, "it is open to everybody," he said. "Including MAN ES' biggest competitors, in fact I would welcome that."

Dr Alan Atkins, CEO of mýa Connection GmbH and mýa Foundation, has a long career working in the "machine to machine" sector, including a role as global head of M2M/IoT with consulting giant CGI, then VP and global head of IOT with Wipro, one of the world´s biggest IT and services companies.

"We already have a platform"

One of the common reactions when asked about joining mýa, Dr Atkins says, is equipment companies (OEMs) saying they "already have a platform."

But for most equipment companies, their "platform" is simply a means for them to handle their equipment sensor data to a cloud system where they monitor and predict performance of that specific piece of equipment, he says.

mýa can add value to this by integrating their existing cloud hosted data with data from other equipment companies, to be able to look at the total system view. So it is not in competition with other proprietary platforms, but a supplement and an enabler.

One login

In the short term, the biggest benefit might be that engineers only need to log in once online to see data from all their equipment from multiple manufacturers, integrated together.

A typical customer complaint is, "I'm so fed up of 20 different reports from different pieces of equipment and not being able to compare the data in one go to obtain a system view," Dr Atkins says.

"When I talk to technical services within OEM organisations, offering after sales services to clients, they say this is great, this is what clients really want. A way to communicate between different platforms without being locked into a commercial third party´s offering."

With this integrated view, you can monitor all the alarms across all of your assets – the status of different engines, running speed, exhaust gases, your pump performance, scrubber performance, and other data you might want to monitor.

When viewing the assets within mýa, you are able to switch views to the OEM´s own asset view and access their applications and graphical representations without having to login again. You don't need to manage lots of different passwords. Authentication has already been carried in the various OEM systems. This provides the user with a single pane of glass.

Equipment as a system

Building on this, one of the biggest areas for potential value from mýa is in how it enables shipping companies, for example, to look at their equipment as a system, rather than as a collection of individual components.

There are many dependencies between equipment. For example, a slowing down pump will mean a reduced flow rate in a pipeline, which will have an impact on whatever is downstream. A gradual loss of performance somewhere can have an impact somewhere else.

Also, if you might want to monitor the performance of a whole system – such as all the pumps, compressors and generators for an oil and gas well head production system.

The platform was designed to integrate the various data streams, enabling people to do analytics at a "higher" level. It also allows a view across multiple "systems" such as a fleet of ships or power plants.

Analytics and apps

The platform can form a basis for analytics. Oil and gas operators, suppliers and other software companies can build tools to generate useful insights from the data.

Data is still owned and controlled by the asset owner, but they can see it is in their interest to allow access to it by other companies.

For example, apps could be built enabling oil and gas companies to monitor equipment, and support decision making about the best time to do maintenance or replace components, or get early warning about emerging problems, with alerts.

mýa works with about 80 standard open APIs, and can provide API keys, so it is possible for a third party software company to be able to integrate with the data given the necessary permission by the data owner, the asset owner.

The service itself could help drive more use of data standards and standard KPIs across the industry.

Supplier engagement

The platform can provide ways for suppliers to become more engaged with their customers during the product lifecycle.

Suppliers can monitor the performance of their products in use, and use their enhanced knowledge of how their products operate, to give customers advice.

They can also monitor the performance of their installed base of products across multiple customers, to better understand, for example, how their equipment wears and where improvements in design could be made.

The data can support selling spare parts and other "aftermarket" services at the right time, generating increased availability and up-time.

www.myafoundation.io.

Spearphishing attack shuts down US gas facility

The US issued a comprehensive report about a spearphishing attack which caused a gas compression facility to be shut down for two days.

The US Cybersecurity and Infrastructure Security Agency (CISA) issued an alert and comprehensive information about a cyberattack on the 'operational technology' network of a natural gas compression facility via spearphishing.

The spearphishing provided the attacker with access to the IT network, which was then used to reach into the operations technology (OT) network. The attacker than deployed "commodity ransomware" on both networks.

This meant there was "loss of availability" on human machine interfaces, data historians and polling servers. The "impacted assets" could not read or aggregate operational data reported from OT devices (sensors), leading to partial "loss of view" for human operators.

The attack did not impact any programmable logic controllers (PLCs), because they do not run on Microsoft Windows. So the attacker was not actually able to control or manipulate operations itself.

There was a separate central control office, in another part of the country, which could "maintain visibility" on operations but did not have the instruments to control the operations.

But all the same, the company decided to implement a controlled shutdown to operations, which lasted two days, loading the "last known good" configuration and replacing some equipment. During this time, the human machine interfaces were taken offline.

Although the company's emergency response plan "called for a full emergency declaration and immediate shutdown," the company "judged the operational impact of the incident as less severe than those anticipated by the plan," so decided to implement only limited emergency response measures, with a four hour transition from operational to shutdown mode, together with increased physical security.

Because of pipeline dependencies, it was necessary to shut down compression facilities elsewhere. This meant that the entire pipeline needed to be shut down for two days.

Recommendations

CISA says that the victim company "failed to implement robust segmentation between the IT and OT networks".

This "allowed the adversary to traverse the IT-OT boundary and disable assets on both networks."

"The victim's emergency response plan did not specifically consider the risk posed by cyberattacks," CISA said. "Consequently, emergency response exercises also failed to provide employees with decision-making experience in dealing with cyberattacks."

"The victim cited gaps in cybersecurity knowledge and the wide range of possible scenarios as reasons for failing to adequately incorporate cybersecurity into emergency response planning."

CISA recommends that organisations make sure their emergency response plans "consider the full range of potential impacts that cyberattacks pose to operations, including loss or manipulation of view, loss or manipulation of control, and loss of safety."

"In particular, response playbooks should identify criteria to distinguish between events requiring deliberate operational shutdown versus low-risk events that allow for operations to continue," CISA said.

Detailed recommendations

CISA published further detailed recommendations. This is an edited list – the full list is online with the link below.

Exercise the ability to fail over to alternate control systems, including manual operation while assuming degraded electronic communications.

Allow employees to gain decision-making experience via tabletop exercises that incorporate loss of visibility and control scenarios.

Identify single points of failure (technical and human) for operational visibility. Develop and test emergency response playbooks to ensure there are redundant channels that allow visibility into operations when one channel is compromised.

Implement redundant communication capabilities between geographically separated facilities responsible for the operation of a single pipeline asset.

Coordinate planning activities across all such facilities.

Recognize the physical risks that cyberattacks pose to safety and integrate cybersecurity into the organization's safety training program.

Ensure the organization's security program and emergency response plan consider third parties with legitimate need for OT network access, including engineers and vendors.

Implement and ensure robust Network Segmentation between IT and OT networks to limit the ability of adversaries to pivot to the OT network even if the IT network is compromised. Define a demilitarized zone (DMZ) that eliminates unregulated communication between the IT and OT networks.

Organize OT assets into logical zones by taking into account criticality, consequence, and operational necessity.

Comments from Bulletproof

Oliver Pinson-Roxburgh, co-founder of UK cyber security company Bulletproof had some interesting observations on the case.

"This sort of attack typically requires a very specific skillset. The last time I heard about malware like this was Triton (named "The world's most murderous malware") malware that could affect safety controls within a petrochemical plant.

"The attackers used a similar approach by gaining initial access and them moved further into the network, eventually targeting the safety controls on the plant."

"The difference is that the Triton attackers focused on safety systems, and these attackers seemed to focus on disruption to plant operation. Triton was believed to be a nation state attack.

