digital energy journal

The UK's offshore technology priorities

A business model for $50 oil

How to manage uncertainty, rather than costs

Using analytics to manage project risk

Repsol's system for early leak detection

April/May 2015 Issue 54

Special report from Mumbai: building a NDR in India - big data at Reliance Industries - managing drilling data at Reliance

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Future Energy Publishing Ltd
39-41 North Road,
London, N7 9DP, UK
www.d-e-j.com
Tel +44 (0)208 150 5292
Fax +44 (0)207 251 9179

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

Conference Producer
Panas Kalliantas
pdkalliantas@d-e-j.com
Tel +44 208 150 5295

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

Production
Wai Cheung
wai@tankeroperator.com

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E-mail: subs@d-e-j.com

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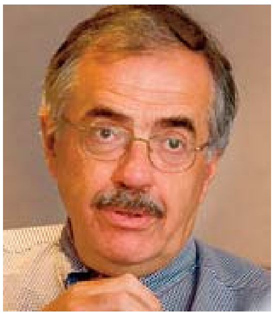
Allowing data to "speak"

by David Bamford



I want to draw to your attention a couple of small-to-medium sized companies that have transformed the ways in which we can understand the Earth's subsurface and thereby make predictions that help us in petroleum exploration and exploitation.

Neftex solved a key problem – or actually a couple of problems – in regional geology, building what one might think of as a "Google Earth for Geoscientists".

Basically, they figured out four things:

1. How to access the vast amounts of public data, available from publishers, national data repositories, geological surveys, in all sorts of different formats, geographies, qualities, and integrate it so that…

2. It could be placed accurately within a precise sequence stratigraphic setting, so it acquired a definitive time stamp, and…..

3 ….located accurately within a sophisticated geodynamics model showing how plates moved through geological time.

4. And perhaps, the key, how to integrate their offering into the work processes of their customers, allowing them to bring their own proprietary data to bear. This is so different to producing a well-argued report (which just finishes up on the shelf).

One of my key takeaways was that, depending on the geological setting - say failed rift vs passive margin vs thrust belt - two or even three non-seismic technologies could work well when integrated with seismic, preferably 3D seismic. It's pretty clear that there is a 'right combination' that can help for each of the basin, play, prospect and producing field scales. This is new and transformational!

How to do this integration is then a critical question.

Geosoft have, I think, a solution to this problem.

Basically, their idea is that a geoscientist-driven interpretation of 3D seismic provides a geological framework into which other measurements, such as density from gravity, or resistivity from an electrical technology, can be inverted, honouring the constraints devised by the interpreter.

In their presentation, they demonstrate that an interpretation can be much improved by using - high resolution (Full Tensor Gravity) - potential field data in such a conjunction with seismic data, in particular showing a Base of Salt problem where gravity data are used to assist the picking of base of salt horizons.

In both examples, it seems to me that the data has been allowed to "speak" rather than having a preconceived model forced upon it.

We will follow up with some of these transformative ideas at an upcoming Finding Petroleum event on "lifting sub-surface interpretation into the 21st Century". Our aim is to reveal how to bring these breakthroughs to the desk of the working geoscientist, petrophysicist, reservoir engineer..................

David Bamford is a director of Digital Energy Journal and Finding Petroleum, and a non-executive director of Premier Oil

The UK's Technology Priorities now

The technology priorities of the UK Continental Shelf are finding a way to develop a 30m boe oilfield for under £100m; finding a way to build wells for 50 per cent of current costs; and finding an automated way to inspect vessels and inspect for corrosion under installation. Our report from the ITF "Technology Showcase" event in Aberdeen on March 4.

A "Technology Leadership Board" has been established in the UK to establish the priorities for technology development in the UK Continental Shelf, and make sure funding and efforts are diverted in that direction.

The Board's program was presented at the Industry Technology Facilitator (ITF) Technical Showcase in Aberdeen in March by Crawford Anderson, VP of the UK geo-market for Baker Hughes, and a member of the Board.

The Technology Leadership Board grew out of the "PILOT" Technology Work Group, formed in 2012, in partnership with the UK oil and gas industry and government, to find ways to improve the competitiveness of the UK oil and gas industry.

It also grew from the UK government's 'Industrial Strategy' review in the first quarter of 2013, which "highlighted need for increased technology focus", he said.

The 2014 Wood Review, commissioned by the UK government, suggested that operators should try to identify the top technology challenges for UKCS and find ways to overcome them, including working out how much oil and gas can technically be recovered and try to reach that maximum, as well as develop EOR techniques.

So the Board aims to provide leadership to the industry in technology - working with the support of a number of organisations including the Oil and Gas Innovation Centre (OGIC), Industry Technology Facilitator (ITF), the Natural Environment Research Council (NERC) and Research Council UK.

There are 18 members, representing operators Talisman, Shell, Centrica, Total, Enquest; also the UK and Scottish government (DECC, BIS, Scottish government); organisations Innovate UK, ITF, OGIC, Oil and Gas UK; service companies AMEC, Baker Hughes, Magma and GE; and universities and the Research Council.

Targets

Already, targets have been set to achieve exploration success of over 35 per cent, average oil recovery of over 50 per cent, and production efficiency to over 80 per cent.

It aims to ultimately deliver 20bn barrels of oil equivalent from the North Sea and establish the UK as a global supplier of capability for mature basins.

Priorities

"As an industry we lack leadership and prioritisation," Mr Anderson said.

The priorities have been split into four legs of exploration, field development, mature field and decommissioning.

Under "exploration," the priorities are to improve subsurface imaging and evaluation.

Under "field development', the priority is to find a way to develop small fields, with subsea tie-backs. There could be methods for low cost well construction, standard subsea solutions, new pumping technology for low energy wells, ways to image fractured reservoirs and CO2 stripping technology.

Under "mature field", the priority is to get EOR, IOR going, and improve production efficiency, integrity and reliability. There could be better subsea well intervention methods, new offshore power sources, more use of robotics and autonomous devices for inspection, and new materials.

Under "decommissioning," the aim is to improve well plugging and abandonment technology. There could be robotic cutting and removal equipment, robotic inspection and monitoring, more research into ways to handle cuttings piles.

The Board went on to identify three key themes it would like to target.

It would like to find a way to develop a 10m boe gas or 30m boe oilfield for under £100m. This project is "championed" by Centrica (gas) and Enquest (oil), supported by GE, Baker Hughes and Magma and NSRI (National Subsea Research Institute).

It would like to find a way to develop a low cost but fit for purpose standard well, at 50% of the current costs. This project is championed by Shell, supported by Baker Hughes and GE and ITF.

It would like to find a way to inspect vessels internally using a flying drone, and find a way to inspect for corrosion under insulation. This project is championed by Total, supported by AMEC and OGIC.

The oil and gas industry would also like to learn from aerospace and automotive sectors, which have also been through difficult times, when the industry has suddenly changed and companies have needed to adapt, Mr Anderson said.

"We have a fantastic track record when it comes to technology and innovation," he said. But "we need to be more multi field, multi company collaboration."

John Wishart, LR

John Wishart, energy director of Lloyd's Register and current chairman of the Industry Technology Facilitator (ITF), told the ITF conference about his company's research to try to work out where oil and gas executives around the world want to improve.

LR interviewed 260 oil and gas executives from national oil companies, international oil companies, mid-capitalisation oil companies and service companies. It then went on to talk in depth to around 16 people.

45 per cent said they wanted to improve safety, 44 per cent said they wanted to improve operational efficiency, 43 per cent said they wanted to reduce costs, 29 per cent said they wanted ways to access new reserves (for example with better imaging or drilling); and 27 per cent said they wanted ways to increase asset lifespan.

There were some geographical themes to the results. In London, respondents said that legal constraints were hampering research and development. In Houston, respondents said that technology implementation was a big challenge.

In South East Asia, the national oil companies were rising as the biggest innovators.

Respondents in both the Middle East and the US mentioned the need to develop fracking techniques which need less water – but due to different reasons – water shortages in the Middle East and public concerns in the US.

Some Middle East respondents said they were aiming for 70 per cent recovery. "I've heard it from CEOs in 3 different NOCs in the Middle East. I think that's something worth understanding," he said.

Further information is online at www.lr.org/energytechnology

Total

Being a leader in technology pays off in many ways, said Philippe Guys, managing director of Total E&P UK, at the ITF conference.

Partly due to its technology leadership, he said, Total has just signed a 40 year agreement with the government of Abu Dhabi to take a 10 per cent ownership in Abu Dhabi's 15 biggest onshore oil fields.

These fields produce altogether 1.6m bopd, more than double the current output of the entire UK Continental Shelf. Abu Dhabi is "recognising our expertise, technology and capacity for innovation," he said.

Total E&P UK employs around 1,200 people, and expects 200,000 boepd by the end of 2015.

It employs 25 geoscience researchers in Aberdeen, looking at improving reservoir modelling, history matching, 4D seismic and other topics. This is one of Total's 7 research centres, with others in Houston Calgary, Stavanger, Doha, Pau (France) and Lacq (France).

Altogether, its research areas include frontier exploration, earth imaging, field reservoir, unconventional, deep offshore, wells, gas solutions and public acceptability.

A major technology priorities in the UK is developing "intelligent" operations and maintenance technology, including robotics and autonomous vehicles, wireless monitoring, and condition based / predictive maintenance and big data. We'd like a "subsea vehicle which can stay 3-4 months subsea and inspect without any vessel," he said.

It wants to improve subsurface imaging, including improving subsurface acquisition and processing techniques, and in particular sub-volcanic (basalt) imaging West of Shetland.

It wants to develop lower costs and improved productivity drilling and completion, including alternatives to fracking when developing tight sands, and ways to drill sidetracks from existing wells.

It wants to find better ways to develop subsea tiebacks, including with all electric subsea control systems, remote chemical storage and injection. It might need better flow assurance and modelling, subsea gas / liquid separation, subsea boosting, subsea pipeline heating, seawater treatment and injection, subsea power, subsea gas compression, and risers made from composite materials.

Under its chosen "Technology Leadership Board" theme, it would like to develop a robotic system for internal vessel inspection.

It would also like to develop an inspection technology for corrosion under insulation. "60 per cent of pipe leaks are happening under insulation," he said.

Apache - getting to $50 oil

Apache Corporation has a business model which aims to get to a point where it can survive with oil at $50 a barrel, said North Sea Projects Group Manager Mark Richardson at Subsea Expo

The "things we do in Apache are the right things for a low oil price environment" - Mark Richardson, North Sea projects Group Manager at Apache Corporation

"Our business model is to get to a point where we can survive at $50 [a barrel oil]," said Mark Richardson, North Sea Projects Group Manager at Apache Corporation (and a former Captain in the British Army), speaking at the plenary session of 'Subsea Expo' in Aberdeen on February 11.

"We continue to see investment opportunity at $40 to $50."

"You need smaller teams and a better approach," he said.

The "things we do in Apache are the right things for a low oil price environment," he said.

On the basis that there is so much oil being stored, Mr Richardson does not expect the oil price to go up very much. "The oversupply in the market will take a long time to get through. I can imagine oil price increasing to $70 in next 2-3 years but not beyond it," he said.

There is a lot of talk about reducing tax on offshore oil and gas companies, but it won't help much because current tax payments are very low. "Of 160 E&P companies in the North Sea, only 9 are [currently] paying tax," he said. Instead, "we need to increase the investment allowances," he said.

"Some [companies] have significantly higher lifting costs. We need to act and we need to act fast. We need more sense of urgency."

"We are [also] overpaid. There's significant cuts that need to be made," he said.

