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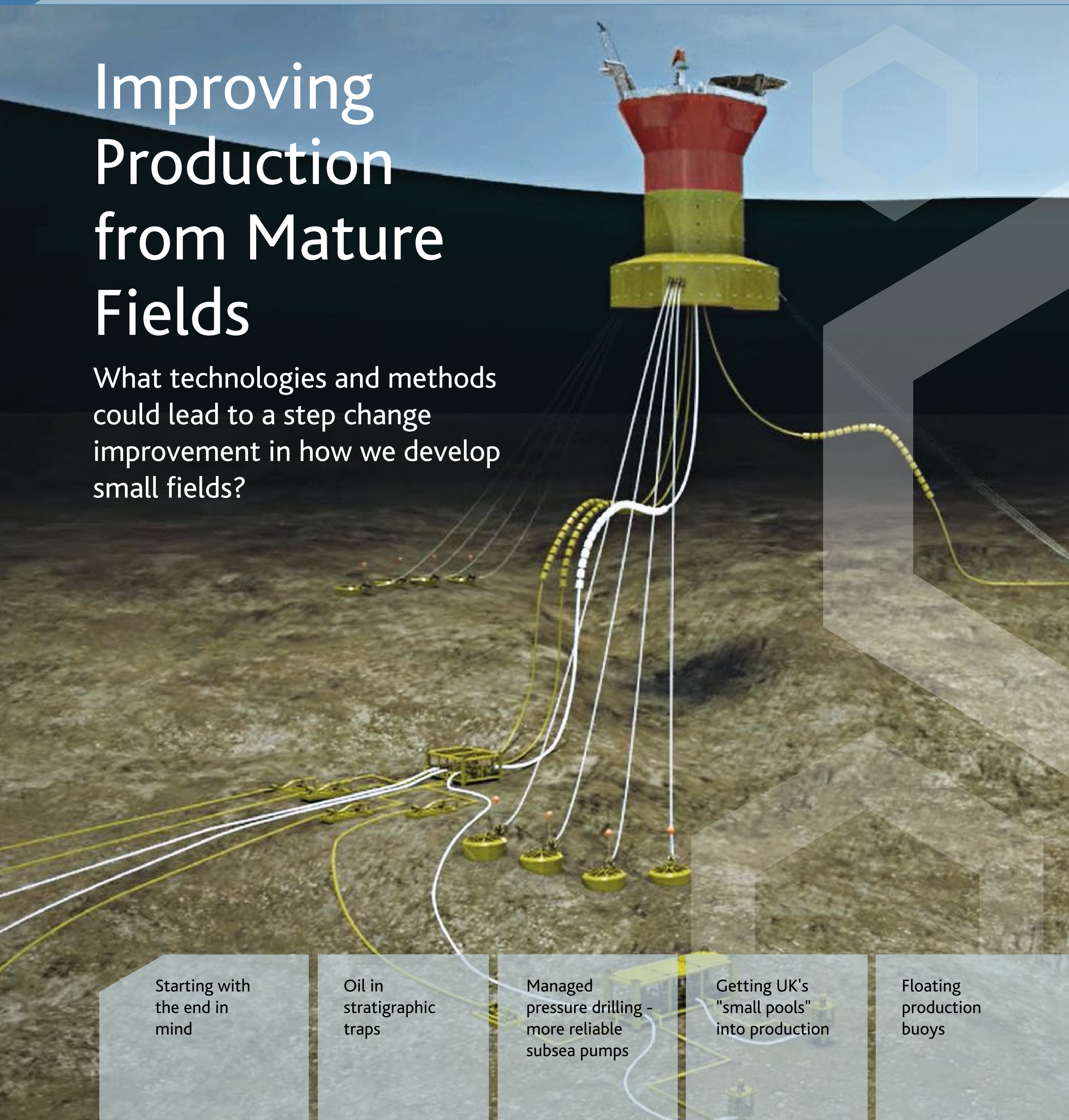

Improving Production from Mature Fields

What technologies and methods could lead to a step change improvement in how we develop small fields?

Starting with the end in mind

Oil in stratigraphic traps

Managed pressure drilling - more reliable subsea pumps

Getting UK's "small pools" into production

Floating production buoys

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Improving production from mature fields

For years, the main focus of the oil and gas industry was discovering and building new developments. Now the industry is increasingly putting its energies into working out how to get more out of the "mature" fields – the ones it has been producing for decades. But there are some great ideas around about how this should be done

The main focus of the oil and gas industry – in UK, Norway, Malaysia, the US, and many more places around the world – is working out how to get more oil from oilfields which have already been producing for decades.

This is something of a culture change for an industry which has always been most excited about the new discoveries and the big new developments. But some of the industry's brightest commercial people, financial people and technical people are applying themselves to the problem – and you can see some of the results in this report.

Perhaps one of the most interesting ideas is 'starting with the end in mind' – where instead of designing faciltiies around the reservoirs we think we are discovering, we try to work out which small reservoirs we might be able to get into production through excess capacity in our existing facilities – and design the project around the margin that we need.

We also look at managed pressure drilling – which basically means drilling with less pressure in the drilling fluid, because you can immediately increase the pressure if you need to. If this can be done reliably, it could be a pathway to much simpler, lower diameter, and so cheaper wells. Wells are a major cost of getting a 'small pools' online.

Other interesting ideas are the 'factory' approach to offshore development – basically involving much more standardisation and waste minimisation – and ideas for new financial vehicles, which take the debt of a new development off the parent company balance sheet.

We look at the UK's "small pools" effort, to try to improve the business case for getting small reservoirs in development and connected to existing infrastructure.

Companies are considering lower cost floating offshore buoys, with very basic processing, but able to provide power to a subsea well below for pumping and injection. They are designing equipment so it can be easily moved to another site, rather than dismantled, when the life is up.

Companies are also planning new offshore developments so that they are less expensive to decommission. Since decommissioning costs are included in the 'net present value' calculation of new developments, reducing decommissioning costs can mean improving the net present value.