"Industrial engineers back in the 80s, when the first industrial control systems where being built, did not have to consider that one day they would be connected to the internet. In addition, segregation in these sorts of networks were also not a consideration."

"As we can see in both examples, the initial network was not the target, but was the first entry point leveraged by threat actor. In this example, they moved to the OT proving that segregation was not effective or was non-existent - similar to the Triton attack."

"We find that during testing our customers, the employees are the weakest link. During our phishing campaigns we will always have some success. The important point to consider is that an attacker only needs one person to fail; all they need is that one piece of equipment or persons to leverage."

"Industrial control systems security requires a very different set of knowledge and skills to protect the site, which is very different to a typical IT network. The focus is not protecting information, its SAFE , correct, efficient and continuous physical operation of the plant."

You can read the CISA alert online here https://www.us-cert.gov/ncas/alerts/aa20-049a

Lone Star - well data analytics-as-a-service

Lone Star Analysis of Dallas provides well data analytics as a service – aiming to build fast models of production systems for its clients and provide alerts and insights from them.

Lone Star Analysis of Dallas provides insights to customers about their wells and production systems as a service, so they don't need to do data analysis themselves.

Lone Star employs people from a wide range of disciplines, including petroleum engineers, statisticians and applied mathematicians, bringing different areas of domain expertise to the task of integrating the data and trying to understand what is going on. Chief Technology Officer, Eric Haney, has a PhD in aerospace engineering.

The core of the work is putting available data together to build a model which incorporates basic physics of the well and production equipment. For example, that a certain flowrate would lead to a certain amount of liquid in a tank after a certain time. It builds a specific model for each well.

Production equipment can include piping, generators, compressors, variable frequency drives. It should be seen as a system because a failure on one piece of equipment, such as a wastewater injection pump, can cause interruption to all production.

The model can cover issues related to supply chain and economics as well as engineering.

The company focusses on real world relationships with the data, not trying to write machine learning algorithms. "We're going to teach it a set of business rules. We can come up with a set of baseline rules that apply to all wells," says CTO Eric Haney.

Over time the model can be fine-tuned to the unique characteristics of any well. "We can adjust some small coefficients," he says. "Perhaps there will be some machine learning involved."

Eric Haney, CTO of Lone Star Analysis

"We know what fluid characteristics do, we know what electrical losses do, we can teach the model as much as we possibly can."

Sometimes 'virtual sensor' data is calculated, where you calculate what a sensor reading would be if you were to have a sensor there, using other data. "We've done some very interesting things where you don't have all the data you would love to have. If you know enough about the system and the physical relationships you can get significant insights.".

For example, for one company, it did not have data about how often certain components needed replacing, but it did have data about how much these components were being ordered, which could be a proxy for the same thing.

The approach could be applied to "anything that has uncertainty and imperfect information," he says. That includes condition based maintenance and real time performance optimization, maximizing cash flow, or whatever matters most to operators.

The models can be used to better understand how the well is operating and identify problems.

It can be used to spot problems with equipment, including problems which are emerging. This means that companies can do maintenance in a more proactive way, and schedule maintenance work at a convenient time, rather than fixing problems.

Lone Star also looks for ways to improve the data it receives, including removing noise, filling in gaps and spotting errors.

The company does not get involved in data connectivity – it integrates with tools such as ABB's Well Head Manager to get data stream from the various sensors on the well.

The best and fastest model

Perhaps the challenge is best described as being able to build "the best model, the fastest possible, do that many times over," Mr Haney says.

"We've got to be able to deploy a model very rapidly and have it running, or it isn't valuable."

"Customers want to see how predictive we can be.

"And they are not willing to wait years while we go through and apply machine learning techniques. They don't have time to wait, especially if you are relying on clean training data to get you up to speed."

The data models can be scaled up quickly from one well to a million, since the software is cloud hosted.

Perhaps it might be possible to "automatically provision" a predictive maintenance model, automatically turning on and off different sections of it.

"If you want your electrical submersible pump monitored, here's the price, we'll take it on ourselves," he says.

"It's not necessarily tenable to manually configure well by well, but we've got some interesting approaches."

"The wells are constantly changing – the equipment, the environment around."

Working with customers

Lone Star is keen to sign subscription agreements with customers, where the customer provides full access to the data, and Lone Star will only alert them when something specific needs to be changed on an asset.

So the client organisations do not need to have their own staff members watching screens, or any alerts telling them that they are operating within spec.

Customers might have a small number of people managing tens or even hundreds of wells – so they need to focus on where they think the highest priority is.

Lone Star has been in business and profitable for 15 years, "bootstrapped by our customers," he says. But the company still considers itself to be in "growth mode", aiming to "open up doors and go faster".

Signing up clients can involve many "beta tests", where companies test out what the company can offer.

It claims that the return on investment seen by its clients has "always been at least 20:1 and as much as 100:1 when they've applied our intelligence."

IFS – 2019 “best year ever” in oil and gas software sales

2019 was probably the best year ever for oil and gas software sales for Swedish enterprise asset management software company IFS, says Colin Beaney, VP energy, utilities and resources.

Enterprise management software company ITF saw probably its “best ever year” for oil and gas software sales in 2019, says Colin Beaney, VP energy, utilities and resources with IFS.

The company provides tools to help companies manage maintenance, supply chains, projects, planning and scheduling optimisation, finances and human capital management.

According to data from ARC Advisory, IFS now has a 16.4 per cent market share for oil and gas Enterprise Asset Management software, compared to 9.7 per cent for SAP and 25.4 per cent for IBM. By comparison, in 2017, IFS had 8.6 per cent of the oil and gas Enterprise Asset Management market, compared to 10.3 per cent for SAP and 28.1 per cent for IBM.

In its 2019 results announced in January 2020, IFS said it had seen 32 per cent growth in both license revenue and earnings (EBITDA) over the past financial year, with total license revenue of $161m, maintenance revenue of $202m, and consulting revenue of $230m.

It saw over 10 per cent growth in “every region and every line of business”. Its field service management business grew 51 per cent.

One recently added client is ARO Drilling, a new joint venture between Saudi Aramco and drilling contractor Valaris.

IFS announced in February 2020 that ARO had installed IFS software to its whole company, with a 9 month software roll out covering 400 full users and 2,000 self-service users, both offshore and onshore.

It is using IFS software for maintenance, supply chain management, finance, and human capital management.

It wanted to “consolidate” a number of pieces of business software, get a better centralised view of the whole business, and simplify work processes. It had a number of different systems which were complex and difficult to scale.

“From streamlined procurement and inventory management to more efficient maintenance of critical equipment on our rigs, IFS Applications has made a real difference in how we operate,” said Anas Mosa, IT director of ARO Drilling.

“The implementation of IFS Applications was a major transformation for our corporation, and I am very pleased that the big-bang rollout project, which covered our 16 rigs, has been a great success.”

Another recent client was Dutch floating production, storage and offload (FPSO) solutions company SBM Offshore, which announced in November 2019 that it was using IFS Applications.

Also engineering company SPIE Group announced in December 2019 that it was using IFS Applications to “unify and streamline” its IT landscape, establishing harmonised operating protocols across five subsidiaries, using the software for project management, supply chain management, maintenance, planning and scheduling optimisation, financials and human capital management.

The software can run both on cloud and on premise.

Darren Roos, CEO of IFS since April 2018, was formerly president of SAP’s global ERP cloud business, and president of EMEA with Software AG.