One way to improve business profitability is to try to improve the culture of contractors, and how they work with operators, and the way operators treat other operators has to change, he said.

Companies do not consider each other's needs enough. As an example, consider if one operator has an aging platform it does not care much about, operating at 60 per cent of the time. A second operator wants to do a subsea tieback to that platform. Since it is operating only 60 per cent of the time, the second operator loses 40 per cent of revenue from the tie-back.

Apache

The company's lifting costs for 2014 were just $16.66 a barrel, he said.

Apache, the 3rd largest oil producer in the North Sea, has the highest production efficiency for the past 2 years, at between 90 and 94 per cent, he said. It operates a range of assets, many of which are 'aging'.

Apache ran 168 projects in the North Sea during 2014, and its project management cost was 4.8 per cent of the total budget, compared to an average for the North Sea of 12 per cent. "With the right collaboration, and if you work closely with the supply chain, you can achieve that," he said.

Apache has lots of subsea tiebacks and FPSO developments, he said.

Subsea engineering

"We use agricultural engineering in subsea," he said, a comment which provoked some protesting from other panel members.

"[Subsea] doesn't need bells and whistles [when they] push up the price and reduce reliability," he said.

In one example, Apache needed a subsea structure to protect a subsea choke valve, and it needed to be installed in December otherwise the whole project would be held up, he said.

The first contractor spent £115k on engineering, planning a structure which trawlers could safely pass overhead, which would cost £485k to build, and be available by the following February.

Apache went to a different contractor who came up with a much simpler design, requiring £30k of engineering and £50k for construction, which would be available on time. "Why couldn't the first contractor do that?" he asked.

Managing risks

"There's a culture that you have to gold plate things and every single risk must be covered, he said. "It is so gold plated it is no longer fit for purpose."

"I blame operators and the way they set the framework," he said. "If the framework is wrong, everybody suffers."

"[Working] in an operator, you [only] get sacked for fiddling expenses and importing risk. So you avoid risk by not doing anything. The best answer is, do nothing , defer, delay, and you get promoted."

But "the risk still stays with the operator, for accidents."

Processes

Oil company people often get too tied up in their processes. "People think that projects are driven by process. It's not. People hide behind process."

"Projects are support functions, not lead functions. You want checkpoints, not gates."

"Once you free the people and allow them to come out of a process system, you'll get better results."

Attitudes

Mr Richardson said that when he came into the oil and gas industry after being in the military, "I was amazed by the competence and training of oil and gas people."

But "we don't leverage on that competence."

The industry gets too adversarial. "The lack of collaboration has been mentioned many times," he said. "A profit means that both sides can win. People have to be more profit focussed."

Instead of endless analysis to try to understand the situation perfectly, leaders should get a project moving in the right direction. "Work on assumptions and make decision and be bold," he said.

A common scenario is where nobody wants to make a decision, so they pass the decision up the chain of command, until it reaches someone who has a portfolio so large he can make the decision knowing if he gets it wrong it won't affect his job, he said.

This is the wrong person to make the decision. "He has no skin in the game and no technical ability," he said. "We need to get decisions made on the coal face."

Projects can be run with small teams. For example Apache ran its 'Bacchus' subsea tieback project with just five people.

As a leader, "my job is only to know the important stuff," he said. "The best answers win, and the best answers are out there in the market."

"Apache has been successful in a high oil price environment. But it's the way we can all do business in a low oil price environment."

Subsea Expo plenary session report

As well as Apache (see previous article) the plenary session at Subsea Expo included excellent comment from Enquest, Subsea UK, Subsea 7, Proserv and NSRI

Our industry is in "perhaps an unprecedented existential crisis," said Neil McCulloch, president, North Sea with Enquest Petroleum, speaking at the Plenary Session of the 2015 Subsea Expo in Aberdeen.

"Enquest was not alone in finding things were starting not to work at $110."

However "margin compression is a real opportunity to do business better," he said. It's "time to get back to the basics and doing the basics well."

"Enquest's philosophy - it's not about being cutting edge, but taking existing technology and being creative around that," he said.

"We are really convinced that [subsea tiebacks] are a key contributor in cost and time scale of tieback developments," he said. "Old infrastructure and small pools is what we do."

So "keeping subsea infrastructure healthy is vital."

There is still a "misuse and abuse of word 'standardisation'," he said.

"The dictionary definition is an agreed way of doing things. But we've created a plethora of corporate bespokes."

"Enquest's philosophy - it's not about being cutting edge, but taking existing technology and being creative around that" - Neil McCulloch, president, North Sea with Enquest Petroleum.

"Why do you need to modify the designs of companies who've been doing it for 40 years?"

The US shale oil and gas industry grew out of a "pathological obsession with standard equipment out of the product catalogue," he said. "If you keep things simple you achieve outstanding results."

Suppliers

"Operators need the supply chain to thrive. We're very interdependent.

"We must appreciate and accept how interdependent we are."

We're working with suppliers to develop [new] cost models," he said. "We expect suppliers to deliver the highest level of quality at the lowest cost."

"It is essential for cost to remain at significantly low levels. This would make the cake bigger and generate a bigger share for everyone."

Exploration driven

Future success in the UK continental shelf will be more Exploration and Appraisal (E+A) driven, he said.

There are 300 discoveries in the UK continental shelf which are considered too small to develop viably. The industry needs to figure out how to develop them at lower cost.

"Subsea Expo cannot stand for 'expo'nentially rising costs. It should stand for 'expo'se the waste in our industry," he said.

Neil Gordon, Subsea UK

"We're in a totally different place this year compared to last year," said Subsea UK chief executive Neil Gordon.

"We're talking about cuts and how we make savings."

"Oil companies are focussing more on managing operating costs rather than capital costs, he said.

"[Our industry is] not the most efficient or the most collaborative" - Phil Simons, VP UK and Canada with subsea service provider Subsea 7.

This means that industry attention moves onto topics like, how can better inspection, repair and maintenance techniques prolong the assets, he said.

Companies are looking harder at how to develop smaller offshore fields cost effectively, which will usually mean subsea tie-backs to existing platforms.

The emphasis on costs means that "It may be one of our most challenging years ever," he said.

Phil Simons, Subsea 7

Phil Simons, VP UK and Canada with subsea service provider Subsea 7, pointed out that despite a lot of talk about collaboration, it is not happening much.

"Who really believes they collaborate?" he asked. "We're not the most efficient or the most collaborative. I believe it's not happening effectively at all levels."

"Our teams are working against each other trying to show the other is wrong."

An example of poor collaboration is the way that oil companies aggressively try to pass risks onto their contractors, he said.

"As a contractor we see clients who push risk on us, which means we have to price the risk," he said.

A collaborative approach, by contrast, would mean both sides trying to understand the risk as well as possible, and who is best placed to accept different aspects of risk.

"Innovation" doesn't necessarily mean designing something from scratch, it can also mean finding new ways to work together, he said.

An example is how Subsea7 worked together with Shell to develop a torpedo shaped autonomous underwater vehicle (AUV), which can travel around the seafloor without being driven by a human, for example to do larger scale seabed surveys and structure inspections.

"Commercialising of new technology is difficult, time consuming and costly," he said. "Proving its worth can only be achieved with client backed trials."

The industry has also "lost touch with the notion of simplification," he said. This means "fit for purpose solutions, eliminating unnecessary cost."

To achieve this, we need to make organisations feel responsible for simplification and achieving change, he said.

Subsea7 follows the 'ESSA' philosophy – Eliminate Standardise, Simplify or Automate, he said. "We have reduced cost without adding risk."

"It would help if oil companies and service companies could make their contract practices more collegiate" - David Lamont, CEO of oil and gas technology services company Proserv.

"Making high value changes in your business can begin with a single conversation and take days to implement," he said. "Sometimes the simplest and most obvious ideas provide and biggest savings in time and cash."

"Not too long ago the key challenge for our industry was the skills shortage. Now collaboration, elimination and simplification are ways of working we all need to address."

Proserv

David Lamont, CEO of oil and gas technology services company Proserv, said he believes the current business environment will help companies to get stronger, leaner and fitter.

It would help if oil companies and service companies could make their contract practices more collegiate, so people understand each other's objectives, he said.

Proserv's business focus is on helping companies prolong the productive life of their oilfields, so it has a good idea of the challenges.

Engineering companies should be aware of their customers' constraints. "If you give an engineer a blank piece of paper and say 'design something', you'll get something without a cost constraint. You need to have cost in mind and design to that cost," he said.

Engineering companies can also take some of the risk, when they are treated as part of the solution, he said.

People talk a lot about standardisation, but you need to have the right sort of standardisation. There's no point in standardising how you build wells, if it means you end up putting components designed for deep water into shallow water wells, he said.

Proserv aims to build components that connect with each other easily, or, as it calls it, the 'USB Approach'. "The more we can make it plug and play, the stronger it will be," he said.

You need technology which will sit alongside your existing offshore structures, not try to replace it, he said.

You need better knowledge of your offshore systems, including from instrumentation, measurements and observations.

Mr Lamont noted that the industry has survived before with an oil price this low. "The oil price has been above where it is today for [only] 20 of the last 55 years," he said. "In the 1990s, the oil price was lower than it is today in real terms."

There are also many service companies in the oil and gas industry offering lower cost services, the equivalent of ALDI and LIDL in the UK supermarket sector. But perhaps what is missing is a willingness from the industry to use them, he said.

"R+D is not the responsibility of the major oil and gas operators. All of us need to be encouraged to trial and deploy new technologies offshore" - Peter Blake, chairman of the National Subsea Research Initiative (NSRI) and Subsea Systems Manager at Chevron's Energy Technology Company.

Peter Blake, Chevron / NSRI

Peter Blake, chairman of the National Subsea Research Initiative (NSRI) and Subsea Systems Manager at Chevron's Energy Technology Company, pointed out that the UK subsea sector is currently worth £9bn, of which around 43 per cent is exports, with exports split approximately 50:50 products and services.

The UK subsea sector is forecast to grow to £11.1bn in 2016. There is particular growth in sales to Brazil, the Gulf of Mexico and Singapore.

"Subsea is 5 per cent of all oil and gas production worldwide, forecast to grow to 9 to 10 per cent by 2017-2018. Along with shale oil, subsea will be a key part of developments [in the oil and gas industry] going forward," he said.

"Subsea tiebacks have really built the North Sea," he said.

Mr Blake emphasised that companies should not expect major oil companies to handle all the necessary research and development by themselves.

"R+D is not the responsibly of the major oil and gas operators. All of us need to be encouraged to trial and deploy new technologies offshore."

The NSRI was restarted in spring 2014, as the technology arm of Subsea UK. "Our remit is to enhance the UK's position as technology provider for subsea industry."

It had a previous incarnation as "National Subsea Research Institute," he said. "It was a great institution but didn't get going fully."

Other sectors of the UK subsea industry, such as wind, wave / tidal and defence, have historically been more cost conscious than the oil and gas industry, and so might be able to teach the industry a little about how to reduce costs, he said.

Obstacles and risks

In a discussion about the biggest obstacles to reducing costs, Subsea 7's Phil Simons said "There is too much conflict in the way we work. It is about working together. The industry is too adversarial."

Chevron's Peter Blake said that the industry needs to get faster at implementing new technology. "Typically idea to a product is 15 years. There's an imperative to do it more quickly. Whatever we do, we need to look at how to short circuit that."

Another problem is the polarisation of projects. "The big projects have become bigger, the small projects have become smaller. Polarisation of 2 different technologies," he said.

