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Exploration Outlook

What's in store for 2020?

The Energy Transition
Climate goals drive big changes

Double Feature
An inside look at BP's Mad Dog 2

Arctic Report
The future is in the north

VOL. 44 / NO. 6


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Source: Tullow Oil

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2020 Exploration Outlook

Exploration and production companies are expected to enter 2020 with measured optimism for offshore exploration prospects, after 2019 delivered a moderate increase in exploration drilling and not-so-moderate rise in licensing activity.

By Eric Haun

ON THE COVER: In 2019 Tullow Oil made two high-profile finds offshore Guyana using drillship Stena Forth. (Source: Tullow Oil)

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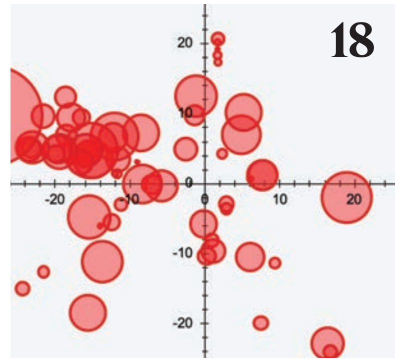
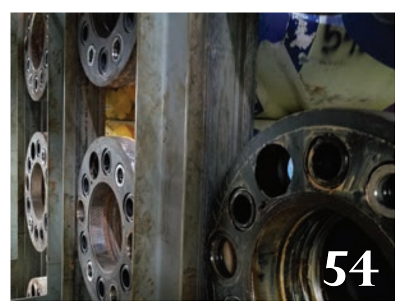


Source: 1st Subsurface

Source: Equinor

Source: CannSeal



Source: Baker Hughes

Source: Halliburton

BY THE NUMBERS

RIGS

Worldwide

Rig Type	Available	Contracted	Total	Utilization
Drillship	22	67	89	75%
Jackup	97	3447	441	78%
Semisub	35	71	106	67%

Africa

Rig Type	Available	Contracted	Total	Utilization
Drillship	2	13	15	87%
Jackup	6	30	36	83%
Semisub	1	3	4	75%

Asia

Rig Type	Available	Contracted	Total	Utilization
Drillship	5	8	13	62%
Jackup	36	106	142	75%
Semisub	13	14	27	52%

Europe

Rig Type	Available	Contracted	Total	Utilization
Drillship	11	2	13	15%
Jackup	7	44	51	86%
Semisub	9	30	39	77%

Latin America & the Caribbean

Rig Type	Available	Contracted	Total	Utilization
Drillship	4	19	23	83%
Jackup	5	5	10	50%
Semisub	6	4	10	40%

Middle East

Rig Type	Available	Contracted	Total	Utilization
Drillship	0	1	1	100%
Jackup	23	115	138	83%

North America

Rig Type	Available	Contracted	Total	Utilization
Drillship	0	22	22	100%
Jackup	17	36	56	68%
Semisub	3	10	13	77%

Oceania

Rig Type	Available	Contracted	Total	Utilization
Drillship	0	1	1	100%
Jackup	0	2	2	100%
Semisub	0	6	6	100%

Russia & Caspian

Rig Type	Available	Contracted	Total	Utilization
Jackup	2	6	8	75%
Semisub	2	4	6	67%

This data focuses on the marketed rig fleet and excludes assets that are under construction, retired, destroyed, deemed noncompetitive or cold stacked.

Data as of December 1, 2019.
Source: Wood Mackenzie Offshore Rig Tracker

DISCOVERIES & RESERVES

Offshore New Discoveries

Water Depth	2015	2016	2017	2018	2019
Deepwater	25	12	17	14	14
Shallow water	85	66	72	46	40
Ultra-deepwater	20	16	12	17	13

Shallow water (1-399m)
Deepwater (400-1,499m)
Ultra-deepwater (1,500m+)

Offshore Undeveloped Recoverable Reserves

Water Depth	Number of fields	Recoverable reserves liquids mbl	Recoverable reserves gas mboe
Deepwater	567	53006	22709
Shallow water	3245	312488	108127
Ultra-deepwater	348	53925	37687

Contingent, good technical, probable development.
The total proven and probably (2P) reserves which are deemed recoverable from the reservoir.

Woodmac Child Fields

Offshore Onstream & Under Development Remaining Reserves

Water Depth	Number of fields	Recoverable reserves liquids mbl	Recoverable reserves gas mboe
Africa	736	28194	40392
Asia	1016	16137	37167
Europe	966	20359	23978
Latin America & the Caribbean	245	39360	11285
Middle East	144	169562	106995
North America	622	25029	4206
Oceania	117	2573	23113
Russia and the Caspian	71	26367	23616

Onstream and under development.
The portion of commercially recoverable 2P reserves yet to be recovered from the reservoir.

Woodmac Parent Fields

Source: Wood Mackenzie

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OE WRITERS


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LOOK BACK **FORGE AHEAD**

I truly don't like stealing her thunder, but Elaine Maslin, in her feature entitled "The Blue/Green Energy Revolution" starting when you turn this page, summarizes perfectly my sentiments as we approach the end of year one in our management of this venerable 44-year-old title. "A seismic shift in the dialogue around big oil and climate has occurred in the past 12 months. It's a change in how big oil is orientating itself around what many call the energy transition. Climate goals – governmental, international and industry led – as well as investor behavior (capital flight from fossil fuel) are driving the change."

To be clear, we see traditional oil and gas as the dominate source of global energy markets for a generation to come. The direction is unquestioned, the pace is another matter. The estimates of 'peak oil', in this context meaning the tipping point of when oil and gas demand will start to diminish not because of supply, rather demand, vary wildly, with some armchair experts saying the mid-2020s, while general consensus takes us into the mid- to late-2030s.

It was during trips to two major energy events in 2019 – the OTC in Houston and Offshore Europe in Aberdeen – where the extent of the movement solidified, as never before had I seen so many indicators, with words like "renewables" and "sustainability" liberally used in nearly every big, overarching industry presentation.

With 2019 under our belt it is the traditional time to offer thanks, and in regards to the *Offshore Engineer* team, our advertisers, our supporters, and yes, even our competitors. A sincere bit of thanks to every person on our team, editorial, sales, production and corporate staff. There are a cadre of customer-facing crew that you see at most of the world's offshore energy events, but there are far more behind-the-scenes that make us all look very good, including **Nicole Ventimiglia** who is our production manager and designer extraordinaire, and **Vladimir Bibik**, our corporate IT director who is the driving force behind everything that we do on the electronic side.

While the acquisition of an offshore energy media title in 2018 might have seemed odd to some given the downturn in the market, it made perfect sense to us, an 80-year-old media company with a long-term view on all that we do. *OE* was an established brand with a loyal following, and energy in all origins and forms is a pervasive, global subject. We are in it for the long-haul, which is the reason we went to the time, effort and expense to produce our first BPA Worldwide Audit Report. The report is a circulation audit of our print title, our traffic on *OEDigital.com* as well as our *OE Today* daily e-newsletter. We have been a member of BPA since the late 1940s, and I am proud to welcome the *Offshore Engineer* brand as the newest member of our family of audited media products. The numbers are clear and the report is available online at https://www.oedigital.com/advertise.

We look forward to being your information source of choice in 2020 and far beyond; watch this spot for some exciting changes and additions starting in January!

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A Blue/Green Energy Revolution

A seismic shift in the dialogue around big oil and climate has occurred in the past 12 months. It's a change in how big oil is orientating itself around what many call the energy transition. Climate goals - governmental, international and industry led - as well as investor behavior (capital flight from fossil fuel) are driving the change.

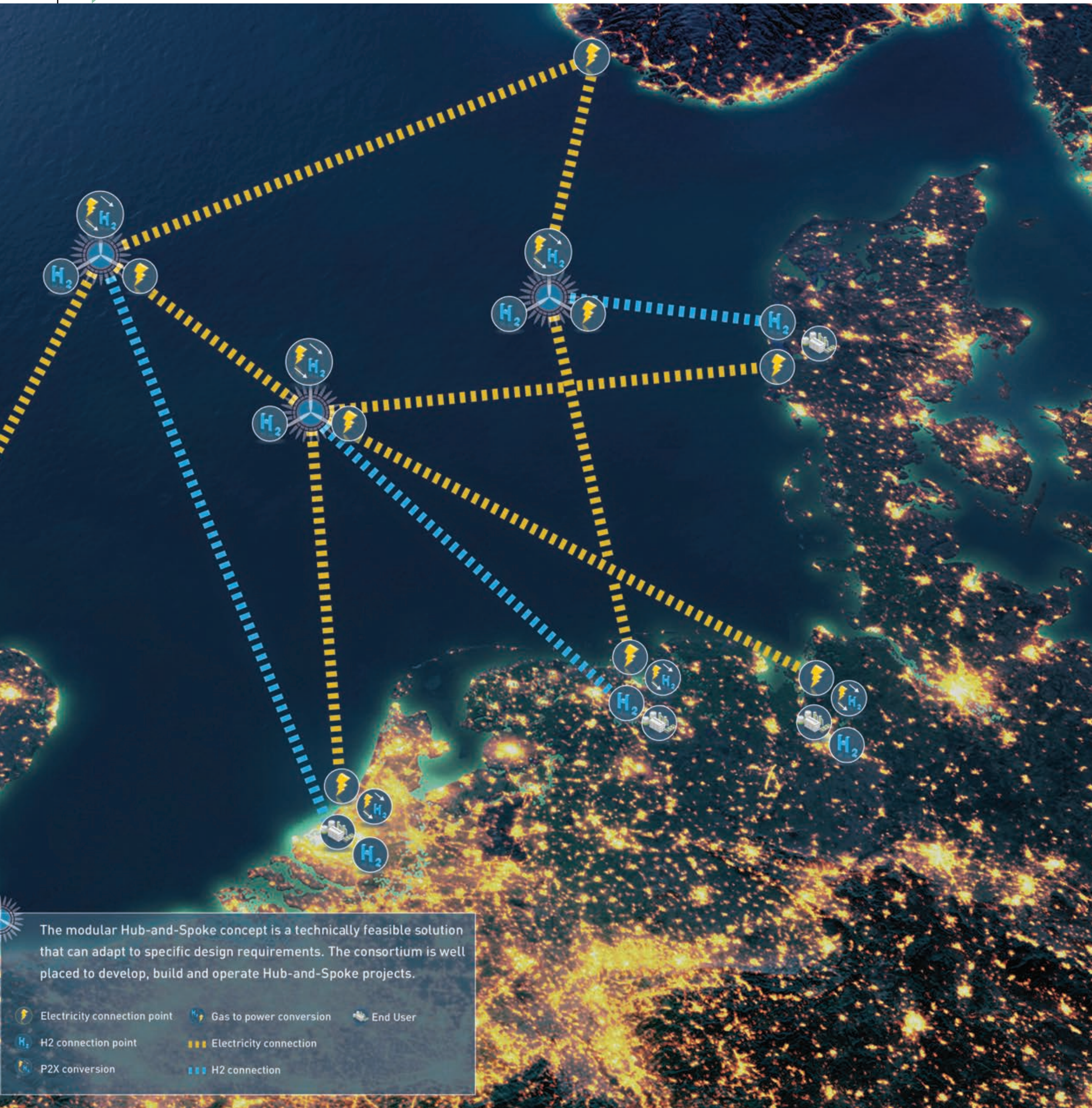
BY ELAINE MASLIN

The landscape is indeed shifting. Andy Kinsella, group CEO at Mainstream Renewable Power, says twice as much capital investment going into wind and solar globally compared with coal, oil, gas and nuclear. In the 1980s, seven of the top 10 companies in the S&P 500 were oil and gas. Now there's just one, he adds.

The result is that companies – operators and their supply chain – are no longer talking about themselves as oil and gas companies; they're energy companies, making energy "safer, cleaner and more efficient for people and for the planet". Talk about the energy transition and decarbonization dominated key conference sessions Offshore Europe, in Aberdeen, in September – when these topics were minor at the previous event.

It's not an entirely new movement, however. Shell, for example, has been talking about cleaner gas for a while. Its execs tell oil and gas industry events about how Shell is transitioning into a broader energy business. "Shell is one of the largest traders in electricity," Jo Coleman, Energy Transition Manager for Shell, told Offshore Europe. Shell sees a big future in charging points, at petrol stations and in homes, she says, as well as trying to grow demand in hydrogen and developing carbon capture and storage (CCS).

The North Sea Wind Power Hub envisions a number of hubs that would great a grid across the North Sea.



