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Developing hydrocarbons in Guyana - is it 'advantaged'?

How better seismic can help find more hydrocarbons

Electrifying UK North Sea operations

Identifying "error traps" in operations

Segmenting networks for cybersecurity

May - June 2022

Asset Performance Management "4.0"

AI for asset management - data and images

Aramco and condition monitoring of drilling RCDs

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

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

Advertising sales:
David Jeffries, Only Media Ltd
djeffries@onlymedia.co.uk
Tel +44 208 150 5293

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Cover image: *Over 20,000 seismic nodes from STYDE were deployed on a CO2 sequestration project in Gibson City, Illinois. The client is CO2 sequestration company Projeo, and the geophysical contractor is Explor*

Developing hydrocarbons in Guyana - is it 'advantaged'?

Guyana's new oil production may generate similar wealth per person as Qatar, Kuwait and Norway. But what should be done with the gas – and is the industry going to be well governed? Topics discussed at our webinar

The South American country of Guyana started producing oil in 2020 and production is expected to be 750 kbopd by 2025. With a population of just 800,000, this could mean a hydrocarbons income per person similar to that in Norway, Qatar or Kuwait.

The oil is deepwater, produced to FPSOs, and comes with associated gas.

While the oil can be discharged to a tanker, there are several options for gas: export via pipeline, floating liquid natural gas (LNG) facilities with tanker export, or re-injection in the reservoir.

We heard that Exxon has plans for a gas to electricity project which would send gas to shore for power generation via a 120 km $1.3 bn pipeline. This would provide a cleaner option for Guyana's electricity generation, the majority of which uses fuel oil with a much greater carbon footprint than natural gas.

However, the estimated 50m cubic feet per day for electricity generation is a very small portion of the over 1 bn cubic feet per day rate at which the project is ultimately predicted to produce on plateau.

With no existing infrastructure for gas transport, the gas would have been flared in projects developed in the past, but today there are environmental concerns about flaring – from the CO2, methane from the 2 per cent unburned gas, and particulates, noise and heat.

The sole operator in Guyana, ExxonMobil, is currently reinjecting the majority of the gas back into the reservoir after using some for power generation. But there is still gas being flared while systems are in the 'start-up' phase. It also means that the proportion of gas in flows coming up through the production wells (technical term is gas oil ratio) will progressively rise.

A broader concern is quality of the hydrocarbon governance. Dr. Zainab Usman, a senior fellow, and director of the Africa Programme at the Carnegie Endowment for International Peace in Washington, D.C. is quoted as saying, "whether revenues remain hidden or aggravate socio-political problems will depend on Guyana's mechanisms for checks and balances."

Alison Redford, an advisor to governments (including Guyana) and former Premier of the Canadian Province of Alberta

Alison Redford, an advisor to governments (including Guyana) and former Premier of the Canadian Province of Alberta, speaking in the webinar, expressed confidence in the Guyanese government's ability to manage the development.

She explained that a newly elected government is pushing for higher environmental performance, including an agreement for 'carbon neutrality', plans to take the gas to market, and introducing fines on the operator for flaring. Exxon has been fined US$4.5m so far for flaring.

Ms Redford emphasised the importance of making environmental plans right at the start of any project.

Patience

David Bamford, a former lead of BP's global exploration program, speaking at the webinar, said he was impressed by the patience ExxonMobil had shown in developing the fields, since it first started exploring in the 1990s. This was under Mobil, a company which merged with Exxon in 1998.

Other companies had already tried an approach Dr Bamford call 'trend ology', expecting to find the same thing in Guyana as they find on the equivalent area of the West African coastline, and also in Suriname and French Guinea, but it didn't work.

And the successful wells drilled in Suriname tended to more gas than deepwater oil discoveries in Guyana, so they would be much harder to commercialise.

Exxon seems to have developed "a profound understanding of petroleum systems," he said, making maps of the source, reservoir and seal. This included analysing the depositional system, source rock maturation, hydrocarbon expulsion, migration, and where in geological time it all happened. This was supported by high quality 3D seismic and attribute anlalysis.

"I would say this is terrific hard work, there are no short cuts, you can admire Exxon's patience above all."

Just 1000km away from the Guyana coastline is Barbados, whose prime minister, Mia Mottley, gave "maybe the best speech at the COP 26 climate change conference," with Barbados under high risk from changes in climate and sea level, Dr Bamford said.

Dr Bamford was personally involved in BP's work to develop oilfields in Angola and the Niger Delta, which were similar projects in that they were new deepwater developments. But they were developed in an era (1990s) when there was much less environmental concern, and decisions were made purely on whether they would make money.

Big deepwater oil projects can be extremely profitable. "If you have done enough appraisal to understand the reserve base well, and you have a good reservoir, then an FPSO based system gives you the opportunity for early development, early first oil."

"When you start looking at the economics, you start understanding why companies like BP abandon places like the North Sea and say, 'we want to spend our money in this sort of system,'" he said.

There are developments in West Africa at a similar stage, in Mauritania / Senegal, and in Namibia. For the 'Tortue' project in the border of Mauritania and Senegal, there are definite plans to liquefy gas and export to Europe. But in Namibia, so far there are only early-stage plans for oil production, he said.

One difference between Guyana and the African projects is that Guyana is considered a 'middle income' country by the World Bank, while many African countries are the poorest in the world, in particular with respect to energy poverty. This means there is more resistance in Africa to any environmental measures which may prevent a development project from proceeding, he said.

Understanding flaring

Oil and gas operators may need to flare for safety reasons. For example, if there are pressure increases in a system due to equipment malfunction or maintenance, the gas can be safely released by diverting it to a flare stack and burning it. This is usually with small volumes of gas and happening intermittently, explained J.L. (Les) Anthony, CEO, Teyshas Energy LLC, a technical consultancy based in Dallas.

J.L. (Les) Anthony, CEO, Teyshas Energy LLC

In the past, the industry routinely flared gas, because it only wanted oil, and considered gas that was produced with it to be a waste. "When I was younger, you could drive through West Texas without headlights on because there were so many flares," he said.

The World Bank Global Gas Flaring Reduction Partnership estimates that a typical flare is 98 per cent efficient in terms of how much fuel is combusted, and methane has 25x the global warming potential of gas. So, the 2 per cent of methane which escapes unburned creates half as much greenhouse gas impact as the CO2 from the 98 per cent of gas which is combusted, and in addition to it.

It means that each cubic metre of gas which is flared causes 2.8kg of CO2 equivalent emissions, he said.

Other environmental negatives of flaring are release of particulate matter (soot), heat and noise. These can impact fishing near the FPSO.

An organisation called Earth Observation Group, in the Colorado School of Mines, analyses flaring globally, with algorithms to differentiate light from flares on satellite imagery, and to determine the composition of gases.

The World Bank flaring group estimates that globally there was 145bn m3 of gas flared in 2020, which caused 400m tonnes CO2 equivalent of GHG impact.

Another US organisation, Skytruth, keeps data about flaring, and Mr Anthony was able to use it to map when Guyana flares started and finished.

Using Skytruth data, you can see the flare from the Liza Phase 1 FPSO "Destiny" was lit continuously from Jan 16, 2020, to June 5, 2020, and the flare on Liza Phase 2 FPSO has been lit intermittently for a number of months over 2022.

Skytruth ranked Guyana 40th in the world for countries which flare, with 0.28 billion cubic metres (BCM) flared in 2020. Although this is a long way behind the No 1 Russia (24 BCM), Iraq (17 BCM), Iran (13 BCM) and the US (12 BCM).

But Guyana will be starting up many more oilfields, which could put it at 14th worst in the world, according to Mr Anthony's modelling.

Exxon's development

Exxon drilled its first well offshore Guyana in 2015. More than 30 exploration wells have been drilled in the last 7 years, with 26 significant discoveries.

The first FPSO on Liza Phase 1, "Destiny" was started up in early 2020; the second, on Liza Phase 2, "Unity", started in Feb 2022. There are 10-12 FPSOs forecast to be used in the final development, he said.

For the third and fourth FPSOs, Payara and Yellowtail, Exxon has produced a forecast of how much gas it expects to flare, with a maximum rate of 200m cubic feet a day, although it said it will aim to flare less.

Mr Anthony estimates that the production over the lifetime of the field could be 8.6bn barrels of oil and 8.6 TCF of gas. That gas volume is more than enough to justify investing in a full LNG 'train' (sequence of compressors), or even more than one.

Guyana is developing a master plan to use the gas for power generation for domestic use, and then develop LNG. But until this happens, gas will be injected back into the reservoir.

With reinjection of all associated gas not flared or used for fuel, total gas production will be 23 TCF by the end of the license period in 2049, Mr Anthony estimates. This means each gas molecule will circulate about 3 times.

This gas production means higher operating costs, higher capital investments, and makes the field less commercially effective, shortening its commercially viable lifetime.

Exxon is likely to use water as the main way to maintain reservoir pressure, with a maximum injection rate which "could be" 1.5m barrels of water per day, Mr Anthony said.

So, there will be increasing water produced with the oil. Exxon plans to treat the produced water and discharge it overboard. This could be 1m barrels of water a day at its peak.

Mr Anthony compared three different options for how the reservoir could be managed, which could have been considered before any development had started.

One would be to re-inject all gas not used for fuel or flared and sell none of it.

The second would be to sell gas for domestic power in Guyana starting in 2024, and then develop onshore LNG production, with 200m cubic feet per day in 2030, rising to 600 in 2040. These projections are in line with Guyana's Oil and Gas Master Plan.

The third is that all gas is sold immediately and there is no re-injection (and dramatically reduced flaring). This option is strictly theoretical due to the field production start-up over two years ago and the timing required to fabricate and commission large gas sales projects.

Comparing the options, while the second and third would need investment in infrastructure, the first option needs more spending on compression equipment, gas injection wells, and higher operating costs of compression, gas handling, flaring equipment and fines.

Guyana government

Alison Redford, who works an advisor to governments (including Guyana), noted that many of the issues Les mentioned are the ones which the government is currently considering. But also, the discussions are progressing.

A new government was elected in Guyana in 2020, which was involved in negotiations for the Payara and Yellowtail developments (the third and fourth FPSOs). Both have different "profiles" for flaring and gas utilisation.

For the fourth FPSO (Yellowtail), Exxon has agreed with the government to do a gas utilisation study, including power generation onshore, and LNG for export.

"Guyana has ramped up in terms of understanding how they need to work with Exxon on developing production profiles," she said. "This includes looking at economic viability of projects and some other longer-term considerations."

What I've seen happening [is that] there's a definite public acknowledgement that the licenses negotiated by the previous government for Liza [phases] 1 and 2 were too flexible in terms of the level of flaring that was be permitted."

"The new government under Vice President Jagdeo and Minister Bharrat started to see some of these problems [and] amended the licenses so they are more tightly controlling flaring."

"The government is working every day to improve the system. The government has zero tolerance for routine flaring and will only allow for flaring in emergency situations and during commissioning."

"That's why it's important that the 'commissioning' [phase] is tightly defined, so flaring doesn't continue indefinitely."

Guyana's Environmental Protection Agency has also put "tremendous investment and development" in their ability to monitor flaring. They can do it 24 hours a day. They have also developed a penalties system."