Apache's Mr Richardson noted that the difficulty forming contracts and commercial agreements can kill off more projects than anything else. "It's an absolute killer," he said. We need the government to make clear rules and make people abide by these rules."

Proserv's David Lamont noted that operators and engineering companies need to work better together. "If we treat engineering houses as a commodity, working at a day rate [to do FEED], we will not get alignment [of interests]. You need to align the engineering team with the project team."

"Engineers will not be fired for taking a conservative view. They will be fired for taking a risk that doesn't work out."

"If you ask people to take risk, they're not going to," said Chevron's Peter Blake.

"One of the things NSRI can help with is understanding what the risk is. Where does the risk really lie and what benefit do you get from taking that risk. Perception of risk is much greater than the risk which exists."

"It is an aversion to risk that is killing the industry," said Apache's Mr Richardson. "Cost of project, speed of the projects is killing the industry."

One audience member noted the frustration that many decisions for North Sea operations are made in Houston, for American owned company. “You’ve got to go to Houston to convince them to use a bit of technology in the North Sea,” he said.

One audience member said, “if you look back years, the IOCS would always be first to take a risk and go first. This has radically changed. I can understand the independents will take a risk, the IOCs will go second.”

Chevron’s Mr Blake said, “My sense is the technology environment is changing. To say operators should sponsor new technology is a myopic view. The tier 1 contractors should be looking at what technology can do, and do the selling job.”

Opportunities

The panel was asked how the industry could get better at sharing what it has learned.

One answer is that we treat some knowledge as completely open rather than worry about keeping secrets.

“The Brent reservoir [competence] and infrastructure should be non-proprietary,” said Enquest’s Mr McCulloch. “Everyone knows the reservoirs.”

The panel was asked where the biggest global opportunities are.

“We’re using North Seas a proving ground, but the opportunities are probably deepwater,” said Subsea7’s Phil Simons. “The North Sea offers a great place to develop new technology.

“For us the Gulf of Mexico is doing extremely well,” said Proserv’s David Lamont. “We're seeing a lot of take-up for very marginal fields to be developed extremely quickly. Our system allows very fast response to opportunities as they come.”

So will the UK continue to lead? “The UK starts from a great place,” said Chevron’s Peter Blake. “The UK industry is huge compared with anywhere else in the world. The subsea technology around the world has come from UK.”

“This is a great basin for testing stuff out, relatively shallow water, relatively well known. We have fantastic academics here.”

The panel was asked how best to attract young people to join the oil and gas industry.

Enquest’s Mr McCulloch said that people should be attracted to the industry because of its enormous challenges.

“The difficulty of the chemistry and physics we have to overcome every day gets greater. 80 to 90 per cent water cut. It requires tremendous ingenuity. It think we still offer a great career.”

On the Oil and Gas UK’s Technology Leadership Board, there have been interesting debates about techniques. The best solution “is not always a widget. It can be an approach,” one delegate said.

In one example, access for replacing a piece of equipment was made by rope rather than by a scaffold, and the scaffold proved to cost three times a much, he said.

INTECSEA - focus on managing uncertainty, not costs

Oil and gas companies might do better in today's business environment if they focussed more on understanding their uncertainty and areas which might be causing costs to rise, rather than just trying to cut costs once a project is underway, said INTECSEA's Ron Doherty

Oil and gas companies often lose project value by not having a comprehensive analysis of their starting point, which could be done for just $5-$10m, said Ron Doherty, manager of field developments with INTECSEA Consulting, speaking at the Subsea Expo session "projects" in Aberdeen on February 11.

Mr Doherty sees this as reflective of a general attitude in the oil and gas industry, where people are very focussed on meeting project metrics such as NPV and Internal Rate of Return (IRR), but don't notice or understand the risks which cause their projects to get much more expensive than planned.

"Companies focus on cost reduction once a project is underway, rather than fully evaluating the unknown areas (risks) in order to make better initial decisions and maximise the value of the asset, he said. But "most scope to influence value is pre-FEED, in the feasibility and concept stage. The problem is that value lost at this early stage is not usually obvious, he said.

Case study

In one field development project example, an oil company had a target was to get to first oil within 36 months, which is typical for a fast track project. This was achieved.

However the project team found they were not achieving the production they had predicted with the wells they had drilled, so the production system was not operating efficiently. This meant that additional production and injection wells needed to be drilled, adding a delay of 30 months before achieving the predicted production.

This damaged the project finances, both through the cost of the wells, and the delay in reaching the expected production profile on which the project economics were based.

The calculations showed that the time delay for not reaching the expected production profile meant an 11.1 per cent reduction in the net present value of the whole project.

When including the extra drilling expenditure, equipment procurement and installation costs, the NPV was down 55.2 per cent altogether.

"This was considered a 'successful' project," he said.

What was missing was an understanding of the initial risk, he said.

The whole system, both topside and subsea, was designed for the expected production rates. The reduced rates required expansion and modifications that were not envisaged, and inadequate allowance had been made in the design.

"If you understand risk, you can take decisions that make allowance for the potential issues, and more easily and cheaply accommodate any variance. If you don't understand the risks throughout the system, then you're gambling."

The company could have invested $5-$10m in a more comprehensive analysis of the subsurface variance, and the impacts on the subsea system and topside facilities. In addition, the technical risks being taken needed to be more fully understood as a part of the overall system.

The value in this example "was lost because the development was built on assumptions and risks not fully quantified. It was not lost because costs of equipment and installation were too high," he said.

Subsurface uncertainty

With any field development, you are going to have reservoir risk, and this is accepted, he said. But it is important for the field development team to have as much knowledge of the certainty of the reservoir as possible.

With this, the development plan could be designed accordingly, with the subsea architecture design and topside support facilities selected to accommodate the most likely production scenarios, rather than just a single profile.

For example, a reservoir with more uncertainty could be designed as a possible later add-in to the plan (as a later tieback), and a reservoir with more certainty could be made more central to the development, even if this means a slightly higher initial cost. Reducing risk, or at least understanding where risk is being taken (reservoir/technical/schedule), can increase the total return from the asset.

"The oil and gas industry also needs to be careful with the mindset of cutting costs, if it means it is not looking carefully enough at the opportunities and risks. After all, how many projects in the present "low oil price" environment can afford to lose 50% of the potential value?" he asked.

Subsea 7 - repair of the Siri platform

Subsea 7 came up with a new way to reduce the swaying / vibration of an offshore platform

Subsea 7 were recently contracted for a project that was part of a major repair of the substructure for the 'Siri' platform operated by Danish operator DONG E&P A/S, in block 5604 / 20 in the Danish sector of the North Sea, about 220km from the coast of Denmark.

The subsea solution, using cable stay technology, is understood to be the first use of the onshore technology being used in an offshore context.

Subsea 7 project manager Alan Cassie said it was "the most interesting project I have ever been involved with", speaking at the 2015 Aberdeen Subsea Expo.

Inspection of the platform revealed cracking to the subsea structure, impacting its capability to carry full design loads.

To reinstate the platform to its design specification a novel platform reinforcement solution, using cable stay technology, was devised. Analysis showed that if the swaying / vibration of the platform could be reduced (from a 6 second period to 3 seconds), only a relatively simple support of the damaged area would be sufficient to reinstate the structural safety of the installation. Without this stiffening of the structure, such a support would not be technically feasible.

The platform is located in the Danish sector of the North Sea, approximately 220km from the coast in 60-65m deep water.

Braces

The chosen method was to fix large friction clamps onto the legs of the platform, and tie them together by high tension steel cables, similar to the stays that are used to brace bridges. This would all 'stiffen' the platform structure, thereby reducing its natural period. Each friction clamp is 6.4m high and weighed 150 tonnes. There are 56 bolts on each clamp joining the front and rear shells together around the leg tubular. Each of the 56 bolts is 1.9m long, and has a mass of around 300kg.

The stay cables between the clamps each contains 169 steel strands, making it thicker than most cables used on bridges. Subsea 7 needed to develop a special system for manufacturing the cables. Also the duct (covering the strands of metal in the cable) needed to be watertight.

The clamp design was handled separately to the overall platform strengthening design, with a different design house, which added to the complexity.

Everything needed to be constructed and installed with a 0.15 degree tolerance. "That's a Swiss watch tolerance," Mr Cassie said.

The repaired Dong Siri platform, complete with cable stay technology

Installing the system required a lot of co-ordination between teams on the ship and teams on the platform.

Surprisingly, the dry clamps (above the water line) proved to be more complex to install than the wet clamps.

The cables were tensioned to 1250 tonnes.

Ultimately the project was successful, with the platform's period reduced to 3 seconds, with a corresponding reduction in the size of the motion. The entire design and installation has been certified by a third party and the platform is now fully repaired. The complex project was executed with a very good safety performance.

Lessons

One lesson from the project was "don't underestimate the complexity and challenge associated with delivering an innovative solution," Mr Cassie said. But "don't underestimate the ability of good engineers to overcome these challenges."
"The novel design had to fulfil specific safety, technical and schedule objectives as well as cost pressures," Mr Cassie said.

"Adapting the methods and practices developed in onshore civil engineering to an offshore project was challenging, but the successful conclusion has advocated the approach.

Often reflecting on smart engineering previously used in other industries offers a better alternative for both contractor and client, which was the case for this project."

Omnisens - 1600km of subsea assets with fibre

Omnisens, based in Morges, Switzerland, reports that its fibre optic subsea monitoring systems are now monitoring 1600km of various subsea assets.

This includes 1330km of subsea high voltage power cables, 150km of heating cable on heated flowlines in the North and Caspian Sea, 20km of flowline bundles in Alaska and 7km of pipe-in-pipe in the North Sea. Also two 21km umbilicals in the Gulf of Mexico carrying oil and gas up from the seabed.

The fibre optic cables can gather data which can be used to monitor temperature and/or strain on the pipeline or umbilical, although the applications mentioned are mainly monitoring temperature.

Temperature data provides condition monitoring and leak detection. An alarm is signalled and the event located whenever a predefined temperature (hot or cold) is reached. This is particularly useful especially for deep water umbilicals which are subject to rapid and large changes in current and load, both of which change the operating temperature of the umbilical.

ROV cables, which experience coiling, rapid changes in load and storage in extremes of temperature are also usefully monitored for temperature to ensure they do not exceed the manufacturers' specifications. Knowing that a cable is operating at a low temperature along its length gives the operator the confidence to increase the load on the cable or run it for longer.

Detecting strain can indicate fatigue on a cable or umbilical, showing the maximum bend, any elongation and the number of bend cycles experienced. This information can be cross referenced with predictive models for model validation, although this is in early stages of development.

Omnisens provide a range of monitoring systems to suit different project requirements. With a long range capability, measurements can be made over a distance of more than 75kms from one interrogator, and potentially further using subsea amplifiers. This means that long flowlines as well as power cables can be monitored, often from on-shore.

The technology has also been installed on most of the larger UK wind farm export cables and several interconnectors. In addition to continuous monitoring, operators have used the system to detect faults in underperforming power cables and umbilicals.

How CSEM improves probability of success

Using controlled source electromagnetic (CSEM) surveys in exploration can help you increase the chances of finding oil, says Daniel Baltar of EMGS

Used in the right way, CSEM (controlled source electromagnetic) surveys can help companies improve the likelihood that the exploration targets they select are the right ones, said Daniel Baltar, global exploration advisor with EMGS.

He was speaking at the Finding Petroleum London forum on February 19, "Non Seismic Geophysics".

An explorationist creates value by making money sometimes and losing money most of the time. So the value equation is the amount of money you make minus the amount of money you lose.