Source: The North Sea Wind Power Hub consortium

Making pledges

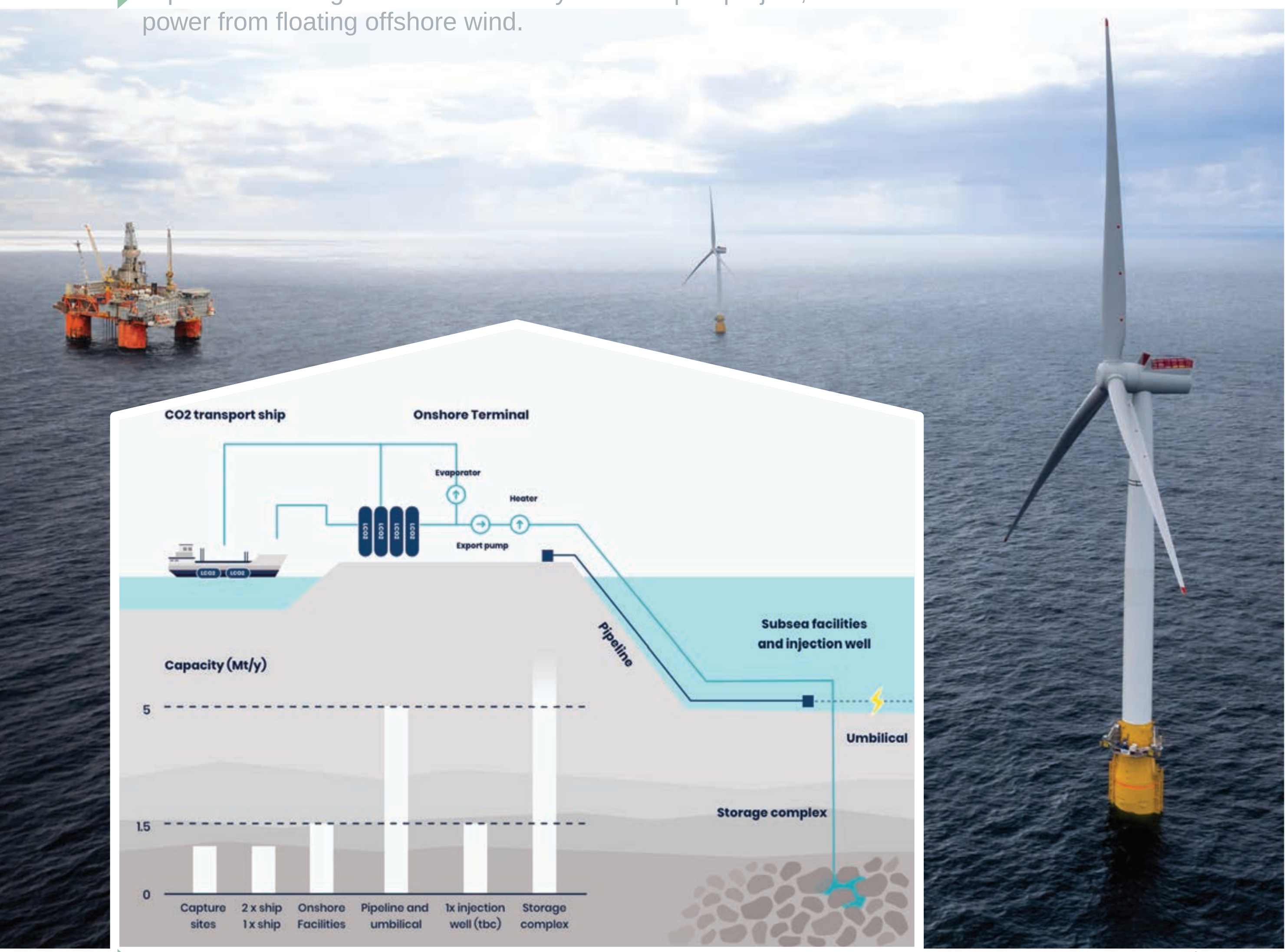
It's not just the majors. At Offshore Europe, industry body Oil & Gas UK (OGUK) launched a Roadmap to 2035: A Blueprint for "net-zero", calling on industry, government and regulator action to both reduce emissions (UK oil and gas production accounts for 3% of total UK greenhouse gas emissions, says OGUK) and help develop and commercialize technologies like CCS and hydrogen. The same week, the public-funded Oil & Gas Technology Center (OGTC) launched a Net Zero Solutions Center.

Earlier this year, the Netherlands Oil and Gas Exploration and Production Association (NOGEPA) signed an agreement with the Dutch government to cut methane emissions by half within two years – from 8,562 metric tons of methane per year in 2017 to 4,281 metric tons per year by December 2020. Meanwhile, the government there will also run a study to look at ways to further reduce it, such as by electrifying offshore platforms. But, concedes NOGEPA, that might require incentives, as well as guaranteed access to the offshore power grid.

Dutch courage

The Dutch have already been looking at how to better connect their energy system and how offshore wind, gas platforms, hydrogen production

Equinor is moving forward with the Hywind Tampen project, which will feed Gullfaks and Snorre with power from floating offshore wind.



Equinor also leads the Northern Lights project, part of a full value chain carbon capture and storage project offshore Norway.

Source: Equinor

and the grid can be better connected to make the best and greenest use of existing infrastructure. Rene Peters, from Dutch research outfit TNO, says that could mean electrifying offshore platforms, which is already happening in some places, but more could be done; connecting power users with generators, like wind farms and potentially opening up marginal fields in doing so, he told the Offshore Energy conference in Amsterdam, in October.

Another option is gas to wire, where natural gas is converted to electricity offshore, then sent by wire onshore. While few options for this were found in the Dutch sector, says Peters, a UK Oil & Gas Authority study last year found 16 potential projects that could be looked at in the UK North Sea. A more viable option in the Netherlands could be hydrogen production offshore, using natural gas and/or offshore wind to power the process then transporting the hydrogen through the existing pipeline network.

Green and blue hydrogen

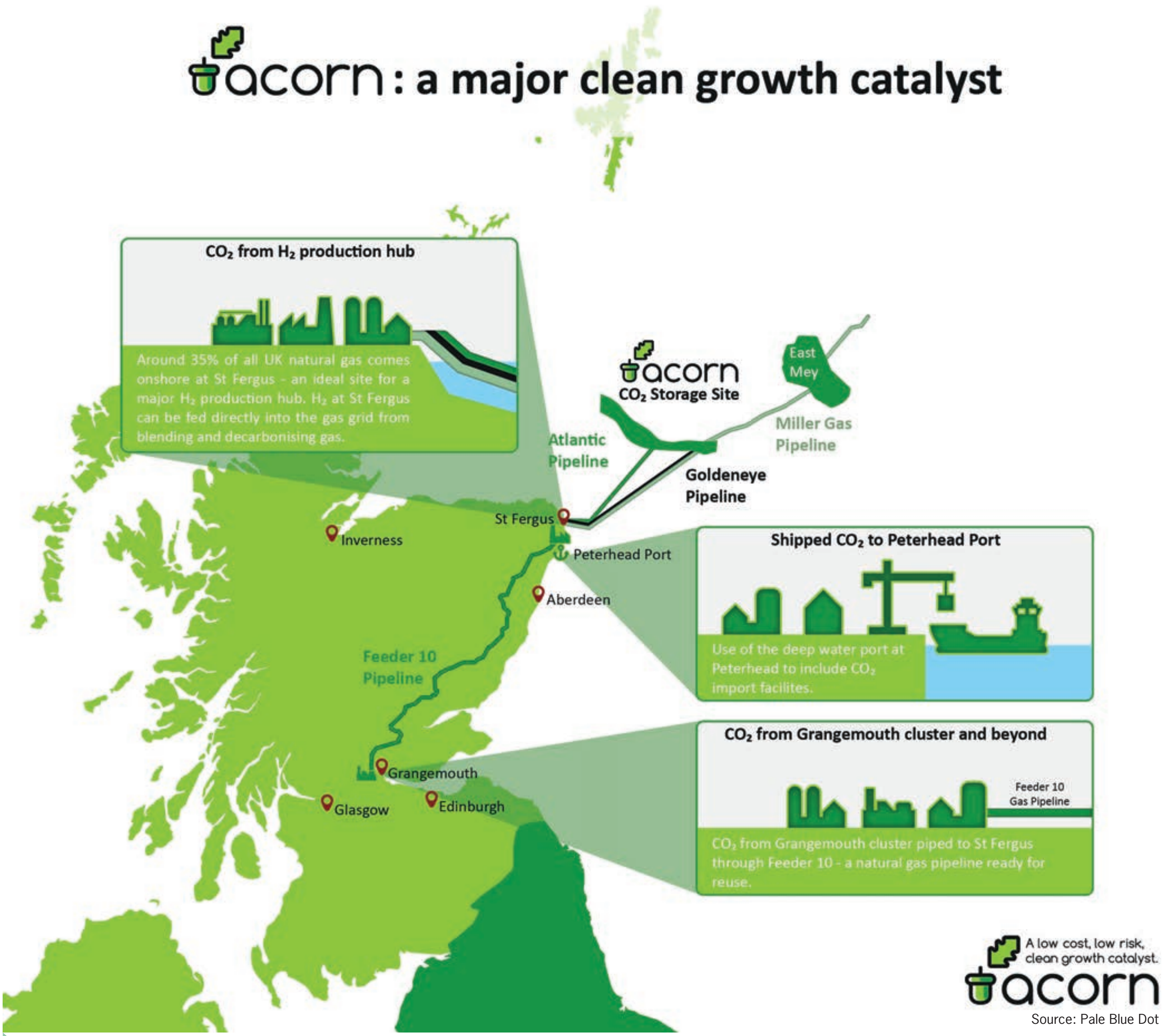
In fact, a two-year "green" hydrogen (make without use of fossil fuels) pilot project has been agreed, called PosHydon – a spin-out project from the North Sea Energy public-private partnership. From 2020, Neptune Energy, working with re-use group NexStep and TNO, is due to host a 1-megawatt (MW) hydrogen electrolyser on its Q13a platform (the first Dutch powered-from-shore facility) 13 kilometers (km) offshore. The hydrogen, electrolyzed from seawater, will then be blended with the gas and piped to shore in the existing pipeline, to produce electricity. In future, this idea could be linked to offshore wind farms to help level out intermittency issues – i.e. instead of shutting wind farms when they're over producing, the energy can be converted to hydrogen.

The potential for use of offshore platforms for hydrogen production, powered by renewable electricity, that also supports nearby marginal fields, and hydrogen export to shore, is also being looked at in the UK. The Hydrogen Offshore Production (HOP) project involving the OGTC, environmental consultancy Aquatera, NOV, Doosan Babcock, Cranfield University and the European Marine Energy Center (EMEC) on Orkney, a Scottish island, is assessing options, from the types of technology that could be used to the transportation logistics and the potential to use repurposed offshore facilities. As an example, Hayleigh Pearson, a Project Engineer within the Marginal Developments Solution Center at the OGTC, told Offshore Europe that a small southern North Sea platform like Markham could host four polymer electrolyte membrane electrolysis units to create 3,500 kilograms (kg) of green hydrogen a day (which could power 10 buses driving for 3500km each, she says). A larger northern North Sea platform could perhaps house 22 steam methane reformers and produce 12,000kg of “blue” hydrogen (made with fossil fuel input) per day. Project studies are ongoing with an onshore test center planned for Flotta an island off Orkney mainland.

Meanwhile, Belgian engineering firm Tractebel, part of Engie, is developing a concept for an offshore platform that would convert power produced from offshore wind farms into green hydrogen using electrolysis.

A connected North Sea

Hydrogen would also feature in the North Sea Wind Power Hub, a mega-island offshore as a hub for connecting massive wind farms and supply-



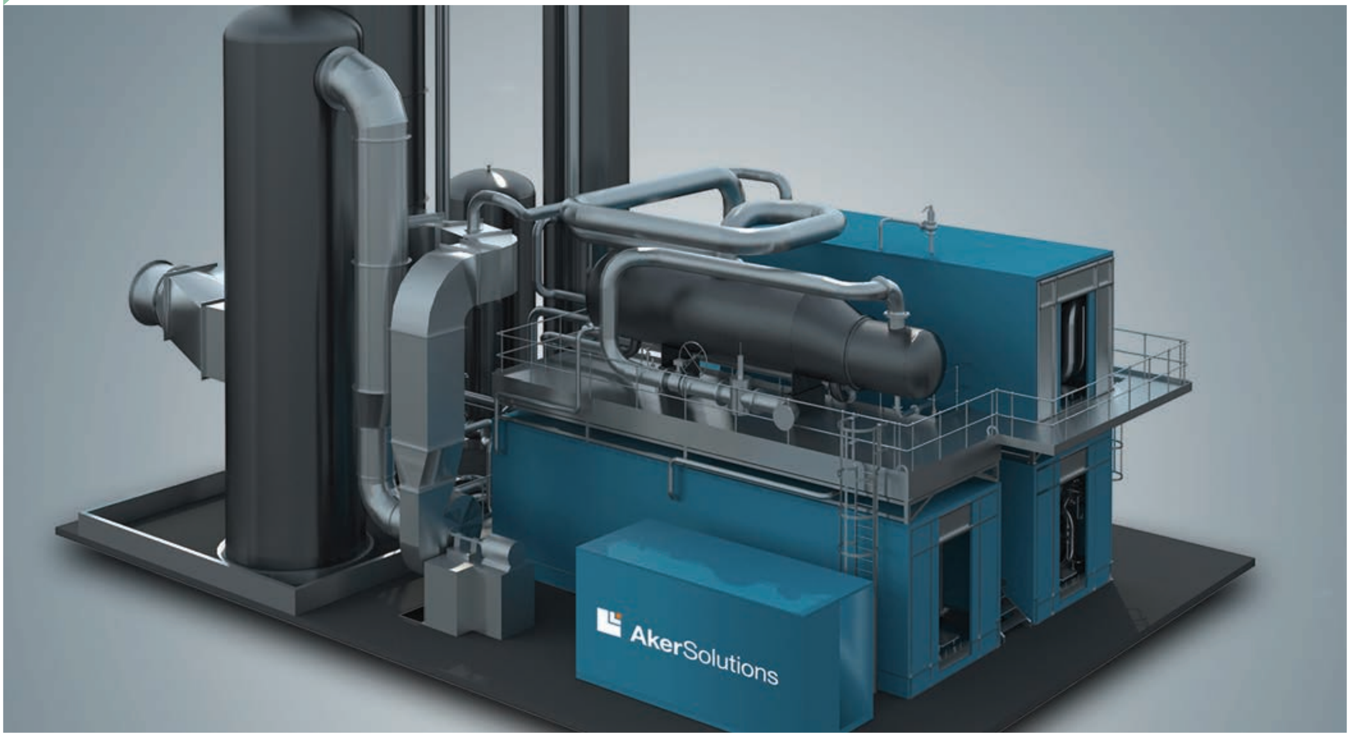
Source: Pale Blue Dot

Pale Blue Dot is leading the Acorn CCS project which would see captured carbon stored offshore Scotland.

Neptune Energy's Q13a platform, set to be home to a hdyrogen production facility under a Dutch pilot project.

Source: Neptune Energy

Aker Solutions has designed carbon capture technology, called Just Catch, that could fit on offshore facilities.



Source: Aker Solutions

ing their power to different countries around the North Sea, to manage the grid effectively. It's a concept launched in 2016 by a Dutch consortium. This year, a feasibility study concluded. Jasper Vis, senior advisor at Tennet, one of the project partners, says it's feasible. But, instead of one large island, a number of smaller – though still big – islands, either artificial islands or more traditional platforms, depending on the seabed, would be better with electricity conversion to hydrogen when there's too much power being produced, he told Offshore Energy.

This would suit the Netherlands, which has big offshore wind ambitions but a limited power grid. Rob van der Hage, business manager offshore, at Tennet, told Offshore Energy that the first hub could be built by 2025. It would alleviate grid issues. Hage says that once all the offshore wind farms that are already planned up to 2023 are built, there's only another 7 gigawatts (GW) of capacity in the grid left. Being able to get power to shore via different routes, i.e. as hydrogen, is an option. The challenge is then is creating demand for hydrogen, he says.