The subject of 'mature fields' is a vast one, involving just about every sector of the upstream industry. Approaches were selected for inclusion in this report based on promising a step change, or a substantially new way of doing something, rather than incremental improvement.

io – developments “starting with the end in mind”

io oil & gas consulting (io), established in 2015 by GE Oil & Gas, now Baker Hughes, a GE Company, and McDermott, helps oil and gas operators plan developments “starting with the end in mind”, as a means of rapidly screening various development options and making the best decisions.

io, a global business headquartered in London, helps oil and gas operators plan their field developments bringing its integrated capabilities, io start with the end in mind and apply systems thinking, embedding a Decision Quality framework throughout. These holistic capabilities are harnessed to develop a field development plan, importantly including a business case, that establishes the best way to move forward, taking all possible factors into consideration.

io calls this holistic approach “starting with the end in mind”, to show that it is different from the usual way of planning the development of fields. It means starting with an idea of what success looks like. Then applying an integrated team from reservoir, wells and facilities, alongside commercial and strategic functions, to see if it can be achieved.

In the “starting with end in mind” approach, you build a single “holistic” team covering the reservoir and facilities encompassing the economics, then try out different scenarios to identify the best solution. No discipline controls how the project develops, and everybody works simultaneously, rather than sequentially – a real example of collaboration at work.

To understand why this approach is useful, consider that with mature field operations, operators are not starting from nothing. They typically have infrastructure which is old but capable of handling more hydrocarbons than it currently does, and a number of larger fields coming to the end of their productive life. They also typically have a number of smaller oil and gas fields not yet developed, which are not large enough to have their own infrastructure, but could be economically viable if they could use infrastructure which has already been built.

Operators have multiple factors to balance. The existing infrastructure and processing facilities may need to be decommissioned if it cannot carry enough hydrocarbons to sustain its operating costs. Perhaps the imperative is to push the decommissioning date as far into the future as possible.

Turlough Cooling

Some undeveloped fields will be larger than others, or be closer to existing infrastructure, or have less reservoir risk.

There are other constraints such as the maximum throughput facilities can handle, the maximum ‘head’ a compressor can generate, and the maximum flow through a well.

If there is a large number of wells, and variation in production rates from them, it adds to the complexity.

There are also many inter-dependent factors, such as the level of compression in gas lift impacting the oil flow rates, which impacts the revenue, and also impacts the date of end of field life.

There may also be aspects of the country’s tax regime and licence terms which affect the option with the greatest net present value.

Perhaps the fields are best developed in a certain sequence, completing the largest or most likely ones first, and planning so that production from a second oil and gas field comes onstream as the first one starts to decline.

Other options to consider can include infill drilling to access bypassed hydrocarbons, injecting water or gas into the reservoir to maintain pressure, or making modifications to the processing facilities.

The usual approach

The usual way that operators work out how to develop fields is usually based on a number of sequential processes, says Turlough Cooling, head of drilling and subsurface at io.

Operators build sophisticated reservoir models, with all the available reservoir data, which they ‘tune’ against the actual production and any new data.

This reservoir model is used as a basis for working out new locations to drill, and what the anticipated production from the new wells will be, and what new facilities are required to handle the hydrocarbons.

This work can take many years, including computer time running the complex simulations, and calculating the costs of building the necessary facilities. It must be done repeatedly for different drilling options.

A systems thinking approach

The “starting with the end in mind” approach is designed to come up with results which are just as useful in supporting decision making as the complex model, but solving it much faster.

A “systems model” can be built of the oil or gas field and its facilities, which people from the various disciplines can collaborate on simultaneously. Note however that this is not a software project – there may be software involved in the analysis, but the analysis is not something performed by a single piece of software.

Tim Highfield

No single discipline has overall control of the model. It is a joint decision making tool. Everybody understands their part of it and can check it is working logically and correctly, says Tim Highfield, Head of Developments with io.

This way, you can be sure that the end outcome makes sense to everybody in their respective functions, even though people are not necessarily able to understand someone else’s parts of the model.

The final result can be analysed in more detail in a higher resolution reservoir simulation, but only to give a second level of verification to the final option chosen, not to actually drive the decision making process.

“This approach of ours offers a more optimised model suitable to help maximise value, better allocate capital, especially with complex mature field operations, and accelerates operators’ decision making into days rather than weeks or months,” Mr Cooling says.

As an example, one undisclosed client wanted to identify better ways to operate a development with 250 wells connected to a number of different pipelines operating at different pressures. It had the option of using compression to improve production, but wanted to work out the best date and point in the system to locate the compressor and the compression power required. This problem was brought to io and it was quickly decided that a systems model should be built to solve this wicked problem.

The objective was to maximise net present value, not necessarily maintaining a production plateau. This is a balance between maximising revenue (linked to production) and minimising costs (spent on any modifications to the facility and compression).

Precise simplicity

It is important to get the right level of simplicity in the modelling – something which will give you similar results to a more complex model, but without over-simplifying.

For example, you might be able to understand production from 250 wells using a few well production depletion curves, rather than 250 curves.

"You can get something that's good enough to make decisions conceptually, and screen rapidly, rather than spending months studying different production cases using subsurface models" Mr Cooling says.

Multi-operator models

The same approach could be extended for decision making where many different operators are involved, finding the best overall outcome.

It enables the participants to avoid a situation where each party is fighting for their own optimal outcome, to the detriment of the outcome for the whole system.

This could be performed for parts of the North Sea, with perhaps the Oil and Gas Authority advocating this type of model, Mr Highfield says.

If confidentiality is an obstacle (rightfully operators do not like to share their strategies with their competitors), a way around is for operators to appoint a trusted consultant to make decisions, whereby the consultant can see individual operators' plans and strategies, but does not share them with others.

This is the way building surveyors work in the UK, where a surveyor is appointed by both sides in a dispute to work out the right way forward, rather than each side appointing their own surveyor and the surveyors arguing on behalf of their clients.

Need to do it now

The UK oil and gas industry has time constraints in that much of the offshore infrastructure will be not be viable to keep in operation within a few years, due to a lack of hydrocarbon throughput, unless more 'small pools' are put into production.

Furthermore, as some infrastructure is taken out of operation, there can be a cascade effect with more small pools being non-viable to keep in production because there is no suitable infrastructure nearby.

A lot of the delay is due to lengthy decision making processes, perhaps due to the complex models which operators use to establish the best way forward. Using 'systems models' could be considerably faster, Mr Highfield says.

Exploration - is there much more oil in stratigraphic traps?

Most oil fields developed to date are structural traps, easy to identify through seismic. But maybe there are many more oilfields not yet discovered in stratigraphic traps, which cannot be easily de-risked with seismic, but where electromagnetics can play a big part, said Daniel Baltar of Fox Geo

Until now, oil and gas exploration has been extremely focused on structural traps, which are easily identified on seismic data.