"They are managing, very well, the environmental impacts that they need to address, whether through flaring or other operational issues."

"They put in place a robust Environmental Protection Agency (EPA) system that is stronger every day with respect to how they are able to monitor and impose penalties on Exxon when they don't perform."

"My sense is, as a government, they are technically qualified and able to manage the issues and doing a very good job at understanding the long-term consequences."

"It could make the most sense for Guyana to move gas to a commercial development level. That will likely be considered as part of wider economic development planning," she added. "There's a lot of development decisions that need to be made. From what I have seen, this is a government which is prepared to consider these options."

The carbon approach

Ms Redford noted that Exxon and the government are working toward a 'carbon neutrality' agreement. "I think that's a big step forward. 2-3 years ago, when the idea was introduced, Exxon wasn't that interested in it."

"Certainly, the world has changed. Exxon has some new active shareholders and directors, and that has changed their view on how they deal with climate issues," she said.

"The Government of Guyana and operators, are all trying to work within this very complicated environment to get to a better place in terms of environmental impact."

"I don't think we have all the answers today, anywhere in the world. I don't think that anyone globally has the perfect answer."

It is very important to think about environmental aspects early on with a major development like this. "Even if you start very early on planning, you haven't started soon enough – that is a lesson that all oil producing countries globally have learned and that is also the situation that Guyana faces. They are constantly striving to do better." she said.

She added that the Barbados Prime Minister Mia Mottley, who had given a compelling speech at the COP UN climate conference, spent 4 full days attending the February 2022 Guyana Energy Conference and Expo 2022, which seems to demonstrate her commitment to Guyana's energy development.

There could be efforts to develop regional solutions for energy supply and climate involving Barbados, Guyana and others, she said.

Mr Anthony noted that with Exxon's development in Guyana, genuine carbon neutrality is not possible, if it implies no emissions of CO_2 at all. "But we're going to do a better job [on carbon] if we flare less gas."

In the global picture, Guyana's oil and gas production could be considered 'advantaged' due to their scale, this allows for capital and operating expenses to be carried by a larger number of barrels, Mr Anthony said.

You can watch a video of the webinar at
www.findingpetroleum.com/event/d08d3.aspx

Finding more hydrocarbons with better seismic

With Russian gas being taken off the market, the world is looking for ways to find more hydrocarbons and get it into production. Neil Hodgson suggested ways that this can be done with modern seismic data

Russian gas imports to Europe had been gradually growing from 447 billion cubic metres (BCM) a year in 2010 to 639 BCM in 2020. They had been predicted to grow to 715 BCM in 2030.

But due to the Ukraine invasion, "that will never happen," said Neil Hodgson, VP geoscience with Searcher Seismic, and a former exploration manager with Matra Petroleum, Premier Oil and GB Group.

He was speaking at a webinar organised by Finding Petroleum on Mar 25.

"Europe's got a problem. Where is [its energy] going to come from?"

"Because Russia invaded Ukraine, we want to point out that attacking another sovereign country is not a good idea. One way you can apply pressure is through economics, and you can't do that if you get gas from Russia."

Many of the pipelines carrying Russian oil and gas go through Ukraine, as he showed on a map. "If anybody is wondering why this war in Ukraine is happening, perhaps this image has something to do with that."

There are pipelines from North Africa into Europe, but can only increase throughput a "a limited amount." Gas can be sent by ship as LNG, which is expensive and has been increasing in price over the last year.

Meanwhile, over the last 2 years, the oil price has been steadily increasing, as the world's economy rebounds from Covid, from $60 up to $100. But there has not been much new exploration.

"For the last 5 or 6 years there's been a feeling that the oil and gas [industry] has been toxic as a place to invest. You couldn't get any money to drill an exploration well."

After the Russian invasion of Ukraine, the oil price shot up further, and was $118 at the time of the webinar, due to concerns about restrictions of supply.

Neil Hodgson, VP geoscience with Searcher Seismic

This means that the commerciality of oil and gas projects looks very favourable in terms of dollar returns per barrel.

"The reality that we find ourselves in today, we've handed our energy security to Russia without thinking about it. That was not a brilliant idea. We've also woken up to the fact that without that gas we would be pretty screwed for energy in Europe. We still have a carbon economy.

That's a different message to the one we've been getting that says, 'a lot of our energy comes from windmills.'"

So today, there is an increasing realisation that investing in oil and gas is not immoral – but companies are looking for oil and gas opportunities which are advantaged in some way – such as by being "easy to find, easy to develop, and easy to monetise," he said.

"By easy, I mean quick. In the [recent] past if you had an oil project, you'd try to get that in production in 7 years. When I came into the industry, a gas project would come into production in 10 years. You'd want to halve that now."

Mature basins

Mature or 'over mature' basins are a good place to start looking for advantaged resources. "You know what's happening to the geology, you've got a good understanding of the subsurface, you can get hold of seismic data and improve it. Our ability to improve seismic data is amazing compared to 10 years ago."

In a mature basin, any new discovery is likely to be next to infrastructure, which means you don't need to do so much building. You have a pipeline system you can connect into. "You've usually got a sophisticated regulator, who understands what you've got to do and will help you do it."

But on the other hand, a mature basin "almost by definition" has already been thoroughly explored. For example, the UK's Southern North Sea has been explored since the 1960s.

But there may be new tricks you can use to find hydrocarbons which previous exploration efforts did not find – using new developments in seismic processing.

For example, it was impossible to gather good seismic data beneath salt domes until about 15 years ago.

Looking at a map of existing gas discoveries in the UK Southern North Sea, a very mature basin, and a map of where the salt diapirs (domes) are, there is no correlation between them. It shows there hasn't been any exploration beneath salt diapirs, he said.

The only gas fields beneath salt domes are fields which were discovered when exploring adjacent to the salt dome, and then it was found that the field extended to below the salt dome.

A geologist would expect a salt dome could be particularly good place to look for hydrocarbons, because they can trap gas generated from Permian or carboniferous organic material. Also, a salt dome could form over the crest of a fault block, he said.

Exploring below salt domes today doesn't necessarily require new seismic data, you can take the old seismic data and put it through modern data processing techniques, he said. Most Southern North Sea data was last processed 15 years ago, some of it over 20 years ago.

"I guarantee that when we reprocess the data it will 'light up' with hydrocarbons," he said.

Another example of how seismic can help with exploration was given for fields offshore Nova Scotia (East Canada). This region can be classified as 'over mature'. Production finished around 2017 and fields have been decommissioned, although a lot of the equipment is still in situ, he said.

Using modern seismic data processing techniques, "we found there's 1.5 TCF of gas never developed in that area, it is just sitting next to infrastructure but not being developed," he said. "Nobody is exploring Nova Scotia offshore anymore."

Mr Hodgson showed an example of Nova Scotia seismic data from 1998 which had been used to find the reservoirs. By today's standards, "it looks awful, you can just about see the top of the sedimentary sequence, you can't see much in it. In the past they determined where fault blocks are and tried to drill fault blocks."

"They developed the fields on this standard of seismic. Just think how much more gas we could find in that area if we had better data."

"You have to look at the latest quality seismic data before you can convince yourself that it is a truly depleted basin. You might think a basin is exhausted when you've produced all the hydrocarbons, but it is only the geologists that are exhausted. If you give them new seismic data, you revitalise their imaginations."

Frontier basins

If you are looking in frontier basins, hydrocarbons will be most advantaged if you find a very big field, because the amount of overall production for each dollar of investment will be greater.

For example, Guyana in South America. This is also an example of a rapid development, with first production coming online just 4 years after the Liza discovery. The field is expected to provide "a couple of billion barrels of oil."

"Even the downside cases of the modelling are pretty big," he said. This means, "you can make an investment decision to develop the field pretty confidently."

Crossing the Atlantic to offshore Namibia, the Venus discovery, recently made by Total, is also very big, about 3bn barrels of light oil. Its "next door neighbour" Graff is also a large discovery. Although it is in 3000m water depths, the benefits of the hydrocarbons outweigh concerns about the complexity.

"A lot of revenue from that will go to the government of Namibia. They will be able to do really great things for the people of Namibia."

On the modern seismic, you can pick out the source rock, which is feeding oil up to the two reservoirs which make up the Graf discovery.

"I was still being told there wasn't a source rock south of Walvis Ridge until half way through last year," he said. (The Walvis Ridge is an ocean ridge which hits land near the North Coast of Namibia / border with Angola).

"Now it's proven and it's generating enough oil to charge this 3bn barrel prospect Venus."

If South Africa wishes to develop oil production, it has "the possibility of this play extending to South Africa."

"There will be plenty of other discoveries in Namibia on the back of this."

To drill in 3000m water depth was unimaginable about 15 years ago; in 2012, the world's deepest well was 3100m offshore India, he said. By 2016, the record was the 3400m Raya well (Uruguay) drilled by Total. By the end of 2021, Total made a new record, the 3628m Ondjaba Well offshore Angola. So, the trend is clear.

The largest prospects may be under over 4000m of water – which we may be comfortable drilling by 2026, he said.

The geological knowledge from West Africa can also be used to explore on the East Coast of South America, around Uruguay, southern Brazil and Northern Argentina. Seismic lines from both sides can be fitted together.

"We see exactly the same geology, the same Aptian source rock, the same basin floor fans stacked on top of them," he said.

So, the Venus discovery has also "opened up the South American play".

India, Eastern Med, Canada

In India, "a lot of seismic data has been acquired (but) not particularly good quality," he said.

There have been limited discoveries. Some areas have been explored only in "relatively shallow" water, but never explored in deepwater. But the plays do look similar to what has been seen offshore Uruguay and Brazil where big discoveries have been made.

"When you re-process the seismic, as we've done over the past year, the geology just leaps out. All these margins in East India have become incredibly prospective. Explorers have never had this quality of data to explore with."

The Eastern Med is interesting because, although it is a frontier basin, it is possible to connect new fields with existing infrastructure. For example, The Tamar gas discovery in the Eastern Mediterranean (offshore Israel), discovered in 2009 and in 1500m water, was brought onstream in 3 years, despite there being only a very small gas market in Israel.

The Zohr discovery in Egypt was developed in about 2.5 years. The initial plan was to tie it back to infrastructure on the Israeli shelf, but ultimately it was tied back to Port Said on the Egyptian coast, 190km.

In Nova Scotia, there may be many gas fields to discover. The Aspy-1 well, a "brilliantly brave" well drilled by BP in 2018 beneath a salt canopy, did prove a hydrocarbon system, although it wasn't a big discovery.

It is 'quite possible' if not 'probable' that any discoveries will be gas rather than oil, because the source rock is deep enough to be in the gas window.

But this may make it easier because there is an existing gas field and infrastructure nearby, close to Sable Island, he said.

Seismic

The secret to success in all these cases is seismic – either getting good, new seismic data, or getting your existing seismic in good condition, with recent advances in processing.

When it comes to acquiring data, consider that 20 years ago, 3D seismic streamers were normally 4km long, with 8 attached to a vessel. now they are normally 8km long, with up to 24 streamers behind one vessel. "That gives you a much better result when you process it," he said.

Seismic vessels often survey today in multiple azimuths (directions), such as going East to West as well as North to South.