Cleaning industry

Another Dutch project, H-Vision, led by TNO with partners including Air Liquide, BP, Gasunie, Shell and Uniper, seeks to create 3.2GW of blue hydrogen plant in the Maasvlakte area, near two existing power plants, to fulfil 20% of heat and electricity in the Rotterdam area. A final investment decision (FID) is planned for 2021, with first hydrogen in 2026. This project will rely on CCS, with some, though not all, of the CO2 produced in the process potentially being dealt with in another project, the Porthos (Port of Rotterdam CO2Transport Hub & Offshore Storage) CCUS (carbon capture utilization and storage) project, which is being led by the Port of Rotterdam Authority with partners Gasnuie and EBN (a state-owned energy organization). This aims to take CO2 from industry in the Rotterdam port area and both supply it to greenhouses, to aid plant growth, and also store it offshore via Taqa's P18a platform, 21km off the coast. "By 2030, we expect to be able to store between 2-5 million metric tons of CO2 every year," according to the project's website. It's targeting FID by the end of next year with start-up in 2023.

Meanwhile, Norwegian operator Equinor is also looking at hydrogen. In the H21 project in the UK, it's been looking at converting the north of England's natural gas system to use hydrogen, storing CO2 produced in the process, 100km offshore. A feasibility study has been done but a front-end engineering and design (FEED) study not yet funded. Equinor's also involved in Zero Carbon Humber, a smaller project, to sequester then store CO2 from the Drax power station, a former coal

An Emissions Elephant in the Room

Carbon intensity reduction is a "huge challenge industry is facing," Ross Dornan, Market Intelligence Manager at Oil & Gas UK told Offshore Europe at the launch of Roadmap to 2035. The industry's carbon intensity has been cut by 16% since 2013, to an average 21,000 metric tons of carbon dioxide (CO2) per million (MM) barrels of oil equivalent (boe). The target is 4,000 metric tons CO2/MM boe by 2050.

Ragnhild Stokholm, low carbon champion, Aker Solutions, told the same event that the average carbon intensity of offshore oil and gas production is 18 kilograms (kg) CO2/boe exported. In Norway, it's 9kg/boe, while it's 21kg/boe in the UK. The UK's poorer performance is due to older facilities, she told the same event. But, small reductions could have a big impact, she says. "Reducing CO2 emissions by just 1kg (per boe) gives reduction equivalent to 8% of greenhouse gas emissions in the UK in 2018. A 9kg reduction (per boe) would equal 72% of UK CO2 emissions. Using power from shore and reducing flaring would help, she says, adding that 145 billion cubic meters of associated gas was flared across the world in 2018 – enough to power Africa.

But, there's a methane emissions elephant in the room. According to Julien Perez, VP of Strategy and Policy at the Oil & Gas Climate Initiative (OGCI), based on International Energy Association (IEA) data, 20% of the estimated 750 million metric tons of methane emissions in 2017 were from fossil fuel production (24% was from agriculture). While methane spends less time in the atmosphere than CO2, it's more potent, and emissions of it from oil and gas have been increasing, so it's a concern, he told Offshore Europe.

A big challenge, says Wendy Brown, International Association of Oil & Gas Producers' (IOGP) Environment Director, is that there are "big discrepancies" between industry published data and IEA data – up to sixfold. The industry has been trying to reduce the uncertainty, she says, comparing different data gathering methodologies at a country level. While similar approaches were used for venting and fugitive gases, gas engine and flaring emissions are different up to 25% between countries. The IOGP, meanwhile, is working on best practices to help reduce emissions, including satellite technologies to spot it, and flare gas recovery technology.

There is an increasing number of tools for monitoring emissions. Anton Leemhuis, senior business developer space at TNO, told Offshore Energy that earth observation satellites are looking at emissions, using imaging spectrometry, such as Dutch satellite instrument Tropomi, on board the Sentinel-5 precursor satellite, which is part of the European Earth observation program Copernicus, can show very detailed maps of methane. TNO is working with others to create even smaller instruments that can zoom in to industrial facilities and monitor them, using a fleet of satellites and for a cost that would be in reach for large corporations, he says.

power station converted to biomass.

In the Netherlands, Equinor is also part of Magnum, a project to convert a combined cycle gas turbine to run on hydrogen and then store the CO2. "We need everything petroleum engineers can offer from geology to drilling and completions to ships stakeholder managers, it's everything," Anna Korolko, Low Carbon Technology Lead at Equinor, told Offshore Europe.

CCS

CCS and skills from the oil and gas industry plays a big role in this picture. Astley Hastings, a research fellow at the University of Aberdeen, following a career with Schlumberger then a PhD in systems biology, says the oil and gas industry "holds all the cards in order to decarbonize globally", not least around CCS. Many industries – fertilizer, concrete, steel production – will struggle to decarbonize so CCS is needed, he says.

It's doable. "CO2 injection for enhanced oil recovery (EOR) has been done for 50 years," he told Offshore Europe. "Separation (technology) is mature. Metallurgy is known and several pilot projects are active. We understand pretty well CO2/rock chemistry and more research is ongoing. Several governments have sponsored projects, so it's spade ready."

But, CCS has been on a bumpy road. There are few projects internationally. Two competing projects in the UK were stopped in 2015 after government funding was pulled. The Snohvit project in Norway stores 0.7 Mt of sequestered CO2 a year in an aquifer via a 153km pipeline and one well. To store all fossil emissions from electricity generation worldwide by 2040 would need 20,500 Snohvits, he says (to store an estimated 15.4 billion metric tons CO2 a year).

From Acorns oaks grow

A project that is now getting some traction is Acorn. Pale Blue Dot, its project developer, secured the UK's first CO2 storage license for the project in 2018. This year, it secured EU funding and new partners including Shell and Chysaor. The idea is to combine reforming some of the natural gas that comes into St Fergus terminal in northern Scotland (that processes 35% of the UK's gas) to create blue hydrogen and sequester the CO2 created in the process to then store it in fields offshore, re-using existing pipelines, eg. Miller, Goldeneye or Atlantic. It would also store CO2 sent via an onshore pipeline from Scotland's central belt and transported via ship to Peterhead port.

Sam Gomersall, Commercial Director at Pale Blue Dot, told Offshore Europe that there's already work to allow 2% hydrogen content in the natural gas grid. A project in Aberdeen is looking to increase that to 20%, locally, then up to 100% following infrastructure conversion work. The group gas funding into pre-front end engineering and design and thinks a project could be up and running by 2024.

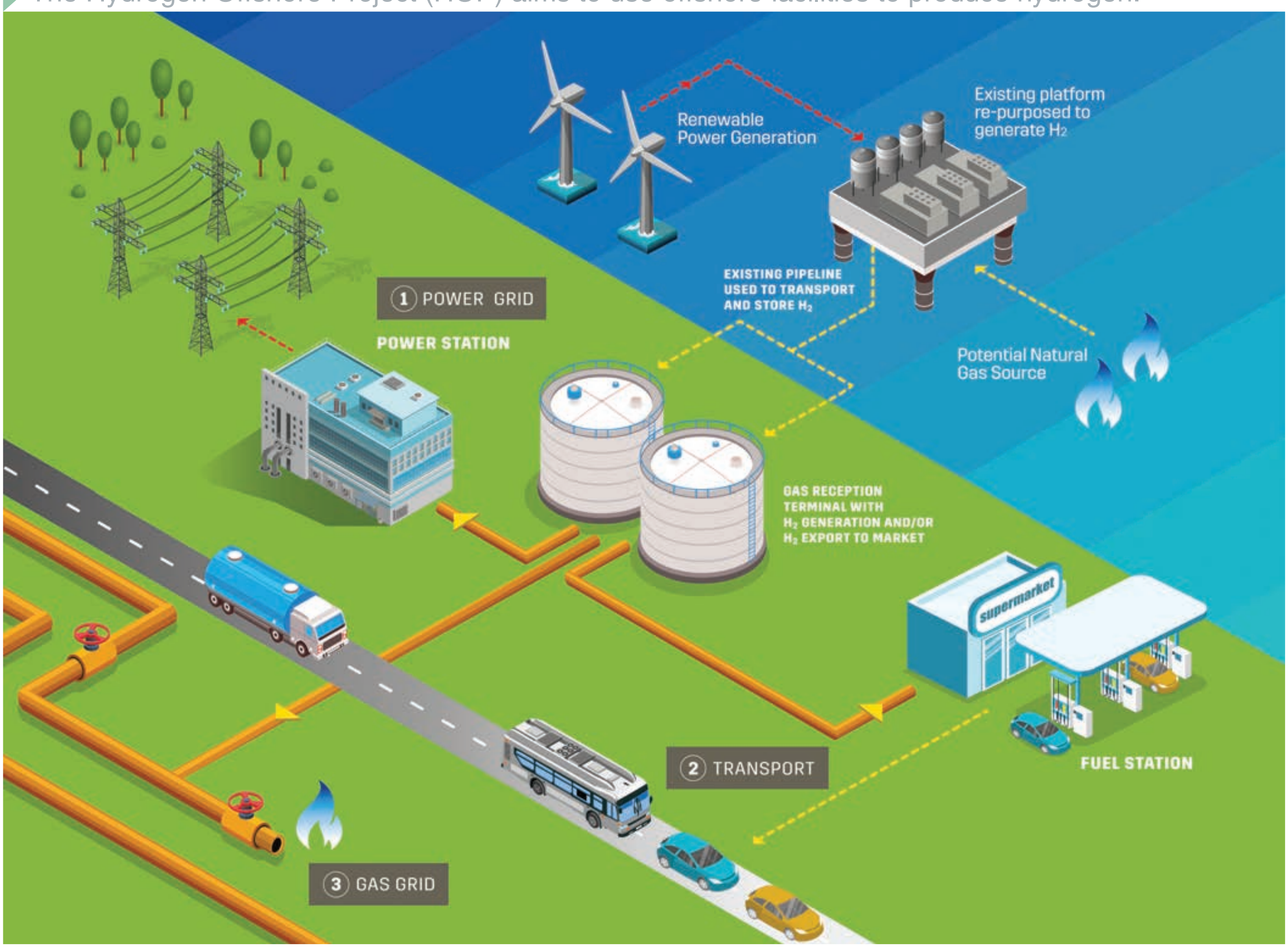
Owain Tucker - Global Deployment Leader - CO2 storage, at Shell, pointed Offshore Europe attendees to existing initiatives, such as the Technology Center Mongstad, in Norway, and projects, including Gorgon in Australia, which will sequester 3.4 million metric tons of CO2 a year, and Boundary Dam power station, where CO2 created is captured using Shell technology and then stored at a rate of 1 million metric tons per year for 25 years.

Northern Lights

There's also the Northern Lights in Norway led by Equinor with partners Shell and Total. This could see CO2 shipped from onshore industrial facilities to a coastal site from where it'll be piped offshore into a saline aquifer for storage. Equinor has a license for Northern Lights and is due to take a final investment decision in 2020, says Anna Korolko, Low Carbon Technology Lead, Equinor, with plans to start operation at the end of 2023. Equinor has already been operating CCS at Sleipner since 1996, with 23 million metric tons stored so far. It also has the Snohvit CCS as well.

Another project, Aramis, back in the Netherlands, is looking to store CO2 from the Rotterdam area. It's being looked at by NAM, Total and EBN, who are eying the offshore K and L blocks as storage sites, Esther Vermolen, Opportunity Manager Energy Storage

The Hydrogen Offshore Project (HOP) aims to use offshore facilities to produce hydrogen.



Source: The Oil & Gas Technology Center

at NAM/Shell told Offshore Energy. NAM is also looking to electrify the K14 platform, 90km offshore, using power from wind, saving 130,000 metric tons per year CO2, she says. NAM is looking closely at how CO2 injection will work and is also considering hydrogen storage in depleted fields, she said.

The CCS process can also be offshore to reduce plant emissions. Aker Solutions offers Just Catch, a CCS technology for offshore facilities where they may be too far from shore for a power link, says Ragnhild Stokholm, low carbon champion, at the company. A recent study for Equinor found two trains could cut 240,000 metric tons of CO2 from onboard turbines a year by dissolving the caught CO2 into water then injecting it.

Another option is using renewable power to reduce offshore plant emissions. Norway has been leading on this front, initially from shore such as from Norway's hydro schemes. Troll was the first field to get power from shore in 2005, followed by Valhall in 2011, with more since, including, most recently, Johan Sverdrup, which in turn will power others.

Equinor is taking this a step further, by installing floating offshore wind near platforms to provide power, an industry first. Its Tampen project, which is due to start up in 2022, will see 11, 8MW floating turbines installed to provide 35% of the annual power demand of the five Snorre A and B, Gullfaks A, B and C platforms, 140 km from shore in 260-300 meters water depth. In October, Equinor awarded contracts worth about NOK 3.3 billion ($360 million) to Kværner (substructures), Siemens Gamesa Renewable Energy (turbines), JDR Cable System (cables) and Subsea 7 (installation and connection) for the project.

These are just some of the projects being looked at – and just in Europe. There appears to be plenty of room to run. Making these projects work commercially will be the next challenge. If this challenge is overcome, the future is looking green. Or perhaps blue.

An important part of the energy transition, new technologies are being developed that unlock efficiencies and enable emissions reductions for oil and gas production projects, from installation through all stages of operation.

Baker Hughes, which has laid out its plan to reduce CO2 equivalent emissions 50% by 2030 and achieve net zero by 2050, says emissions reductions can be achieved during the installation and use of its Aptara TOTEX-lite subsea system, which includes the lightweight compact tree, modular compact manifold, composite flexible risers, SFX wellhead solution, modular compact pump and subsea connection systems.

Aptara components are significantly lighter and more compact than conventional systems, says Ewan Kent, Program director for the system. At 30-40 metric tons, the tree, for instance, can be up to 50% lighter than conventional trees, he says.

Size and weight reductions achieved by an innovative flow path within the body of the tree ultimately lead to carbon footprint reduction, Kent says. The system can be transported and installed using smaller road transport vehicles and offshore vessels with smaller deck space and smaller lift requirements, which generally emit less pollution into the environment.

In addition, the tree uses unique tree caps that are swappable over the life of the field, eliminating the need for additional infrastructure such as a high-integrity pressure protection system (HIPPS) or subsea boosting station. "Because the tree cap has additional functionality built in, we can actually, for example, build our HIPPS into the tree cap, whereas in the past you would have to build the HIPPS as a whole subsea structure," Kent says.

And because the blocks are smaller, time and energy required to weld and build this system is reduced from four or five weeks to two. "We're in the process of calculating the energy cost of machining and manufacturing the system," Kent says.

A prototype Aptara system has been built and tested in June by as a proof of concept, Kent says. The operator, which at this point is still unnamed, has asked Baker Hughes to design and deliver a system for use at one of its fields in 2020.