However there may be much more oilfields yet to find in stratigraphic traps, where the oil is trapped between different rock layers. These are very hard to de-risk using only seismic, because seismic cannot easily tell if there is a trap and does not provide much information about the fluid content, said Daniel Baltar, partner in Fox Geo and formerly Global Exploration Advisor for EMGS ASA. Hence stratigraphic traps can be in an early stage of creaming because they have been typically regarding as high risk (likely to contain brine) by the industry, hence there is potential for large discoveries even in mature areas.

Daniel Baltar

But this is exactly where electromagnetics can play a part – because brine conducts electricity (is less resistive) and so brine filled sediments show up on an electromagnetic image as low resistivity bodies.

The oil and gas industry's experience with unconventionals illustrates that it is possible to change things, but change typically requires "changing several things at the same time", he said. So if we want to explore high potential stratigraphic plays, we can't expect to succeed by using the same methodologies that have not succeeded in the past.

How CSEM works

Controlled Source Electromagnetic (CSEM) surveys generate an electromagnetic field through the subsurface, and measure what comes back using electromagnetic receivers.

Most of the material in a sedimentary basin except salt water is highly resistive (not conducting electricity at all). Oil and gas are also resistive.

Hence resistivity can be a great indicator of brine presence or absence, and of the amount of brine not present in the sediment. Hence large and thick hydrocarbon accumulations will show up in the CSEM as high resistivity bodies.

Working with CSEM

Geoscientists have used this CSEM data to evaluate and better understand different drilling options which have already been identified with seismic. In the jargon, they can make a better 'creaming curve', or better order to drill the prospects, with the best looking one first.

An example is on Wisting, a discovery in the Barents Sea in Norwegian waters. The main play is an early Jurassic reservoir in rotated fault blocks. The main risk of the play was a lack of seal.

Before using CSEM, most oil companies had identified the presence of the wellknown play, but had deemed it too risky given the high seal risk owing to its shallow burial depth. But with the CSEM, it was possible to see that there were differences in the resistivity in the fault blocks, indicating some them could be hydrocarbon filled, and lowering the seal risk.

Subsequently they the play was drilled and there were 3 oil and gas discoveries in a row, in the right size order, largest to smallest. “That is a very outstanding thing to do, extremely hard to do in reality” he said.

Another example was the Kayak field, a discovery made by the Norwegian oil company Statoil near a dry well in an unproven play with a strong stratigraphic component. It is very likely CSEM has been used in the decision to drill this prospect, it had been discussed by EMGS in publications several times before. Drilled in 2017, it found 40m barrels. Statoil has not yet found the oil water contact so they don’t know how large it is, Mr Baltar said.

CSEM data processing is much advanced over the past 15 years, current CSEM inversion is equivalent to seismic full waveform inversion.

“You can place things in depth and get an image you can compare to your seismic,” he said.

One challenge with EM is explaining to companies that it does not give them a 100 per cent likelihood of success, but when the typical chance of success in exploration wells is as low as 15 per cent, a small de-risking is enormously valuable.

One of the biggest barriers is that most oil and gas companies are not used to integrating CSEM in their decision making, he said.

Mr Baltar started a company called Fox Geo to provide a range of services around using electromagnetics in exploration.

Reducing drilling costs with managed pressure drilling – and better subsea pumps

Managed pressure drilling can help reduce the costs of building a well, if it means that the ‘safety margin’ of pressure in drilling fluids can be reduced, and so the well drilled with less pressure, and so constructed with a simpler design. More reliable subsea pumping could be a key component to broader market acceptance

Managed pressure drilling is not a new technology, although it is not widely used. The basic idea is that you control the pressure of drilling fluid more precisely. This can be a way to reduce drilling costs, if it means that the well is drilled with fluids under lower pressure than with conventional drilling – and this is a pathway to a much simpler and slimmer well construction.

One problem with managed pressure drilling for subsea wells (until now) has been the complexity and low reliability of the subsea pumping equipment. But a Norwegian company, Fuglesangs Subsea, has developed a new pumping system which could be much more reliable, and so make managed pressure drilling much more viable.

Fuglesangs estimated that overall, managed pressure drilling can lead to a 30 per cent reduction in the overall cost of a well. Considering that constructing a well can be half the total cost of getting a “small pool” into production, this can mean reducing the total cost of the development by 15 per cent, perhaps a big enough difference to get many marginal projects sanctioned.

Bear in mind that hydraulic fracturing, a technology which transformed the entire industry and the economy of North America, also involved a number of different technologies and concepts to be introduced at the same time. Perhaps “bundle of new concepts” is the way the oil and gas industry makes big steps forward.

Explaining managed pressure drilling

The basic idea of managed pressure drilling is that the driller is able to continually adjust the pressure in the drilling fluid, or “mud”.

The main purpose of drilling fluid is to stop any high pressure reservoir fluids from dangerously coming up through the well out of the subsurface, as they did in the Deepwater Horizon disaster, or in the famous ‘gusher’ images of early oil wells. There is a column of fluid in the well, which creates a pressure outwards from the well, which balances pressure from reservoir fluids trying to get into the well and out to the surface.

The critical parameter is that drilling fluid pressure is in the window between the frac pressure and pore pressure. If mud pressure was higher than the frac pressure, mud would force the rock open. If lower than the pore pressure, reservoir fluids would enter the well.

In a conventional offshore production drilling scenario, the riser is always full of mud with cuttings, as the mud flows down the centre of the drill string (powered by traditional topside piston pumps) and mud with drill cuttings (sand / rocks) flows into the riser casing annulus and is returned to the surface).

In an Managed Pressure Drilling (MPD) system with a pump , the riser column is connected to the suction side of the pump. Stopping the pump means that the riser fills up. Starting the pump and evacuating mud through a separate return hose to the surface, reduces the level in the riser and thereby reduces Bottom Hole Pressure. A video explanation from EC Drill is online at https://youtu.be/oDwjBLjfjqU

This means that it is possible to drill with mud at a lower pressure downhole than would be normally used, safe in the knowledge that if higher pressure was suddenly needed (for example if the well encountered a high pressure reservoir), higher mud pressure would be immediately available.

There are big potential financial benefits to this. Normally wells are drilled to a certain depth, then casing (metal tube) is put inside the well to stop the well from collapsing, and then the drilling continues deeper at a narrower diameter, inside the first well casing. This results in the “telescope” well design.