Ease of implementation

Colin Beaney, VP energy, utilities and resources with IFS believes that one of the reasons oil and gas customers like IFS so much is its ease of implementation,

“We’ve got a product that can be implemented in a relatively lean, mean, rapid way,” he says. “That suits organisations which are looking to change what they are doing.”

For example, one new client wanted to set up a new joint venture company quickly, and wanted software it could get running quickly, without taking on high costs of software licenses for the legacy systems used by its parent companies.

“They are looking for a business IT infrastructure that’s open, easily interconnected, and with the breadth to cover the things they want,” Mr Beaney said.

Clients often want new software quickly because they want to enter new markets, such as an oil company getting involved in electric vehicle charging, domestic electricity sales, or renewable energy.

Oil and gas industry projects themselves are often reducing in duration, so companies are under more pressure to find software systems they can deploy quickly, he says.

So IFS beats its competitors by offering a faster “time to value” and fewer failed projects, he says. It is constantly “winning” against the market leader in ERP software.

Enterprise resource planning software does not have a great reputation in the oil and gas industry for ease of implementation. It has been common at oil and gas digital technology conferences to hear complaints about enterprise software solutions taking much longer to implement than was expected, and not delivering the value that was expected, or customers don’t implement the full product capability.

Moving from one ERP software system to another from a different vendor, “definitely can be done – I would not suggest it is easy,” he says. “Some of the challenges are about getting the data out of the legacy system.”

Although when companies are looking for software for new joint ventures, they do not have any legacy software to migrate data from, he said.

Asset management

Another unique factor about IFS is that the company started offering software for asset management – so its core modules are areas such as maintenance, project management and scheduling.

This gives the software a much better fit to what energy companies want, compared to software companies in the enterprise space with a background in manufacturing or purchasing, Mr Beaney says.

“In energy, customers want people who understand critical asset management. They want software vendors that can manage all of the intricacies of new facility build, new vessel build, as well as the operations and maintenance.”

The core industries IFS targets are aviation and defence, manufacturing, services, energy / utilities / resources, and engineering / construction / infrastructure, all asset heavy industries.

Validere - analytics to understand HC quality

Validere Technologies, based in Houston, Calgary and Toronto, provides an analytics based service to advise customers about the quality of their flowing hydrocarbons.

From the well to the customer, hydrocarbon flows come in a wide range of specifications and quality levels, and it is very useful for people involved to know more about the quality.

But gathering together available data and making inferences about it is a very complex technical and analytical challenge. This is what Validere Technologies, based in Houston, Calgary and Toronto, is tackling.

The company was founded in 2014, so just about qualifies as a start-up. According to Crunchbase.com it has $25.7m total funding in 6 rounds. Major investors include Wing VC, Greylock, and Sallyport, which also backed energy technology company RigUp.

The platform is priced by monthly fee.

Validere builds models of available data, validates it, and then 'pushes' out insights to the client.

Validere also has an online platform, "Validere Edge", which connects together buyers and sellers of commodities, based on a need for products of a certain quality.

Data challenges for producers

Oil producers need oil to meet a certain specification in order to be transferred onto a buyer. If the spec is outside a certain range, the oil cannot be sold under this contract.

There are various ways to take and measure samples, including desktop devices and sending samples to a laboratory.

Fitting an instrument "inline", so it can automatically take samples out of the pipeline, can cost $500k, says Mark Le Dain, vice president strategy at Validere.

Sometimes companies have instruments which are not calibrated correctly or which go out of calibration quickly. There can be errors in data gathering and recording.

And oil shale wells in particular have high decline rates, and the specification of the oil tied into a system can quickly change as the reservoir depletes and is replaced by new production.

Supply chain data challenges

Companies involved in the oil and gas supply chain, and midstream operations, can also benefit from product quality data in many ways. They can use the data to optimise their own processes and make sure there are no problems when hydrocarbons change ownership.

When oil changes ownership, the important data points are the price, volume and the specification, or quality. But data about the price and volume is far easier to gather than data about quality, Mr Le Dain says.

But companies can pay big penalties or costs if they try to supply products which are outside their customers' specification.

For example, if they load out of specification crude onto a truck, it can get refused at a terminal, so they have to pay for it to be delivered somewhere else. There have been stories about entire pipelines getting contaminated after some crude of the wrong specification was pumped into them.

Often volumes are mingled together, making it even harder to track what is being bought and sold.

The company's service is not limited to helping customers analyse only their own data, as it helps them interact with the supply chain most efficiently. . So it can track product quality as it is handed from one owner to another, provided companies give permission for their data to be used in this way.

This way, refineries and intermediaries purchasing crude can use the service to get a better understanding of what they are buying.

Consider that a maritime shipping company might want to avoid using a fuel supplier it does not know, because of risks that it could be provided with substandard fuel with compatibility risks.

With better information about the provenance of this fuel, a company could be able to buy fuel from a previously unknown, but lower cost supplier with more confidence, Mr Le Dain says.

Other benefits from having better data include identifying leaks or theft in hydrocarbon flows, optimizing margins, getting a better understanding of markets, and resolving custody disputes.

How to analyse data

The starting point of data analysis is to gather together all available data – including any "inline" devices, sensors and sample test results.

There has always been a large amount of data available about fuel quality, but is often "scattered around, incorrect, or not actually used in economic decision making," Mr Le Dain says.

The available data is used to put together a physical model about the liquid properties. Many data errors or inaccuracies can be identified from the process of putting this model together. When you find that data doesn't fit the model, something must be wrong somewhere. For example, it can show that fluids which were moved from tank A to tank B can't possibly have the properties that the sample says that they do.

This can lead to additional testing, or an understanding that there is a flaw somewhere.

Validere employs experts in both fuels and data science to put together these models. Co-founder Ian Burgess has a Ph.D. in Applied Physics from Harvard.

Where there is data which would be desirable but is not available, the modellers use engineering and physics models to try to work out what this data would be if there was a sensor to record it. This process is sometimes called developing virtual sensors.

For example, a physics / engineering model may describe a relationship between viscosity and density, or what the vapour pressure would be.

Sometimes these virtual sensors have actually given better data than inline instruments, because inline instruments need regular calibration.

Validere also develops its own engineering models, based on cases where it does have the data from sensors. So (for example) it can directly measure both viscosity and density for many different oil samples and build a model about how they relate in different conditions.

Ultimately, as a result of the data gathering and modelling, it has much better data to provide to the client, for use making supply chain decisions.

The challenge of building systems to better gather and manage fuel data can be much more about implementation than designing clever solutions, Mr Le Dain says.

Subsea - advances in wireless monitoring

Advances in subsea monitoring and wireless communications technology make it possible for offshore operators to get much better insights into their equipment and processes, said Moray Melhuish from WFS Technologies

Some oil majors are planning to have 100 per cent unmanned systems for their subsea systems by 2025. So no projects requiring Remotely Operated Underwater Vehicle (ROV) or divers, operated from a vessels above, to undertake condition monitoring, said Moray Melhuish, commercial director, WFS Technologies.

This adoption of 'subsea Wi-Fi' enabled devices could lead to significant reductions in the cost of operating offshore facilities.

WFS is developing projects together with BP for subsea structural monitoring, and with other majors for subsea process monitoring, he said.

As well as monitoring the condition of offshore structures, WFS envisages a network of smart monitoring devices along a pipeline, each passing data along to the next. The data can be used to predict blockages due to wax and hydrate build-up and monitor sand.