Aptara TOTEX-lite subsea system

Source: Baker Hughes

Marginal Fields, Global Opportunity

Unlocking marginal fields in the UK North Sea has led to a project comparing a global database of fields, discoveries and prospects, to clarify strategy for license holders and the supply chain alike in petroleum basins. Mike Cooper, 1st Subsurface, outlines the work and the prize.

Source all figures: 1st Subsurface

In 2015, a project was launched to unlock stranded and small discoveries in the UK Outer Moray Firth (OMF), one of the most prolific regions of the North Sea which is facing a dramatic decline if no further investment is committed. Unlocking overlooked marginal fields should transform the region's fortune.

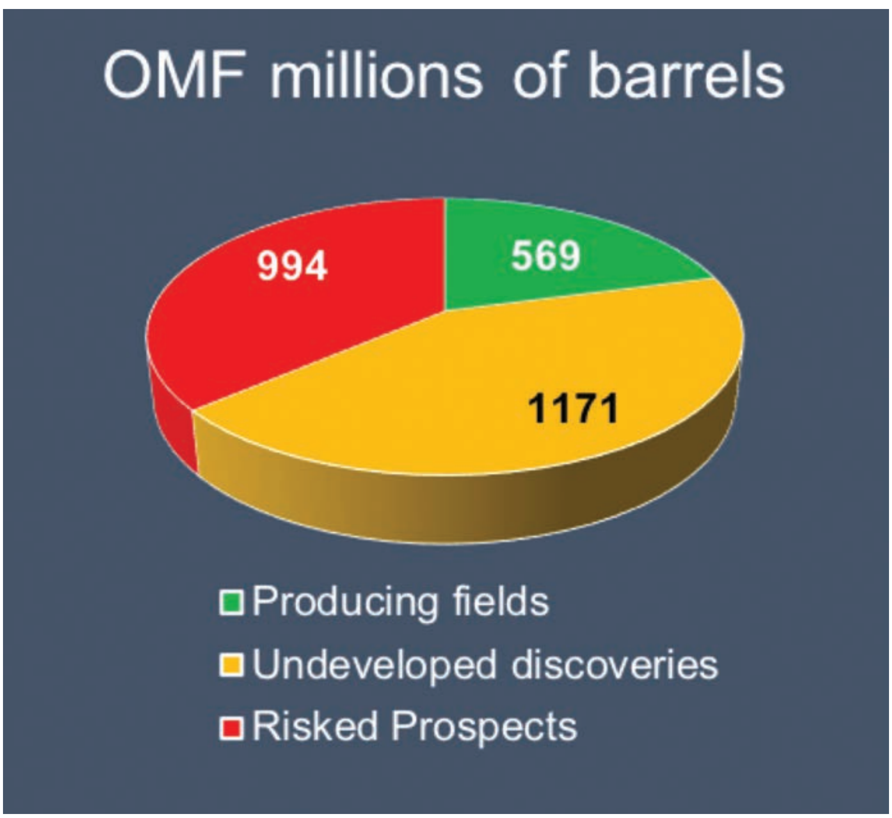


Figure 1: Reserves distribution in the Outer Moray Firth with 1.17 billion boe in undeveloped discoveries and a further 0.99 billion boe risked resources in undrilled prospects, according the 2019 OMF Special Interest Group study.

What are marginal fields?

Marginal fields can be defined in various ways, but almost always it comes back to the fact that they have barriers to investment. Small size is a common factor, but infrastructure access, access to finance and license ownership also constrain development. For most, a fundamental review of every value driver is required.

The UK Oil & Gas Authority (OGA) estimate there is 3.3 billion barrels of oil equivalent (boe) in over 300 undeveloped discoveries on the UK continental shelf (UKCS), with 1.17 billion boe identified during the OMF project (see Figure 1).

In addition to the undeveloped (contingent) resources there are almost 1 billion boe in risked prospective resources. With such a big prize, how can industry make the opportunities investable?

The history of the North Sea has predominantly witnessed the development of individual assets. Notable exceptions have typically been in response to prior price crises – such as

CRINE (Cost Reduction Initiative in the New Era) which was a collaborative program to simplify and standardize developments. In the OMF, a significant number of opportunities, on their own, are untenable. However, with access to a credible shared dataset of opportunities, licensees are looking to create hubs and unlock opportunities, to create real value propositions.

As an example, the OMF participants are developing a strategy for unlocking some 175 million boe (mmboe) of sour oil and 75mmboe of sweet crude in stranded discoveries. The strategy identifies the optimum solution for tiebacks to existing installations as well as areas where new clusters are needed.

Another example is using powerful visualization tools enable the opportunities to be characterized and summarized. Figures 2, 3 & 4 illustrate the size and distance of opportunities which are identified within 30 kilometers (km) of the Piper field.

Figure 4 clearly shows the distance and quantified size of opportunities within a 30km radius of the Piper field. There are resources of approximately 250mmboe in discovered fields, with four clear "jumps" indicating sizeable discoveries. Further tools are used to discriminate fluid type, flowline size requirements and a high-level screening of the probability of flow assurance issues.

By unlocking simplification and standardization benefits, rapid "what if" evaluations, result in a transparent and consistent assessment of hub potential. For example, TROVE utilizes analog and host production performance data along with reservoir characteristics, fluid type and screening development schemes with evidence-based production profile modeling for

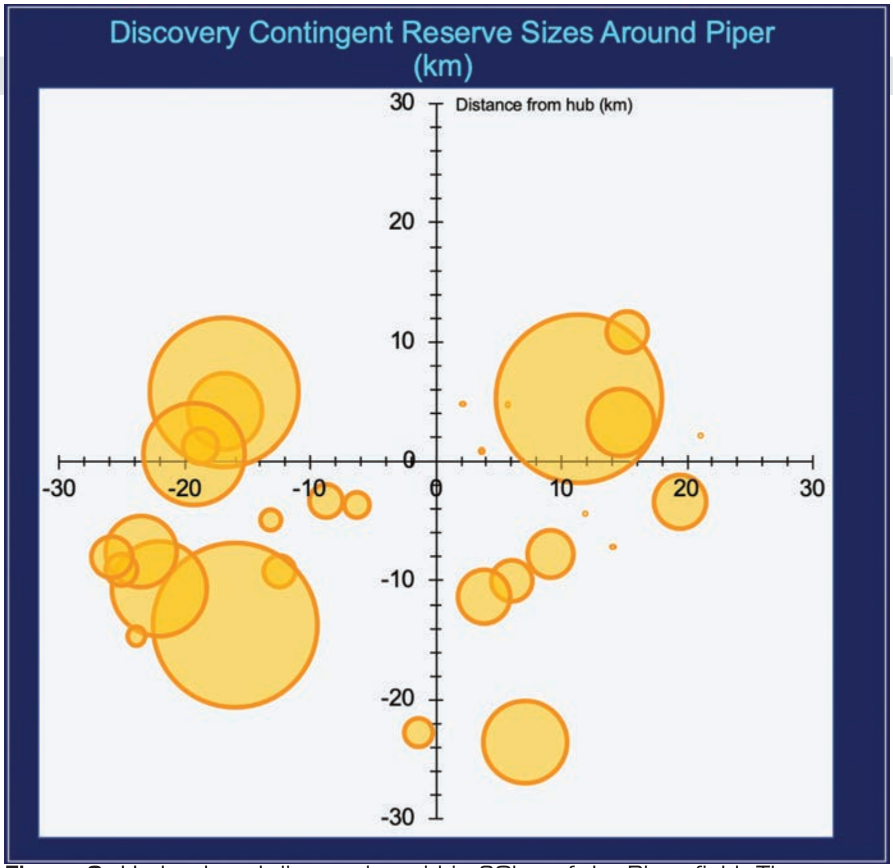


Figure 2: Undeveloped discoveries within 30km of the Piper field. The reserves scale is indicative on the plot for clarity, discovery descriptions and reserves available in TROVE.

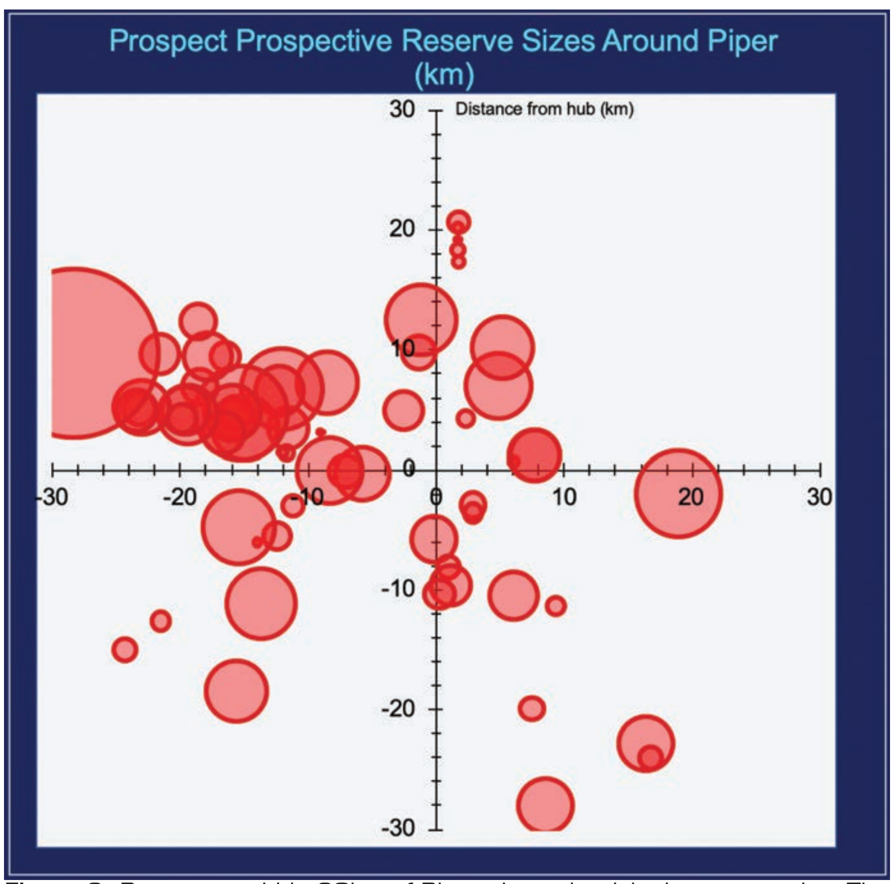


Figure 3: Prospects within 30km of Piper shown by risked resource size. The reserves scale is indicative on the plot for clarity, reserves available in TROVE.

hub screening. These may then be rapidly screened under various scenario constraints – e.g. the chosen pipeline size limits to accommodate throughput, whilst optimizing arrival temperature and pressure.

In the OMF, the principal formations occur at widely varying depths, with widely varying fluid composition and a wide range of pressures and temperatures. A different approach is thus needed.

"It's about deciding which design options are most relevant for a hub," says Paul Lindop, project coordinator for the OMF Special Interest Group, a consortium of major operators in the region. TROVE is used to identify which design bases are most applicable for all unsanctioned discoveries – delivering value through "design once, use many", taking everything from single well natural flow through to multiple wells with water injection and gas lift. Once screened and ranked the most value adding design bases can be taken through a front-end engineering study to provide the foundation of a "development playbook" for the basin.

What are the benefits of designing for a portfolio?

Working over a portfolio with simplified designs and standardized equipment reduces deployment cost, ownership cost and project risk – improving project economics. This effectively reduces the minimum economic field size hurdle. By utilizing reusable equipment, the cost is further reduced. Designing for reuse is one of the principles behind the UK's Oil & Gas Technology Center's (OGTC) Tie Back of the Future initiative. The OGTC is actively collaborating with the OMF participants to make such initiatives happen.

The approach is equally relevant for an existing installation looking to form a strategic plan to exploit satellite resources or a new hub where there is insufficient existing capacity or limited remaining field life at the existing hub.

For an emergent hub, the tools are the same but by optimizing new hub locations, strategies can be formed by the participants based on shared data optimizing all assets within the capture area.

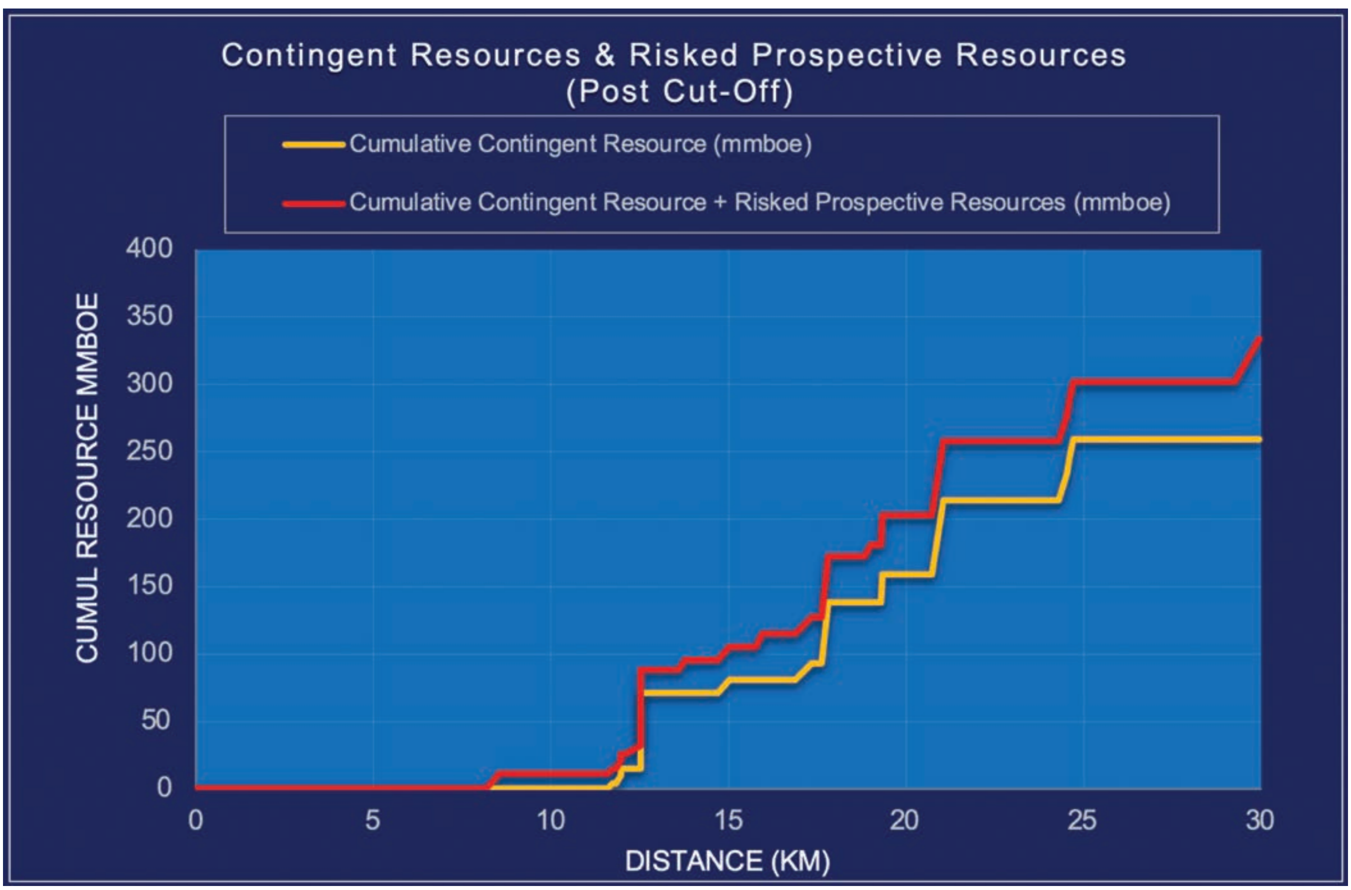


Figure 4: Undeveloped discoveries and risked prospect sizes by distance from Piper field.