A well may only need to be 6 inches diameter at its deepest point, but the start of the well is drilled at a much larger diameter, to allow for many step-in stages. The bigger the diameter of the well, the slower the drilling and the higher the costs.

If managed pressure drilling means that there is less well-bore damage (because the drilling mud is at lower pressure), perhaps there won't need to be so many step-in stages, and the drilling could be done at a smaller diameter to begin with, ultimately leading to a much less expensive well. The drilling can be made with less stopping and there is less cementing work involved, another source of cost and risk.

Managed pressure drilling is also a great help when drilling through uncertain geology, when you don't know what pressures you may encounter. Rather than have mud at a much higher pressure to create a safety margin, you can just apply the higher pressure immediately if you ever need it.

It means that you do not need such a big riser (because mud is not being continually pumped from downhole and back up to the drilling rig through the riser).

Subsea pump reliability

One of the biggest issues with managed pressure drilling on offshore wells is the complexity of the pump, which must be on the seabed (in order to be able to pump drilling mud up the riser to increase pressure). The pump must be variable speed (to achieve different levels of pressure). It must also be able to pump rock fragments in the drilling fluid (the secondary purpose of the drilling fluid is to bring drill cuttings out of the well).

Fuglesangs Subsea of Oslo was invited to develop a new type of subsea pump for this purpose in 2009, where one of the test criteria was to pump 1000 metric tons of rock up to 50mm in size.

The company had previously made pump systems used in the mining industry for 25 years but was new to oil and gas. It developed a 500 kW centrifugal pump, Mudrise™, for the task, where the pump action is through a rotating impeller, like a propeller on a boat. Previously mainly only positive displacement and disc pumps had been used or trialled for this.

So far 16 of these pumps have been sold to various subsea mud pumping applications, and pump-based MPD systems are in use by Statoil on the Troll field and Lundin in the Barents Sea.

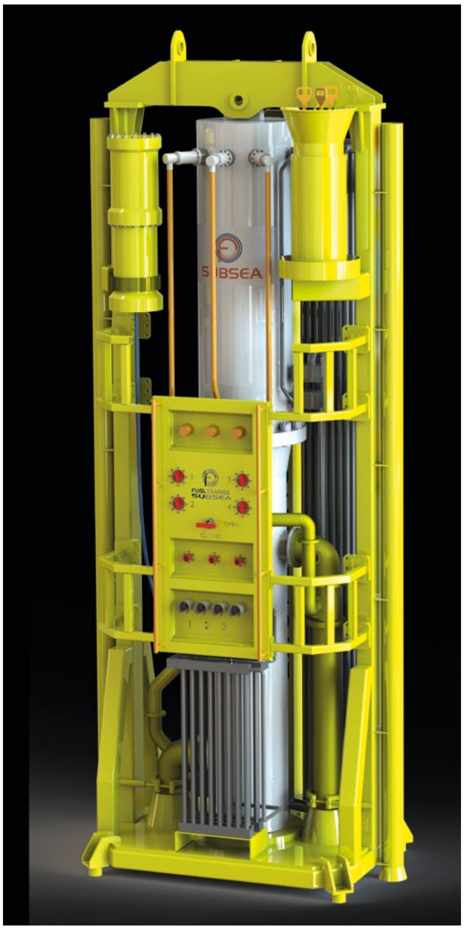
The biggest source of failures (70 per cent) on subsea pumps is the mechanical seal, which prevents mud from leaking out and stops water from getting inside the pump, says Alexander Fuglesangs, founder and CEO. The pumps have complicated systems with different fluids, where the fluid acts as a sealing barrier.

The company has taken a "very disciplined and systematic" approach to understanding the failures, why they happen and how to reduce them. For its new Omnirise range of pumps, the company is developing a way to use magnets to transfer power to the pump shaft, creating a hermetically sealed pump replacing the mechanical seals and barrier fluid system.

Mr Fuglesangs emphasises that a traditional subsea pump intended for permanent installation on the seabed (Mudrise™ pumps are only intended for campaigns of 1-12 months at a time) can have a total lifecycle cost of north of NOK 1bn (US$128m), of which only 10 per cent could be the purchase cost – there are also costs of installation, operation, energy, maintenance and repair, downtime (due to failure or to maintenance) and disposal.

Oil, Gas and Water Injection pumps

Fuglesangs is building on its subsea pump experience to develop a subsea pump which could be used for oil, but without requiring a complex "variable speed drive" on a platform, to manage the power supply to the pump, as other subsea pumps do. It also does away with the need for fragile mechanical seals and complex barrier fluid systems.



Fuglesangs' "Omnirise" subsea centrigual pump

Companies have used electric submersible pumps (ESPs) in wells for many years to pump oil out of reservoirs. These need to fit inside a well at its smallest diameter point, so are long and thin, typically 20-50m long. They have complex couplings, bearings and seals, making them very fragile. They have also shown to be less suitable to horizontal wells.

The variable speed drives, with associated process, control and barrier-fluid equipment, weight between 90 and 500 tons. The variable drive changes AC input current, to DC, and then to AC again. The system generates a lot of heat and so needs its own cooling. The space and weight implications of such equipment is a considerable limiting factor to more widespread use of subsea boosting pumps, even if they are proven to be the most effective tool in the "IOR Toolbox".

With the Fuglesangs pump, the speed variation is managed within the pump itself, using a technology called "hydrodynamic coupling". The system is based on a Voith Torque Converter with an impeller and a turbine. The rotating shaft from the pump motor drives the impeller, which then drives the hydraulic liquid through the turbine, which drives a second shaft. The system can be adjusted real-time for how much of the power of the first shaft transfers to the second.

The first full pump, called "Omnirise Single-Phase Booster", under development with Statoil, AkerBP, Lundin and NOV and will be in 'manufacturing' during 2018, with factory acceptance testing starting in early 2019.

It aims for a CAPEX of under 50 per cent and OPEX of 20 to 80 per cent of other pumps on the market.

Oil companies have said it can reduce production cost by $5 to $15 a barrel.

Fuglesangs was founded in 1855, originally making sleeping bags, and has been in the same family ownership for 5 generations. It started making pumps in 1982. The subsea division Fuglesangs Subsea was spun out as a separate company in 2013.