The costs of acquisition and processing can be 10x higher than before. But if it identifies targets which are worth drilling, then this cost is worth paying.

The modern data can be used to supplement the existing data, not just replace it.

Modern processing techniques can do more with more complex structures, such as steep dip.

Land seismic surveying techniques are also improving, and there is more room for further improvement, he said.

"The amount of onshore 3D seismic [ever acquired] is relatively small compared to the amount of 3D seismic we have offshore now," he said. But this can mean, "the room for making huge leaps forward with your understanding onshore is much greater than it is offshore, by acquiring new, relatively cheap, 3D surveys."

People

Mr Hodgson was asked whether we still have enough people capable of understanding seismic data and geology to do exploration.

He replied that if the industry has a low attractiveness to graduates, it could be blamed on society's toxic view of the industry.

But on the other hand, oil and gas exploration does not need as many people as it used to. Individual exploration staff can monitor a much larger area today than they used to be, and calculations can be done much more quickly.

And the industry still has "absolutely brilliant geoscientists," he said.

"I've got a lot of confidence we do have the people to do this exploration. It's a case of letting them follow their ideas."

Geoscientists around the world increasingly come from the country which owns the reserves, he said. "When I worked in Egypt for British Gas in the 1990s, all the papers written about the Nile Delta were written by expats [Westerners]. Now they are all written by Egyptians. I think that's exactly how it should be."

You can watch the webinar online here

https://da2a8e76d046f8c4460d-5bf7032422e-b40a5ff2f5b0d01f92144.ssl.cf1.rackcdn.com/Mar25-let's%20find%20gas.mp4

Electrifying UK North Sea operations

UK offshore operators are making plans to electrify operations, in order to meet a target to reduce emissions from upstream activities by 50 per cent by 2030. A webinar discussed developments, ideas and challenges

The UK oil and gas industry has agreed (with the government) a target to reduce greenhouse gas emissions from upstream activities by 50 per cent by 2030, compared to 2018 levels, with further reductions to zero by 2050.

A big part of achieving that is running offshore platforms from electricity, either from nearby renewables, or from the onshore grid. Plans were discussed in a webinar on March 23, 2022, "Electrifying North Sea Oil and Gas production", organised by Offshore Energies UK.

Because offshore generation from generators can be inefficient, big CO2 savings can be achieved by connecting to onshore grid power, even if it is generated from fossil fuels. The UK's onshore grid, powered by a mixture of sources, makes a quarter as much emissions per MWH as offshore generation.

And 50 per cent reductions in emissions almost certainly cannot be achieved just by running equipment more efficiently or flaring less – it probably does need some kind of electrification.

Meanwhile shore power in the UK is getting more expensive, and there may not be enough of it available, with many thermal (fuel combustion) power plants being closed in Scotland.

Using nearby wind power may seem like the better option, because it avoids the need to lay cables from shore. But there are complexities, in that wind turbines need a certain lifetime, typically 30-40 years, to be cost competitive. This lifetime may be much longer than the expected life of the platform. And of course, you will need power when it is not windy.

Power from shore is probably easier to set up than offshore generation, noted James Bridgland from ABB.

But perhaps the right answer over the longer term is a combination of nearby wind generation, existing onsite generation from diesel, and connection to the onshore grid for both buying and selling surplus electricity.

Guy Appleton, Finance and Growth Director, Kellas Midstream, a company which operates gas transmission infrastructure, noted that power prices in Norway are lower than in the UK. But similar electrification projects have still proven commercially challenging in Norway. "It is challenging for companies to recommend spending a substantial amount of money to a project which is uneconomic," he said.

However, Norway is approaching 40 per cent of oil and gas production electrified "in a few years." The Norwegian side of the North Sea has many of the same operators and suppliers as the UK side.

Screenshot from the OEUK webinar. Will Webster, Offshore Energies UK; John Grady, Shepherd and Wedderburn LLP; Guy Appleton, Kellas Midstream; Michael Dodd, DNV; Thibaut Cheret, Offshore Energies UK; James Bridgland, ABB

Any offshore electrification solution needs to have connectivity to the grid if the economics are going to work, otherwise the wind farms will be stranded assets if the associated platforms are decommissioned, Mr Appleton believes. "It's not in anyone's interest to put wind farms in the North Sea which have a life of 10 years."

"If you can't get grid access by 2025, that will be a major barrier for offshore electrification."

ABB, Aker Solutions and Kellas Midstream announced in early 2020 a plan to join forces to explore offshore electrification in the UK, pooling their expertise, which covered design, infrastructure and commercial innovation.

They looked at a number of different options for how it could be achieved commercially, what changes to the regulatory model would be needed. They also looked at what could be learned from Norway. This includes Norway's CO2 tax and its lower electricity costs.

Wind lease round

The UK government has a special lease round in 2022 offering companies the right to build wind farms close to oil and gas platforms, specifically to supply the platforms with wind generated power.

Companies can apply to build up to 5.7 GW of wind farm, to operate for around 25 years. The wind farm can be sized up to 5 x the electricity needs of the platform, or hubs of platforms, it will connect to.

There is a separate 500MW "innovation lease" specially for new technology.

The application takes place in June 2022, with offers made in Autumn, and final planning approvals to be completed in 2023.

Regulatory perspective

Under UK electricity regulations applying onshore, companies purchasing power pay a number of different levies, including transmission costs and renewable obligations costs.

Whether or not these levies would apply to offshore customers would be a major factor in the commercial viability. "The question is whether it's realistic or reasonable for the offshore industry to bear such levies," said John Grady, Partner, Shepherd and Wedderburn LLP, a corporate and commercial law firm.

"Those levies are all targeted by activities which benefit onshore consumers, not offshore consumers."

If the oil and gas industry makes a private arrangement to take power direct from offshore wind farms, it can avoid these levies, and would not need to rely on the national transmission systems.

Power could be sold at a fixed price, with an agreement that the oil and gas company would have first option for all power generated, before the power is then made available to the onshore grid. Although the wind farm could not provide a "generation guarantee" since wind cannot guarantee a specific level of output.

It is probably important to keep the gas and diesel generators in the North Sea available for security and reliability reasons, he said. The electricity from these generators could perhaps also be sold to the onshore national grid at times of severe shortage of power.

Oil and gas companies considering offshore renewable power may want to consider a number of risks, including being reliant on a wind farm which hasn't been built yet and may have construction problems, or that the electricity supply has outages, planned and unplanned. Also, that the generator may become insolvent. "I would want a portfolio of sources of power," he said.

Having a fixed price agreement with a wind farm operator means that an oil and gas operator has some protection from electricity price changes.

Wind farm contracts are typically 15 years at least, in line with arrangements for financing projects, which can be for 15+ years.

"For some platforms it's not going to make much sense, because the platforms have a shorter life." In this case, "we need a solution where the platform takes [the power] for 10 years and someone else for 5-10 years."

"You could have some sort of common purchasing body and tie it to grid access once platforms have shut down."

The regulatory framework around the onshore network may need to be reviewed so it can accommodate power supply from offshore much faster.

There are also regulatory concerns about having a complex offshore power network which won't be needed once the platforms are no longer operational.

But also, there needs to be acceptance that perfect planning is not possible and caution itself comes at a cost, including in energy security terms.

"There has to be an acceptance that things will go wrong - we will build assets which may be stranded, and errors will be made. It is just inevitable because none of us have perfect foresight," he said. "Things need to be built and decisions have to be made and some of those will not turn out as we hoped."

"The onshore grid isn't going to be ready for some time," he said. "2030 is probably highly optimistic.

"We've got to do each stage in as simple a way as possible, so it doesn't close off optionality later on.

DNV / power grids perspective

Michael Dodd, business director power grids UK and Ireland DNV, discussed the challenges of putting together a suitable power grid.

There are various initiatives to build an offshore grid, with bodies involved including OEUK, NSTA, the UK government and National Grid. There's "a huge momentum rapidly gathering," he said.

There is likely to be power interconnection from this offshore grid with other countries, including Norway, Belgium and France.

"When you start to map out what that looks like - it gets very complicated very quickly," he said. "We're looking at different ways of planning the offshore grid space to make sure co-ordination is able to be delivered."

"Offtake arrangements will get increasingly complex."

There could be a wind farm making power which goes to a platform or goes to shore, or being used to generate green hydrogen, which is then sold.

Mr Dodd noted that standalone turbines can be more expensive to build and operate per turbine than an array. Also, their costs increase as you go further offshore, and use floating rather than fixed turbines.

An electrification system will need control systems, perhaps batteries, and a security system.

While the costs of wind are falling rapidly, higher costs make it harder to make projects work, he said. Having a wind turbine dedicated to one offshore platform would be very hard to make commercially viable.

OEUK perspective

Will Webster, Energy Policy Manager, Offshore Energies UK, said that the challenge could be defined as working out what can be done most quickly.

It is complex technically, commercially and in terms of regulations. We "need to ensure the frameworks work for all the parties involved."

The power connections between parties are different to how they have been done in the past, with multiple options involved.

And there will be continuously increasing demands for power offshore, and more connectors. "The upgrades required to the system will probably increase."

"The more complex connections become - the more difficult they become to integrate with the wider system."

He noted that one advantage of wind is that it can be built at any scale, unlike, say, nuclear power. This provides more flexibility.

Worley Parsons

Graeme Wilson, business development director of engineering contractor Worley Parsons was asked what he thought was the easiest way to electrify from a technical perspective.

Better co-operation helps increase the pace, he replied. Not just with regulators, but also within operators and supply chain companies.

Technical standardisation would help, he said. Some areas are particularly complex, such as modifications to brownfield assets, which has been likened to "open heart surgery", since these systems were never conceived to run on an outside electricity supply.

Standard modules would make it more straightforward. "That's how we make it as simple as possible in the grand scheme of electrification."

"What we're talking about is very complicated. An element of simplification is required to make us work at pace going forward. Pace is really important, to meet the targets set out by the North Sea transition deal."

Mr Wilson was asked, as an engineering contractor, whether it is easier to work with a blank sheet, or to re-use existing assets. "When doing large projects, working from a blank sheet of paper is in ways easier," he replied. "But the old infrastructure shouldn't be written off."

"Some assets designed and built in the 70s and 80s now have 20-30 years life [left], they were so well engineered. [We can] take that as an opportunity."

Best model for electrification

Speakers were asked which model they would prefer, one where a regulated "transmission owner" (TO) designs, builds and operates the transmission network, or it is done by an independent developer; or if there should be a separate "Independent Transmission Operator (ITO)" appointed to run the network, maybe with some involvement in the construction.

There is general agreement that the transmission system should not be operated by an oil and gas company, in case they deny access to competitors.

Thibaut Cheret of trade association Offshore Energies UK said he preferred the option where a transmission owner designs it, and then there is a competition for a transmission operator to build and operate it.

John Grady, Partner, Shepherd and Wedderburn LLP said he preferred that a developer design and build the network, and then a transmission operator to operate it, or a transmission owner would build and operate it. "These are the simplest options. They involve less regulatory changes, [so] they might happen sooner.".

Will Webster, Energy Policy Manager, Offshore Energies UK said he preferred the option where an oil and gas company designs and builds the transmission network, and then hands it over to an operator; or alternatively a single transmission owner builds and operates the network.