Finally, Figure 5 shows the field size distribution in the deepwater and ultra-deepwater of the US Gulf of Mexico. Thirty-ninie fields of less than 10mmboe have been sanctioned at these water depths. This seems a far cry from the North Sea where 10mmboe has historically been mooted as a lower limit for materiality and economic development. Though such fields have been developed in the North Sea and continue to be considered for development, there are certainly lessons to be learnt when deepwater challenges can be overcome to develop economic investments, compared to the generally much shallower North Sea equivalents.

The costs associated with deepwater drilling and increased capital for deepwater infrastructure and deployment has clearly not hindered significant numbers of projects beyond the continental shelf in the US Gulf of Mexico.

Conclusions

There is huge potential in unsanctioned discoveries in the UK and globally. TROVE is used to unlock stranded resources by conducting rapid screening analyses and evidence-based strategic planning at a portfolio scale. License holders and the supply chain unlock value through simplification and shared standards driven by real data; in a collaborative process and achieving this through an auditable database of field, discovery and prospect data feeding tools to analyze remaining reserves at existing UKCS hubs.

The Author
Mike Cooper is Managing Director of Aberdeen consultancy 1st Subsurface specializing in technical subsurface and infrastructure analogue databases. Mike was formerly Exploration & Subsurface Manager for several companies including Lundin, Centrica, EnQuest and Kerr-McGee. Mike is acting CEO of Arenite Petroleum Limited and a former director of PESGB, during which he founded the Devex & jointly founded the Prospex conferences. Mike graduated 40 years ago from Leeds & Newcastle University with degrees in Geology (BSc) & Petroleum Geochemistry (MSc).

Figure 5

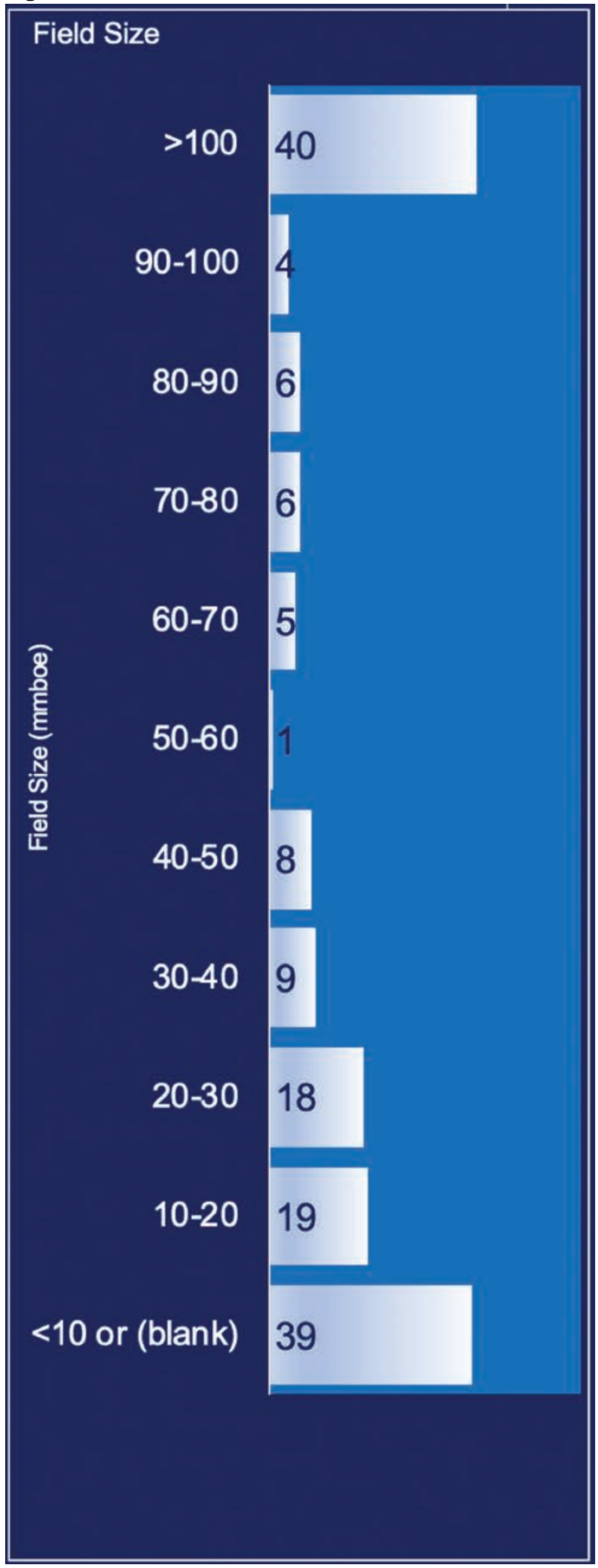


Figure 6

Asset
Atlas
Atlas NW
Baccarat
Balboa
Boomvang West
Calliope
Callisto
Condor
Cooper
Crown & Anchor
Dalmatian
Dalmatian North
Dalmatian South
Daniel Boone
Diamond
Diana South
Dulcimer
Einset
Ewing Bank 998
Garden Banks 205
Gladden
Goose
Green Canyon 29
Green Canyon 75
Harrier
Ida/Fastball
Lost Ark
Manta Ray
Mississippi Canyon 68
Ochre
Pilsner
Pyrenees
Raptor
Sangria
Sargent
Seventeen Hands
Shaft
Shasta
Supertramp
SW Horseshoe
Telemark
Tiger
Wide Berth

From Marginal *to* Major

BY WILLIAM STOICHEVSKI

It's not your typical marginal field — centered on a concrete gravity-based structure (GBS) that once boasted production records — but Draugen in the Norwegian Sea had become "immaterial" to Shell. When it first delivered oil in 1993, Norwegians looked forward to the spoils in 1.4 billion barrels (bbl) oil in-place. Today, that number's down to less than 17 million bbl, minus satellites. When Shell sold the field to new Trondheim-based indie, OKEA, in 2018, serial entrepreneur and CEO, Eric Hagene, decided to turn infield reserves and a minor nearby discovery into production hub Draugen. So far, the plan is working.

Unlike, Hagene — a geologist by training and founder of oil companies Det Norske and Aker BP — investors weren't all that thrilled by the marginal discovery, Hasselmus, or those infield reserves. They failed to make a planned $100 million listing spectacular, although they helped raise $35 million.

For less than the price of an Equinor fast-track field development of five years ago, OKEA — owned by Hagene's holding company and by Thai energy outfit Bangchak — bought Gjoea near the Sleipner platform and what was left of the Draugen area (complete with production infrastructure for major production).

Draugen's age showed. Some 190 meters of corroded carbon infield pipelines with pinhole size leakages had to be replaced with "stainless" steel lengths (done in a record seven days). Two subsea trees needed to be changed out, and applying predictive maintenance on sprawling oilfield infrastructure, the company discovered, meant an array of plant needed more monitoring and contractor integration. Safety officials added that vibrations topside, especially in high-seas, would need constant vigilance.

In fact, OKEA'S Draugen, unlike Shell's, is a massive flip job, a major renovation and grab of whatever area reserves will make the GBS as hub. "We think it'll be 25 more years with OKEA," a jovial Hagene says. For him, getting down to work means not wearing his characteristic bow tie.

"It was a billion-barrel field. We'll take the last 100,000 barrels," he says confidently. Why not go for it. Shell, after all, is understood to have the decommissioning costs on at least the GBS. So, for the next eight to "25 years", that frees OKEA to produce whatever's within reach from the platform. With the price of carbon-emissions credits skyrocketing, he might even earn money on emissions credits should the platform be electrified from shore, though that's not a given. A list of fields slated for a next round of "electrification" from shore appeared in Norwegian newspapers recently, and Draugen wasn't on it.

No loss. Start-up OKEA is still making 22,000 bbl per day (bpd) at the depleted Draugen and has earned 500 million NOK ($54.6 million) in the first half of 2019. To take the

Source: OKEA

prize — the capture of migrating and trapped area oil — a number of things will have to fall in place.

Development

The trees and pipeline change-outs were part of preparing Draugen for the long-term, Hagene says. The field also got a safety and automation (SAS) upgrade that included a digitalized control system revamp.

To provide the payback sought, Draugen — which once broke a record with a well that produced 72,000 bpd — will have to be run cheaply, or like a marginal field. To get started on the path to profit, the Odfjell Drilling semisubmersible Deepsea Nordcapp in October 2019 began drilling a series of wells: two this year, with at least three more planned for 2020.

The first well, Infill O, was pilot drilled toward an expected 2.5 m attic oil layer in October, but instead made contact with the 5 m main part of the Rogn reservoir. The well was drilled with a "highly cost-effective, slim design, and the top-hole section was batch-drilled with a well at the Skumnisse discovery (underway as of this writing), or well 6407/9-12. It took just five days to learn what Infill O had done, but the jury's still out at Skumnisse.

August seismic preceded the spudding of these, OKEA's first operated wells as a company. It is understood that 4D seismic had also been ordered for Infill O and Skumnisse. "We're sure there's oil there, but is it one meter thick or five meters thick," says OKEA VP of investor relations and communications, Staale Myhre. Cramped into a Trondheim office meeting room, he sounds as confident as his boss. "What we're targeting is 24.3 million bbl (including 4.3 million bbl from infill drilling). Skumnisse revealing 20 million bbl would be terrific start to a Draugen drilling campaign that'll run to year-end 2020.

That second appraisal well is of the discovery, Skumnisse, which "looks a lot like Draugen," according to Hagene. A new pipeline from Skumnisse to a revamped Draugen production system is understood to be planned. As part of its digitalization drive, and in an effort to boost the morale of workers and investors alike, OKEA is "broadcasting" the Skumnisse well's logs from aboard the Deepsea Nordkapp. "What damage can it do," Hagene asks with a smile.

The raw data from the drill crew won't move markets, but partners and interested parties — like ConocoPhillips, with its own area interests — will benefit from knowing whether oil's migration at Skumnisse has drifted past the infill drill area.

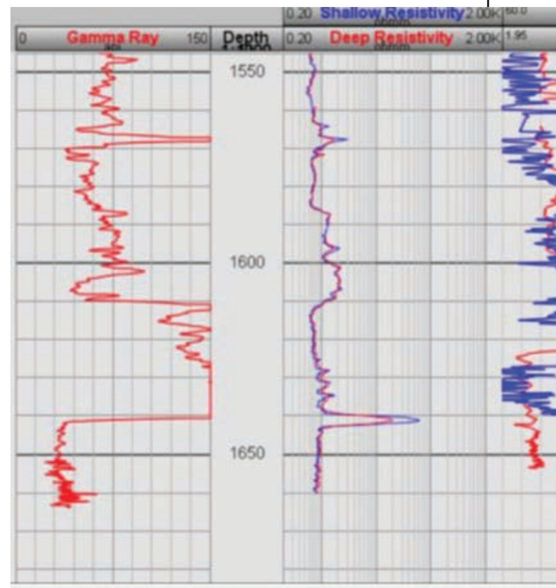
FID

Meanwhile, the Draugen-area's other Shell discovery, Hasselmus, looks like it's heading for development.

Hagene speaks only obliquely about that part of Draugen. He talks

Source: Author

Eric Hagene Serial Entrepreneur and CEO, OKEA



Bold reporting: OKEA's live stream wellbore progress at Draugen

up technology and calls his asset-playing OKEA a tech company. Once fleshed out, a concept for the field will be shown Norwegian authorities by year-end ahead of a final investment decision (FID) scheduled for mid-2020. Developing this "immaterial" Shell discovery seems a sure thing, however, as — by mid-2021 — first gas at Hasselmus has already been penciled in.

After that, the only planned Draugen area activity ought to have been an appraisal of Infill 0, now understood to have been cancelled. While a concept is worked up for the 15-year-old Hasselmus discovery, "debottlenecking and cost-cutting" is planned for the Draugen GBS and area infrastructure, which is considerable after a 2001 Shell buildout.

The OKEA way

On his way to Skumnisse and Hasselmus barrels, Hagene says he'll support any innovation the supply chain proffers that'll help earn more. He says he'll even support competition among innovators, especially in his beloved Trondheim, home of Norway's engineering schools.

"We don't ask for the solutions up front," he says, adding, "That's the big difference between us and some of the others." Instead, he lets suppliers "deliver as they prefer — not just at the early capex stage" — but throughout operations. OKEA has been developing the Draugen hub idea "since April 2018", and the planning is already said to be accommodating new supply-chain solutions. There's a sense OKEA will hang around for the life-extended field's lifetime, so there's time to approach via supplier portals or at Trondheim or Kristiansund.

"We've picked up licenses around Draugen. We see them as tie-ins to Draugen. [Others] never saw it that way," Hagene says, a nod to more stately rivals.