The exploration "positives" could be calculated as the value of a successful well multiplied by the probability of achieving economic success, and the "negatives" could be calculated as the cost of exploration multiplied by the probability of economic failure (or 1 - probability of economic success).

Probability of economic success shows up on both sides of this equation - so if you improve it, you can increase your gains and reduce your loses in just one go, he said.

An EMGS CSEM (controlled source electromagnetic) survey vessel

The source of the low 'probability of economic success' is the 'uncertainty', he said, although you could use the word 'ignorance' to mean the same thing, he said.

The CSEM survey technology has been available for over a decade, but the ability to interpret and process the data has improved a great deal in recent years, he said.

Up to around 2010, "the measurement was there but you couldn't actually interpret it. There were a small group of people who could look at it and make sense of it, but most people couldn't."

Understanding fluids

You will be successful with oil and gas exploration if the targets you pick had the four factors of trap, reservoir, charge and seal, and the volume is large enough to make the reservoir viable to develop.

Mr Baltar presented a study made by an (unnamed) company of 120 dry wildcat wells they had drilled, showing that subsequent analysis found that 10 per cent failed due to the trap being absent, 15 per cent had no reservoir, 30 per cent had no charge and 45 per cent had no seal.

Explorationists spend most of their time looking at seismic, to assess if there might be a trap or reservoir, he said, therefore these are the best understood parameters in the evaluation and are a relatively small source of error. A full 75 per cent of failures occur because of an absence of charge or seal, which comes down to understanding the fluids absence or presence in a certain area of rock. "Fluid is more challenging", he said.

CSEM is good at helping understand fluids, in particular because salt water shows up strongly, because of its low resistivity, he said.

Reservoir volumes

CSEM can also help assess reservoir volumes.

Studies have shown that the reservoir volume turns out to be the main factor predicting how much oil and gas you will ultimately produce, and this is a much more important factor than rock porosity, saturation and recovery factor, he said.

Using conventional analysis, it is very hard to predict reservoir volumes. Studies by one oil major in the Gulf of Mexico showed that it had close to no ability to predict the size of reservoir volumes, as calculated by comparing predicted volumes and actual volumes for a number of reservoirs which had been developed, he said.

How CSEM works

CSEM surveys are made by leaving receivers on the seabed. The seabed receiver is attached to a cement anchor, which then dissolves, leaving only a pile of sand on the seabed. Then you tow a high energy electromagnetic source using a vessel. The electromagnetic energy goes down into the subsurface and some of it is measured back up by the receivers. You typically use very low frequencies (as low as 0.1 Hz), and power of 1,500 Amps and above.

By analysing the data gathered on the seabed, you can build a three dimensional picture of the electrical resistivity of the subsurface are.

Brine (salt water) shows up strongly, because it is low resistivity (conductive). Everything else in the subsurface has a high resistivity, he said. So you can see where the brine is.

Also, the bigger the area of the resistive body, the stronger the electromagnetic signal. This enables you to get a sense of the rock volume.

In a study of reservoirs which had been developed, the predictions of net rock volume generated using CSEM showed a high correlation with the actual volumes, so long as the reservoir was above a certain size. For very small reservoirs CSEM was not able to make such good predictions, he said.

So electromagnetics can help you get a better understanding of both fluids and reservoir volumes, the two most important factors for success as described above, he said.

Negative test

CSEM can offer a useful negative test. Since hydrocarbon has a high resistivity, if there isn't high resistivity in the area you are proposing to drill, it means you are either about to drill into saltwater, or something else - but very unlikely to be a large hydrocarbon volume, he said.

In a hypothetical portfolio that could be representative of any major EM user frontier exploration portfolio (e.g., companies in the Barents Sea or the Gulf of Mexico). The typical Probability of Economic Success (Pe) in such circumstances is around 10 per cent. Mr Baltar estimated that it would have been able to increase this to around 30 per cent using the technology in a consistent manner.

Mr Baltar was asked about the chances that CSEM could give you a false negative - in other words, instead of helping you screen out unlikely reservoirs, it stops you from drilling a good reservoir.

Mr Baltar replied that CSEM is usually very good at telling you if a reservoir is small. So "if your minimum economic field size is large enough - you can be relatively certain you're not going to walk away from major reservoirs," he said.

Building on this idea, you could also use the technology to determine the best sequence of drilling, so you can try to drill the wells with most potential first, maximising the net present value of the whole play.

Workflows

The biggest challenge with introducing CSEM is changing the way industry works. "Most people in the industry are not used to CSEM derived resistivity," he said. "So it is people and workflows which are the challenges right now. There are a lot of people to be trained."

In order to get the most value from CSEM, you have to adopt it and work with the data systematically. "You need to adapt your workflows, otherwise it doesn't work," he said.

"EMGS is helping quite a few companies to develop the right workflows," he said.

"We are still struggling to talk to companies about the right evaluation workflow," he said.

"Companies are trying to derive saturation from CSEM. It makes no sense, adds residual value."

Carbonates

Mr Baltar was asked how well CSEM can be used to find oil and gas in carbonate reservoirs, which can be very complex.

Mr Baltar said that carbonates are very difficult to interpret from seismic data - electromagnetics might not make it any easier, but they do not make it any harder either. "Carbonates are difficult but that's what they are.

Permanent reservoir monitoring

Another audience member asked why the technology isn't used for permanent reservoir monitoring, because it can give a clear picture of what is happening (particularly if oil is replaced by salt water in the reservoir). "It is just an application which hasn't been looked at," he replied.

In one case, EMGS did a survey on Statoil's Troll field, and managed to spot an injection well, which it hadn't previously been told about.

You can see Daniel's talk on video and download slides at www.findingpetroleum.com/video/1137.aspx

Gravity gradiometry and magnetics in East Africa

Beach Energy used a gravity gradiometry and magnetics survey from CGG to help in their exploration efforts in Lake Tanganyika in Tanzania, East Africa. Ben Young from CGG explained how it works

In 2010 Beach Energy used a gravity gradiometry and airborne magnetic survey to help in their exploration efforts in its block under Lake Tanganyika in Tanzania, East Africa.

The analysis of the survey data helped map the basin structural framework and the depth to magnetic basement. The gravity gradiometry also helped facilitate the imaging of the rift zone and the interpreted sediment thickness. This helped the placement of further seismic surveys, said Ben Young, Business Development Geophysicist at CGG.

He was speaking at the Finding Petroleum conference in London on January 28, "Finding African Oil".

Since the survey was done, Australian oil and gas company Woodside has farmed in 70 per cent of the project (July 2014).

Geography

Lake Tanganyika sits on a rift valley, about 3,500km long and between 40 and 800km wide. It has at least 2 'arms' - with the Eastern branch associated with volcanic intrusions, and the Western branch, under the lake, with less volcanics.

The rifting created the valley which the lake sits in, and many fault blocks, all creating possibilities for different types of oil plays.

Lake Tanganyika is over 600km long and 40-80km wide.

The block owned by Beach Energy is approximately 7,200 km2 and covers the southern portion of the Tanzanian side of Lake Tanganyika.

Very few wells had been drilled into the rock, which made predicting sedimentary rock thickness very difficult.

There had been some 2D seismic recorded in the 1980s, which showed sufficient sedimentary deposits for hydrocarbon generation, and a lot of seismic reflectivity, Mr Young said.

It showed an inter-layered sequence of sands and shale, could provide source, reservoir and seal for oil and gas.

There had also been some naturally occurring oil seeps in the area, which increased chances of prospectivity, he said.

Surveys

CGG made its survey with a fixed wing aircraft, the Falcon Airborne Gravity Gradiometry (AGG) system.

The original technology was originally developed for the US Navy, to help map the seabed floor during the cold war. Later an airborne system was developed in collaboration between Lockheed Martina and BHP Billiton. CGG currently has 5 such systems globally.

High resolution airborne magnetic (HRAM) survey was acquired at the same time.

The survey was made in just 42 flights ('sorties') over the period September - October 2010, surveying with a line spacing of 330m, covering 27700km in total.

Magnetics

The survey results showed up a number of magnetic 'anomalies'. This likely suggests that the basement is composed of highly magnetic material probably shallow volcanic intrusions.

You can see the interpreted magnetic basement thickness.

Gravity

The gravity gradiometry data can do more to show up small features in the subsurface, he said.

To work with it, you need a high resolution digital terrain model to allow for terrain corrections. In the case of water coverage detailed bathymetry data is required.

Beach Petroleum had already acquired detailed bathymetry (depth data) of the lake.

It also used 15m resolution Landsat data, showing satellite imagery of the earth, and 90m resolution STRM (Shuttle Radar Topography Mission) data, a high-resolution digital topographic database of the earth.

The analysis showed up old water drainage patterns going into the lake.

The final interpretation showed 4 major 'depocentres' (location of the deepest deposit in a sedimentary basin). Two major depocentres were identified in the north and west central part of the survey area with sediment thicknesses in excess of 4km and 3km, respectively.

Beach Energy was most interested in finding out which area had the deepest sedimentary thickness.

In the interpretation, CGG did 'magnetic depth slices' at 700m and 5350m, and estimated (or 'pseudo') depth slices on gravity at 1100m and 5000m.

The gravity gradiometry data showed a lot of faulting against basin boundaries, which could potentially locate hydrocarbon traps.

It put together a sediment thickness model. "You want enough sediment to have hydrocarbon prospectivity," he said.

This model correlated with the structural interpretation made from seismic, "so we knew this probably made sense," he said.

The analysis showed 4 half grabens (where a block of the earth's crust has dropped relative to the neighbouring blocks). There were areas where the rock has been stretched and thinned.

Following the analysis, Beach Energy conducted a 2D seismic survey in 2012, looking in more detail at the areas of interest.

There had been a number of oil seeps seen at the edges (flanks) of the grabens, and close to the "depocentres", all indicating presence of an active petroleum system.

View Ben's talk on video and download slides at www.findingpetroleum.com/video/1130.aspx

Using big data to overcome subsurface challenges

The oil and gas industry would particularly like to use big data to improve production and drilling, said Pranaya Sangvai, Cauvery Basin Business Unit Head with Reliance Industries

"Business success is based on the quality of decisions that we make" - Pranaya Sangvai, Cauvery Basin Business Unit Head at Reliance Industries.

Reliance Industries' E&P venture is keenly studying Big Data Applicability, said Pranaya Sangvai, Cauvery Basin Business Unit Head at Reliance Industries, speaking at the Digital Energy Journal forum in Mumbai on February 4, "Doing More with E+P Data".

The intent is to find ways to optimise efficient drilling and enhance production."What would be very useful, right now, would be tools to help detect well problems before they become serious, from analysing the data," he said.

"Business success is based on the quality of decisions that we make," he said.

"Huge data is gathered and acquired from exploration through appraisal to development of the discoveries. The proper integration and analysis of this data, with historical data, is of paramount importance to take crucial decisions of multimillion dollars to billions of dollars investments."

"We need to extract value from the growing volume of the data. If an organisation has no good strategy for big data, I think the company is going to be doomed."

The data which people really need to make decisions is often not available, he said. "When we look at data and want to take a decision, we generally find there's a gap," he said. "This gap either needs to be eradicated or really needs to be closed, that's what we feel today."

Big data strategy

At a corporate level, Reliance Industries has already taken note of Big Data, he said.

Reliance is developing data road maps for its various business and functional frameworks.

The company also has a very strong IT support to its oil and gas division. The proper blend of IT and subsurface knowledge base is an advantage in reaping the benefits of Big Data.

Mind-set

In any industry, the biggest challenge with implementing new data systems are changing people's mind-set, he said.