Getting the UKCS "small pools" in production

There are a number of initiatives in the UK oil and gas industry to try to make 'small pools' (small reservoirs) in production. These were discussed at a forum organised by the Oil and Gas Technology Centre in Aberdeen in January at the "Subsea Expo" event

Oil and gas analysis firm Wood Mackenzie has done a study of all the 'small pools' identified by the UK's Oil and Gas Authority, to help assess the overall business opportunity. The study was made in late 2017.

Mhairidh Evans, principal analyst, Wood Mackenzie, notes that there have been changes in the sort of projects the industry is looking to develop, which favour small pools, such as a bigger interest in short cycle, quick payback projects, and the 30th licensing round (closed November 2017) having a focus on mature areas of the North Sea.

Wood Mackenzie counts 110 infrastructure "hubs", which small pools could be connected to (i.e. existing offshore platforms). 50 per cent of these have less than 25 years remaining. By 2025, only 10 per cent will have 25 years remaining. This is not due to the platforms becoming old and unsafe, it is because there is not anticipated to be enough hydrocarbons flowing through them to make them viable to keep operating. So that creates a big incentive and need to get small pools onstream.

Wood Mackenzie reckons there is 3bn boe total in 275 undeveloped small pools, of size 3-50m boe.

Of these, 2.5bn are within 25km of 'qualifying infrastructure' (i.e. infrastructure that could be used).

If projects are only given a go-ahead if they are profitable at $50 a barrel, it thinks 1.5bn of this 2.5bn is viable. A further 300m barrels would be viable if companies plan around a $65 oil price.

If some of the ideas about "Tieback of the Future" being developed by OGTC (see next talk) are implemented, there could be a 400m boe available.

There were about 1.1bn boe of small pools put on offer in the 30th licensing round, including some smaller, or high temperature high pressure discoveries, many discovered "decades ago".

The beneficiaries of these projects would be the companies taking out licenses for blocks containing the small pools – and the companies who own the hubs. This includes oil majors, independent and private equity.

There are 37 'hubs' which could benefit from these small pools, identified by Wood Mackenzie.

There are many other factors than economics to get projects to go-ahead, including technical issues and other commercial factors. There may be ways to reduce the development and abandonment capital expenditure.

If the UK develops small pool expertise it may be exportable. Wood Mackenzie calculates that 25 per cent of the world's viable 'small pools' are in the UK North Sea, but the top 10 countries in terms of recoverable resource, largest to smallest, are Norway, UK, Nigeria, China, Malaysia, Australia, Indonesia, Vietnam, Canada, India.

Tie-back of the future

The Oil and Gas Technology Centre is driving a project to develop a 'tie-back of the future', focused around 6 features – re-usable pipelines, less onerous 'safety zone' requirements, re-usable control systems, advanced flow management, "plug and play" equipment, and a general theme of "remove, refurbish, re-use".

The aim is the half both the cost and the time required to develop small pools.

So far, 25 operators, supply chain companies and technology companies are involved in the 'tie-back of the future' project. OGTC has invested £250k in engineering work. As of February 2018, it has 5 technology projects underway, 13 technology proposals in the pipeline and 6 integrated studies completed. Specific ideas included so far include mechanical hot taps, mechanically connected pipelines, multi-use pipelines, integrating renewable energy systems and unmanned facilities on platforms supporting the wells.

Graeme Rogerson, projects manager with OGTC, believes that all of this could reduce the cost of tie-backs by as much as 50 per cent.

There are many challenges, for example if the industry is re-using equipment, then there may be an increase in risk. It might require a new contractual and commercial model.

It may be possible to use 3D printing techniques and other methods to make subsea equipment lighter but without losing strength, taking lessons from the aerospace industry.

Further information about the project is online at Theogtc.com/tiebackofthefuture

Graeme Rogerson, projects manager with OGTC

Safety zones

One cost reduction idea is that it may be possible to reduce the amount of metal infrastructure placed on the seabed to protect subsea infrastructure from fishing nets – by simply asking the fishing industry to fish somewhere else.

Subsea companies also bury flowlines to protect them from fishing nets, another major expense that may be avoidable, said Iain Craik, development engineering team lead at Lloyd's Register.

The project team has been in discussion with the Scottish Fishermen's Federation (SFF) about how it could work.

A challenge is that 60 per cent of vessels catching fish in UK waters are not British vessels, he said.

Premier Oil – unmanned operations

Premier Oil is developing a number of facilities in the North Sea with reduced manning, as a way to reduce costs, said Robin Simpson, Development Projects Manager, Premier Oil, speaking at the Subsea Expo "small pools" event.

Its oil platform on the Solan field, West of Shetland, was designed to be operated unmanned. People have stayed on the platform to get the systems commissioned (up and running). It took about two years to get to the point where it can operate unmanned. Production started in 2016.

Premier designed the platform to operate unmanned, initially planning to be unnamed within a year of start-up. According to the initial idea, the manned work would be just for commissioning systems, not operating them. It has taken a little longer. "2 years on, we've completed the water treatment operation, we are on the cusp of it now," he said.

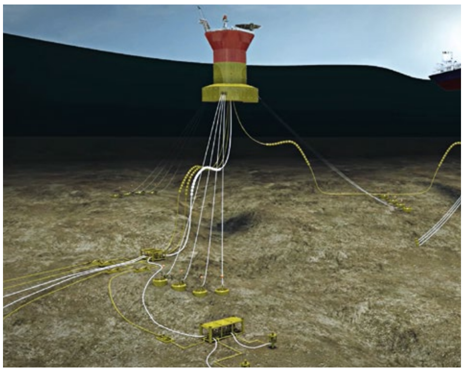
Its "Babbage" gas platform in the Southern North Sea is now a "not permanently attended installation," he said. The platform is linked to 5 wells in production. The platform has a limited amount of water / gas separation and has wet gas metering.

Premier Oil has been considering having an unmanned production facility for its operations offshore of the Falkland Islands in the South Atlantic. There is no established oil and gas industry in the region. "There's no reason why this shouldn't work in the North Sea as well," he said.

It is possible to check for many problems remotely, such as with acoustic leak detection tools on valves, he said. This means that anyone visiting the platform can make sure they have all the necessary spares with them.

Crondall Energy – floating production buoy to support small pool development

Floating production and subsea consultancy Crondall Energy is developing a design for an unmanned offshore production buoy which could help get small, deepwater fields into production



The Crondall Energy floating buoy design – receiving production from subsea wells and sending hydrocarbons on to a nearby hub

Floating production and subsea consultancy Crondall Energy is developing a concept for a floating production buoy, operating as a normally unattended installation (NUI).