Michael Dodd, DNV noted that the quickest way to do it would be something akin to plug and play, "which in my mind means centrally planned and centrally delivered, to the extent that its possible."

James Bridgland of ABB agreed that systems being centrally planned and delivered would work well from an ABB perspective and may mean less competition. "To drive the cost of electricity to a level which is beneficial, you need the competitiveness of the marketplace," he said.

Graeme Wilson of Worley noted that "competition is great but sometimes stifles innovation. Whatever we go after needs to be done in an innovative manner. What we are doing here is pioneering."

you can watch a video of the webinar online

https://vimeo.com/691414593

SEQual – asking about your human factors policies

If, as a supplier, you want to work in Aberdeen with operators including Shell, BP, and Harbour Energy, you need to answer questions about your human factors policies as part of your SEQual 'pre-assessment'

SEQual, a supplier pre-qualification scheme based in Aberdeen, is asking suppliers to fill in a questionnaire about their human factors policies.

The human factors section of the questionnaire begins with the question, "Are you applying human factors / human performance as per the industry guidance," said Dr Marcin Nazaruk, speaking at a Step Change in Safety webinar.

Dr Nazaruk is co-chair of the Aberdeen based Human Factors working group of the Step Change in Safety organisation, and chair of the Society of Petroleum Engineers Human Factors Technical Section.

The "industry guidance" referred to is a free guidance document published by the SPE Human Factors Technical Section, which can be downloaded at https://spehfts.org/hf-per-industry-guidance

There are 7 human factors questions in the SEQual questionnaire, within the HSE section. They cover demonstrating and integrating practical application of human factors.

The first question companies are asked is if they have a documented human factors / human performance policy – and if it is integrated with other policies.

In the questionnaire, companies will be asked if their risk assessment process and training covers error traps in addition to hazards. Also, if the error traps identification is integrated into your company forms and templates.

A human factors policy "is not an attitude or a communication campaign, it is a set of tools which needs to be integrated with your policies," Dr Nazaruk said.

The human factors policy includes operating procedures, your incident investigation, risk investigation, proactive learning (looking for factors which increase the likelihood of human error), behavioural safety, consequence management (or the 'just culture') and demonstrating accountability.

Background to SEQual

SEQual is a supplier "prequalification scheme", where suppliers are asked to fill in a questionnaire, with the results made available to buyers. SEQual launched in May 2021.

The idea is that suppliers only need to provide the information once, rather than provide it multiple times to different potential customers. So, although it may take a long time to fill in the form, once it is done, they do not need to provide the information again, only provide updates or answer new sets of questions.

The SEQual project team found there was a lot of commonalities between questions being asked by different companies, and harmonised the questions.

The term 'pre-qualification' is used because it is for checks which buyers want to make before deciding about which supplier to use – it qualifies them to be considered.

SEQual buyers, who require a SEQual submission from any supplier before considering giving them new business, include Apache, BP, CNOOC, Harbour Energy, Neptune Energy, Repsol, Serica, Spirit Energy, Shell and TAQA.

Suppliers currently under a contract with an oil and gas operator do not need to qualify in order to continue under their contract, but they may need it when they renew the contract. Customers may also look at the data when doing a performance review.

There is also another similar procurement service FPAL – although the SEQual buyers are committed to using SEQual exclusively, and buyers are free to choose which service they use, said Sakthi Norton, SEQual scheme manager.

Sakthi Norton, SEQual scheme manager

SEQual is an industry owned scheme (not profit making), operated by an organisation called LOGIC (see www.logic-oil.com), which is a subsidiary of industry association Offshore Energies UK.

SEQual is reviewing the questions every year. It is also developing a tool to gather and store feedback, and for suppliers to pose questions to buyers.

"As we continue to operate SEQual we know we'll always be open to feedback and will adjust how we implement the criteria, so it is working for buyers and suppliers," she said.

Questions

All the questions and assessment criteria have been written by SEQual buyers, many of them based on the questions they were using before the scheme was set up.

There is a structure to questions, where the previous response determines the next question.

A lot of questions might start with asking if you have a 'documented policy / procedure' for something, such as a documented human factors policy. If you answer yes, you are directed to upload the document; if no, you are asked to state how you manage that element.

"Not every company may have fully structured documents / procedures for everything," she said. "It doesn't mean you don't practise these things. It doesn't [necessarily] matter whether you've written it into a document, or it is communicated more directly in the company. We want to see what it is you do."

"Some other questions ask, 'do you do something'. 'Do you have a behaviour-based safety program'. If 'yes', please tell us what you do. If 'no' that's the end of the question flow."

The workload to complete the questionnaire is estimated to be between 1 and 6 weeks.

"There are 3 very large question sets, there is a lot of detail we are asking for. Buyers are looking for a high level of assurance," she said. "We encourage suppliers to take the time you need to complete it to a good standard."

Once this is done, the work should just involve updating things which have changed or adding new documents or renewed documents.

"It's a big job the first time, but it will save you time and effort not having to input that same information time and time again," she said.

Assessment

Suppliers can be assessed with a desktop assessment or an onsite assessment, with onsite assessment only required if some aspects of the suppliers' response are deemed high risk.

The desktop assessment may involve answering some further questions from an assessment team.

The assessment team want to ensure that documents / descriptions supplied relate to the question, and cover specific points it is looking for, in documented policies, procedures, or descriptions about how things are managed.

"It doesn't matter how you've written it up or how you capture it. The key criteria assessors are looking for is what you do," she said.

The assessment also looks at document dates – when they were issued and last reviewed, with most documents needing to be dated within the last 2 or 3 years, to show there is a continual process of reviewing them.

While buyers will initially be looking for 'compliance', that you have everything the questionnaires ask for, it is valid to say 'no' to a question, and a buyer will then make their own decision about what to do.

Two of the assessment companies are Lloyd's Register Quality Assurance Limited and Bureau Veritas Certification UK.

The assessors' criteria is determined by technical experts working for the buying companies, such as their internal health and safety teams.

While the costs of the assessments themselves are met through the SEQual scheme by the buyer community, a scheme administration fee of £480 + VAT is charged to suppliers for each assessment.

Finally, a supplier gets a 'status of compliance' and becomes visible to buyers.

When companies are considered 'compliant', it should mean "buyers can feel comfortable that they are able to work with you, and their baseline requirements are covered," Ms Norton said.

Error traps in operations

The concept of 'error trap' is about factors which can shape human performance, but are not necessarily considered in a risk assessment. Dr Marcin Nazaruk explained more

The most common way to manage risks is through a 'risk assessment', a structured process of identifying hazards and the controls you have in place to stop them from causing harm.

The philosophy is that if you have adequate controls to stop the dangerous hazards, your risk is sufficiently managed.

"That is important but may be insufficient," said Dr Marcin Nazaruk, co-chair of the Aberdeen based Human Factors working group of the Step Change in Safety organisation, and chair of the Society of Petroleum Engineers Human Factors Technical Section.

For example, if a worker is tired or stressed, that is a circumstance which may increase risk, but not show up on a risk assessment because it is not linked to any specific hazard.

Dr Marcin Nazaruk, chair, Human Factors working group, Step Change in Safety

Other examples of error traps could be someone's mood after a conflict with a supervisor. Also complex or badly presented procedures, poorly designed equipment, unusual situations, difficult systems, insufficient time, a difficult working environment, boredom, interruptions and distractions, demands for multitasking, high workload.

Organisational factors can be error traps, such as the working hours and staffing, insufficient supervision, simultaneous operations, the planning process, the competency management system, the financial resources, other conflicting priorities, your procurement processes, the change management.

An error trap could be defined as a factor which may shape performance.

It is important to differentiate 'hazards' with 'error traps'. Hazards are specific things which may lead to harm, such as chemical exposure, ignition sources, spills, open holes, bad weather.

An error trap can be difficult to directly classify as a source of harm. It is something which may increase the likelihood of mistakes.

As an example of an error trap, Dr Nazaruk showed a photo of an operator who needs to press buttons on a control panel, but the panel has vertical pipes in front of it. The pipes restrict the movement of the hand, and the visibility of what the hand is doing. Also, the labels on the panel were very small.

Insufficient time is an error trap, in that if a job takes 5 hours when you follow all the steps, but someone only has 3 hours to do it, that forces people to miss out some steps.

"It is important that job conditions allow for execution of work in the way it is designed," he said.

The concept of error traps should be understood by frontline operations staff, supervisors and other people supporting operations – and they can be taught to look for error traps when discussing the challenges that they face.

Not following procedures

When people don't follow procedures, that may lead to poor overall performance, so it is an error trap. It is important to understand the reasons that procedures are not followed, rather than just blame people for not following them.

Dr Nazaruk presented the result of a survey of 400 workers in high-risk onshore facilities, asking them for the biggest reasons that procedures were not followed.

One of the biggest reasons was, if the procedures were followed to the letter, the work could not get done in time, he said.

Another big complaint was that it was difficult to find the right procedure – for example a procedure which was 100 pages long, of which just one paragraph was needed, and there was no list of contents.

Other reasons were: that people don't understand why the procedures are necessary; they prefer to rely on their own skills and experience; they think they already know what is in the procedure.

Another issue is the software used with the procedures, whether it helps people find the documents they need.

It is good practise when developing procedures to involve the employees who will actually be following them, he said.

If you want to evaluate your company's procedures, you can review how often they are updated, if you monitor how closely they are followed, and if they are designed to help avoid error traps.

How could better procedures be written? Professional writers could have a role, but it needs to be someone familiar with the industrial risks, he said. It is better if you can identify the conditions which influence the job and make it difficult.

Accident investigations

Error traps can be identified in accident investigations - and perhaps one way to determine how well you have investigated an accident is to see whether you have found them – the factors which may have negatively influenced performance.

Dr Nazaruk gave an example of a typical accident investigation at varying levels of depth, to show where the error traps were identified. The example was a person who injured their hand reaching into a machine.

Level 1 in investigation depth is to blame the operator for injuring their hand, reaching into a machine which was still switched on. "This is not an acceptable finding - it doesn't change anything, we haven't learned anything, we haven't improved anything," Dr Nazaruk said.

Level 2 was to recognise that the operator believed that the machine was automatically disabled when the guard had been lifted – and so the operator needs to be retrained. Mr Nazaruk's view was that it was better, "we get into what they are thinking," but just proposing a retraining is not an acceptable corporate response.

Level 3 was to acknowledge that while the operator had been trained about when the machine was automatically disabled, they were trained on a different machine to the one in which they had the injury, and the training machine did actually have an automatic disabling function. So, the recommendation is that people should be trained on the machine which they actually use.

A level 4 investigation result was to acknowledge that the machine had not been fully tested before being put to use, did anybody know it did not have a 'disable when guard removed' function.

A level 5 result shows that the procurement process was not as thorough as it could have been in making sure the item had this function, because the machine had been needed quickly. The recommendation is to amend the procurement procedure to improve a thorough risk assessment.

By these steps, we transition from 'blaming a person' to working out how organisational practises could be improved, he said.