In every industry, people at a senior level often feel that they don't need anyone to advise them, or need proper analysis of the data, since in the past they have been successful without it to a certain extent, he said. "Today, if you want to change that attitude, it becomes a little difficult, but I believe it's possible," he said.

Getting new technology implemented in E&P is hard. "Most of the time there's a question mark, [people ask] has it really been used in other E+P companies. We are unsure about the technology or its benefits are yet to be proven. And so on."

Also, "we really lack the skills of big data," he said. "When we don't have a big data skillset, we try to avoid the change".

E&P people often look for return on investment (ROI) for implementing new technology.

Evaluating ROI can be as difficult and pointless as trying to calculate the ROI of buying chocolate for your child, he said. "If my son asks for a chocolate, I give it to him. It giving any ROI? I don't know," he said.

If we think IT can provide a benefit, and we can afford it, we could just implement it without trying to work out ROI, because of so much of uncertainty and crudeness involved in quantifying intangible benefits, he said.

Government restrictions

Legal restrictions about moving offshore seismic data outside the country can make life difficult. Getting permission to move data can take 3-6 months.

"For approval of the proposed e-transfer of seismic data, the operators in India are still struggling to satisfy procedural quorum of various agencies involved. We need to overcome the procedural difficulties," he said.

Some people think seismic data "is very crucial data," he said. But the "raw data doesn't give any information for anybody to use."

There is a big gap of technological understanding between E&P operators and government authorities and lots of time is spent on education.

Sometimes, while doing so, technology changes, so we get approval on obsolete technology, he said.

"One such example is data storage. While we were discussing physical data storage (hardware), the emergence of cloud technology storage was seen more useful. But now we need to address how secure is cloud storage. Such things take toll on merit of the proposal," he said.

Managing data

Managing data is a big challenge. "We have data at rest, data in motion, and data in many forms, structured, unstructured, text, and multimedia. Unstructured data is 80 per cent of overall data volume," he said.

At one particular time Reliance used to generate 1.4tb data from internal sources, and 1.1tb per day from external sources. Raw data was over 2 terabytes per rig per day. Most rigs have over 40,000 sensors or data sources. He believes full data utilization is possible only if Big Data is put in practice.

For real time data, it would be useful to have something like a centralised clearing house, he said.

Reliance is fortunate not to have large amounts of legacy data and therefore Big Data Adoption will be at much faster pace than other companies, he said.

Watch Mr Sangvai's talk on video and download slides at www.d-e-j.com/video/1568.aspx

National data repository in India

India has a project to build a National Data Repository (NDR) - but is there enough support to make the project work?

Helping India build a National Data Repository: Chandan Kumar Bahman, Superintending Engineer (IT) with the India Directorate General of Hydrocarbons.

The government of India has provided funding for a National Data Repository (NDR), with a 6 year contract awarded to Halliburton on Feb 2014, covering one year to set the centre up, and five years for operation, said Chandan Kumar Bahman, Superintending Engineer (IT) with the Indian Directorate General of Hydrocarbons.

He was speaking at the Digital Energy Journal forum in Mumbai on February 4, "Doing More with E+P Data".

Over the five years, the NDR is expected to take 1008 2D surveys, 528 3D surveys, data for 8,400 wells, 16,800 well reports and 33,600 scanned logs.

The NDR is defined as a "a government sponsored data bank to preserve and disseminate upstream oil and gas information and data in order to promote and regulate hydrocarbon exploration and development activities," he said.

The data can include seismic data, well logs, g+g data, cultural data (well header data, blocks, basins), production data and archives.

Efforts to develop the NDR started a number of years ago, but "many regions did not take off as expected," he said. "We did not get the kind of co-operation from the operators [we wanted]."

"If the basic work is not done, then the final work will be very difficult to achieve."

About DGH

DGH is the oil and gas regulatory body in India, established in 1993, under the administrative control of India's Ministry of Petroleum and Natural Gas.

It provides technical advice to the Ministry, reviews exploration programs and advises the government on offering acreage. It has a mandate is to regulate the "preservation, upkeep and storage of samples pertaining to petroleum exploration."

DGH's role includes preparing data, requesting bids, evaluating bids, awarding blocks, and keeping an eye during exploration and development. The bid evaluation aims to be as transparent as possible.

DGH manages all kinds of data including structured data (e.g. financial and production data), semi structured (field development programs, test results, regulatory clearances) and non-structured (correspondence, reports, documents and legal data).

The best way to build it

Ashok Tyagi, general manager of the Indian School of Petroleum and Energy, and a former General manager (Exploration), Oil & Natural Gas Corporation (ONGC), suggested four models the NDR could be built by.

Model 1 is where the government dictates and drives the project, forcing oil companies to provide data, which is then used in subsequent licensing rounds.

Model 2 is where the project is initiated by government but supported by oil companies, where some oil companies use it to share data between each other where they have sharing agreements.

Model 3 is where the system is driven both by oil companies and government, where the system is built in a similar way to oil companies' internal data management systems, and can rely on this system as a back-up if they lose their own data.

Model 4, Mr Tyagi's preferred solution, where the data is still stored by the oil companies but available on demand, but they submit metadata to the national data repository. This means that users of the NDR can easily search to see what is available, and retrieve what they need. Mr Tyagi said this was his preferred option, particularly as the security issues would be comparatively easier, and it would be easier to start.

This also means that the data is only stored in one place, so there is no complex data replication challenge.

Benefits

From an oil companies' perspective, a NDR will enable them to gain information on demand, reducing the time spent finding data. It will also help them to interact with other oil companies, service companies and the government, Mr Tyagi said.

From the government's point of view, a NDR will help the government make sure it is maximising its royalties, and also help attract investment to India, by being able to provide prospective oil companies with better information.

Challenges

Key issues to resolve are working out the specific objectives of government / regulators and also of the Indian upstream industry, Mr Tyagi said.

Oil companies might use it just as a place to send the required data, or they might use it more actively.

In order to make sure it works, oil companies need to accept that their data is a national asset, but also their perspectives need to be borne in mind, he said.

There could be a minimum 'core' service and additional services to meet companies' specific needs.

There needs to be a mutually worked out cost model. The project needs to be financed, and steps need to be taken to ensure it can work long term.

There should be a 'cost committee', with representation from operators, governments, the service provider and an independent financial institution, he said.

The companies involved need to decide on the legal, data security, commercial, operational and technical framework.

Someone needs to work out the data model, the data flows and the workflows, he said.

Data could be provided in Energistics standard formats, including WITSML, ProdML and RESQML.

The components of the NDR include a core data model, data loading / exporting tools, quality control tools, search engines and data integration tools.

The regulators should provide rules as a foundation for how the NDR is used, and then define the reporting schedules, reporting standards, routines for release of data, and how the system should be developed over time. There could be tax relief to oil companies which join the NDR.

Service organisations can have the role of choosing the technology and processes for quality control, data storage, retrieval and data distribution, and develop procedures for data handling.

It would be useful to look at other examples from around the world, including Norway's DISKOS and the UK's Common Data Access, he said.

Pranaya Sangvai

Pranaya Sangvai, Cauvery Basin Business Unit Head with Reliance Industries Ltd, also at the conference, said he was very interested in India's Directorate General of Hydrocarbons (DGH) project to develop a national data repository (NDR).

But there still seems to be a lack of 'intent' to develop it, he said.

"The intent has to be there, and the intent is missing," he said.

Part of it is that companies are afraid of losing control of their data, something which they have just kept to themselves for decades, he said.

View Mr Barman's talk on video and download slides at www.d-e-j.com/video/1554.aspx

View Mr Tyagi's talk on video and download slides at www.d-e-j.com/video/1558.aspx

Managing drilling data at Reliance

Reliance Industries is building a central repository for its drilling data, and developing processes to ensure the data is high quality. Rashmi Bhangale, data manager with Reliance Industries in Mumbai, explained how it works

"Drilling offers maybe the best opportunity for improving cost performance" - Rashmi Bhangale, Data manager with Reliance Industries in Mumbai.

"Drilling is the most expensive and challenging part of the [E&P] business," said Rashmi Bhangale, Data manager with Reliance Industries, speaking at the Digital Energy Journal forum in Mumbai on February 4, "Doing More with E+P Data".

This means that drilling offers maybe the best opportunity for improving cost performance, she said.

And by having drilling data better organised and structured, it should be possible to identify ways to reduce costs and improve performance, she said.

Once you have good data, "you can derive business value out of it," she said. "You can make faster and better informed decisions. You can plan your future wells."

Reliance set an objective to have a central database, which would provide good quality drilling data to people in accordance with the requirements of their role.

"All this data will help us for statistical analysis and benchmarking," she said. "One truth, one data. You can ensure the data is trusted. It will help us to track operational efficiency, and also prepare for the future. You have the consistent data in the office."

The central database can generate drilling reports and statistics, to be sent to the government to meet regulatory requirements, and also to be used within the company.

Reliance is using Landmark's Engineer's Data Model (EDM) as a centralised data repository.

The reporting and analysis done by Halliburton Landmark's OpenWells operations reporting system.

Data capture

Data would be captured as it is generated at the rig.

The database will include data from drilling operations, completions, well testing, and quality control reports.

It gathers data about causes of non-productive time (NPT) and lessons learned.

The most important aspect of drilling reporting is the Daily Drilling Report, "which everybody looks forward to," she said.

The data is automatically replicated to the central server as soon as it is gathered. So the information is made available to authorised interpreters immediately after it is entered.

Integration

Integrating data together when it is in different data formats is difficult.

"Every contractor has their own way of storing the data," she said. "Large volumes of complex data in different proprietary formats are generated."

"If data sources and formats are different it is very difficult to correlate the data."

Reliance has a project underway to standardise the nomenclature which is being used in drilling, so everybody uses the same terminology and vocabulary.

Quality control

The data will have consistent quality control, with defined best practises, workflows and procedures, units of measure, activity and cost codes, she said.

It is then validated for correctness and completeness. The quality control would be done both by drilling engineers in rig and office and the petroleum data management team. The quality control is done manually.

View Rashmi's talk on video and download slides at www.d-e-j.com/video/1573.aspx

What data managers do

Nalin Jena, Upstream Data Manager with Indian oil company Reliance Industries Ltd, gives his views on the best way to do E&P data management and what data managers do. *By Nalin Jena*

Good data management leads to better and faster decision making, leading to improved asset performance.

Good data management aims to improve the productivity of geoscientists by reducing the time they spend on accessing data, improving data quality, creating an integrated working environment in which the data, systems and applications function as a single unit.

Poor data management means you're reinventing the wheel again. Something that's been done before, gets done again, so you've just completely wasted resources.

The cost of data management is so small compared to all the other expenditures, like drilling of wells that it isn't a cost constraint, it's a people constraint, recognizing what should be done and having the resources in terms of people to actually do it.

Good data management usually aims to develop a centralized database which helps geoscientists to have all data at their fingertips.

The data manager will decide where the data is to be stored; define the naming convention and the guidelines to be followed once the user has finished with the data.

The data being managed needs to include digital images, structured technical data, unstructured emails, spreadsheets and video files.

The data manager needs to define the most appropriate architecture and operational environment to store and retrieve the data effectively and efficiently.

Discipline

Many exploration and production companies are building a data management discipline that competes with the geoscience and engineering disciplines.

Earlier E&P data management used to be focused on only geology and geophysics domain, but now it is broadening out to cover all of the functions like drilling, production and reservoir.

The data management team can consist of geologists, geophysicists and IT people.

Data managers need domain skills, such as understanding of seismic, well log, geology, drilling and production.