Sensors, batteries and comms

There have been massive improvements in sensor technology in the past 10 years, with a significant reduction in cost and improvement of capacity - and that applies to subsea sensors as well. As an example of the collapse in the cost of sensors in our every day lives, today each of us has an accelerometer built into our smart phones – unthinkable just a few years ago. WFS takes advantage of these low cost, highly capable technologies in creating its subsea networks, Mr Melhuish said.

Wireless subsea communications are desirable, because eliminating the wire reduces cost of installation, and improves reliability. WFS' provides communication systems can transmit information through both water and air, so condition transmitted by subsea equipment can be received on a platform with no through water-air cable or dunker required.

Moray Melhuish, commercial director, WFS Technologies

Subsea devices are available which are non-metallic, which means they are light weight, easy to install, don't corrode, and do not interrupt the Seatooth radio signals used in subsea communications.

The costs of batteries, a critical component in subsea electronics, have also collapsed, dropping from $1000 per KWh in 2010 to $158 per KWh in 2019. Quality has improved too, with design life now up to 45 years, he said.

The technology was originally developed for the military to send video data through submerged bunker walls.

The radio signal can travel 40m through water, carrying between 1bps and 100mbps, with the maximum bandwidth decreasing as distance increasing. After 40 metres, you need to install a repeater to re-broadcast the signal.

Other technologies for subsea communications are acoustic data (sound) and optical systems (light). But they cannot also go through air, so the receiver also needs to be submerged. Acoustics can typically carry between 1bps to 1mbps for distances up to 4000m. Optical systems can typically achieve 1mbps to 300mbps distances of 150m, but the amount of sediment in the water is a big factor.

It is possible to make hybrid systems (with radio, light and acoustics), using whatever is most appropriate for the particular demand.

The big potential is when you use subsea sensors together with wireless communication. Installing cables subsea is very expensive in both capex and opex, so wireless communications has a significant cost impact.

Wireless communications through water needs a lot of energy, and so the sensors needs to be 'smart' about how they use battery power. For example a temperature sensor can be programmed to wake up once a month, take a temperature reading, and then only transmit the data if it is in a certain range or showing a certain trend. Receiving a warning as part of a subsea condition dashboard is far more valuable than being bombarded with a torrent of data, which can result in critical information being overlooked.

The Smart Clamp

WFS produces the Seatooth SmartClamp fatigue monitor (see illustration above), which is retrofitted underwater on the jacket (brace) of an offshore platform, and records the stresses which the jacket has been placed under over long periods of time.

The stresses are measured directly using strain gauges, and the information correlated with structural motion, ambient temperature and water pressure for the calculation of wave height and frequency.

The data is logged on the device, and a dashboard of condition information transmitted from the clamp to a SeaHub antenna fixed to the platform above the water.

The diameters of the device are adjusted to suit the structure it is destined for. With a 1.2m internal diameter, it weighs 300kg on the earth's surface, but on the subsea the force of the water makes the relative weight of the clamp just 70kg, which is light enough to install by a Remotely Operated Vehicle (ROV).

One major oil company is interested in monitoring the fatigue in its subsea well heads in a similar way, providing a subsea Wi-Fi network to enable wireless monitoring around each subsea tree.

"At low cost we can provide the information required to enable better decision making based on real time and trended data, set our red, amber, green parameters," he said. "This is game changing stuff for our offshore industries."

How the energy industry is changing – reports from Aberdeen

The Subsea Expo in Aberdeen in February had a number of interesting talks about how the oil and gas industry is changing, from Oil and Gas UK, Wood Mackenzie, the Renewable Energy Catapult, Scottish Hydrogen and Fuel Cells, and Westwood Global Energy

Michael Tholen, director of sustainability at Oil & Gas UK, said that we "live in an age of uncertainty in energy" – including a switch from concerns about oil running out (peak oil) to concerns about demand running out. But oil and gas is still more than three quarters of the UK energy mix.

He was speaking at the Plenary Session of the Subsea Expo event in Aberdeen in February 2020.

"We'll get to net zero [CO2 emissions] by 2045 to 2055 – most countries won't," Mr Tholen said.

Mr Tholen noted that there is talk about "blue hydrogen" made from gas, and "green hydrogen" from renewables, and some people argue that the future hydrogen industry should be all "green".

"Consumers want hydrogen in a way which is carbon zero and cost competitive," he said. On this basis, we should "be colour blind", not caring about whether the hydrogen is made from gas or renewables, if the hydrogen from gas involves carbon capture and storage.

Carbon capture has been in discussion in the UK for 15-20 years now, "It hasn't started for a number of reasons, primarily commercial issues. There's big confusion about what the business model is," he said. "Recently we've seen a clearer trajectory – industrial processes and blue hydrogen."

Mr Tholen noted that wind technology used in the UK is still largely Scandinavian. But in the carbon capture and hydrogen sectors, UK companies have an opportunity to own the technology. "What we do in the CCS space will have huge ramifications globally," he said.

Oil and Gas UK will shortly publish a white paper of "how our sector is going to adapt," he said, perhaps including plans for more of the industry's output to move towards hydrogen.

Mr Tholen noted that the wind sector is already seeing its first decommissioning. He is keen to see the wind sector have the same rules as the oil and gas sector has, for example a requirement that nothing can be left part abandoned.

Wood Mackenzie

Mhairidh Evans, principal analyst, Upstream Supply Chain with Wood Mackenzie, said that the oil and gas industry is now being hit by "brand new structural forces" – much more than the previous patterns of upcycles and downcycles.

While people recognise the need to decarbonise energy quickly, the actual pace of change we will see is "pretty unclear," she said.

The energy transition is already "changing the way companies behave and investors feel. A reduced activity level is now relatively normal. There are fewer projects going ahead." It leads to lower demand for equipment and services, and so the supply chain continues to contract further.

The number of contract awards for subsea trees, a measure of subsea projects around the world, declined greatly from 2013 to 2016 after the crash. It increased healthily in 2017 and 2018. But 2019 was actually slightly lower than 2018. We will probably never get back to the peak of activity of 2013, although there will be a steady rebound up to 2023, she said.

The biggest UK subsea project sanctioned in 2019 is actually in wind – the UK's Dogger Bank, a £9bn project. "Wind is predicted to double globally between now and 2025."

From an investor perspective, it helps that the "certainty levels" in wind are higher than in oil and gas. And wind projects are getting steadily bigger and more complex, while oil and gas projects are not.

But the anticipated returns to investors are still much lower for renewables than for oil, she said. As an example, Wood Mackenzie anticipates that an investor would get 5 per cent return on solar PV, 6 to 7 per cent on offshore wind, and 8 per cent on onshore wind. Meanwhile they would get 15 per cent return on oil and gas exploration, 20 per cent on "pre FID conventional oil", and 32 per cent on North American onshore oil. [Note – these calculations were made before the March 2020 oil price crash].

Subsea suppliers could be advised to stick with oil and gas, since it will still be needed for the foreseeable future, but also be aware of the pressures to reduce costs and decarbonise, and meanwhile look for ways to diversify and capture growth in "new energy".

Ms Evans noted that the offshore wind business is a much more standardised and commoditised business than oil and gas, which makes it easier to get projects going. But the contracting mechanisms are completely different to oil and gas, with government involved as a buyer.

Digital

One of the questions Wood Mackenzie gets asked most about is what is happening in the digital arena, who is doing what, and how one company compares with another, she said.

We are seeing some convergence in the topics of digitalisation and decarbonisation, with digital technology being used to help decarbonise. There is much more "sensorisation".

But overall, "we expected to be a bit further down the [digitalisation] journey than we already are."