The buoy could be used above deepwater subsea wells, to provide the production facilities and utilities required to produce the field.

The technology will enable subsea wells to be connected into a nearby hub platform if a basic subsea tie-back is frustrated by distance or the requirement for local services such as power or chemical injection. Otherwise, the buoy can provide production facilities locally and export produced hydrocarbons into pipeline infrastructure.

The buoy is constructed in two parts, the hull and topside deck, both are designed as separate floating structures.

For installation, both the hull and topside-deck will be floated to site independently. The hull is connected to moorings and risers before being temporarily submerged. Once the topside-deck arrives on-site it is floated over the hull and they are winched together before the complete facility is de-ballasted to an installation draught. This approach reduces the need for expensive offshore vessels during installation.

When the field finishes its viable production life, the buoy can be easily un-installed and moved to another field for use again on different projects.

Equipment

The topside-deck houses most equipment on the production buoy, including power generation. Topsides facilities and/ or utilities required for the field application are located on an open production deck with little equipment located within the hull.

Since the facility will be normally unmanned and remotely operated, equipment installed onboard must support remote operation and monitoring.

As a result, equipment selection for the buoy is focussed on minimising maintenance, allowing the buoy to be maintained during planned visits every few months. The use of condition-based-monitoring and risk-based-inspection techniques will maximise the effectiveness of this maintenance approach.

The facility concept is designed so that offshore personnel access the facility for routine maintenance using "walk to work" vessels rather than helicopters. This enhances personnel safety and increases the work that can be achieved during planned maintenance periods by offering an increased maintenance crew size and the opportunity for day and night shift operation.

Maturing the "design concept"

David Steed, Crondall

Crondall is starting a study with the Oil and Gas Technology Centre in April 2018, looking at maturing the "design concept" for the buoy, based around actual industry requirements.

The plan is to develop a design for the buoy which could operate in the Northern North Sea, in 150m water, producing 20,000 bopd of oil with a low to medium gas oil ratio (about 25,000 barrels including water).

As of March 2018, five companies had committed to join the project, and there is match funding from OGTC. More companies are welcome to get involved.

The study will be run in two phases. Phase 1 will focus on the facility's design and equipment selection required for remote operation and will prove the facility can be operated as a NUI. Phase 2 will mature the design further and demonstrate the economic feasibility of the production buoy as a development concept for small pools.

"The study will stretch the envelope of what can be achieved with NUIs in terms of production capacity and water depth. The goal is to demonstrate technical feasibility and look at what it will cost to deliver and run." says David Steed, project manager with Crondall.

What does a "factory approach" for offshore mean?

If the UK offshore oil and gas industry is going to stay viable, it needs to become more of a factory production line. Chris Wheaton explained what he thinks this means

One of the strategies most likely to lead to commercial success in the North Sea is to take a "factory" approach, thinking like a manufacturer rather than a producer, said Chris Wheaton, investment manager with Stifel, a London investment banking firm.

To see what a 'factory approach' looks like, UK oil and gas companies can look across the Atlantic to see how companies are developing unconventional oil and gas resources, as described in the previous talk. They are drilling an enormous number of wells continuously in the same way and continually pushing costs down, he said.

UK North Sea is in competition with US unconventional players, and indeed all other basins globally, in that they are competing for the same pool of investment capital, he said.

The point is that the decline in oil prices has meant action is starting to be made towards a factory approach – and results are becoming apparent, and more profits are being made without any help from the oil price. Yet a lot more progress is possible in this direction, he said.

"To do it, you have to think like a manufacturer, maximise uptime, maximise throughput, get control of operating costs," he said. "In offshore the large majority your costs are fixed, so by improving uptime your cost per unit improves."

Taking a manufacturing approach may also mean looking for more effective ways to work with other companies, rather than the traditional adversarial relationship between operators and contractors. For example models where both suppliers and operators share the pain and share the gain. The same can apply to service companies in their relationship to their own suppliers.

Oil companies might do well to think, how would an automobile company or an aerospace manufacturer think about running facilities like this, he said.

The track record

Industry association Oil and Gas UK has calculated that North Sea operating costs doubled from 2007 to 2014. But now costs have been halved in just 3 years. "A fantastic performance," he said.

In this period that operating costs doubled, there was also a 15-20 per cent reduction in uptime ("production efficiency"), down to about 65 per cent in 2012. "You wouldn't run a factory at 65 per cent uptime, and you can't run the North Sea at 60 per cent uptime," he said. Since then uptime has improved to 73 per cent in 2016, according to OGA figures.

The Oil and Gas Authority has split the causes of production shortfall into four buckets of production facilities, wells, pipelines and shore facilities, and the largest of those is facilities uptime. There is still the potential to improve further across all four areas, he said.

However Statoil's production uptime in Norway is better – 90 per cent– and that can be taken as a rough figure for the entire Norwegian Continental Shelf, since Statoil operates two thirds of Norwegian production, he said.

The most unreliable platforms are not necessarily the oldest ones, he said. Production efficiency is actually lowest (about 58 per cent) for platforms built 10-15 years ago (2003-2008). Older platforms are showing a higher production efficiency.

Working with data

Data gathering is an important part of the "manufacturing" concept. Over the past few years the cost of gathering data [sensors] and analysing data has fallen dramatically, he said.

"The more data you have the better, given how easy it is to analyse large chunks of data," he said. "It is much cheaper to look for patterns and opportunities in data than it's ever been. There's so much more the industry can do on this."

"Better data means better safety, better productivity, less unplanned downtime. You can predict when you need to change something and also when you don't need to change something.

You've got better people productivity. You can attack wasted time on wasted tasks, focus expensive people on what really matters."

Chris Wheaton

There are opportunities for creating digital models of offshore plant, sometimes called "digital twins," which can be used to test out plant modifications or production optimisation schemes in the virtual world.

"That's really exciting, it takes an awful lot of effort and risk from offshore and manages it better onshore. The more planning and preparation you can do onshore the better. I think this is a really interesting area for data," he said.

The industry has found ever more inventive ways of using its 'data exhaust', he said. For example oil companies are finally starting to employ data specialists to look through (for example) archived production data, and try to find useful insights from it.

"The more data we've got the better it is. I think there's a big chunk of data completely worthless and some data worth its weight in gold. The rest of the world has got value out of data mining, I can't imagine the oil industry being any different."