Supply side

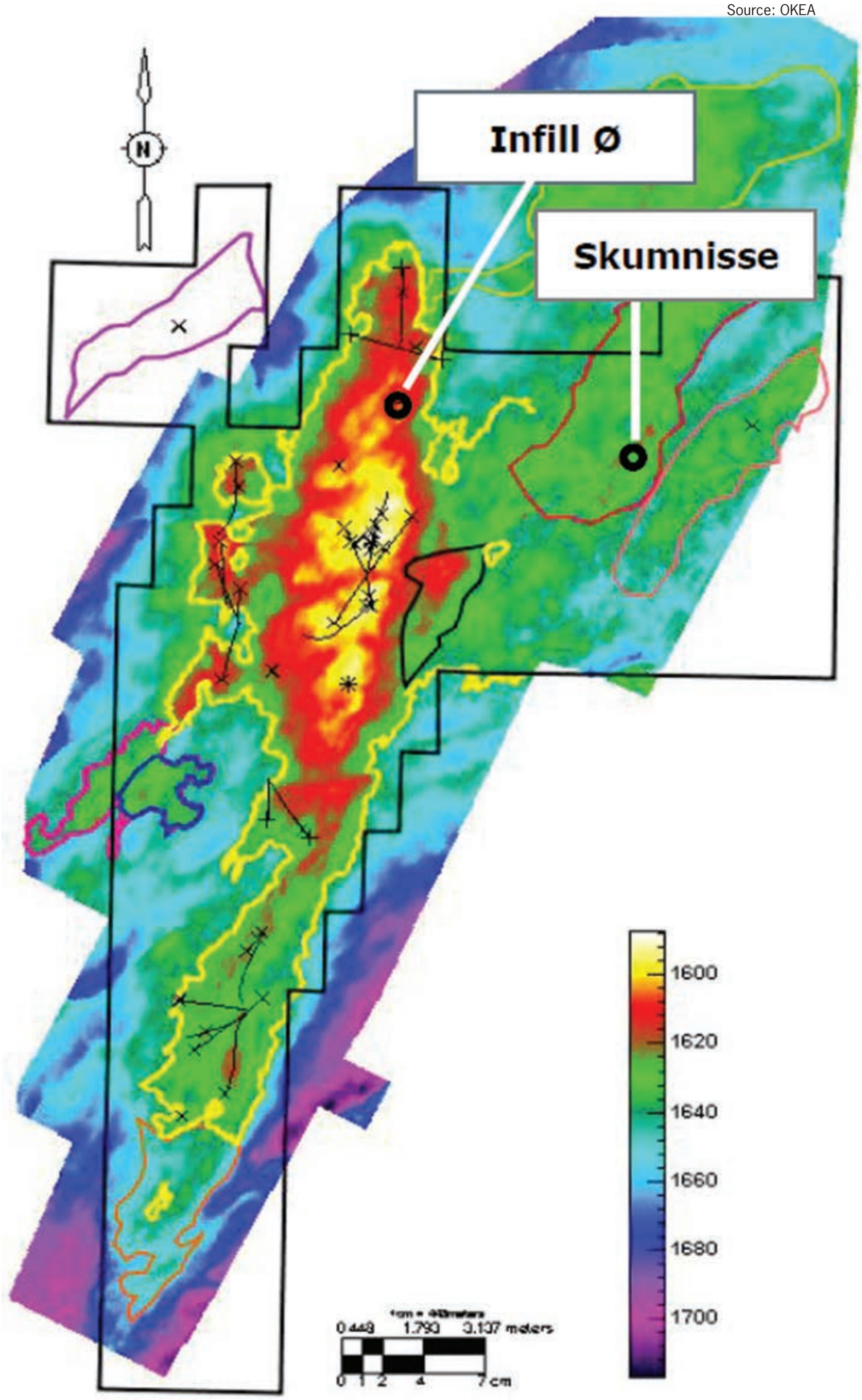
He knows, however, that Draugen area wells need about 6,000 bpd to 7,000 bpd min. to stay in production.

At Gjoea, OKEA and partner Neptune Energy are planning a Phase 1 of redevelopment with a new subsea template. At Grevling, the OKEA pattern becomes clear, as this Shell field was declared "marginal" when oil was $70 a barrel. Now, Okea appears to be planning to use a jack-up or floating producer tied back to the Sleipner platform. "Decision gate" for Grevling is March 2020. Already, new trees are being preordered. Vendors being nominated include Gusto MSC; Kanfa (topsides), Siemens (telecoms); Cameron (risers); Axess (yard lift). For now, fabrication yards have only been invited to tender: "no discussions" are ongoing yet with those yards, although they'll have to use said vendors.

But first, the Skumnisse will have to reveal its secrets, live via real-time well log on OKEA's website. Processed results are expected by year-end 2019. For now, Draugen and Gjoa together

Source: OKEA

Source: OKEA



combine to produce 9,648 barrels of oil equivalent per day (boepd) and 8,135 boped. With Brent oil holding above $60, 44.56% owner and operator OKEA seems well-equipped for price dips at Draugen, which is still providing the company with over 50% of its total production.

"$60 is quite OK, I think," Hagene assures us. He would know. He founded independent Det Norske (now Aker BP), in the 1990s, when North Sea oil dipped below $20 and Norway was producing a million barrels via just six large fields. A '90s production decline forced the government to incentivize the supply chain and small oil companies by 2006. That paved the way for Norway's first indies.

Hagene's indie intends to transform Draugen from shrunken giant to a hub of 100,000 bbl. The results of OKEA'S first operated wells, 6407/9-11 and 6407/9-12 in the Norwegian Sea, could speak volumes about whether they'll accomplish that vision. So, too, will the Hasselmus FID.

The target: a top section seismic image of the Draugen field

Raising the Pipeline Inspection Game

Source: XOCEAN

By Elaine Maslin

There's a shake-up happening in the pipeline inspections business. More evolved remotely operated vehicles (ROV), digital aspirations and unmanned surface vessels (USV) are driving a new era of data acquisition and deliverables.

It's offering something of a revolution in the amount of new insights that operators can acquire on their pipelines, while reducing offshore campaign time.

Some of those operating in the space are Equinor, Shell and BP. A big driver has been reducing cost, as well as minimizing safety exposure. It's the latest evolution in this space, Tom Glancy, Advisor Pipeline Mapping & Geographical Information at Equinor outlined at an October Hydrographic Society meeting in Aberdeen.

He says remote vehicle operation – during his own career – has gone from untethered manned submersibles (putting humans at risk) to ROVs, to unmanned underwater vehicles (UUV, usually referred to as autonomous underwater vehicles/AUVs, while not being wholly autonomous, highlights Glancy). While the move to ROVs removed humans from risk, the tether connecting them to a support vessel limited their scope. AUVs meant surveys could be done faster, but, AUVs weren't able to stop and do detailed spot assessments if and when an issue was spotted.

A more recent evolution has been toward fast ROVs. Equinor has agreements with the two main providers, DeepOcean, using the Superior ROV, and Reach Subsea with the Surveyor Interceptor ROV, says Glancy. While both are tethered, they can survey faster than an ROV, at 4 knots (kt) compared with 2kt, says Glancy, thanks partly to their onboard HD imaging and laser packages. But, that does also means they come with a support vessel – and over overheads that comes with.

XOCEAN's XO-450

These fast ROVs have become a popular tool, completely changing the traditional pipeline inspection workflow. "Over the last two-three decades, pipeline inspection been a relatively simple workflow; one campaign, utilizing two contractors, doing two separate surveys," starting in April and ending in August, Calum Shand, senior project surveyor at Shell told Offshore Europe in Aberdeen earlier this year. First, a geophysical survey vessel tows a remotely operated towed vehicle (ROTV) with a side scan sonar over the open water pipeline sections. Anomaly reports are then created, necessitating a second survey where a work class ROV (with a DP2 class vessel), undertakes spot dives and acquires video footage which is then used to plan any further rectification. But, "it's time consuming and relatively inefficient, with regards to using a two-vessel campaign," says Shand.

Increasing efficiency

For Shell, with more than 200 pipelines and umbilicals, totaling 3,000 kilometers (km) in length, in the UK North Sea alone, easier, faster surveys is a tangible bonus. In 2018, Shell ran a new survey using DeepOcean's "Fast Digital Imaging Service". This involved a Kyst Design Superior ROV, with auto tracking capability, operated from the Edda Flora vessel on a 45-day nonstop campaign, starting in September 2018. The Superior was fitted with Teledyne dual head multi-beam echo sounders, Edgetech side scan sonar and sub bottom profiler, pipetracker, a CathX ultra-high definition (UHD) cameras (x3) and high specification inertial navigation. An ability to launch the vessel in up to 4.5-meter seas meant work could be started earlier in the season and run late into Autumn, says Shand, with speeds of 5kt in acoustic mode and 3.5-4kt for pipeline inspection.

Furthermore, having the side scan sonar meant the vessel could break out of the pipeline survey to execute "ad-hoc fly-by jobs", such as a jack up rig site survey in the Shearwater field, says Shand. But, the biggest benefit was the UHD stills created by the CathX system, that enabled "incredible detail". "When you zoom in, you presented with sub-centimeter detail and can make inferences about what's going on, such as scoring on the top of a pipe from fishing interference," he says.

Combined with high-resolution multibeam bathymetry data, these UHD photos offer a completely new way of review incidents and anomalies, through 3D mesh models and color point clouds, with automatic comparison of annual survey data sets now possible, he says. "These data sets are creating quite a stir," says Shand. "It's a radical change."

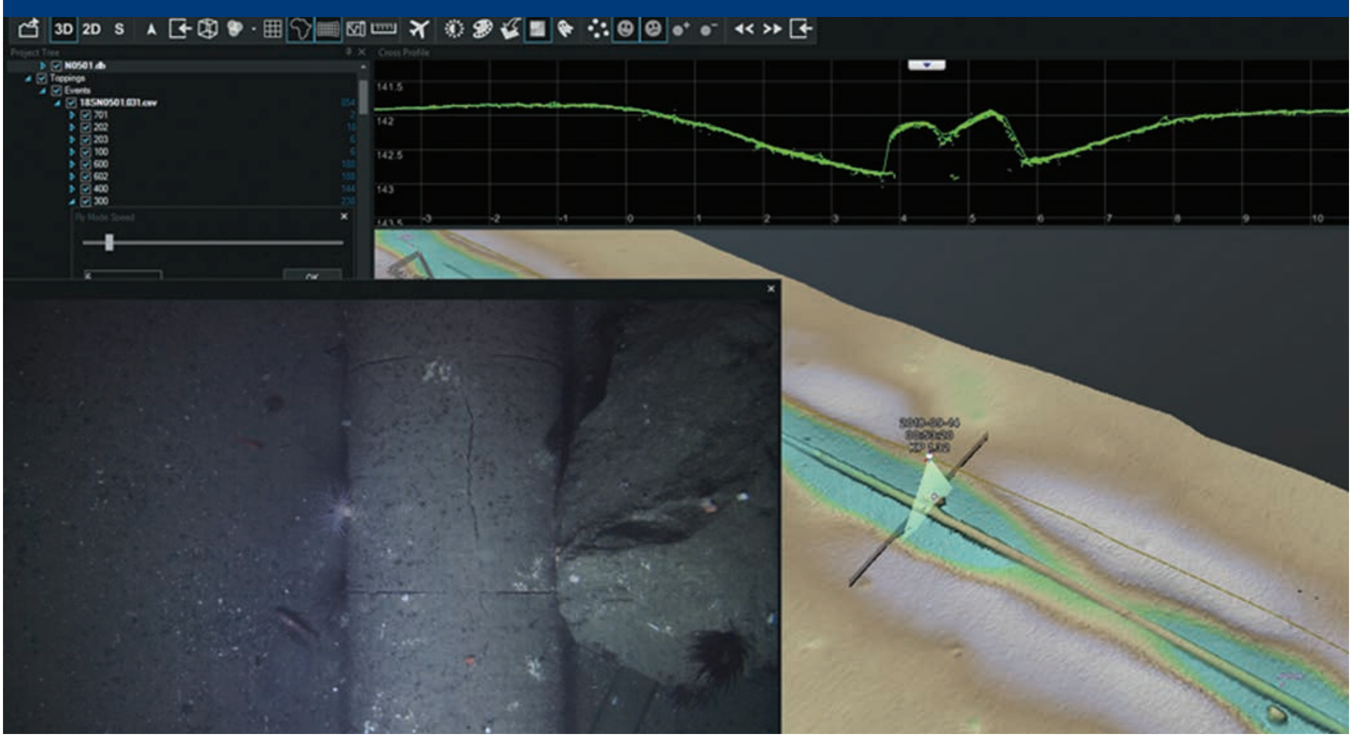
Data driving decisions

With this capability, remediation can also be faster. For example, on discovering a new pipeline free span, Shell was able to export the muiltbeam data and pass it to the contractor – Van Oord – who were able to accurately calculate the amount of rock needed. What's more, pipeline engineers now have a better ability to compare legacy 'as-built' information, with recently "as-found" multibeam data.

This year [2019], Shell went back out again, this time with Reach Subsea using the Surveyor Interceptor vehicle,

Boulder Kissing Pipe from Shell

Source: Shell



designed with MMT and Kyst, fitted with boom arms. These provide better circumferential coverage of the pipe. “We have gone from doing one campaign with two vessels to one campaign with a single vessel / contractor,” says Shand. “We’ve saved around £800,000 ($1 million), compared with the old way of doing it, and emit less carbon dioxide (CO2) as a consequence” largely thanks to 50% less vessel time.

There has been a learning curve, especially around trying to automate the associated data processing and then in handling the sheer volume of data generated, adds Shand. There are also some barriers to doing this work differently, related to behaviors and workflows. But, Shand says the potential is significant, including integrating external, GIS-linked, 3D modeled survey data with CAD models and also internal pipeline inspection data, enabling a powerful view of the entire pipe system. Adding machine vision and deep learning on to that, where rocks, debris, scouring, etc. detection is automatic, will enable more automated operations and greater ability for predictive analytics instead of reactive operations, says Shand.

Fast Digital Imaging Inspection

Fast Digital Imaging Inspection (FDII), moving from video to digital that can enable automated eventing, and increasing inspection speed, has also been a driving force for BP. Eric Primeau, a Senior Technology Specialist for BP, told Subsea UK’s Underwater Robotics conference in Aberdeen that it’s about taking a bottom-up approach, selecting a sensor package, then the vehicle that package should go on, instead of picking the vehicle first.

The company ran its first FDII campaign with DeepOcean in 2017, performing 478km of pipeline inspection, with UHD digital imaging, laser, dual head multibeam and side scan sonar at an average of 5.1km/hour. The project was completed in 94.7 hours compared with 578 hours predicted with a traditional methodology. Final data included 3D mesh and colorized laser point clouds.

BP has followed up with another two campaigns in 2018, with MMT and i-Tech7, and then another in 2019, again with i-Tech7. Throughout these projects, BP has also been testing non-contact field gradient cathodic protection sensors. Like Shand, however, processing the data gathered by this approach has been a challenge.