Some of the companies who are most successful have worked with external partners – not just start-ups, but also big tech companies such as Microsoft and Google, "platforms to do this at scale".

Also, "We need to see commercial incentive [for digitalisation] much more plainly stated," she said.

Renewable Energy Catapult

Andrew Jamieson, CEO of Offshore Renewable Energy Catapult, the UK's leading technology innovation and research centre for offshore wind, wave and tidal energy, said that we have 10 GW of offshore wind installed in the UK, as of February 2020.

The UK's 2030 target has been increased from 30 GW to 40 GW. The UK's Committee for Climate Change (CCC) is looking for "at least 75 GW by 2050", if we are going to use more electricity for heat and transport.

The challenge is to find ways to maximise economic value for industry as we build this, including building the supply chain, he said. This will involve working with the oil and gas sector. There are "some big divides to be crossed."

There is increasing focus in the wind sector on operations and maintenance, with much talk about better ways to use data and analytics to do it more efficiently.

"It's got to be robotics and autonomous, drones more than vessels," he said.

There are a number of different viewpoints about floating wind, but it will be needed if we are going to get to 75 GW of wind power. Other countries have much less shallow water than the UK, so have no option but to go straight for floating wind.

Floating wind has challenges with anchoring / mooring, operations, maintenance, and finding cranes which can lift the enormous floating wind turbines. "These things haven't been solved yet."

Oil and gas supply companies can get involved in sectors of this, and may find it is very similar to challenges with floating oil and gas equipment. "We don't need to think about the whole structure."

The current risk reward structure in the wind sector is very geared to winners – so contracts go to the best suppliers – but it does not leave much breadth or optionality in the supply chain, he said.

Scottish Hydrogen and Fuel Cells

Nigel Holmes, CEO of the Scottish Hydrogen and Fuel Cell Association said there are only two "vectors" which let customers have energy with no CO2 – electricity and hydrogen.

The challenge is where the hydrogen comes from – and working out how to use hydrogen to better integrate wind into the UK's energy system.

Currently hydrogen is nearly all generated from fossil fuel, with no CCS involved, and mostly for industry – oil refining and fertiliser.

Already some fertiliser companies are asking if they can access very low cost electricity, and so make hydrogen themselves by electrolysing water. "They don't seem to be considering the "blue hydrogen" option," he said.

Aberdeen can claim to be the largest hub of renewable hydrogen in the UK, but is only making 100 tonnes a year. There are other renewable hydrogen projects going on in the Orkney islands, as a way to utilise surplus renewable energy.

There will need to be a steady growth in both supply and demand to grow the market, he said.

Already there are companies planning offshore wind farms considering having an option to produce hydrogen, and there are industrial customers in Netherlands and Germany actively sourcing "green" hydrogen.

Germany has gaps in its energy supply as it pulls out of nuclear, and the Netherlands has plans to decarbonise its chemicals sector. Hydrogen could play a role in both of these.

OGTC perspective

Martyn Tulloch, Net Zero Solution Centre Manager with the Oil and Gas Technology Centre, said that the Oil and Gas Technology Centre's original technical vision was the themes of "fix today", "unlock potential" and "transform tomorrow".

But with the push towards decarbonisation in society, transform tomorrow "came quicker than expected," he said.

The UK offshore oil and gas sector together uses 1.14 GW of power in its operations, so emits more CO2 than any industrial cluster onshore UK, he said. Perhaps some of this could be replaced by renewable energy.

Mr Tulloch presented data from scenarios from the UK's Committee for Climate Change on where we might be by 2050, showing electricity use more than doubling from 300 TWH/year now to 650 TWH/year in 2050, due to electricity replacing gas and oil for transportation and heating.

Around half of this will come from offshore wind, and gas with carbon capture making up much of the rest.

Meanwhile we will have a large hydrogen production, for energy consumers which cannot use electricity, such as ships, large transport, heat and industry.

Investment in oil and gas is expected to gradually reduce from £24bn a year now to £11bn in 2050, while investment in wind goes from £2bn a year now to £16bn a year in 2050.

But the "hydrogen with carbon capture" market will grow from 0 now to £13bn in 2050, and the standalone carbon capture market will grow from 0 now to £9bn in 2050.

So by 2050, the combined oil and gas, hydrogen and carbon capture markets are predicted to be £33bn, more than double wind, he said.

Westwood

"Volatility is the new paradigm everyone has to get used to," said Arindam Das, Group Head of Consulting at Westwood Global Energy Group

"E&P cashflows have improved since the downturn. We think they are ready to re-invest, but we don't see that."

Some of the places making Final Investment Decisions (FIDs) at the moment are Brazil, Australia and Nigeria, he said.

Expenditure in North Sea exploration and production is likely to stay stable at $30bn a year, Mr Das estimates, with "no huge spikes or drops".[This talk was before the March oil price crash].

There is big investment going into offshore wind, with plans to have 66 GW in Europe by 2030, 22 GW in the US, 30 GW in China, and 30 GW in the UK by 2030, he said.

The average water depth of offshore wind is 30m now, but will steadily increase to 45m by 2025. Also the distance from shore will steadily increase.

There will also be a big market for subsea cables, perhaps 15,000km for offshore wind in Western Europe from 2020 to 2024.

Marginal fields operations – new approaches

The Subsea Expo forum in Aberdeen in February included a number of talks with new approaches to marginal fields operations, from Pharis Energy, Jersey Oil and Gas, Amplus Energy and Indigotigre

Pharis Energy of the UK has plans to develop a heavy North Sea oilfield using polymer flooding. The technique is like water flood, with polymers injected into a field through an injection well, causing the heavy oil to flow into a production well.

Polymers are chemicals with long molecular chains. Polymers injected into a heavy oilfield can mix with oil and reduce its viscosity, enabling it to flow into production wells.

The company's initial plan was to produce the field using water flood for 60m barrels, and steam flood for a further 111m barrels.

But over the past year, the company decided to change its plan to using flooding with polymers.

This is because experience by Canadian Natural Resources in the heavy oil field "Pelican Lake", Canada, showed that polymers can produce oil which is 5,000 centipoise viscosity. The previous limit was thought to be 150 centipoise, said Steve Brown, CEO of Pharis Energy.

The company had been planning to inject 4 x pore volumes of hot water to produce the 60m barrels, and 1.5 x pore volumes of steam to get the 111m barrels. But now it has decided to do polymer flooding from the

Steve Brown, CEO of Pharis Energy

start, with a much tighter well spacing, and using low salinity water (which also offers better recovery).

Economic modelling showed that hot water flood would need an oil price of $46 to break even, steam flood between $42 and $46, but polymer flood would break even at $38, or $35 with low salinity water.

Polymer flood also has a better CO_2 performance. The hot water would mean 25kg CO_2 emitted per barrel of oil produced, steam would mean 90kg, but the polymer just 12kg CO_2 per kg. "We think we've got a much better reservoir recovery mechanism," he said.

This would mean the project would no longer be just "marginal", he said.

The company has licenses for the Pilot field in the North Sea. It was open acreage in 2014, very well appraised, with 263m barrels of oil.

The reason nobody wanted to produce it was that the oil is too thick to produce by normal means. The previous owners gave up (relinquished) the license, Mr Brown said.

There are two different suppliers of polymers. "I'm not sure that's enough competition to get a good price."

Mr Brown would like to enter into more of a partnership agreement with a polymer supplier, although the it is basically just a purchase transaction.

There is much scepticism about whether polymer flood can work offshore, just as there was with steam flooding. Although Chevron has been doing polymer injection at the Captain field in the North Sea since 2018, the assets being acquired by Ithaca Energy in November 2019.