They also need IT skills such as data modeling, database development, data integration / reporting /migration, project management and analytics.

So geologists and geophysicists are provided with all kinds of IT training, and the IT people are trained in geosciences domain.

Working with the 'business'

The data management team is still struggling to capture the added value created by the interpreters, such as horizons, markers, faults, geological models, reservoir models, analysis and reports.

The data management team cannot decide which model, horizon or report is the correct one to store.

So it is important to have a close working relationship between the data managers and the business functions.

Another challenge is the link between the static data and the dynamic data. Static data (e.g.geological or geophysical) needs a different approach than reservoir data that is more dynamic over time.

It is important to manage the relationships at a number of levels within the organization like data manager meet with various users of the data, where issues are brought up and solved.

The data management team should adopt a proactive approach to raise issues and propose new solutions without expecting the business to tell them what they need.

Too often, the data management community is waiting for the business to tell them what they need and the domains are waiting for the data management to come up with solutions.

Audit

Apart from defining policy, procedure and naming conventions there should be periodical audit to ensure that the policy and procedure are followed by the user.

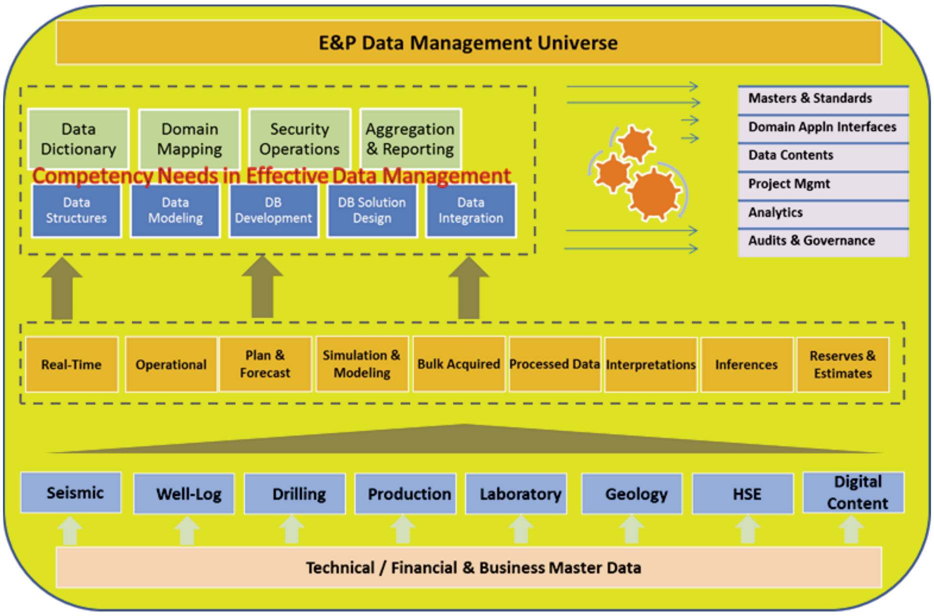
The audit should check availability of data, to see if it is getting to the right people, right data and right time.

It should check on redundant data stores.

It should check on appropriate use of data, taking into account business sensitivity, confidentiality, retention.

It should check the documentation of what data is added to which data repository and when.

It should check the documentation of data sources used for data processing and publishing.



Using analytics to manage project risk

We have all heard about the big cost overruns oil and gas companies have seen on major capital projects – but what is less known is how analytics tools can help manage them. Swami Ranganathan explains how it can be done

By Swami Ranganathan

Swami Ranganathan

64 per cent of oil and gas mega projects have cost overruns, according to a recent consulting firm study of 365 mega projects.

This means that project cost performance has become a very important issue for the industry as a whole.

A Projects Business Intelligence Solution (PBIS) could help save more than $15m for a typical offshore capital project by providing early visibility into future spend and schedule changes through historical and predictive analytics.

It could provide the capital project teams with a decision support capability to develop strategies well in advance to address any emerging financial risks that are likely to manifest.

Reasons for overruns

Capital projects can experience cost overruns for many different reasons. This includes scope changes; design and specification changes to address engineering challenges; material and labour cost escalations; schedule acceleration, delay or cancellation by project teams; delays in sub-system construction by contractors; installation/transport vessel availability, mobilization and demobilization.

In one example for a capital project fabrication work by a contractor for a super major operator, the cost was found to exceed the budget by 25 per cent resulting in over $300m in additional expenses for the fabrication work alone with knock-on effects on other project deliverables. (see chart to right) Unplanned expenses over and above budget affect both project economics and cost controls.

In several instances, cost overruns have resulted in the project teams ignoring cost controls to allow spend to exceed approved budget (to avoid work disruption). In some cases spend goes beyond the 10 per cent tolerance limit, before the budget is extended and additional commitment (change order) is formally approved by all relevant partners.

NPV IRR

The effect of cost overruns on project financials such as the Net Present Value (NPV) and the Internal Rate of Return (IRR) are very well known.

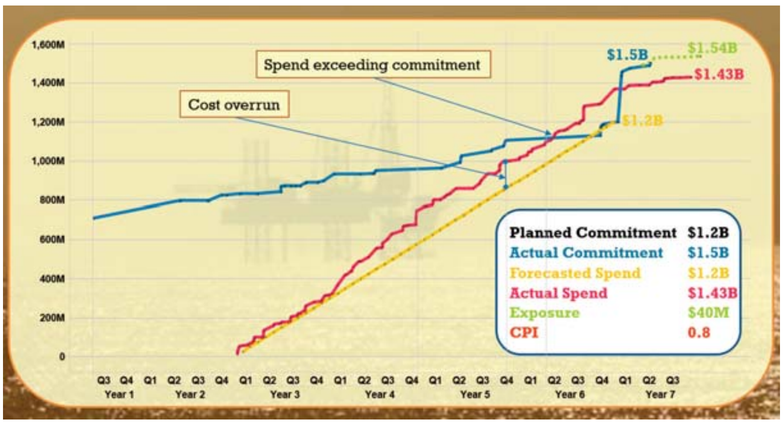
Take the example of a giant project in Kazakhstan. The project was sanctioned at $13bn and was estimated to start Front End Engineering Design (FEED) in 2001. It was expected to pump 1.2mbd (million barrels a day) of oil beyond 2005/2006. At $90/barrel and a discounted cash flow rate of 8%, the NPV for such a project would have been over $100bn with an IRR of over 50 per cent.

Instead, the project has seen economic losses so far because of implementation delays (to beyond 2015) and cost overruns (to over $43bn).

Capital project development work could last for several years and could continue even after first oil. During this period, the material and service costs could fluctuate considerably depending upon the demand and supply situations.

Demand and supply

The price of oil usually dictates the demand condition. When the price is high, several new projects become financially viable and operators start developing them at the same time, increasing the demand for engineering, procurement and construction (EPC) work.



How cost over-runs happen. A capital project fabrication work by a contractor for a super major operator.

To address the demand, suppliers augment their facilities and support systems simultaneously, sometimes resulting in the supply overshooting demand.

In one example, demand and supply for floating vessels was estimated at 1.8m and 2m metric tonnes respectively in 2011 for 2012. But the actual tonnage turned out to be 14% and 18% higher in 2012.

In 2011, the industry was expecting the demand to surpass supply.

However, despite a robust demand that exceeded the original estimates, the supply continued to top the demand in 2012 leading the analyst to revise both the demand and the supply forecasts upwards for all subsequent years.

Business Intelligence

A Business Intelligence solution is needed by capital project teams to predict future changes with a high degree of confidence well in advance so that the existing procurement strategies can be modified with least impact on project financials.

For example, a procurement manager could lock in the rental rates of an installation vessel for an extended period of time based on the defined project installation schedules in order to obtain cost savings.

But if the installation schedules change and they are not anticipated in advance due to lack of visibility and predictive analytics, then the procurement manager may have to change the contract at the last minute.

In the process, not only are all the advantages of the prior strategy lost, but also additional expenses may be incurred, especially if penalty clauses are included in the original agreement.

As the project progresses, the timeframe between the work commitment and the work execution starts to shrink fast, reducing the time available to the project team to address unplanned project costs.

Do it earlier

Project monitoring and control activities are most effective in the earlier phases of project execution.

As the project progresses, the timeframe between the work commitment and the work execution starts to shrink fast, reducing the time available to the project team to address unplanned project costs.

The project team could have 8 to 10 times more time to take corrective actions during the FEED phase of the project when project activities are Front End Loaded (FEL) when compared to the execution phase when the work has either already started or is close to completion by the contractor.

Predictions

You can try to predict project costs in advance rather than rely upon the present project performance.

For example you can analyse leading indicators such as commitment requests from the contractor (variation order requests or VORs) and work requests from the operator that are likely to translate into future commitments.

For example, if the contractor were to request a platform deck crane capacity increase, then this specification change may require a pressure increase of hydraulic utility, material change of certain components (like changing the grade of steel used in the crane and other parts), additional platform space, additional transportation and installation costs and so on.

A detailed value engineering or value analysis on such requests with a thorough understanding of its impact on other construction and installation activities could provide the necessary assurance against unanticipated cost increases that affect the project economics.

Access to information

In order to conduct any analysis, the required information needs to be available centrally.

Capital project teams are having to focus on where to get the information for the analysis instead of conducting the analysis itself.

Even if they know where the information resides, they have challenges getting access to the various project information management systems including finance, project planning and procurement.

Many projects utilize different specialized systems, both internal and external to the operator organization to record different activity sets. Records are often not normalized across systems.

Business Intelligence Solution

One approach is to build a Projects Business Intelligence Solution (PBIS), with a data warehouse and a data visualization tool.

Using dashboards, you can analyse spend, schedule and their leading indicators at different levels and compared against each other.

The analysis could involve comparing and contrasting similar project activities or categories of work, reviewing contractor performance across different projects and evaluating exceptions, such as sudden spikes in spend.

Spend could be categorized and categories subject to frequent deviations from forecasted values could be filtered and studied further.

If required, the project team could drill down to individual transactions within such categories to better understand the reasons behind the deviations and to institute the necessary corrective actions.

Patterns could be recognized and extrapolated using time series models to provide future forecasts. Statistical models developed through such techniques could then be continuously improved to get better fit between the forecasted and the actual values.

Swami Ranganathan is an Oil & Gas professional based out of Houston, TX.He was formerly with BP. For any queries regarding this paper, he can be best reached at +1-214-578-0845.

Repsol's early detection system for leaks

Oil major Repsol has developed an automated oil leak and spill detection system, gathering data from radar and infrared cameras

By Jose Vicente Solano Ferrandez, HEADS Project Leader, Repsol

Jose Vicente Solano Ferrandez, HEADS Project Leader at Repsol

In 2011, Repsol and technology company Indra joined forces on a project aimed to enhance both offshore and onshore oil spill detection, developing a system called HEADS (Hydrocarbon Early Automatic Detection System), the world's first water-based hydrocarbon leak early detection system.

HEADS employs a combination of hydrocarbon detection sensors (infrared cameras and radars), algorithms and intelligent software to quickly detect the presence of hydrocarbons on the surface of the water.

The infrared image sensors are used to detect hydrocarbons based on two physical properties - heat transfer coefficients and emissivity between water and hydrocarbons.
These properties enable us to detect hydrocarbons on the surface of the water with temperature differences as low as 1 degree C, despite adverse weather conditions.