Going without a manned surface vessel

Yet, this method still requires use of a manned support vessel. So, operators have been trailing use of USVs for pipeline inspection. Earlier this year (2019), BP tried pipeline inspection using an XOCEAN XO-450 USV – a first for the North Sea. Deploying the USV out of Peterhead, in northeast Scotland, BP surveyed a shallow water section of the 30in abandoned Miller export pipeline. On a second run, from just 2.5m water depth to 40m depth over a 4.75km section of pipeline, the USV was set up with an R2Sonics Dual Head multibeam system, Valeport SWiFT sound velocity profiler and Applanix POSMV OceanMaster for vehicle heading, attitude, heave and velocity.

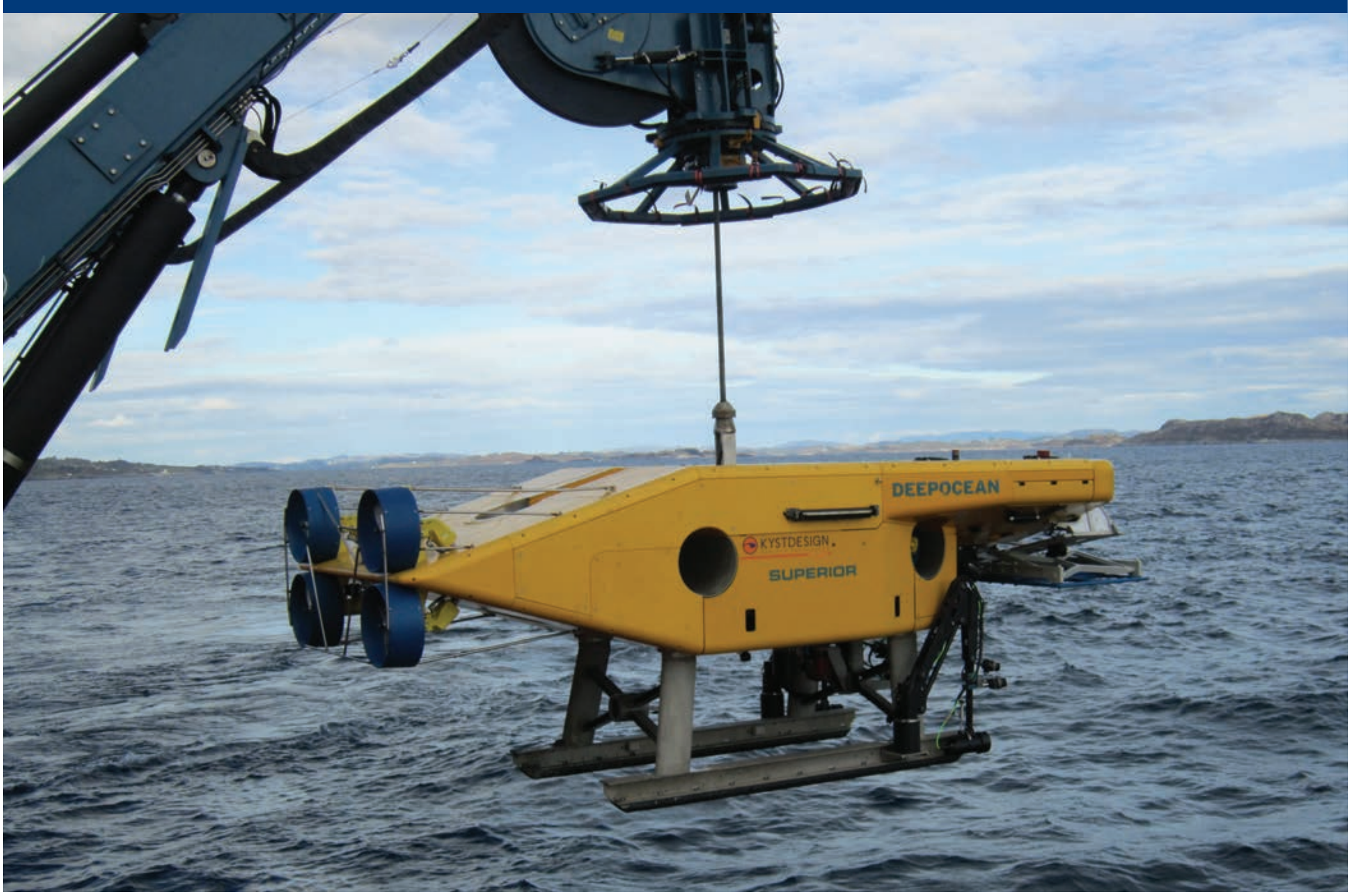
Success on the Miller project led BP to commission the same system for deployment in the Caspian Sea in Azerbaijan for inspection of hundreds of kilometers of shallow water pipelines (12-25m water depth). "The offshore industry is on the cusp of great change as the use of USVs increases and functionalities develop. It's challenging the use of manned vessels for routine inspections," Primeau says. "The USV is becoming a standard tool for performing high resolution seabed surveys and it's also a gateway for developing complementary underwater systems, such as the integration of ROVs and AUVs."

Shell's also been looking at USVs, Shand says, testing an XOCEAN XO-450 along the coast north of Aberdeen on a short trial survey in 2019. Here, while data and bandwidth will be a challenge, the roll-out of 5G and use of the cloud will help, opening the door to real-time inspection and analysis, he says.

Equinor has also been using USVs for pipeline survey. In September 2019, XOCEAN completed pipeline surveys

The Superior SROV

Source: DeepOcean



for Equinor off the east coast of England and the north coast of Germany. Using MBES, four pipelines totaling 120 miles in length in from 2-40 meters water depth, were surveyed in water depths from 2-40 meters, XOCEAN has said. Another USV vessel operator, 4D Ocean, has performed inshore surveys for Equinor earlier this year with a hull-mounted MBES.

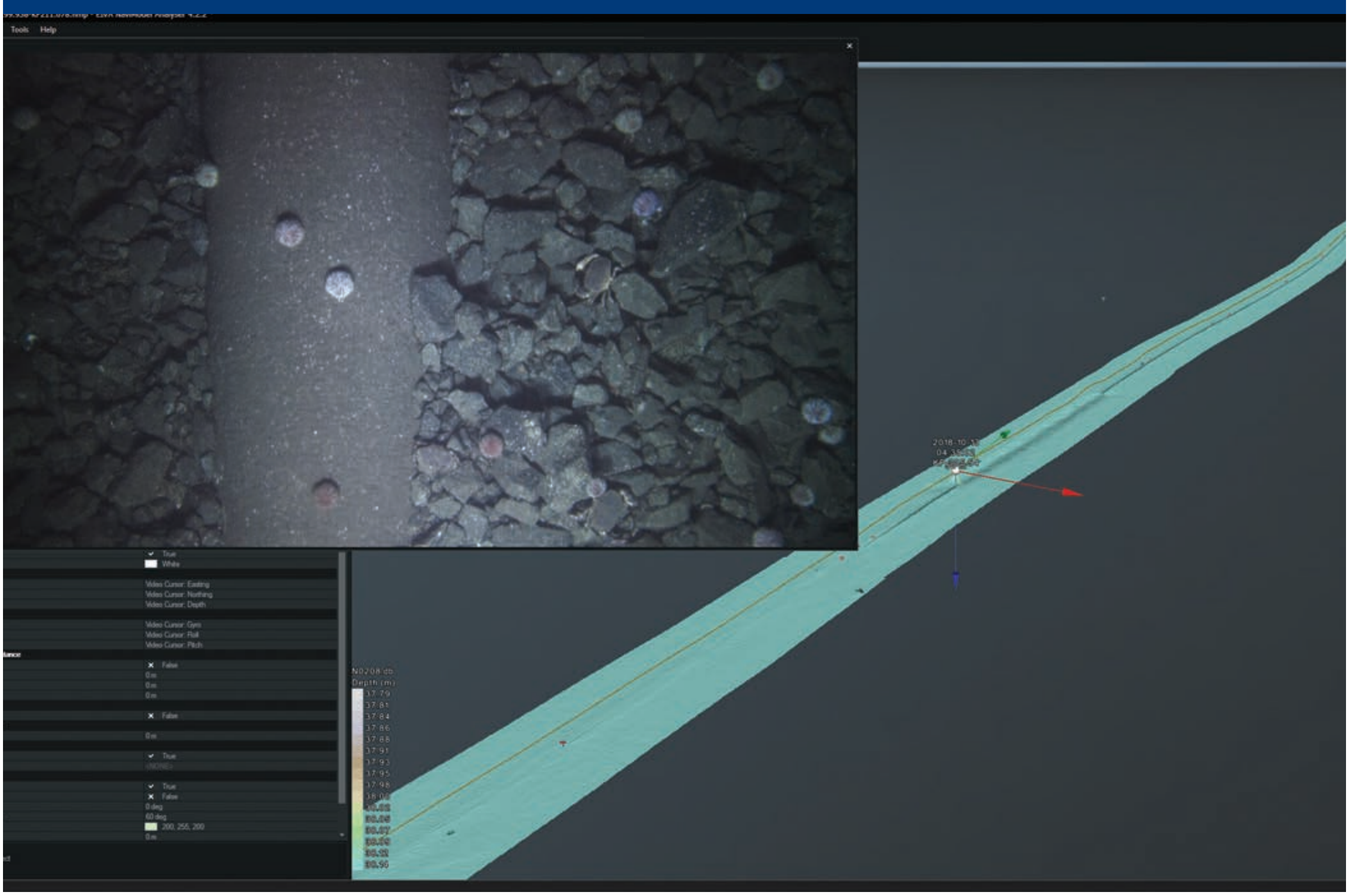
XOCEAN has also done what it's claimed is the first trailing wire cathodic protection (TWCP) pipeline survey from a USV, also in September 2019. This involved TWCP surveys, with multibeam sonar, for PX Group on pipelines up to 9km from shore near Shetland and off the coast of Aberdeenshire. PX Group operate and maintains, for North Sea Midstream Partners, the St Fergus Gas Terminal and associated Frigg UK and the Shetland Island Regional Gas Export System (SIRGE) offshore pipelines which link the Aberdeenshire facility with the North Sea.

Combining USVs with AUVs

However, sensors onboard USVs will only reach so deep. If deeper water pipeline surveys are to do done with USVs, an alternative approach is needed. That's meant deploying an AUV from a USV – and that's just what Swire Seabed has been doing for Equinor, in Norway. In October 2018, in the first of two projects, it deployed a Kongsberg Hugin AUV with a small surface vessel that enabled it to maintain position updates and communication to a control from in Bergen. The inspections were performed on three pipelines between Kollsnes (an onshore plant) and Troll A (just 65km off Bergen). In total, 180km of pipeline was inspected over two AUV dives with bathymetric, synthetic aperture sonar and HD image data acquired to verify the subsea pipelines' integrity.

In July 2019, Swire then laid claim to the "first fully unmanned offshore pipeline inspection 'over the horizon'", surveying up to 100 km from the shore, again for Equinor.

Visualization from Shell's pipeline inspection campaigns. Source: Shell



The SEA-KIT housing a Hugin AUV for remote pipeline operation. Source: Swire Seabed

This saw a Hugin with MBES, side scan sonar and CathX camera system, used in conjunction with a SEA-KIT Maxlimer USV, made by UK firm Hushcraft. Four pipelines, totaling 175 km in length, were surveyed, again using bathymetric, synthetic aperture sonar and HD image data. Using the SEA-KIT Maxlimer meant the Hugin could stay offshore doing the survey for longer – docking at sea in the USV to recharge, as well as using it as a communications and control link to the remote center in Bergen. Swire says that by using a small unmanned vessel, fuel use – and carbon emissions – are reduced by 95%. Tom Glancy puts it another way – putting people offshore is reduced 100%. His ultimate goal is to have no surface vessel at all.

[Editor's note: Swire Pacific Offshore (SPO) announced in November it will shutter its Swire Seabed subsidiary from the end of February 2020 as oilfield services firms continue to feel the effects of the pronged industry downturn. Vessels currently managed by Swire Seabed will be operated and marketed as part of the SPO fleet based in Singapore.]

The next steps

Some are working on this. In 2018, Modus Seabed Intervention deployed one of its HAUVs (a modified Saab Seaeye Sabertooth AUV) offshore Northwest Australia to perform approximately 240km of pipeline survey using a CathX Scout laser profiling and HD imaging spread alongside a multibeam echosounder (MBES). While this was performed with the HAUV on a tether from a vessel, for real-time data collection, it would be possible without at tether, the firm, which has more projects in the pipeline, as it were, says.

Oceaneering's Freedom hybrid vehicle, while much promoted with regards to subsea resident vehicles, was in fact initially designed for autonomous pipeline survey. Oceaneering's key goal was to have an efficient aerodynamic vehicle that could stop and carry out additional inspection work, if it detected an anomaly. Indeed, Steffan Lindsø told an Underwater Intervention Drone demo event near Stavanger in October that vehicle's first project, in 2020, would be a pipeline inspection, "probably in the UK".

Kawasaki Subsea is also testing its second-generation vehicle, which incorporates pipeline tracking for survey inspection, offshore Japan. This year (2020) it will come to total to test pipe tracking with DeepStar and the Nippon Foundation. There's been disruption in the pipeline inspection space, and there's more to come.

Source: I-Tech 7

FDII

Machine vision technologies are also helping to improve how pipeline surveys are provided. i-Tech 7, part of Subsea 7, is one of those providing close-inspection fast digital inspection services, increasingly supported by automation.

Its fast digital inspection pipeline services are provided via a dedicated skid which can be easily shipped and mobilized on board any of the work class ROVs in its fleet, depending on where services are required. The skid is fitted with a modified CathX Pathfinder suite, which has three ultra-high definition cameras – port, center and starboard – laser profilers and a pilot camera, synchronized between still images (a safety feature, so that the high-powered strobing LED lights do not influence the ROV pilot's view).

Using a digital imaging suite like this means surveys can be run faster, at 3-4.5km/hour, compared with video-based surveys which have traditionally been run at 1km/hour to allow manual eventing online and to avoid blurred imagery, says Danny Wake, Chief Surveyor, i-Tech 7. A general visual inspection project for BP, in 2018, which covered eight pipelines, with a total length of 310km, plus two structure inspections, saved 10 vessels days (taking just over 14 days) against traditional pipeline inspection speeds. Equivalent savings were realized for the 2019 FDII pipeline inspection campaign for BP, with the added benefit of contributing to reduced CO2 emissions.