As a general observation, Mr Brown believes today's oil and gas industry is far too constrained by internal processes, which end up obstructing new developments when trying to do something different.

The stage gate process, in particular, could be described as "the "best way of beating innovation out of a project" – giving people opportunity to block progress by raising objections, he said. Eventually it forces you down to a tried and tested route, such as water flood in this case, which wouldn't work.

In decades before, there was much more willingness to try out new concepts, he said.

Well construction

The plan is that the wells will have "dry trees" – well heads on platforms, rather than subsea.

The reason is that subsea wells turn out to be more expensive than wells drilled from platforms – including paying for the trees themselves, subsea flow lines, manifolds and risers, he said. This means that the optimum well spacing for wells is further away, which in turn makes the polymer flood less effective. The company was planning 30 simple wells with a close spacing.

Subsea would still work out cheaper if it was a small number of wells in one location, because it saves the expense of building a platform.

But with a larger number of wells in the same location, you can have all the well heads on one platform, so get savings in initial construction costs and maintenance, he said. The well head can be used for equipment, such as variable speed drives for electrical submersible pumps, which are still easier to handle with surface well heads.

The breakeven may turn out to be something like four of five wells from one location, "but this is very case specific," he said.

Jersey Oil and Gas

David Larcombe, engineering and commercial manager with North Sea operator Jersey Oil and Gas, talked about his company's ambition to have a carbon neutral development, taking power either from offshore wind turbines, or from shore.

There is nothing new about subsea power cables – there are a number of cables crossing between the UK and Europe. But the capital requirements are high, he said.

The viability of the subsea power could be improved if the power could be sold to other operators in the region, he said.

The company has a project in the Greater Buchan Area (GBA), in the Central North Sea. The GBA has 6 fields, a number of reservoirs and a number of companies involved, who might be persuaded to purchase the shore-generated power.

The wider region, known as the Outer Moray Firth, has 300m barrels of potential resources, 140m barrels of discovered volume, 36 years of production history and a lot of production data.

Having a power supply means that companies do not need to operate their own gas turbines to generate power, and handle the associated cooling challenges.

They can use electrically actuated valves. It makes the topsides simpler, reduces the weight which the platform needs to carry, and reduces the manning needed.

Jersey Oil and Gas started operations in 2017.

Amplus Energy

Amplus Energy, based in Aberdeen, is pioneering the use of what it calls "Versatile Production Units" – vessels which can be used for a range of production tasks – on a project in Angola.

The company does not own its own assets, but aims to sign broad reaching agreements with asset owners to produce fields, and undertake much of the decision making itself.

It is currently working in this way for a "large oil company in Angola", with a project to develop a marginal field.

The company's working arrangement with the client was basically "give us the keys," explained James Lund of Amplus Energy, where the company took over the entire task of drilling and production management.

The operator in Angola had its own funding, but a similar approach could work in the UK to get small pools into production, but where Amplus would also find funding, if the operator did not have funds available.

Amplus put together a team of companies to provide technical services, including Transocean drilling wells, and Halliburton doing reservoir studies.

By focussing purely on economic return, rather than maximising ultimate recovery, it found that it should be possible to produce 93 per cent of the anticipated 20 year production, in just 10 years.

On one field, containing 55m barrels of oil and 170 bcf of gas, Amplus put the field into production for \$6 to \$11 a barrel while the previous operator had costs of \$26 a barrel, with a CAPEX saving of around 50 per cent. "We didn't look at ultimate recovery, we looked at what was economic," he said.

Amplus produces what it calls "Versatile Production Units" (VPUs), offshore vessels which can be used for a range of tasks in production. These vessels can be newbuilds or conversions of existing hulls, such as drill ships, which have a big deck space, and space for large oil storage tanks.

Typically they have DP3 class dynamic positioning, and around 40MW of power generation onboard. They can have cranes, subsea installation equipment, and the option of different process modules placed on the deck.

If there is gas being produced together with the oil, it can be consumed in a turbine (for power generation), or perhaps piped into nearby infrastructure, otherwise it may need to be flared, he said.

https://amplus-energy.com/

Indigotigre

Indigotigre Ltd, based in Market Harborough, England, is aiming to develop a project with offshore oil and gas production integrated with renewable energy.

TIGRE is an acronym for "Transition to integrated gas and renewable energy". Renewable electricity would be used to power the gas production, so there would be no scope 1 or 2 emissions at least (emissions from the processes of production). This could be a way to offer life extension to existing gas assets.

Rob Hastings, CEO of Indigotigre, is a former director of energy and infrastructure with the Crown Estate, and director of the British Wind Energy Association.

Offshore wind electricity can work out much cheaper than the total costs of generating electricity using diesel generators offshore, Mr Hastings said.

The company is also keen to develop a "gas to wire" project. This is where gas is produced offshore, combusted offshore in a turbine to make power. CO_2 from the turbine is sequestered, so it is zero CO_2 emission power.

This project is called SELAS, is an acronym for "Sequester emissions at location of source."

The CO_2 can be used to improve further gas recovery by injecting it into a gas reservoir. In this case it is important to be able to demonstrate how much CO_2 has been produced and what happened to it, to show it is really zero CO_2, Mr Hastings said.

The company has been working on a study for a year, funded by the UK government, with Schlumberger contracted to do subsurface work.

There are three technologies which can be used for separating out flue gas offshore. Amine solvents on the flue gas (the standard carbon capture method), post combustion cryogenic separation (cooling the flue gas so CO_2 freezes and separate it that way), and oxyfuel combustion, where you separate air into oxygen before combustion, and burn gas in oxygen.

Amine separation is the most mature technology, but was decided to be not suitable for offshore use. Oxyfuel separation was considered more promising for offshore deployment, with the size of plant needed.

In the Q+A session, Steve Brown of Pharis Energy noted that his company had considered molten carbonate fuel cells as a CO_2 separation method suitable for offshore, when it was previously planning to produce its fields using steam flood, with a lot of CO_2 involved in creating the steam. This has an additional benefit of generating electricity. It is a "relatively mature" technology, currently being trialled by ExxonMobil in Alabama.

Mr Hastings replied that the aim of the program was not so much technology development, but deploying technology which has already been developed.

Equipment for marginal fields

We heard about a wide range of equipment which can help produce marginal fields at Subsea Expo, including unmanned production buoys, low cost conductor installations, subsea tanks and pig launchers, and ways to extend control system and pipeline life

Crondall Energy, an engineering consultancy based in Winchester, England, has been developing a design for a normally unattended production buoy since 2014, through its subsidiary Buoyant Production Technologies, the technology is named 'Floating NUI'. (See illustration on the front cover of this issue).

The buoy is designed to support power generation, topsides processing equipment, storage of chemicals for injection, and control systems. When configured as a 'Production Buoy', It can provide standalone production facilities for up to 30,000 bopd, enabling economic production of stranded fields that are too small to be produced by a small FPSO, but unfeasible for production via subsea tieback.

Floating NUI can also be configured as a 'Power and Utility Buoy' supplying power and utilities such as chemicals at the wellsite to support long range or technically challenging subsea tiebacks. In this configuration, the functionality offered by the buoy eliminates the need for an umbilical from the host facility and reduces the associated brownfield modifications at the host. This can overcome technical challenges with the subsea tieback as well as improving the field economics. In this configuration the buoy does not provide any processing facilities and well fluids are transported to the host facility via a flowline.