A hint that you are 'not quite there' is when an investigation result says there is only one root cause, or the root cause is 'human error', 'behaviour', or 'noncompliance with procedures'. Or if the investigation has a judgement label like complacency, recklessness, laziness, or overconfidence.

A bad investigation result focuses only on what a person did or should have done, and corrective actions are behavioural or administrative.

"Just focussing on the bias may be at the cost of understanding error traps," he said.

Proactive learning

Another useful technique is "proactive learning", to try to find the causes of accidents before they happen, he said.

It is easy to assume that, when something is done without an incident, everything was done properly; conversely, it is easy to assume that, when there is an accident, it is because something was done wrong. It is easy for people to believe success and failure are fundamentally different, he said.

But actually, success and failure are very similar, in that people are doing the same things in the same way, and may be skipping steps, 'working in the line of fire', or not noticing hazards. The difference is that with failure, something actually goes wrong as a result.

So the conditions which may lead to accidents already exist - and can be addressed before the accident happens.

Dr Nazaruk gave an example of an operation to move a 7 tonne spool of cable a short distance in a warehouse. This task was done regularly.

The crane control was attached to a cable, which was not long enough to allow the operator to stand in the best location to see what the crane was doing. So, two people were involved, a spotter giving instructions to another with the control, such as with verbal commands of left, right, forwards and backwards.

This created opportunity for accidents due to miscommunication. This error trap could be removed by using a wireless control device. "This is an example of proactive learning."

There had not been any accident, but if there was an accident, the investigation would probably find this as a possible cause for it. But the error trap probably would not have been identified through a standard risk assessment process, since there is no specific hazard.

Segmentation to achieve cybersecurity

Segmentation, using firewalls already available in operating system software, is a good way to stop hackers getting from one part of the network to another. But it can be fiddly to configure. Illumio offers software which makes it much easier

It should not be possible for a virus to hop easily from one part of your digital infrastructure to another. Many people have wondered why digital systems are built which make this so easy.

Operating systems like Windows and Linux do actually have firewalls in them which can be configured to set specific permissions of what specific users or other systems can do, and that has been the case since Windows 2008, says Trevor Dearing, Director of Critical Infrastructure Solutions at Illumio, a cybersecurity company based in Sunnyvale, California. The problem is that "no-one could work out how to use them."

Illumio provides software which makes it much easier to configure native firewalls, by clicking on a map displayed on screen to set the permissions.

"We get information from the firewalls to understand what communication is happening. [Then] we can push rules to those firewalls," he said.

"You would think that's a fairly simple thing to do. At scale it gets quite tricky."

Compartmentalising networks in this way has become standard practise in organisations which are closely built around their IT systems, such as banking. The banking sector was one of the first to use Illumio's software.

Trevor Dearing, Director of Critical Infrastructure Solutions at Illumio

Now it is seeing more interest from industries which have a lot of IT, even if IT is not central to what they do, such as hospitals, manufacturing, utilities, and oil and gas, he says.

Illumio has been involved in developing cybersecurity services for upstream oil and gas and other infrastructure sectors. Most of the company's upstream oil and gas clients are in the US, Asia and Australia, he says.

Hacker approaches

Mr Dearing notes that there has been something of a shift in the way hackers operate, over the past few years.

Before the pandemic, hackers were focused on stealing data and threatening to sell it if a ransom was not paid. Now, they've recognised they can make more money through 'denial of service' – cutting down people's access to their IT systems, so they cannot operate their businesses, he said.

So, ransomware is increasingly being designed to infect as much of the organisation's networks as possible, and get quickly to its highest value assets, where it can cause most disruption.

One reason the impact of the Colonial Pipeline attack were so high was that the owners saw a need to shut down all digital systems completely in order to ensure ransomware was constrained, he said.

The compartmentalisation approach

Compartmentalisation involves making a 'zero trust segmentation' in your systems, down to application and workload level.

"You stop all communication except for the bits that you know are verified and safe," he said. "That is effectively what zero trust does. It only allows appropriate people, applications and methods to occur. You're segmenting your environment into these closed spaces."

The compartmentalisation is done virtually – within the software – rather than with a physical separation.

"What we do is very simple - identify who is allowed to talk to things - and let them do it or don't let them do it. It is a simple layer that we can put in place quickly."

For example, the production part of the network can be compartmentalised from the administration part.

You can also take production systems out of the range of phishing attacks by disconnecting them from anything using e-mail. Even if the systems have passwords, they are not provided by e-mail.

"It could be that on an oil production platform there are people in admin groups who are receiving e-mails and stuff like that. We can keep that separate from the actual production part of what's going on the same platform," he says.

Note that compartmentalisation is a different way to achieve cybersecurity than the most common approach, based on scanning communications and hard drives, to differentiate normal communications and applications from those of a hacker.

Conflicting with integration

Compartmentalisation can conflict with efforts to better connect systems together, such as operations technology being integrated with information technology, or when suppliers manage their customers' inventory.

The increased amount of cloud and remote working is also creating more integration between systems – and so more potential threats, Mr Dearing says.

We are seeing enterprise software like enterprise resource planning (ERP) "creeping closer and closer to the production facilities," he says. "As ERP systems add more modules and more interconnectivity, then effectively that software is moving further and further down that stack."

"Organisations see there are real benefits in being able to push integration further and further towards the edge."

There has also been a culture for years of allowing all communication to happen everywhere. There have been many benefits to this, but it has also created hacking opportunities. Ransomware uses the same ways of connecting between systems as the legitimate software, he says.

Companies need to find the right balance between getting the benefits of closer integration and the cybersecurity benefit of compartmentalisation. Although if they make the effort to configure their firewalls at a granular level, they may be able to have both.

How the software works

Illumio's software creates a map of your network, which makes it easy to see how the different parts within it are connected, and how they are communicating.

Using Illumio's software, it is possible to show the map on a screen, and click on it to determine what you do or don't allow. For example, if you want to allow a pump to communicate data with a certain Windows machine, you can explicitly allow that. "You can click on things and apply security policy to them. Allow certain communications, ringfence certain applications, put that boundary in to stop certain things."

To create the map, Illumio works in alliance with companies which offer services to 'scan' the OT environment and build up a picture of all the objects – and this data can be imported into Illumio's map.

It can also collect data from vulnerability scanners. These scan your networks to determine which machines do not have certain patches installed, or which have certain other vulnerabilities. These can be shown on the map.

Illumio's software can be used to connect certain identities, or people, with certain permissions. Identity management, connecting a person with an 'identity' on the network is handled separately.

The software also has an option to close off communications between compartments immediately, such as if you detect ransomware in one compartment. There's a "virtual big red button that says, stop almost all communication until we've found where it is and where it's got to."

AspenTech – what 'Asset Performance Management 4.0' means

"Asset Performance Management 4.0" could be defined as building a digital model of the equipment – so you can see where problems are emerging and better understand the risks and what to do about them. Mike Brooks of Aspen Technology explained more

There have been a number of iterations of Asset Performance Management (APM) systems over the past decades, from basic data gathering and analysis (1.0), information sharing and data integration (2.0), and condition based or rules-based maintenance (3.0).

APM 4.0, building on this, is using high fidelity pattern recognition and digital models to compare what is happening with what should be happening, and any course of action. says Mike Brooks, global director of APM Solutions with software company Aspen Technology.

Mr Brooks has been working in the oil and gas industry for 24 years, including at oil majors ExxonMobil and Chevron. He worked in Chevron's venture capital division for 4 years. He was also a leader in five industrial IT startups.

APM 4.0 software could show you a map of where the specific areas of concern are on your plant, not just where the sensors are showing concerning data, he says. The main difference is that APM 4.0 wants to assure not only that it is available and running, but that it can operate at peak performance for its lifecycle, and that the money you spend on asset health is directed towards the areas that most constrain the operation. Depending on the level of sophistication, it could show you an emerging problem before it gets serious and give you advice about what to do about it.

The software uses data patterns, models, and simulation, including simulations of fluid flows and equipment. It analyses the possibilities, and what they could lead to. It can work out the problem areas.

You can work out the probability of certain events occurring, such as the probability of a machine degrading to a failure.

The simulation can be used to plan shutdowns and work out the best time to shut something down, or if there is a way to keep the plant running for a short time while maintenance is done, such as by filling intermediate tanks to be able fulfil the product deliveries while the service and repairs happen.

In one example, a simulation model was made of a refinery which had petroleum coke as one product, being loaded onto rail wagons. The model determined that the biggest constraint in the whole process was the supply of empty wagons.

The system may be used to reduce leaks, not necessarily by detecting them, but by identifying patterns which may lead to the machine leaking.

"For criticality, risk, and cost analysis We build a model of the whole process, it doesn't matter if it's a chemical plant, refinery or upstream, mining, pharma, and so on. You can simulate all the way through," he says.

Building these models is not cheap or quick – but then neither is equipment downtime or reduced capacity due to storage concerns, etc.

The models can show which items are the most critical, and so you can better understand the costs and risks if that item is not working, and so decide about what to do.

The software is designed to help companies maximise the performance of the asset. This is the most important business criteria after safety, environmental, and legal issues, he says.

Asset performance is not necessarily about 'utilisation' – a high performing asset is one which is needed when the surrounding operation needs it, not necessarily available all the time. It may also be one which operates most efficiently in terms of energy consumption or other costs, or which can maintain output quality.

APM 4.0 can be compared to getting a car tuned – it isn't just about making the car reliable; it is about making it run better, Mr Brooks says.

Maximising performance involves continuous monitoring, detecting, quantifying risks, knowing what to do, predicting when you might go off target, and executing the changes that could bring things back to full performance.

Fitting with how people work

At the same time, experience has shown that it is very difficult, if not impossible, to introduce new software to an organisation, if using it would involve changing the way people work, Mr Brooks says.

Some oil company customers have said they do not wish to buy software products which demand large changes in work processes, no matter how good the technology is.

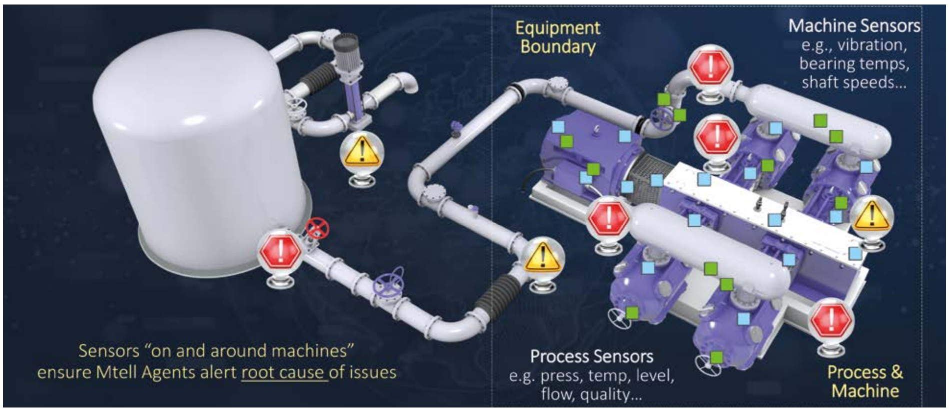
It does not always work to try to persuade people that the technology is better than what they currently have, because people typically overestimate the value of what they have got and know. Mr Brook cites the famous quote from James A. Belasco and Ralph C Stayer: "change is hard because people overestimate the value of what they have, and underestimate the value of what they may gain by giving that up."