The radar scans the water for abnormalities and recognizes differences in the roughness of the water's surface when hydrocarbons are present. It is capable of working long range, recording data from up to five kilometres

OFS Portal®

Founded in 2000, **OFS Portal** is an organization which consists of diverse supplier members who are committed to promoting eCommerce and reducing cost. We have a non-profit objective to ensure we promote the best approaches for the industry. In addition to advocating strong protection for the security and confidentiality of electronic data, **OFS Portal** has gained the trust and confidence of the entire upstream oil and gas industry. We do this through our proactive advocacy approach toward best practices to reduce costs and complexity while increasing the speed of adoption.

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You will then join more than 200 E&P Oil Companies around the world from small Independents and NOCS to all the IOC majors who have joined our community to benefit from the adoption of best practices and Oil & Gas Industry standards from PIDX.

Our members, who fund OFS Portal

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OFS Portal Advocates Best Practices

First, by drawing on the industry's experience, OFS Portal's Integration Competency Center prescribes best practices and provides guidance for practitioners and novices to achieve the best return on investment. Speed and breadth of adoption have a significant impact on returns and that is why OFS Portal advocates the use of best practices. OFS Portal has the depth of experience and the thought leadership to guide you through to a successful implementation of eCommerce in Oil & Gas

OFS Portal Supports Standardization

Second, OFS Portal brings its members' intimate knowledge of the global industry to the worldwide effort to develop data and business process standards suitable for the upstream oil and gas industry. OFS Portal and its members are active participants in PIDX INTERNATIONAL (Petroleum Industry Data Exchange, Inc.), the oil and gas industry's eBusiness standards body.

OFS Portal Creates Trust

Third, OFS Portal works to help all participants establish the contractual relations necessary to protect the buyers' and the suppliers' intellectual property rights in the data they transmit and exchange.

OFS Portal Delivers Value

Fourth, OFS Portal operates a shared platform for the publication of catalog content from its supplier members using open and uniform electronic data standards.

1330 Post Oak Blvd., Ste. 2025 Houston, TX 77056 USA
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away, and built to operate at full capacity in adverse weather conditions.

These sensors work together to monitor every stage of the operation, maximizing reliability and safety.

Indra's provision of advanced image interpretation and algorithms help the system to minimize misclassifications and false alarms, one of the biggest challenges for oil leak detection systems.

HEADS features real-time data processing, with its radars, infrared cameras, and command and control centres working together to accurately identify spills.

It does not require a system operator. When the system confirms an oil spill, it automatically activates the alarm and simultaneously collects and analyzes all data related to the occurrence. The system has a response time of less than five minutes.

Data from vessel Automatic Identification Systems (AIS) is used to identify ships in the area, and establish a relationship between oil spill detection and the trajectory of these ships.

Development

Repsol and Indra commenced this project in late 2011, and built a multidisciplinary team comprising over 20 experts and researchers with backgrounds in the oil industry, physics, chemistry, software programming, radar technology, and algorithm science.

The development consisted of four stages of evaluation, beginning with technical-economic viability testing at Repsol's Technology Centre, located in Madrid, which has a laboratory that simulates climate conditions at sea.

The following three phases (design, installation and final test) were carried out through two pilot studies at Repsol's Tarragona Industrial Complex and the Casablanca platform.

The project successfully completed each of the four stages, demonstrating the accuracy, reliability, and safety of all of the system's properties.

Indra, a consulting and technology multinational company, provided its expertise on image interpretation, algorithms, and the development of real time data processing.

Repsol and Indra have registered the patent with a standard Patent Co-operation Treaty (PTC) application.

Automating your accounting

Automated accounting workflow solutions can help you increase efficiency and reduce costs, writes Richard Slack

By Richard Slack, CEO, Oildex

Richard Slack, CEO, Oildex

An automated accounting workflow solution allows accounting teams to process invoices, cut out hand keying and export data within a greatly reduced timeline.

When this tool is combined with a network of vendors who jointly utilize the platform, this tool becomes even more powerful.

Automation also presents sophisticated digital insights into cash flow. This enhanced visibility allows companies to take stock of their assets and make better business and financial decisions.

Automation tools also provide for significant cost savings while boosting productivity and reducing errors and delays.

Process invoices

By streamlining and digitizing the manual and paper based process of coding, routing, and the approval of supplier invoices, E&P companies gain clarity.

This clarity allows them to make stronger and more accurate financial predictions.

Teams have the ability to generate reports from this digital data which is useful when making projections and presenting to shareholders or lenders.

Additionally, accounting departments are able to identify and take advantage of significant early pay discounts.

The cost to process a single invoice, according to a survey by Ardent Partners, was $14.21 in 2014. Implementing an automated accounting tool drives down that cost by 70-80%.

In addition, switching to a paperless office helps companies eliminate the costs associated with lost or incorrect documents.

Productivity

An automated accounting workflow solution allows teams to be more agile and productive in their process. Teams can move faster without worrying about errors or misplaced invoices as all documentation is held in a singular database.

Centralised database

When making the switch to a paperless and automated workflow tool, E&P companies are able to manage all of their financial documents and information in one digital and central repository.

This repository ensures that a company's financial history and data are kept both safe and secure. Data is backed up continually and additional levels of security can be added to keep unauthorized personnel from seeing sensitive materials.

A paper based accounting team without an accounting workflow tool may have documents and historical financial documents distributed among several different locations, filing cabinets, offices or even warehouses. This storage tactic makes it difficult for companies to retrieve and compile information and reports in a timely manner.

On the other hand, a digital repository of information allows organizations to retrieve and share data and information more easily and quickly. Not only does this make compiling reports simple, it also saves time in the event of an audit and is priceless when it comes to disaster recovery.

Monitoring equipment integrity

Automated sensors, continually recording and sending data wirelessly, can help oil and gas companies get a much better insight into the condition of their equipment. Jake Davies explains how to do it

By Dr Jake Davies, marketing director, Permasense

Dr. Jake Davies, marketing director, Permasense

The corrosive effect of produced fluids, or the erosive impact of produced sand particles in oil and gas equipment is well understood.

But, information about the impact of these corrosive or erosive materials on the actual integrity of the asset is surprisingly light.

Traditional sand detectors can assess the presence of sand, but cannot measure the detrimental impact of that sand production as it occurs.

Established inspection methods can intermittently measure pipe wall thickness, but due to the associated costs and safety risks, manual inspections are carried out at infrequent intervals and can require production to be shut-in for the duration.
These solutions are unable to provide an accurate, complete and real-time picture of the levels of corrosion or erosion as these events occur.

As a result, operators only have a snapshot of their asset integrity. With this minimal information, it is almost impossible to predict whether their fixed equipment is good for another five months or another five years.

In order to protect asset integrity and mitigate the risk of an infrastructure collapse, conservative production rates and the associated drop in revenues are the norm.

Sensors

Imaging having automated sensors permanently attached to strategic points in the infrastructure to take continuous, robust measurements of remaining pipe wall thickness, and using wireless technology to send the gathered data for analysis at a central, safe or convenient location, offshore or onshore.

Operators would gain immediate insight into exactly what is happening in their fixed equipment at any given time.

There would be no need for guesswork. Data quality would be improved, since monitors are permanently installed and the frequency of measurement would allow operators to see the wall thickness of the equipment changing as it happens.

They would see how the infrastructure responds to all the unpredictable and generally uncontrollable variables at work within the upstream environment.

They could see what affect an unexpected change in temperature, flow rate or other uncontrolled external variable has.

They could assess what changes result from more intense flow rates, and understand the precise effects of erosion-mitigating and corrosion inhibiting strategies – and adjust them as necessary for optimum output.

These kind of tools, which give operators access to real-time data, can enable them to optimise operational decision-making, leading to improved asset uptime and increased profitability. In this environment, high-quality solutions can make a tangible difference to operator margins.

Operators are in a far better position to create a much more cost-effective programme for monitoring the integrity of their assets.

They save money on expensive manual inspections and have a long-term gain from enhanced asset reliability and availability.

Automated monitoring of asset integrity combined with appropriate data analysis also gives operators the confidence to drive their assets harder within the appropriate parameters, for potentially enhanced revenues.

How to build a ‘digital asset’ - AVEVA

Having a 'digital asset' describing a physical asset means you have all the digital information about the physical asset in a way that it is easy to access, says AVEVA's Harald Gunnerød

The ‘digital asset’ concept is about managing the all the Lifecycle Information (LCI) concerning the plant and to make sure it is available to the right people at the right time.

It is about making large amounts of information possible to understand and connected to relevant information across disciplines said Harald Gunnerød, senior account manager with AVEVA Solutions, speaking at Digital Energy Journal’s Stavanger conference on December 9 2014, “People and Offshore Engineering Data”.

A ‘digital asset’ should be a useful tool to help you work out how to, reduce engineering time, reduce plant downtime and and increase visibility for the operators and EPCs. Good access to correct information will reduce errors and the likelihood of accidents, he said.

The information is aggregated together, and continually evolves along with the plant the information is describing.

The information can be presented in a WEB portal, it is live data based on the actual “as built” information and grouped logically. As an example the datasheet of a valve can be linked to both the P&ID, the equipment list and the 3D presentation allowing the user a holistic view of the data concerning the item.

The ‘Digital Asset’ does not need to reside in AVEVA software. The portal might link to document management software and other company databases. The important part is that the information is available, and that we know the quality of the information, he said.

What data you need

When building a digital asset, you first need to figure out what data you are going to need in a lifecycle perspective.

In the brownfield area the digital information might be missing or obsolete. In this case you have to assess what you already have for the plant, find out how to capture the remaining information, and then repurpose it for operational use. Great developments has been done in the area of 3D scanning and the possibility to work with the data captured.

You have to establish what data you are going to manage, how to store it, and make sure it is accurate. Secondly how you will make the information available as a single source of truth for people who want to know about the operated condition of the plant.

"We need to make sure the digital assets we are building are consistent and includes the necessary information. That leads to the importance of having the class library defined, such that we can assess the quality of these master data that we are basing these decisions upon."

The processes of developing the access to a digital asset needs to be pragmatic and non-intrusive.

"Clearly this isn't just a software solution, it requires defined processes and governance. It also requires commitment from the organisation, the people that will actually do the work"," he said.

Often a further required step is developing data standards. "This then becomes the minimum tier for new information that's been added to the asset," he said.

AVEVA has worked within this field for a long time and have suggestion and solutions for many of the challenges discussed. Watch the video from the presentation and feel free to contact us.

See the talk on video at
www.d-e-j.com/video/1322.aspx

Why we fail to manage control system software

Control system software management processes in the oil and gas industry often fail due to lack of corporate support, responsibilities not enforced, lack of deployment support, lack of training and poor vendor inclusion, writes Christopher Goetz

By Christopher Goetz, director, Kingston Systems

Christopher Goetz, director, Kingston Systems

The oil and gas industry, specifically drilling, has come to recognize that managing software installed on Automated Control System PCs and Programmable Logic Computers is a critical engineering practice to avoid Non-Productive Time (NPT) and lost time injuries.

This comes in the form of Software Management of Change (SMOC) processes, procedures and policies.

These SMOC steps are now commonly identified by equipment owners as vital in maintaining the integrity of the software code and security of the control systems from inadvertent code regression or cyber threats like STUXNET.

However, in our review of how they are implemented on old and new rigs around the globe, we have yet to see a successful deployment.

Here, we will examine five of the most common reasons that Kingston Systems sees as the failure of SMOC to take hold, leaving the rig vulnerable to costly NPT.

Lack of corporate support

Consistently, we see that corporate management is quick to add work load and requirements for activities, but slow to add funding and technical or service support for the key policies and procedures that must be in place for SMOC to take hold.