Communications to the host platform can be via VSAT, microwave link or fibre optic cable along the flowline.

The Floating NUI product range bridges the gap between short distance, simple subsea tiebacks and small standalone FPSO solutions, says David Steed, general manager of Buoyant Production Technologies.

Mr Steed estimates that a Floating NUI supported subsea tieback would make commercial sense if the field is in the region of 20km from the host platform. However, if the buoy replaces a need to make expensive modifications to the host facility, the distance required to make the project breakeven is shorter.

The buoy sits in a water as vertical cylinder, with high density ballast placed at the lowest point as a 'keel' to increase stability and allowing more weight to be placed on the topsides.

The buoy is configured for launch at shallow quaysides. Requiring a 5m draft at the launch site, something most construction sites have.

The last event before the virus - Subsea Expo in Aberdeen in February

The hull of the buoy and its deck can be built independently, with the deck later floated onto the hull. It may suit for them to be built in different locations, for example with the hull, which requires less technical competence to build, made in a host country for an oil field, to satisfy local content requirements, and the deck and topsides equipment built elsewhere.

The equipment is designed for remote condition monitoring and infrequent maintenance. There is no helideck – this adds to weight, cost and maintenance burden – instead the deck would be accessed with a "walk to work" vessel.

The compact size of Floating NUI and normally unattended operational model drive low CAPEX and OPEX, enabling a low lifecycle cost development option for stranded fields in deeper water. The technology is targeted at Operators looking to increase production of existing hub facilities by tieing in increasingly remote and/or challenging satellite fields.

Can you extend pipeline life?

Many companies want to know if or how they can extend the use of a pipeline beyond its design life. Jeremy Summers, field development manager at technical consultancy Atkins, explained some of the thought processes to go through

Of the 45,000 km of pipeline in the UK Continental Shelf, the average age is 23 years, and the typical design life was 20 to 25 years, said Jeremy Summers, field development manager at technical consultancy Atkins.

At the end of the design life, you have to do a "life extension study."

The question is what scope this work takes. It could be anything between a detailed forensic examination, or just reviewing some key documents. The choice is not obvious. "We've seen studies of between 40 and 300 pages for not too dissimilar pipelines," he said.

The pipeline safety regulations simply say we should "manage risks appropriately."

If you do every activity which is suggested in the various pipeline maintenance codes (NORSOK and ISO), "that's a very large scope. You don't want to do any more work than you heed to."

For example, you can consider analysing the safety systems, control systems and valves, as well as the integrity of the pipeline itself. But it may not be necessary.

The operator basically wants to know if they can carry on operating the pipeline.

A starting question to ask yourself could be, which of the risks are likely to change over your planned life extension time. For example, will the pipeline be operated under different parameters, such as a lower flow rate? This may change the risks.

You don't need to look at failure modes which are not going to change with time, because you can work on the basis your existing risk management regime should be able to handle these.

If you can address the increase in risks which you identify, it will be OK to extend the life of the pipeline.

Having previous experience can be very useful, but no-one can mitigate all the uncertainty, he said.

For example, Atkins worked with one of

the world experts in "top of line" corrosion assessment" (corrosive condensed water on inner wall of the upper half of the pipeline), who had written software for modelling corrosion. Atkins engineers had found that the corrosion patterns were different to those this software was predicting. So they discussed some of the models with him about why this might be.

If you can do an internal inspection of the pipeline (with a pig) that can be helpful.

You don't need to look at every element in detail – but there some areas you will want to look into in detail.

As a consultant, you could recommend that they do or don't do an inline inspection, or find ways to assess a threat in more detail. They could gather more monitoring data, or change the inspection regime.

You should not try to assess something which is not possible to assess, such as the rate of corrosion loss.

Neodrill – reduce conductor installation costs

Neodrill, based in Stavanger, Norway, has a plan to reduce offshore well construction costs by using a basic construction vessel, rather than an expensive drilling rig, to install the conductor pipe

Neodrill, based in Stavanger, Norway, reduces offshore well construction costs by using a basic construction vessel, rather than an expensive drilling rig, to install the conductor pipe.

The daily costs of a construction vessel are typically 5 to 15 per cent of a drilling rig (so as little as 1/20th of the cost).

The conductor pipe is a large diameter pipe set into the ground before drilling, to provide the initial stable structural foundation. It protects shallow sands from being contaminated by drilling fluids, and prevent washouts (loose top soils and gravel). It is typically up to 1,000 feet long.

The conductor pipe is normally installed by a drilling rig, after drilling a large diameter hole into the seabed. Installing the conductor can take 2-4 rig days, and is also a potential source of problems which take more time. It is cemented the same as casing.

With Neodrill's method the conductor pipe is installed by suction anchor method, creating a negative pressure differential inside the base, which pulls it down. Installing the conductor this way typically takes 24 hours of a construction vessel's time, in 2 x 12 hour shifts. No cementing is needed. There is also less energy needed for construction, and so less CO_2 emissions.

The company was founded in 2000, and the conductors were first installed in 2006. There have been 23 installations done since then, with the busiest time now. "We have 6 orders and think we can double it, so add 50 per cent to our track record this year," said Wolfgang Mathis, COO of Neodrill.

One customer is Siccar Point Energy, which used the method on an appraisal well being converted to a production well, West of Shetland, in 1082 water depth.

All of the flowlines and umbilicals can be put in place before the drilling rig arrives on site, with production tubing connected directly to the conductor. This means that production can begin immediately after the well is completed, the well head has been placed on the conductor, and the main capital expenditure (on drilling time) has been spent.

Another benefit is that the drilling rig does not need to ever drill large diameter holes. You can start drilling with a 17.5 inch, rather than starting with a massive 36 inch hole.

The company gathers geotechnical data to get a sense of how well the section method would work, including from the Norwegian Geotechnical Institute. If it is on a field which is already in production, a large amount of data is already available.

The conductors have been installed at 99m to 1500m water depth.

The construction vessel needs a crane with enough capacity, and you need a ROV which can go deep enough.

One of the biggest concerns is that the conductor might cause the soil below the structure to "wash out" (fall away from the hole). "It is the biggest argument against the technology," he agreed. "But we didn't have any incidents yet."

One of the biggest obstacles is the reluctance of people in the oil and gas sector to be first to do something, he said. You usually have to sell the idea to multiple departments, and it needs enthusiasts within the company. But with the track record, it gets easier, he said.

A video of Neodrill is on YouTube at https://youtu.be/MZLWymZxLfc

NOV – storing oil, pigs, and water treatment on the seabed

Oilfield equipment company National Oilwell Varco is developing a range of technologies for subsea production – including subsea oil storage, automated pig launchers, subsea chemical storage and subsea water treatment

Oilfield equipment company National Oilwell Varco (NOV) is developing a range of technologies for subsea production – including subsea oil storage, automated pig launchers, subsea chemical storage and subsea water treatment.

There is a system to store oil on the sea floor, with individual tanks able to store up to 60,000 barrels. These tanks can be configured in a cluster of five units each, giving a total capacity of 300,000 barrels per cluster.

It has a membrane design (like a plastic bag), rather than being a pressure vessel. The pressure inside the membrane is the same as the pressure outside, so it does not need be designed to be strong enough not to crush under the weight of the water and can be placed at any water depth.

This subsea storage could be connected with unmanned platforms on marginal fields, or used as an alternative to "Floating Storage Units (FSU's)". These are typically used together with fixed platforms, spars, semi's or TLP's, in areas with little infrastructure.

There is a control system which can monitor the level of oil in the membrane, and so detect any leaks.