AspenTech found it may be better to make software which fits into the way people already work, or which has a company's work processes built into it. "It can't have too many changes away from that work process, it's got to be easy to follow. It's no use throwing technology at them."

Consider alerts sent by the software. It is easy to make software systems to make alerts, as we all know, but it is only useful if someone does something with the alert. People need to have confidence in the alert, then be able to evaluate the consequences (if whatever you are being alerted about happens), and then be able to do something to prevent it happening.

"We spent a lot of time looking to see how we can improve that."

When the software presents its analytics output to people, it is more useful, and easier to fit into people's working processes, if it gives them options, rather than put numbers in front of them. For example, they could choose between two outputs from the modelling, one which predicts



MTELL software – visualise the health of a complex piece of equipment. See where sensors are located, see where problems have occurred, identify areas of concern, determine mitigation strategies.

a longer time to failure but with a lower accuracy level, the other the opposite. The choice might depend on how they see the level of risk, or their assessment of the model.

Software should not overwhelm people with complexity. Like with a smart phone, the 'smarts' are kept on the inside of the machine, not the outside.

Some of the software tools use machine learning, but the user doesn't necessarily need to know about it. Indeed, Mr Brooks advises his own sales staff not to focus on machine learning when they promote the products; it's about the job the software does, the specific use case for specific personnel roles.

Just having machine learning is no longer a differentiator for software companies, he argues. "Every [software company] is doing machine learning. It's like saying, we use C++. So does everyone else. The real question is what you are trying to do with machine learning."

For operators

As the technology matures, AspenTech is increasingly able to provide tools to equipment operators to help them understand and stabilise a problem, rather than having to pass the data onto data scientists or engineers as an interim step.

A vibration problem could cause equipment damage within a day, so there is a big benefit in operators knowing how to solve the problem, rather than give it to engineers to resolve, which can take a number of weeks.

The operators need to "get the equipment to a safe place," Mr Brooks says. "The most important thing is to make sure equipment is stable." AspenTech detects the inherent patterns, links the information in data streams on behalf of the users, and helps them develop corrective insights. The system continues to learn and shares the learnings with other users.

Failure modes

One of the most important functions of the software is understanding how degradation leads to failures with equipment. The data pattern-driven approach means that the understanding of failures can be data driven and completely objective.

This makes it different to Failure Mode Effects Analysis, a common industry technique. FMEA "is held in the industry as a silver bullet. Personally, I don't think it is," Mr Brooks says.

"It is based on inductive reasoning [developing a theory] not deductive reasoning [testing a theory]."

"We are taking FMEA and adding AI/data driven constructs. That way you can get much closer to the truth."

With equipment, there are 'causes' of problems and 'failure modes' which are not necessarily the same, although with our machine learning pattern matching it has been possible to link them together, only one multi-dimensional/temporal data pattern gives a one-to-one link between cause and failure mode.

For example, multiple different cause conditions can lead to the same failure mode. You can be sure there will be a failure even if you don't know why the failure will happen. But AspenTech can tell you why it fails and how it fails.

In one case, an oil company had seen five bearing failures and thought they had the same root cause. But data analysis showed that four were similar, but the fifth had a different pattern, showing it was caused by something different.

Criticality measurement

Another important part of the software is determining which equipment is most 'critical' – so you will prioritise your attention on it.

Again, the model-based approach enables this to be done in a more objective, data driven way, Mr Brooks says.

"The ways that people [normally] measure criticality for asset equipment is very dubious," he says. For example, they try to calculate a 'risk priority number' for each item, by multiplying a number of estimated risk factors. But if two of those numbers are a little wrong, the multiplied number can get very wrong.

These risk priorities can be "decided by a group of risk professionals who have been in the business for a long time. It's apparently all based on opinion, but data can lead to the truth," he says.

The criticality of a piece of equipment depends on its role in the wider process, and that can be different on each site.

For example, a catalytic cracker fractionation column in a refinery cannot function if the wet gas compressor, which moves the vapours away from the column, is not working. It is a serious problem, recognised as critical since a quarter of the refinery could shut down. But the top pump-around pump could cause the same and is rarely deemed critical.

Anomalies and machine learning

A third important part of the software is looking for anomalies – something in the data, or the relationships between data, which shows something which is not normal.

Understanding whether you are looking at an anomaly is not easy. Inaccurate models produce false anomaly alerts. The AspenTech technique produces highly accurate results through direct pattern recognition in data stream, without intense knowledge of engineering or data science. Regular manufacturing staff can build them without knowing more than they know now.

Machine learning is used because it is the superior way to compare multiple data streams. People can personally typically monitor about 3 data streams. Some Computer logic (without machine learning) can be written to work on a limited number, understanding how one data stream usually relates to another.

But a compressor on an oil platform might have 100 data streams from its sensors, and machine learning can see across all those 100 data dimensions, where humans and other technologies cannot.

Some machine learning tasks are classified as 'supervised and unsupervised learning'. In supervised learning the computer examines multi-dimensional and temporal data that results in a specific event such as a machine failure. But unsupervised learning uses clustering techniques to determine what normal behavior looks like. You show the computer different patterns, and it can see the difference between patterns which show normal operations, and patterns which show a problem.

"We have a special process that reduces the 100-dimensional picture into 2D. It's not exact but better than one scenario by itself" and gives the user a much clearer picture of what's actually happening.

"Humans always gravitate to, 'what's the one sensor that's telling me that its wrong,' Mr Brooks says. "It turns out that's not the deal. It is the relationship between multiple sensors that tells you where it's going. One sensor tells you when you are close to failure."

Relationships between Different sensors change as a problem progresses and impart the most useful insights.

"As it gets closer to failure it is the vibration that tells you. [But] if you only look at vibration, you're going to find damage that's already happened. You want to find it before the vibration tells you there is damage."

By analysing the patterns between the data, it can be possible to learn about patterns which emerge months before any visible failing. "Anyone can tell you a compressor will fail two days before [it fails], but to do it two months before that, takes a lot of understanding of the patterns," he says.

Audio sensors

Audio sensors (microphones) could achieve much more than they do now to detect problems at an early stage, just as the earliest warning of an engine problem could be an experienced engineer noticing the noise change.

"I have a lot of respect for audio signals, and even outside the frequency range that we can hear," Mr Brooks says. "We don't have the right sensors yet, but they are coming, I've seen some early prototypes. Sometimes these sensors take 10 years to develop.

Because the audio signals are being analysed using machine learning, it is "very tolerant of signal noise," Mr Brooks says. "You're looking for a pattern, and for how one pattern compares with another one. ML doesn't care what the signals are - it's just looking for patterns. You can push the audio data into machine learning."

Self-optimising

The goal is to make plants which could be considered self-optimising. "The Self-Optimising Plant (SoP)" takes information from the various planning, optimisation, and asset health software packages and amalgamates them," he says. Then it determines what needs to be done.

For example, if there is a problem with a compressor being over-driven, the SoP application could find a way to change its operation so that damage is not being caused and a failure is avoided.

The technology is advancing in this direction. "That's where we're heading, that's a major corporate direction," he says.

Getting there is about bringing the workflows together between different software tools, such as historians and models. There will be messages and then workflows exchanged between applications, something which Mr Brooks defines as "interoperation", rather than integration.

Setting it up

The Mtell product for reliability engineers could take as little as a few hours to set up for a simple piece of equipment, or 2 days for a bigger compressor, or a number of months for an entire plant, including onsite testing.

It can be possible to set up a number of different machines at the same time. You can start with a small data pattern recognition model and then expand it rapidly across many machines of the same type.

As a minimum, AspenTech needs the collection of enough data to be able to work out what is 'normal' across say a year or more. The Mtell predictive application can start to learn and share knowledge from that point.

It doesn't necessarily need large volumes of data – in one example, a system was set up on a slurry pump which only had 4 sensors, looking at temperature and pressure of fluids going in and out and motor amps. The software was able to provide 4 weeks' notice of an impending problem.

For a bigger pump on a refinery, which had 50 sensors including vibration, the system could identify problems 4 months before they happened.

AspenTech recommends that 5 is the minimum number of sensors to use for pattern recognition. "It doesn't care what kind of machine, as long as you've got the data," Mr Brooks says.

Software products

The Asset Performance Management tools are developed for different users and different use cases.

The "Aspen Mtell" product, for reliability engineers, looks at reliability, and ways to stop machines breaking or other asset problems. It is analysing sensor data to get an idea if there's degradation happening, and then prescribes what maintenance task should be done.

It can identify problems before a person does, although a person would then decide if it is important enough to make any change.

It can also help a person better understand the problem which generated any alert.

It shows images where people can visualise what is working and what is not working on their plant, or where the concerns are.

The product ProMV is for process engineers, looking at broader processes with chemicals and manufacturing, predicting where errant conditions may occur, and what can be done to correct the issue. It suggests adjustments that can help avoid problems with yield, quality, and waste product.

In upstream oil and gas, this system could be used to help companies reduce flaring, by identifying the operating patterns which lead to flaring being needed, analysing what is happening in real time, and what changes might help reduce likelihood of flaring. An unexpected shutdown always imposes risks, and from a sustainability perspective the carbon release during one flaring incident can surpass all the releases for a year. A major advantage here is detecting an impending issue with sufficient time to plan a safe and orderly shutdown that will not lift the flare valves or lead to unsafe conditions.

In one example, AspenTech helped an herbicide company identify that it could create a superior product by having less heating in one stage, and faster cooling in another.

The Fidelis product is for planners and plant engineers, so they can determine decisions which would make the best return on investment, covering both CAPEX and OPEX. It can be used both in plant design and plant operations.

It can look at one entity within the plant, or how it is interacting with others around it upstream and downstream, including operations, maintenance, logistics and other factors. It can quantify criticality of any individual component in terms of its relationship with other assets and events, and its real effect on the plant profitability.

Fidelis can help you work out what to work on first, or what events are most likely to cause problems, such as weather, flow limitations, personnel shortages, storage limits, or shipping limitations.

Aspen Event Analytics is a tool for front line workers, especially operators, to help them identify 'not OK' operating data patterns and advise them what to do about them.

For example, a control system indicated an abnormal and erratic pressure change on a compressor. The Event Analytics could show which sensors had a changing pattern, so the operator could quickly assess, understand and correct the problem.

This software is reactive rather than predictive. Sometimes the operators will observe that something unusual is happening, and use the software to better understand it, or see if the same thing happened in the past.

Each individual application is developed around the problem they solve in the domain, not what the technology specifically does. "I tell our [sales] guys, don't start talking about technology, if you're doing that, it all sounds the same," Mr Brooks says. So, talk about the users, their roles, and how we help solve their specific problems.

Its approach combines domain expertise, pattern recognition of specific equipment, and modelling of the system and process the equipment is part of. "You can't separate the machine from the process, or the process from the machine," he says. "A machine will operate differently in a different process. If you add the domain knowledge you can get much closer to the real solution."

"With a data science product, you can't do anything until you understand the domain," he said. "We worked hard to have that domain knowledge built in."