This lack of a clear mandate sends a clear signal to maintenance crews. Something akin to "Figure this out on your own. It needs to be done, but we won't help. If you mess up and we have a software or cybersecurity incident it will be you that gets the attention."

A defined corporate mandate with funding and support for the initial design, rollout and long term maintenance of SMOC is the solution.

Responsibilities note enforced

As the SMOC gets little attention from corporate management, the defined roles and responsibilities carry little weight in the field.

While all field personnel have a defined role in SMOC, in practice, these responsibilities are ignored and the job falls on to the head of a single individual. And often the role is taken on board with resentment due to the poor role definition, support and training.

Thus, the work load becomes unmanageable, and it is poorly and inconsistently applied. Kingston Systems has seen wide variance in execution levels between facilities and even between crews on a single facility. A cultural adjustment is required to make SMOC work. This requires a team or inclusive deployment and support plan. It is not something that can be established overnight.

Deployment support

As mentioned, the change cannot happen overnight. As with any new process there is a deployment front-end load. A large amount of activity that must be done before SMOC can be effective.

To be done correctly, the contractor should have a dedicated deployment team that attacks this front-end work load, provides training and coaching and gets the system up and running.

This does not seem to happen. Rather, the new SMOC process, roles and tools are emailed out and the expectation that SMOC be in place immediately. Corporate is often surprised when one year later there has been little positive motion and SMOC is still not functioning. Deploying SMOC is a larger endeavor than realized. The cultural and personnel needs have to be addressed as part of the deployment plan.

No training

A consistent gap Kingston Systems sees in audits is the lack of even the most basic training to relay the who, how, what and whys of SMOC. Today, the rigor of following SMOC does require a cultural change and does require that all team members understand their role in making the process work.

The lack of training further supports the lack of corporate and deployment support. And again without these the roles and responsibilities are misconstrued, the application becomes weak and inconsistent. An inconsistent SMOC program falls critically short of meeting its mission of protecting code and securing hardware.

Vendor inclusion

We consistently see that vendors of the control system have been slow to support the owners in their efforts of SMOC deployment.

This hesitance or passive resistance is surprising considering that the vendors seem to consistently be the primary source of regression and cyberattack through their direct actions with their own equipment.

As a bright spot in the discussion, this seems to be changing. Several vendors have started presenting better SMOC solutions, and have been more open about sharing versioning and other components with drilling contractors and equipment owners.

To help overcome some of these issues Kingston Systems utilizes a simplified online software version control register. This interface encompasses all of the key elements required for SMOC in a simple package that supports all vendor systems and helps address the training gap through its interface and training content. However, it is only a tool.

A Software MOC program cannot be successfully implemented without addressing the five failing points we have identified.

Christopher Goetz is the founding director of Kingston Systems and has 20 years of oil and gas experience to the field of rig auditing and operations. Based in Houston, Kingston Systems works with Operators and Contractors to review, build and rollout successful Software MOC programs on facilities and rigs.

Iceotope - liquid cool your computers

By liquid cooling your high performance computers, you can get a lot more computer processing power for the same space and cooling power, reckons UK company Iceotope

Iceotope has developed a liquid cooled computing infrastructure which the company believes makes it much cheaper to cool a room of high performance computers.

The oil and gas industry is no stranger to liquid cooling of course, but it has not been used extensively for cooling its vast estates of supercomputers necessary for oil exploration.

As computers have more powerful CPUs and bigger memory footprints, Iceotope believes that we are reaching the limits of the amount of cooling which traditional air-cooled computer designs of today can handle.

So high performance computing system operators will be looking for ways to increase performance density without increasing the corresponding energy use.

Some oil and gas explorationists are starting to use liquid cooled supercomputing clusters, Iceotope says. CGG is reported to be using liquid cooled computers in one of its data centres.

In a liquid cooled environment, performance enhancements can be more easily achieved as the CPUs can run at their maximum frequency for sustained periods of time without failure from overheating, Iceotope says.

Iceotope can cool up to 60kW per rack and provide 40.8% better performance per watt compared to air cooling, the company says.

University of Leeds

An Iceotope system has been installed at the University of Leeds' School of Mechanical Engineering, where a number of PhD students and researchers specialising in thermofluids and cooling are using the system.

Dr Jon Summers, a senior researcher in Leeds' Institute of Thermofluids, noted that the liquids can carry on cooling for much longer than air in the event of any power disruption.

Dr Summers found that the system required 88 per cent less cooling power than the previous indirect liquid cooling system the Institute was using. It could capture 89 per cent of the energy at 45 C which could be used for building heating elsewhere.

The system

The liquid cooled servers look like any other air-cooled computer, except the systems have no fans, so are nearly silent in operation.

There are various sorts of liquid cooling for servers. With "indirect" cooling, the server is cooled by air, and then the air is cooled by water. With "direct" cooling, the liquid is circulated directly around specific components, the rest cooled by air. With "total" liquid cooling, all active components are cooled by liquid. Iceotope offers "total" liquid cooling.

The technology utilises two different coolant loops.

Each blade computer is sealed and immersed in a special fluid (the 'primary' coolant), based on Solvay and 3M products, which flows around the computer via natural thermal convection.

The heat from the primary coolant is absorbed in a secondary bespoke coolant, which has twice the heat capacity of mineral oil and very low viscosity.

Heat from the secondary coolant can be transferred to hot water if required, and used in the building central heating system. This has already been successfully implemented in some Iceotope installations.

Harris CapRock - Ku, Ka, C, one antenna, one service

Communications company Harris CapRock Communications has launched a new offshore satellite communications service, Harris CapRock One, which provides Ku, Ka, and C band satcom with one antenna, one price and guaranteed service availability

"We've suffered from the best effors for long enough" - Tracey Haslam, president, Harris CapRock Communications

Oil and gas communications company Harris CapRock Communications has launched a new offshore communications service, "Harris CapRock One", which can automatically switch between different satellite communications bands and wireless communications in order to provide the best service.

The user is given a single price for the satellite connectivity, which they pay no matter which satellite the data is being sent through. Harris CapRock guarantees to provide 99.999 percent service availability, for an agreed data speed, anywhere in the world, for that price.

The service can also include radio communications where available, such as microwave and 4G.

A company can be given security of communications service, promised at 99.999% uptime, rather than a vague promise of 'best effort'.

"This is a step change for us," says Tracey Haslam, president, Harris CapRock Communications. "We've suffered from best efforts for long enough."

"Harris CapRock is going to drastically change the way our clients experience managed communications services," she says.

"People want to have what they have onshore when they are offshore, and they want to have it through a single device," she said. Offshore operators are typically asking for 5mbps at the moment, Ms Haslam says. "A lot of them want 10 mbps, but they can't afford that price. So they stay at 5."

Antenna

As part of the service, Harris CapRock has developed a new 2.4m antenna which can communicate in C, Ku and Ka bands, and switch band without any onboard technician required.

This means that you don't need more than one satellite antenna. The days of offshore platforms having four different antennas to communicate with different satellites, all using precious deck space, can be over.

The antenna uses materials originally developed by Harris Corporation for military applications.

This is the first time an antenna has been developed which can communicate by C, Ku and Ka band, Ms Haslam says.

Smart box

The antenna is connected to a special 'smart box' called Intelligent Communications Director (ICD) which can work out which satellite to use, based on an internal GPS and database of the various satellite network footprints.

The device can also take into account data speeds, latency and cost when routing the data.

This means that a drill ship or rig can use the faster Ku / Ka band services while it is under their coverage, as most offshore oil producing regions are, but move to C band coverage while it is being re-positioned across open ocean. The switch happens without the crew noticing.

The data can also be delivered via radio (wifi/cellular), or fibre communications where they are available, for example when a vessel is in port, or microwave (long range line of sight) links are available.

"Right now, people will often have a satellite service on when they're in range of a LTE [4G cellular] signal," she says.

The system can automatically switch to a different satellite if it loses connection for a physical reason, such as an offshore platform sitting between the drilling rig and the satellite.

The first antenna which can communicate using C, Ku and Ka band.

It can automatically be configured to use new satellite services as they become available.

It is possible to set up multiple networks onboard with different access rules, for example you can have one perhaps high cost, super reliable service for real time data, and another for crew personal communications.

Satelites

Harris CapRock uses a non-geostationary Ka band satellite constellation, operated by O3b Networks, which means that the satellites are moving in medium earth orbit (MEO) at all times, and so the satellite antenna needs to track them as they pass overhead instead of tracking with a fixed point on earth.

Because they are closer to the earth than geostationary satellites, the data latency (time for data to go to the satellite and back) is shorter, which means that they enable much smoother web browsing or working with software hosted remotely.

The C band satellites are geostationary, so the satellite antenna needs to make sure the antenna is pointing directly at the satellite, as the vessel rocks on the waves.

The data analytics funnel

The way the oil and gas industry works with data can be depicted as a funnel, with raw data going in one end and usable data coming out of the other, writes Ketan Puri

By Ketan Puri, enterprise architect for big data, Infosys

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I would like to depict oil and gas data analytics using a funnel.

Just as a funnel is used to channelize fluids and do processing like filtration, the data funnel depicts the controlled processing of data.

The data flows through the funnel, get channelized as desired and processed using various analytical models. The data can be simultaneously be fed in to other funnels for further processing.

Data cannot be analysed in its raw form. It needs to undergo lot of pre-processing before real analytics techniques can be applied.

Pre-processing may involve multiple operations on the datasets like rule based extraction, aggregation, splitting, transformation, filtration, truncation, noise reduction and much more depending on the business need.

The data logically need to traverse through multiple funnels before it can be analysed. This journey of the data from it raw form to analysable state is called Pre-processing.

The analytics funnel can be applied to streaming data (data in motion), staged data (data at rest), or to the data from various other funnels. The funnels can also re-stream the data and apply advanced analytics models. It all depends upon how we configure the properties of the funnel.

From purely analytics perspective we can divide the analytics funnel into three zones of data exploration / discovery, data modelling and analytics,

Data Exploration / discovery

This zone provides ability to explore the data at rest and identify data patterns. It allows the user to connect to multiple data stores with ability to plug and play various visualization tools. The key objective of this zone is to gain an understanding of the data sources, data sets and discover patterns that can help the business to gain deeper insights.

Data modelling

This zone leverages the understanding of the data from the exploration and discovery zone and extract the key patterns that help the business to meet their need. These patterns are used to create analytical models.

The models can be estimation models to better understand the business processes, or predictive models to forecast business behaviour under given set of parameters or prescriptive models to recommend actions and proactively respond to business situations. The key objective of this zone is to develop analytical models catering to a specific business need and identify associated data sets.

Analytics zone

In this zone the analytical models developed in the modelling zone are executed. The models can be deployed on the data lake to extract value from both the streaming data or from the data at rest.

This zone also provides the ability to perform pre-processing of the data and responding to the business with the insights.

Finally the insights are fed back into the data lake providing business a better understanding of their data. The insights are then validated against the business requirements.

The process repeats continuously churning and refining the data in the data lake. In due course of time with substantially large data sets these models evolve into predictive and prescriptive analytical models directly feeding into the business processes optimizing the processes and adding value to the business in multiple ways.

Processes

Here are some oil and gas processes which use a data funnel:

Oilfield exploratory analysis provides seismic data analysis creating the basis for exploratory drilling

The **appraisal management process** provides key inputs from the reservoir data analysis leading to drilling appraisal wells

The **drilling and completion process optimization** provides preventive techniques for blowouts, determining well bore trajectories for maximum reservoir coverage and avoidance of potential NPT.

Other processes include **oilfield production optimization** and **performance forecasting techniques.**