NOV purchased the patent to the system in 2017. It followed work qualifying the membrane from 2013 to 2015, feasibility studies from 2014 to 2018, and large scale verification from Q4 2019, until Q4 2021. The Oil and Gas Technology Centre (OGTC) and Equinor are partners in this project.

NOV has also developed an automated "pigging" station to frequently wax piping to optimize flow-assurance – known as the Subsea Automated Pig Launcher (SAPL).

There is an automated pig launcher, which is a device that can launch a pig on receipt of a control command. It has a number of pigs ready to send, so you can pig at any time.

The "pig" is a device which is propelled through a pipeline by the fluid flow, to do a task like cleaning or inspecting a pipeline.

It is common for companies to install a "pigging loop", where there is a way for the pig to get back to the starting point – but this means a lot more capital investment, basically doubling the cost of the pipeline.

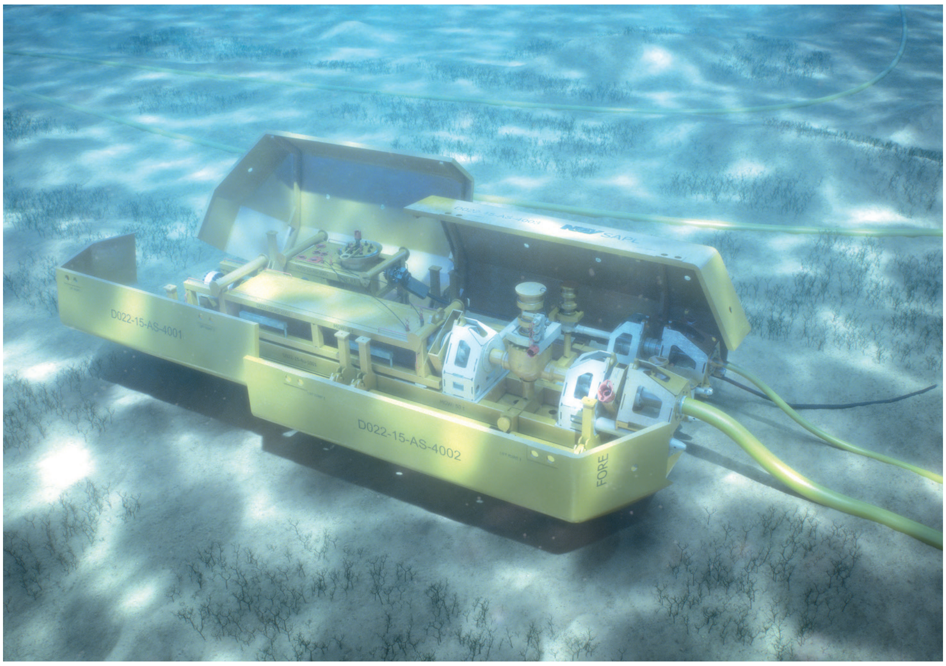
With the SAPL, you can install a number of pigs at the starting point in a "cassette" holding device, delivered by vessel. They are then launched through by a control system. The pigs can be removed from the pipeline on the offshore platform, where the production line goes for further processing. So there is no need for a "pigging loop" – which means a big reduction in cost, enabling more cost efficient tie-backs by eliminating the need for a second flowline.

Another project is subsea chemical storage. NOV has developed a modularised system, where the tank can be easily filled by bringing it to surface, or by a "trickle line" pipeline. The tanks are between 40 and 250 m3.

Chemicals are added to production streams for a number of different reasons- such as reducing corrosion, scale, hydrogen sulphide, bacteria, hydrates, wax, asphaltene precipitation or during shut down operations.

There are often limits of how much additional weight can be added to topsides, so putting chemical tanks on the seabed is a way to work around this.

There is a modular unit which can include tanks of different sizes, a boosting (pumping) or dosing system, a power supply system and a fluid transfer system.



The Subsea Automated Pig Launcher

Another product is produced water "polishing" – a system for cleaning produced water on the seabed. The sand is removed via a sand accumulator and the rest of the water sits in a tank, and any solid particles sink to the bottom.

This can make it possible to treat produced water on the seabed, and then discharge it to the sea, or re-inject the water into the subsurface. So you avoid the cost and energy consumption of bringing it to the topside platform for treatment. Another important point is that by removing the water subsea, you also remove the hydrate potential. This gives better flow-assurance and avoids expensive heated pipeline systems or insulation.

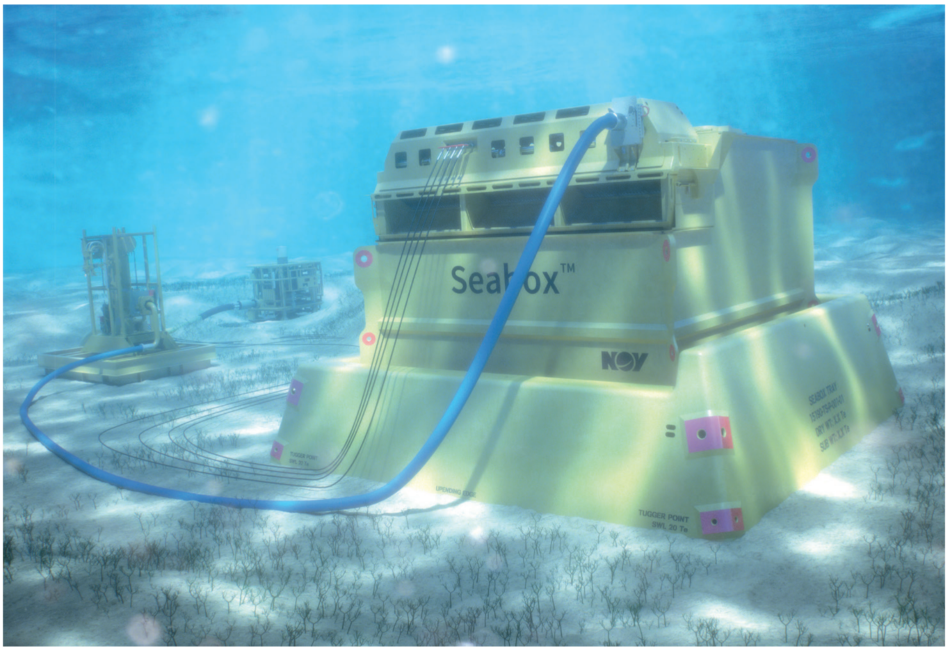
It can make it possible to develop new wells to be tied back to existing infrastructure, and also reduce intensive topside modification costs.

A "subsea water treatment and injection" program called Seabox can disinfect water on the seabed and remove organic material. It does this by using an electro chlorinator, applying electricity to separate salt into sodium and chlorine, with the chlorine then killing any microbes, disinfecting the water and removing organic material. No chemicals are required.

The system has had a field application test with ConocoPhillips' Ekofisk platform, where over 12m barrels of water were handled, and 500,000 re-injected. "It is a good solution for congested platforms," said Rune Høstmark, product manager with NOV.

The pathways to reducing the cost of marginal field developments can include having more production systems and equipment on the seabed, minimising the number of topside modifications necessary, minimising the number of new flowlines, having more automated and unmanned systems, finding ways to maximise the life of existing assets, and minimising the amount of greenfield capex you need to make, Mr Høstmark said.

Learn more about NOV's subsea technologies at nov.com/subsea.



Subsea water treatment and injection

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Some of the presentations from Subsea Expo are online at **https://www.subseauk.com/9245/subsea-expo-2020**

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