Templates are used as a starting point for building the pattern recognition artefacts, that we call Agents, of common equipment such as pumps and motors, so the work can be half completed at the start. Templates include the typical sensors included on the equipment, and the typical failure modes. Agents are pieces of software that do the work for the end user, they contain the smarts in engineering and data science for doing rote and repetitive function far more often and faster than humans.

Some of the software is cloud hosted, some is not. "A lot of energy companies do not want their software supported in the cloud, usually for security reasons," he said. "They want software that can be installed inside their firewall."

"I don't think [user hosted] is a bigger installation task," he says. "The cloud makes it much easier for vendors like us to provide and scale. But for individual users, unless it's a big corporation, it's maybe not such a big deal."

Using AI for asset management on data and images

AI is being used for asset management in analysing data and analysing images. Two experts explained what is happening and how to do it, on an AVEVA webinar

AI is used in asset management in two different ways – to better analyse data, and to better analyse images.

Engineering and asset management software company AVEVA is aiming to 'infuse' its existing and new software products with this AI, said Mike Reed, senior manager of AVEVA's AI centre of excellence, based in Chicago. He was speaking at a webinar on Apr 13, "Implementing AI for Enhanced Asset Management."

AI works particularly well for software running on the cloud, because it is easier to build tools which pull data out of multiple cloud software products," he said.

AI for asset data

AVEVA sees the various forms of AI on asset data in terms of ever-expanding circles, where each stage adds more to the previous one, Mr Reed said.

Stage 1 is stand-alone automated analytics, data tools which run through operational data, looking for differences to normal behaviour, and which can analyse images. They can also learn patterns of normal behaviour and so spot if something is different to the norm.

Stage 2, known as "condition-based rules," is where the results of the Stage 1 analytics trigger some specific step to be followed. This can be known as 'dumb AI'.

Stage 3 is guided analytics, sometimes known as "light touch AI", where you are analysing streams of data, finding relationships between data which you did not know about before.

Stage 4 is what Mr Reed calls 'advanced analytics' - trained AI models built around open platforms, covering machines, systems or processes, together with background knowledge such as engineering, operations and historical data. Also, known patterns of failure and known anomalies.

A form of this is predictive analytics, which is done by combining some level of AI with historical data, so you compare what seems to be happening now with what has happened before.

Mike Reed, senior manager of AVEVA's AI centre of excellence

For example, if you are about to rush out of the office at 5.33pm to catch a train, it could tell you that most of the other times you left at 5.33pm, you did actually miss the train. Or it could tell you that according to its modelling, you need to leave the office at 5.30pm to do all the necessary steps involved in getting to the train.

It is possible to get much better insights from data with AI techniques, compared to straight analytics or rules-based techniques, he said.

Working with data

Predictive analytics can get more meaningful insights from data, Mr Reed said.

Basic analytics techniques might be limited to showing you graphs of data – but there's no means of detecting from that whether what you are seeing is normal or not.

And basic analytics is limited in what it can do with alerting. A system can be configured to sound an alert if a certain sensor reading goes above a set point, such as a temperature being too high. But this set point needs to be set wide enough to handle normal changes in behaviour, seasonal variations and product variations, without an alarm going off in normal conditions.

But if the set points have too wide a range, the system will not detect any problems. Or, you will find that by the time the system operations have gone outside the set point, you have gone 'past the point of no return' – something is damaged, and you need to take reactive steps, he said.

With a predictive analytics system, in contrast, you can overlay what is happening from where you think you should be, also using data from other sensors.

The point of concern can be the point where the signal diverts from what it would be expected to be, he said.

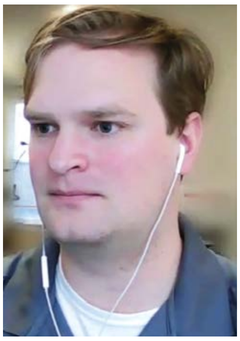
An analogy could be the monitoring systems some of us have on our own body, such as for blood pressure or cholesterol. If they start deviating from what we expect, that can be an early warning indicator of something going wrong to the body.

How much maintenance

A big challenge with preventative maintenance is working out the right amount of it to do, he said. AI should be able to help with this.

If you do too little maintenance, the equipment will ultimately break, which can be very expensive. You are always in 'fire-fighting' mode, fixing problems. But 'over maintenance' means doing work which doesn't need to be done.

Before we had computers, there were basically three modes of maintenance – preventative maintenance, where you did maintenance tasks at the interval suggested by the manufacturer; rules-based maintenance, where maintenance is done according to certain logical rules; and condition-based maintenance, where maintenance is done based on some condition monitoring, he said.



John Leighton, Sr. Presales Consultant with AVEVA

With AI, you can automate the analysis of the condition-based rules, and then develop the 'predictive' mode, comparing where something is operating to where it should be operating, to get a better idea of what maintenance is needed.

The system can work out the best amount of maintenance to achieve the multiple goals of preventing failures and reducing equipment downtime; reducing costs; improving safety; extending equipment life; and optimising the asset strategy.

Across the company

If you are implementing predictive analytics 'at scale' such as across a company, there are ways that models can be re-used to save time.

For example, you can create templates of models for one piece of equipment which can be re-used on other equipment of the same type. The model can include what is known about the behaviours of that equipment, he said.

The templates can be used to compare one piece of equipment with another, if it is configured similarly and on the same site.

AVEVA has its own 'template' models of equipment from its work in multiple industries, including power, oil and gas, manufacturing and chemicals.

It is possible to take data out of multiple predictive analytics systems to give guidance to the person in charge of running the whole plant. For example, it can tell them which items are going out of range, what they need to address, and what information they need to pass onto others.

The analysis can also try to identify the remaining useful life of a piece of equipment, or how long until something becomes inoperable, where maintenance work is essential rather than a choice.

There can be analysis of the start-up and shutdown patterns, to see if they would work better at a different time scale.

"This is all integrated in the software and between the software," he said.

Over the whole company, many customers use "enterprise-wide solutions, with a central predictive analytics server connected to multiple historians on different facilities," Mr Reed said.

Getting started

The best way to get started might be to run AI tools on the data in your historian, since it has a large amount of historical data ready to use. "The predictive analytics platform can sit on that and talk to it," Mr Reed said. "You build the models based on sensor data that you have available."

Systems are typically deployed in 1-3 months, Mr Reed said. The deployment phase can itself have a value, if you discover system anomalies during this time.

A side benefit is that you focus on making sure the sensors work. Otherwise, "if sensors are not required to operate equipment, and if something goes wrong, it typically gets put in a queue to be worked on and gets forgotten about."

"Since we're leveraging those [sensor data] in the models, we're going to fix them if they are not working."

Vision AI

Another way to use AI for asset management is to analyse imagery. AVEVA has a software tool "Vision AI Assistant" for this. It can use any images, including from phones, webcams or drones.

There are two primary modes of operation – anomaly detection, where you are looking for something unusual, and 'discrete state classifier', where you are looking for something specific, such as whether an image shows apples or oranges.

An example of using anomaly detection was a system to detect problems with a chain in a conveyor on a factory.

This chain is very critical to operation of the whole plant, driving a conveyor which moves parts from one station to another. The chain is nearly a mile long and takes 22 minutes to go completely around, and the company had 10 such chains.

If a chain damage is not identified straight away and the chain snaps, it needs to be rethreaded, a time-consuming task. The costs of breakage was so high the company was employing people to personally monitor the chain – but it was a difficult job to keep paying attention to, particularly on the night shift.

AVEVA's Vision AI system could identify the difference between a normal chain link, and one with a broken metal plate. If the chain ever got snagged, and had a broken link, a snap was likely.

For training, the system was shown images of what 'normal' looks like, so it can identify an abnormal chain link. Any anomaly is scored, with a higher score for a bigger anomaly.

The system makes an estimate of the deviation (level of the anomaly) according to an algorithm. This can be a large deviation in one sensor, or multiple sensors showing a small deviation at the same time.

That is analogous to waking up in the morning and feeling lots of aches, pains, and having a sick feeling and sweating. Individually they may be minor, but getting them all at the same time indicates a problem.

The other way to use Vision AI is a discrete state classifier. An example is monitoring flares in upstream oil and gas – whether they are lit and for how long.

EPA regulations require operators to submit data about how long flares are active. This data is also useful commercially. "If the flare is running 24/7, you're pumping more than you can handle," said John Leighton, Sr. Presales Consultant with AVEVA.

The system was trained to work out if a flare was on or off from the image. It can also look for black smoke and determine if a pilot light is on or off. It can measure the size of the flare, which is likely to correlate with the gas flow rate to the flare.

The data was gathered using a static video camera.

These discrete state classifiers can be part of a data processing 'pipeline' model, where raw images go in, and the insights come out.

As part of the pipeline, you can tell the AI which part of the camera's frame it should be looking at, so it does not get a false positive from the sun.

A more complex example was a system to inspect welding of a component in a manufacturing process. The inspection needed to be done accurately and quickly.

The system was programmed to look at two specific areas of the image of the component, detecting burr detection and a bimetal bend. It could be programmed to detect anything which is easy to 'see' visually, such as the height of a biscuit or the colour of a soda drink.

Typically, anomaly detection may need 1000 images for training, and a discrete state classifier uses 100 images for training, Mr Reed said.

The AI Vision could be used in asset integrity management, in determining whether a certain component was running properly or not. It could be used with thermal camera images of temperature patterns, and used to identify hot spots.

Getting good data quality is normally easy, for example for the chain imagery a camera is taking a clean image of the chain every time its beam is broken, indicating the chain has moved to a new link.

Condition monitoring of drilling RCDs

Aramco Researchers have developed a system to do condition monitoring of Rotational Control Devices (RCDs). These 'seal' the well while allowing the drill string to rotate and move up and down in managed pressure drilling

By Krzysztof Machocki - Aramco Overseas, Aberdeen Technology Office; Zahrah Marhoon - Saudi Aramco, EXPEC-ARC; Amjad Shaarawi - Saudi Aramco, EXPEC-ARC; Ossama Sehsah - Saudi Aramco, Drilling & Workover

Aramco Research Teams, based in the UK and Saudi Arabia, have developed a technology solution for monitoring the condition of rotating control devices (RCDs).

These are devices that 'seal' the well during managed pressure drilling while allowing the drill string to rotate and move up and down.

Managed pressure drilling (MPD) is a technology that allows for rapid and precise wellbore pressure control, especially in formations of uncertain geomechanics.

The RCD seal is a crucial part of the MPD equipment but is prone to various failures.

This new technology monitors the condition of various RCD parameters, and allows the users to identify and act on the early indications when the RCD is about to fail during MPD jobs.

The sensors used for condition monitoring measure vibrations, acoustic emissions, rotation, pipe movement, temperatures, and contamination level in the coolant fluid.

This system then displays all the critical measurements, in real-time, to the user. So they provide early indications and warnings to prevent catastrophic RCD failures during the critical parts of drilling activities.

Additionally, all of the recoded data is then used for further processing and analysis to seek statistically significant correlations to predict future time-to-failures using ML techniques.

Drilling RCD Condition Monitoring

Background to MPD

When drilling a traditional oil and gas well, the specific drilling mud is used for various critical reasons: to lubricate the bit, clean the well from the cuttings, and provide hydrostatic pressure. The mudflow system, at the surface, is typically open to atmospheric pressure.