Remote operations

The future of the oil and gas industry cannot be with more massive conventional projects, with a massive jacket, massive topsides and 200 people working onboard, Mr Wheaton believes.

"Recently I was offshore on a platform with a complement of 190 people. I tore my hair out [asking] why do you still have 190 people on the platform - have you seen the oil price?"

There is an increasing number of oilfields being operated from onshore, for example Statoil's Johan Castberg platform. Statoil is also creating a 'digital twin' for the Johan Sverdrup project so it can be run from onshore if desired.

Statoil says it aims to develop a "remotely operated factory", Mr Wheaton says. "These kinds of opportunities are really about saving people time, maximising people's productivity, focussing on maximising production, maximising cash flow, shareholder value," he said.

Remote or onshore operations can also be used in drilling and optimising production. "This industry has only just started to look at these opportunities," he said.

Fields per operator

It is interesting to look at differences in the number of operators on either side of the North Sea.

Norway has 26 producing license operators on 110 producing fields. If you exclude operators which are just exploring, and take out Statoil, you end up with 13 operators on 53 producing fields, so 1 operator managing about 4 fields, "which sounds kind of where you'd expect."

In the UK there are 29 producing operators in 322 producing fields. That works out at 10-11 fields per operator. "That seems to be a large number," he said.

There is a valid argument that the UK has more smaller fields than Norway, because it started producing 5-10 years earlier, but still it seems a lot of fields which an average operator looks after.

Supplier collaboration

Aker BP presented an interesting case at a capital markets day in January 2018, how the company managed to reduce the costs of a traditional subsea tieback by 30 per cent, through different business models, sharing risk between contractors and license owners in different ways, Mr Wheaton said. This means that contractors have an incentive to look for ways to reduce project costs.

Three years ago, an average upstream project globally was 19 per cent over budget, with 9 months late. This makes a big dent in the value of the project and returns to shareholders. Now, in some companies, the opposite is happening, with projects often coming in early and below budget. "That's how you create a factory style manufacturing process," he said.

Decommissioning

A further issue is decommissioning costs, an increasing issue on the UK North Sea. Half the costs of decommissioning, and much of the risk, are in wells.

Part of taking a "factory" approach to North Sea operations is working out how to squeeze more value out of the assets before they need to be decommissioned, thus pushing the liability out.

Then there is a huge incentive for operators to collaborate together, put equipment into a pool, try to get unit costs down.

There is a big need for more decommissioning data, to help get a better sense of the risks, which is not available from the handful of big projects completed to date. With more data, it might be possible to get better arrangements for decommissioning insurance, and access third party capital.

"That means potentially more sources of capital for the North Sea, more investment, more recovery of hydrocarbons. That's a really good virtual circle to get into."

Standards

"I think there's more to do on standards," he said. "I think you've got to have common data standards, data platforms, to really share information," he said.

The automotive industry had a big push for standardisation in the 1980s, and its practises were then taken up by the chemical industry.

The downstream oil and gas industry has made much more use of standards than the upstream. This work may spread to upstream, now we have many former downstream people managing upstream, such as Shell CEO Ben van Beurden and ExxonMobil CEO Daryl Woods, both former heads of downstream in their companies, he said.

Rob Gill – reducing costs of new offshore developments

One way to reduce the costs of new offshore developments is to use standardised, simplified offshore infrastructure, with well heads on platforms rather than subsea, tying back to the existing 'hubs', said Rob Gill of Petromall, formerly with Advisian

Given that much of the UK North Sea infrastructure is currently grossly underutilised and will shortly need to be decommissioned due to lack of hydrocarbon production (not due to aging of the asset), it makes sense to look for low cost ways to get more hydrocarbons through it, said Rob Gill, consultant with Petromall, formerly EAME business development manager with Advisian Worley Parsons.

This can only be done by increasing production from existing wells (e.g. through EOR) or by developing new fields or "small pools" which can be 'tied back' to the existing infrastructure, Mr Gill said. This talk focussed only on small pools.

The UK Oil and Gas Authority has been helpful in identifying 300 small pools in the UK sector of the North Sea which could be developed which haven't been developed yet. These have been analysed in terms of their size and distance from existing infrastructure. They are more likely to make viable development projects if they are larger and closer to infrastructure, and the reverse is also true.

The industry typically considers a 10m barrel "small pool" as too small to bother with, Mr Gill said. So it may be useful to consider that a 10m pool could provide $300m of revenue (at 50% recovery and a $60 oil price). There are very few other industries which would consider $300m too small a sum to bother with, he said.

Subsea vs platform well head

A first consideration is whether the pools are better developed with subsea wells or with platforms. Platforms are typically more expensive to build, but make for much easier well intervention work later (putting tools and equipment into the well to improve production).

A number of designs for platform well heads have been developed which are as simple (in terms of the services they offer) as the subsea equipment, so do not include any compression or processing.

The costs of putting the well head above the water mainly depend on the water depth, and so the amount of steel needed for the legs, whereas the cost of a subsea development is fairly independent of water depth, he said.

Roughly speaking, at 30m water depth, you could build a well head above the water for the same price as one subsea well. But at 90m water depth, one well head above water would cost the same as three subsea well heads – so you would need to have three well heads on the same platform to make it worthwhile.

North Sea platform costs are a little higher due to weather and waves, and based on real calculations a well head platform is typically the same cost as two subsea wells in the Southern North Sea, and the same cost as four subsea wells in the central and Northern North Sea, he said.

A well head platform is "low cost, low risk, completely unmanned, with no accommodation, no processing whatsoever," he said. There is generally no helideck. It can be produced in standardised modules, thus reducing the design and construction cost.

Personnel access is by so called "walk to work" vessels, which have a walkway from a vessel to the platform. The walkway "compensates" for wave movement, i.e. uses sensors and motors to keep the walkway completely still, even though the vessel is moving on the waves.

The "walk to work" system is also the emergency escape route for personnel (so the vessel will be there as long as people are).

Examples of standardised designs

Engineering company Worley Parsons did a lot of work developing standardised platforms in the Gulf of Thailand, working for Unocal (later acquired by Chevron in 2005).

They managed to reduce the typical installation time from 8 days to 2, with a range of different innovations, such as different methods for putting tubulars into the seabed ("swaged piles" rather than "grouted piles" in the jargon.

The platforms could be manufactured quickly to order without any new design work required, put on a barge two at a time, and then offloaded offshore. They also have bolted connections, so that platforms could be moved somewhere else after use.