Therefore, the majority of the bottom hole pressure is generated by the hydrostatic pressure of the drilling fluid column. In general, the denser the drilling mud, the more pressure will be generated at the bottom of the well.

To drill the well safely, the density of the drilling mud must be carefully selected and monitored throughout the entire drilling process to avoid wellbore instability problems and well control incidents.

These wells are usually drilled with a certain pressure overbalance to allow for safe drilling operations.

Managed Pressure Drilling (MPD)is an alternative method. It allows controlling the bottom hole pressure in a more precise way. It has been developed and successfully adopted and used within the industry to enable drilling of more challenging wells. MPD is currently being more and more widely utilized, especially offshore.

An additional benefit of MPD systems is that they can quickly detect changes in formation pressure while drilling. This gives feedback to the drilling crew on the critical pressure changes. It allows them to rapidly regain control over the well to prevent dangerous hydrocarbon influxes and non-productive time.

MPD systems can also increase the rate of penetration and lower the cost of drilling mud.

The current MPD systems are closed-loop systems. Therefore, they eliminate the risk of any dangerous gases rising to the surface and around the rig crew personnel and equipment.

MPD equipment

The Rotating Control Device (RCD) and choke manifold within the MPD equipment package allow the creation of a closed-loop system and rapid regulation of the downhole pressure.

This closed-loop system, with surface pressure gauges within the MPD equipment, allows monitoring of any formation pressure changes. It is possible to precisely adjust the bottom hole pressure to the corresponding formation pressure profile.

The RCD sealing element is one of the essential features that enable maintaining this pressure. The pressure is applied and adjusted between the RCD seal and the wellbore while permitting pipe movement.

There are various types of RCDs. All of them can be connected to the top of the blow out preventer (BOP) stack. There is a stationary housing, sometimes called the 'RCD bowl', and the sealing element, or bearing assembly, that connects the stationary bowl with the dynamic drill pipe inside. This allows for various pipe manipulations while operating under pressure.

All of the current RCDs are manufactured and tested according to API 16 RCD specifications. The dynamic pressure tests within this specification require to prove the RCD's ability to maintain the pressure during multiple cycles of specific pipe manipulations. These tests significantly improve the standardization and characterization of the general RCD performance.

It is essential to remember that the conditions where the new RCDs are tested are different from the typical MPD job environment. The drilling rig conditions will vary from rig to rig and, on some occasions, can be significantly more challenging.

As a result, there are occasions where premature RCD failures can occur without a significant warning to the operator. Failure to maintain the closed-loop system MPD operations can result in dangerous drilling scenarios, leading to well control issues, well stability issues, and stuck pipes.

RCD failures

Failures of the RCD to maintain the closed-loop and pressurized system can be slow, with small leakage around the sealing element, or very rapid, with a total failure of the sealing component.

While gradual pressure losses can be easier to detect and address by the crew members, both of these failure types can be very dangerous if not addressed in the correct time and manner.

Failures can happen due to many factors, and sometimes, the early signals cannot be detected, even with strict inspection and maintenance procedures and before reaching the recommended hours of operation.

Condition monitoring

For safe MPD operations, it has become important to develop a system that allows monitoring the condition of this crucial MPD element.

The new RCD Condition Monitoring equipment was designed to capture multiple system measurements in good operational conditions. It alerts the operator when the operating conditions and the environment have changed, giving early warnings that a failure might happen to the RCD.

This system was designed to operate in hazardous areas classified as "Zone 0," "Zone 1," and "Safe Zones." It can work in high ambient temperatures and environments with dust particles, which are usually present while drilling in the desert.

It is a non-intrusive system - installation doesn't require any modifications to the existing MPD system.

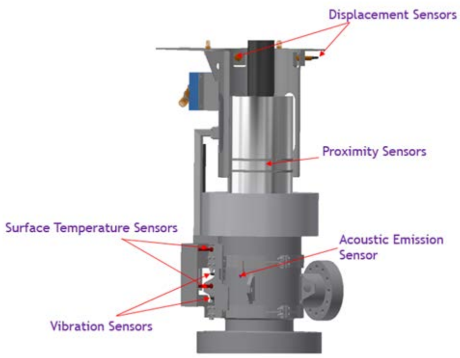
The system consists of various sensors mounted onto the jacket attached to the RCD (see illustration).

In the initial stage of research, the system was designed to operate in a passive mode. It was collecting data and showing the results on an integrated Human Machine Interface (HMI) in the form of time-series plots. This allowed the user to spot trends and any trend deviations. All the essential measurements are shown in real-time to the operator in the field.

The passive mode for this equipment was chosen to avoid any potential false alarms before sufficient data samples are collected from various jobs and adequately analysed.

This condition monitoring system is now operating in the field and capturing data.

Sensors and measurements



Aramco RCD condition monitoring. A 3D model of an RCD condition monitoring system mounted on a dedicated RCD (Source: Aramco Overseas Company).

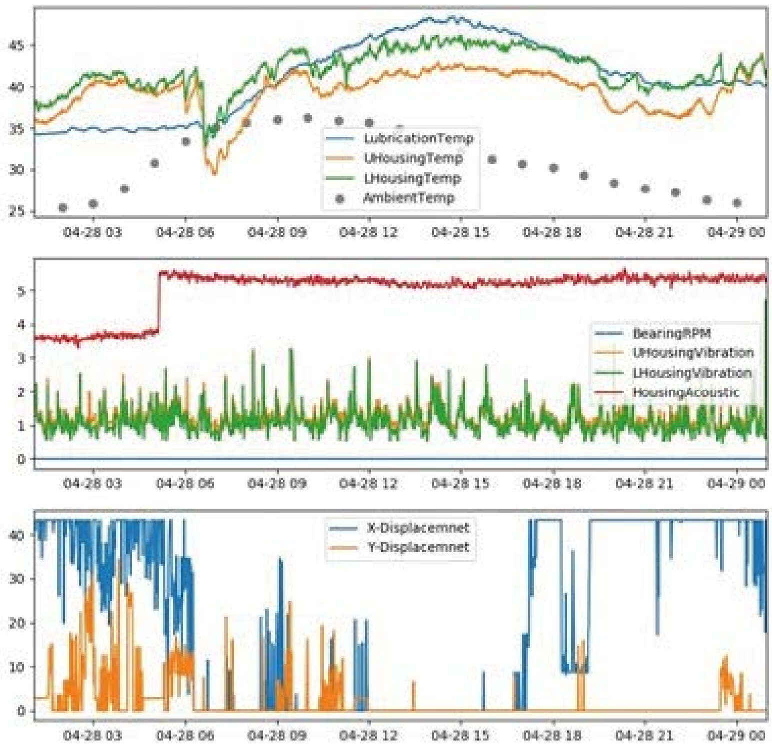
Various non-intrusive sensors are included in this package and attached directly to the RCD and related MPD drilling machinery.

The illustration shows the position of the sensors and the overall jacket that allows a quick system installation in the field.

Rotational Speed Sensor - the primary function of this sensor is to take the measurements of the bearing component rotation speed versus the stationary bowl. In the current passive mode, any significant fluctuations in the time-series plots from these measurements provide the operator with the inside of the bearing problems.

In the advanced analytics stage, post job, the measurements from these sensors are then correlated to the rotational speed of the top drive to monitor any slippages between the top drive, drill pipes, and RCD. For example, a difference in rotational speed could suggest a problem with bearings or seals.

Displacement Sensors - these sensors monitor the position of the drill pipe relative to a stationary datum and the change of shape in drill pipes. Proximity sensors measure the drift of



Aramco RCD monitoring system - collected data displayed on three charts

drill pipes concerning the top drive and the RCD positions.

In the current operational mode, the operator can notice any potential misalignment between the top drive and the RCD and when the tool joint approaches the RCD sealing element.

The data from these sensors allows tracking the movement of drill pipes into and out of the well and helps understand the unique RCD response for each of the tool joints passing through the seal.

Vibration Sensors - these monitor the vibrational signature from the interactions between the seal and the drill pipes, and help measure the condition of the bearings. Vibration data also offers information on the system's response to the ongoing drilling operations.

Temperature Sensors - by measuring housing temperatures at two different locations, the operator can notice early problems that will result in temperature changes in the specific areas of the RCD. For example, some temperature changes might be expected to come from the change in the friction factor in the bearings and the seals.

Acoustic Emissions sensor - this sensor is mounted on the housing and can measure acoustic emissions inside the RCD bowl. The acoustic emission measurements are related to the ongoing operations and the RCD responses to certain drilling events.

Each sensor then sends the measurements to the data acquisition system for processing and storage.

Data handling

The current design allows storing raw data from the sensing equipment with a corresponding time and date stamp.

The data is saved on various mediums as a backup, including integrated local storage and a removable SD for further data analysis.

Collected data is displayed on an integrated display on the central unit, Human Machine Interface (HMI), allowing the operator to interact with the system, read and adjust the alarm levels, modify graphs for more precise analysis, and set some basic parameters.

The processed data triggers simple alarms and provides operator feedback. These alarms are communicated to the user through visual and sound events. At the early stage, they help with self-troubleshooting the system by detecting any readings significantly off the scale. This is a way to check the system and sensors are functioning correctly.

On completing each job, all the data is transferred directly from the central unit to a dedicated device for more sophisticated analysis.

Installation and deployment

The system was used for an MPD job on a land rig in challenging desert conditions during its first field deployments.

The sensors were pre-attached into an add-on jacket that is easily attachable to the RCD already pre-installed to the BOP stack.

The add-on jacket design was chosen to minimize time spent on sensor installation activities in the field. It made it easy to standardize the positions for each of the sensors, making sure the measurements between all collected data from different jobs can be correlated together in further, advanced data analysis.

The Human-Machine Interface was positioned inside the MPD container to provide shelter against the sand particles and high ambient temperatures that are usually present in desert drilling environments.

A special multicore cable with low signal attenuation properties connected the sensors via a junction box installed on the jacket and the HMI.

Pre-installation, post-installation, and operational checks were followed to ensure that the system was functioning correctly and data was captured appropriately. Post-job tests and maintenance work was also carried out to prepare the condition monitoring system for additional deployments.

This condition monitoring system was designed with the user in mind, ensuring it is easy to set up and safe to use in zone-1 hazardous areas during drilling activities.

Initial field deployment results

During the first field deployments, the condition monitoring system measured, recorded, and displayed various desired parameters to the operator.

Several trend observations were made, and various drilling events were observed, recorded, and displayed to the operator in real-time.

Different vibration levels were observed at various speeds of the running pipe and during running in and out of drill pipes.

The proximity sensors detected events like tool joints passing through the RCD, allowing us to measure the unique RCD response to each tool joint at different pipe running parameters.

These measurements were displayed during the job in the field to the operator in real-time.

Specific trends formed during different drilling-related activities.

Currently, more data is being collected to understand the RCD critical responses while it is approaching closer to the failure.

More data collected in the future is expected to help in improving the advanced data analysis part of this technology. This will help quantify the health of the RCD sealing and bearing components, identify applicable trend deviation limits, and predict a safe operating window for the critical MPD operations.