Worley Parsons decided that a design with 16 slots (for different wells) might be good for a majority of projects, so they made it the standard size. They designed a jacket with a lower weight, and a topsides which are fully automated, with space for booster compression. They managed to reduce the construction costs from $10m to $6m between 1993 and 2003. Worley Parsons has 500 such unmanned platforms currently in service.

On a similar platform in New Zealand, staff will visit every 6 months, and send an automatic pig launcher into the well to do an inspection. A new automated system is being developed to stop slugging.

Another platform standardisation project was recently initiated by Saudi Aramco, under the label "3S", standardisation, simplification and 'simultaneous' operation. The Persian Gulf water depths range from 10m to 50m.

The only variability in the standard structure was in the length of the legs. Saudi Aramco also standardised on just two topside designs, powered or unpowered, and standardised on 10 well slots.

Today, if an engineer in Saudi Aramco wants an oil platform, they should specify whether or not it is powered, the water depth, and the soil conditions for the piling arrangement. No further design needs to be done. If someone just wants 5 well slots, they have to have 10. "While each platform may not be optimised for its location, the entire supply chain is optimised," he said.

If the standardised jackets and topsides can be manufactured separately that also makes the project more efficient, he said.

Companies are also looking for ways to make platforms easier to install, perhaps with the same jack-up rig which was used for drilling, rather than bring in another heavy crane.

Worley Parsons in Coogee, Australia, developed a tripod design, which could be launched directly from a barge, only requiring a 5 tonne crane. Not needing a heavy crane vessel gives operating companies a lot more flexibility.

The platform has been designed in two different sizes, "large" (12-16 well slots) and "smaller" (4-6 slots). The only allowed variability is in the height of the legs in between, which can be altered in increments of 1m.

"It changes the concept of a production yard to a production line," he said.

In the Southern North Sea, there are many unmanned platforms in the Dutch and Danish sectors, many without any helideck, relying on 'walk to work' technology for access from a vessel, as described above.

Unmanned wellhead platforms was a major topic of conversation for the Stavanger ONS conference in Autumn 2016, following a study on the subject done by the Norwegian Petroleum Directorate, and a number of designs proposed as a standardised structure for the deeper water of th North Sea.

Heerema won a contract to install a

platform for Statoil in 105m water.

Kvaerner made a contract with Aker Solutions to design "subsea on a stick", a platform in 120m of water. That is about the depth limit for simple platforms, because it is the limit of depth that a jack-up rig can work in, and going deeper requires more expensive equipment.

"All of the larger operators in Norway really have taken this onboard," he said. "Statoil, Conoco Phillips, Ekofisk area, Aker BP, Lundin,

They've all been looking at wellhead platforms."

By comparison, one of the first unmanned well head platforms, in the Norwegian sector of the North Sea, had a 2,000 tonne jacket, which was put in place using a 10,000 tonne crane, which was all the company had available.

How many small pools?

Taking these ideas back to the OGA's analysis of small pools in the North Sea, Mr Gill thinks that it could make it viable to produce a field which is just 3 or 4m barrels of oil recoverable using standardised wellhead platforms. In the Northern North Sea, where costs are higher, perhaps 9-10m barrels would be the minimum viable size.

Altogether, 60 per cent of small pools identified by OGA could be targeted, equating to 94 per cent of the oil. "I don't think this is a solution for very small pools, but certainly we could hoover most of them up."

Investability

Another factor is how companies can raise the money from investors for wellhead developments. Currently oil companies are not in strong flavour with investors. This is indicated by oil company shares having a lower average price/earnings ratio than most other large industry sectors, including consumer, financials, healthcare, industrial, IT, materials, telecoms, and utilities, he said.

Earnings are not so high for oil and gas, so the reason for the low P/E ratio must be that investors perceive oil and gas companies to be very high risk.

And typically it is small independent oil companies, rather than majors, which are interested in developing small fields, which are perceived as even higher risk.

The perceived risk is further exacerbated by forthcoming changes to accounting rules which require companies to put assets on lease (such as a FPSO) in their balance sheets, both as assets (equity) and as debt, and consider the lease payments as 'interest'. This worsens their figures for debt/equity ratio and interest coverage (profit before interest and tax divided by interest).

One way companies can make small pool development projects look more attractive to investors, and keep their debts off their own balance sheets, is by setting them up as new companies controlled by the operator, or "special purpose vehicles," Mr Gill suggested.

If the operator only maintain a minority stake in the SPV, then the SPV's debts do not have to be added to the debts of the parent company. However the operator can maintain control over the SPV by having an agreement with all shareholders that the operator has exclusivity over purchase of its oil.

The operator can put the initial cash into the SPV, and then sell equity to other companies, including 'farm-in' operators, private equity and traders. The SPV can also take bank loans.

There could also be an agreement that the first oil revenues would be used to pay suppliers and contractors, before any owners get paid, thus giving suppliers an incentive to help get the project onstream faster, he said.

Reduce decommissioning costs for an offshore project

A group of decommissioning engineers are using their offshore experiences to compile a list of ways to build platforms so they are easier to decommission and remove. This compilation should lead to reduced decommissioning costs and in turn an increased Net Present Value at the start of the project

Decommissioning specialists from 24 international oil and gas companies are pooling their experiences. They are providing a database of ideas for building offshore oil and gas facilities so they are easier to decommission.

The purpose is to reduce decommissioning costs - and hence increase the net present value of an offshore project. Because the net present value calculation when sanctioning a project includes decommissioning costs.

For example, if the decommissioning task involves flushing (cleaning) pipelines, a pump will have to be connected to the pipeline at the platform, and piping fitted to handle the flushed fluids. It will be much easier to design this at the outset, than add in new pipework and have to find space for the pump while the decommissioning work is going on.

Alan Stokes, decommissioning manager for the oil and gas consultancy Advisian is compiling the database of lessons learned from offshore decommissioning projects.

The 'lessons learned' are freely available on the Society of Petroleum Engineers PetroWiki page here **http://petrowiki.org/Design_for_decommissioning**

The experiences are laid out as a check list of issues and mitigations. As a Lead engineer finds a check list much easier to use than a long manual of recommendations.

The database is open to all. Anyone can submit an idea to the website - then two moderators decide whether or not to include the ideas.

Alan calculates that the savings from taking all the recommendations onboard into the design could be equivalent to finding a way to halve the amount of steel used on the development (which is quite hard to do).