Pipeline engineers also get orthomosaics and 3D models of the pipeline which can be located spatially (rather than sequentially, like video). But that's not all. I-Tech 7 has been working with US IT, science and technology firm Leidos on ways to automate the data processing routines to provide useful information to engineers faster. For example, automatically analyzing imagery to extract images containing possible events, thereby dramatically reducing the amount of imagery to be reviewed by a human. i-Tech 7 ran its first survey using these techniques this year (2019).

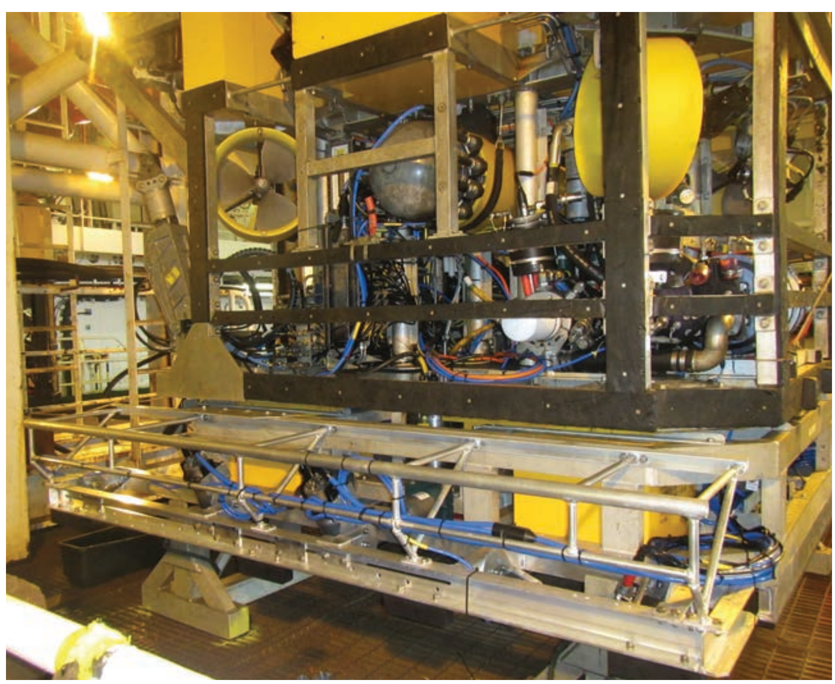
Interestingly, it's a technique not limited to digital imagery. Some 60% of the algorithms developed for digital inspection will also work on video, says George Gair, Global Inspection Manager at i-Tech 7, making broader use of this technology.

"The holy grail is automatic classification and eventing," says Wake. "We're making steps towards that, tuning the algorithms, increasing automation, starting with machine vision that detects possible events." The next step after that is doing the detecting live, giving engineers faster access to inspection results so they can act on them more quickly.

Despite the hype around these types of technologies, including machine learning, which use computing power to compare millions of images and detect specific attributes, it's not that easy, especially in an industry that likes to do the opposite to standardized designs. Having the training data – images of pipelines – is also difficult.

But, about 90-95% of the pipeline integrity issues that are found tend to be freespan and burial exposure related, says Gair, so this has been the company's main focus. Damage, which tends to be atypical, will take more time. Humans will also still be needed in some parts of the process, he says.

In terms of vehicle platform, i-Tech 7 has stuck with ROV-based skids. While using AUVs also helps run surveys faster, they tend to swim higher above the pipeline and don't necessarily carry the full FDII sensor packages that offer such comprehensive view of the pipe, says Wake. While there has been focus on having systems that are able to stop and gather more data if an anomaly is detected, he says, with the FDII data, where you can see the pipe from more angles than just from above in ultra-high resolution, engineers already have all the information they could need – they'd not need to go back and do more detailed inspection.



2020 Offshore Exploration Outlook

By Eric Haun

Exploration and production (E&P) companies are expected to enter 2020 with measured optimism for offshore exploration prospects, after 2019 delivered a moderate increase in exploration drilling and not-so-moderate rise in licensing activity.

RISING FROM THE ASHES

When the oil price began its nosedive in 2014, offshore exploration activity spiked in parallel, falling nearly 40% before bottoming out in 2016-2017, said Rohit Patel, a senior analyst at Rystad Energy. In unison, offshore exploration expenditure dropped by almost 60% from 2014 to 2017 mainly due to lower cashflows, the growth of US shale and reduction in offshore acreage awarded, Patel said. "This also resulted in a drop in conventional discovered resources, and the reserves replacement of E&P companies fell below 20%."

But then came 2018, "the year of transition", which brought the first uptick in global offshore exploration well count since the start of the downturn, leading to expectations that 2019 would deliver "a much-needed resurgence" in offshore exploration, Patel said.

For the most part, 2019 has delivered. As of November, Patel pointed to an 8-10% increase in the number of offshore exploration wells drilled compared to 2018. "In line with this, global discoveries of conventional oil and gas have also shown a promising growth in 2019 with the total offshore discovered resources YTD reaching almost 8.5 billion boe (vs 2018 total volumes of 7.5 billion boe)."

"Gas discoveries have edged out oil discoveries in 2019 with gas to liquids ratio of 65:35 in YTD offshore discovered volumes. Excluding Americas, gas discoveries dominated oil discoveries in all other regions. The trend is estimated to continue in 2020 with growing demand for gas across geographies, led by Asia and Middle East."

Overall, Patel anticipates offshore exploration activity will continue its upward trajectory in the year ahead. "We can expect to see a moderate rise of 4-7% in 2020 compared to 2019," he said.

Licensing activity, too, has been on the rise. "2019 witnessed high levels of licensing activity compared to last several years, driven by stability in oil prices and more attractive of fiscal terms offered by countries in a bid to improve on domestic exploration investments. Subsequently, offshore acreages awarded YTD are up more than 25% compared to 2018, which is encouraging as the commitments and work programs associated with these awards are expected to drive investments in offshore exploration in near term."

"Growth in licensing activity seen in 2019 is expected in continue in 2020," Patel said. "2020 will continue to witness momentum in licensing activities with more than 50 licensing rounds to be conducted across the globe."

Patel said Africa will see the highest increase in licensing activity, with several smaller countries in Southeast Asia (Myanmar, Thailand, Timor-Leste and Bangladesh) and the Americas (Guyana, Barbados and Panama) also active in licensing arena in 2020.

DISAPPOINTMENTS AND OPPORTUNITIES

"After many years, operators in Northwest Europe, Africa and Asia Pacific were seen exploring actively in frontier regions in 2019. The continued benefits of higher cashflows, efficiency gains and cost reductions are expected to encourage operators to run high risk frontier exploration campaigns in 2020," Patel said.

That's not to say there haven't been letdowns. "2019 has continued the theme of peaks and troughs," said Gregory Brown, Associate Director - Offshore at Maritime Strategies International Ltd. "While there has been some particularly encouraging greenfield discoveries such as Yakaar-2 off Senegal and ExxonMobil's continued success off Guyana, activity in other frontier regions such as the Barents Sea has disappointed."

Looking ahead to 2020, Brown said the number of contracted rigs suggests "activity will increase, but the magnitude may disappoint some of the more bullish outlooks.

Total will drill its first exploration well off Lebanon. The partners will use Vantage Drilling's Tungsten Explorer to drill the well in Block 4.

Source: Vantage Drilling

While activity in South America should be robust – Mexico, Brazil and Guyana in particular – markets such as Norway could disappoint."

"Equinor will drill between 20-30 wells off Norway in 2020 – a steep fall from approximately 40 prospects drilled in 2019," Brown noted. Equinor will focus on the western part of the frontier market in 2020 as the Norwegian energy company and others exploring in the region will hope to discover recoverable reserves to support estimates that more than half of Norway's yet-to-be-discovered reserves lie in the region, Brown said.

Globally, Brown predicts near-field exploration rather than frontier work will provide better returns. "Near-field exploration has been a particular standout in mature markets. The range of independents working in mid-deepwater in the US Gulf have had a series of successes that should support the brownfield tieback market for some time."

"We look at West Africa as a tieback market – particularly Angola and Ghana – and will watch Eni's activity at the East and West Hubs closely," Brown said.

HOTSPOTS

Both analysts agree that South America, Africa and Australia will be key regions for exploration growth in the year ahead.

When asked where the hotspots for 2020 exploration might be, Brown said, "Brazil is the obvious answer", noting that an increasingly diverse operator mix – including Equinor and Shell among those joining Petrobras in exploring the deepwater pre-salt – will be key to success in the region.

In 2019 Tullow Oil made two high-profile oil discoveries on the Orinduik block, opening a new Upper Tertiary oil play in the Guyana offshore basin. Joe-1 and Jethro-1 were drilled by drillship Stena Forth.

Source: Tullow Oil

"Brazil is on the verge of a revival in exploration activity in 2020, thanks in particular to the high interest shown by major oil and gas companies in the pre-salt province beneath the deep waters of the Santos and Campos basins," said Patel, who also counts the South American country among 2020 hotspots. "International players have picked up acreages in Brazil's offshore licensing rounds during last two years by paying huge signature bonuses – totaling in billions. It can be inferred that big players seem to be quite optimistic on the prospectivity in the region. The commitments from the recent licensing rounds are expected to trigger a surge in exploration drilling in the region with numerous high impact wells already on cards."

Elsewhere in South America, "Tullow's success with the Jethro and Joe probes, despite containing relatively heavy oil, should eventually open up a second play off Guyana," Brown said. The independent operator will drill three exploration wells off Guyana as it looks to de-risk the discoveries in the Orinduik block.

Mexico is another hotspot, Patel said. "Mexico is expected to see an eventful 2020 as international companies have lined up to fulfill the pending well commitments on the offshore acreages that they acquired in rounds 1 and 2.

"Around 20 offshore exploration wells will be completed in 2019 and we expect the 2020 well count to be in a similar range. The results of 2019 wells, particularly those in the less explored deepwater areas, will be watched closely by the industry and they will play a large role in shaping industry's perception of Mexico's deepwater exploration potential and will determine the growth in activity in near term," Patel said.

Brown noted, "Shell's first deepwater well of Mexico spuds in early December, and is due to complete in February. Chibu-1EXP will be drilled in more than 2,700 meters of water and is the first of 13 that Shell has committed to drill in the Campeche Basin."

In South Africa, Total will drill another exploration well in the 11B/12B block in the first quarter after opening up a new play with the approximately 1 billion barrel Brulpadda prospect in the Outenqiua basin this year, Brown said.

"Meanwhile, perhaps less discussed, is activity off Southern Australia. Cooper Energy's Annie-A discovery in shallow waters was the first in the basin for 11 years," Brown said.

Patel said, "Australia is witnessing a comeback in offshore exploration in 2019 and 2020. After [Santos'] recent Dorado discovery and the subsequent successful appraisal drilling, there has been some optimism amongst explorers focusing on the Australian waters. The North West shelf area, where the Dorado discovery was made in 2018, is going to drive the growth in exploration in 2020. Also, around three high impact wells are expected to be drilled offshore North West Australia in 2020.

"Additionally, South and West Africa, Mediterranean and Caribbean waters are also expected to witness increase in exploration drilling and licensing activities in 2020. These three regions also hold number of high-impact wells expected to spud in 2020," Patel said.

Rystad, set to publish its 2020 high-impact wells report in January, has shared five of its around top-30 wells to watch for 2020. The highlighted wells, which hold potential to yield significant value for the operators if successful, fall into either of the two high impact categories:

- ***Focus for company:*** These wells are highly talked about in the industry and also strategically important for the company and the region.
- ***Large prospective resource:*** These are wells targeting prospects for which the operator reported pre-drill estimate is quite significant. A success at this well can result in a massive discovery.

Country	Well name	Block	Operator	Rystad high impact category	Comment
Azerbaijan	SAX01	Shafag-Asiman	BP	Focus for company	BP will drill a deepwater well on the Shafag-Asiman block in the Azerbaijani sector of the Caspian Sea. Shafaq-Asiman is a large gas and condensate prospective structure and the partner in the block, SOCAR, has estimated that the structure could potentially hold 500 billion cubic meters of gas and 65 million tons of condensate.
Australia	Ironbark	WA-359-P	BP	Large Prospective Resources	BP-led joint venture is expected to drill the Ironbark-1 exploration well in the WA-359-P block located in Carnarvon Basin offshore Western Australia. The Ironbark prospect has a best estimate of 15 tcf of prospective recoverable gas.
Namibia	Venus	Block 2913B	Total	Focus for company	Total will drill the Venus-1 wildcat well on Block 2913B in the Orange basin offshore Namibia. The ultra-deepwater wildcat will target a potential resource of 2 billion barrels of oil in a Cretaceous fan play.
South Africa	Luiperd	Block 11b, 12b	Total	Focus for company	Total is planning to drill a well in Q1-2020 targeting the Luiperd prospect in Block 11b, 12b located in the deepwater Paddavissie fairway offshore South Africa. Luiperd is the largest of the five prospects previously identified in the block using 2D seismic data and is expected to be located in the oil window. The result of this well will be closely watched as a follow up of the game changing Brulpadda gas-condensate discovery in the same block in early 2019.
Egypt	Volans	North East Hap'y	Eni	Large Prospective Resources	Eni is expected to spud a wildcat targeting the 10 tcf Volans prospect in North East Hapy license offshore Egypt. Drilling is expected to start in late 2019 and results of the well are expected in the first quarter of 2020.

Source: Rystad Energy

The Future is in

Source: Vår Energi

The Goliat oil field has been producing for nearly four years.

THE NORTH

By Kåre Storvik

Sea uses

While others are known as rulers of the seas, Norway has been more known as users, locally and worldwide. No wonder, since Norwegian waters are covering an area of close to six times the size of the Norwegian land areas.

There is considerable potential for growth in many sectors of the ocean economy, including the seafood industry, marine biotechnology, seabed mining, maritime transport and trade, coastal and maritime tourism, maritime surveillance and of course energy (including both renewable and non-renewable). Together these sectors make up the ocean or 'blue' economy.

Notably, most of the Norwegian waters are in the North. The Arctic is Norway's most important foreign policy priority. Arctic policy will be considered in the context of ocean policy.

Sea uses have been the dominating source of income for Norwegians in the North. Joining fishing and seafood production – and more recently fish farming – oil and gas production from Norway's northern waters is of growing importance.

Norway's maritime knowledge, acquired through hundreds of years as a seafaring nation, and the offshore oil and gas activities, have powered Norway's position as a world leader within offshore technologies. These technologies, of paramount value for Norway's future in ocean utilization, may even be more valuable than the remaining oil and gas resources.

Oil and gas

Just before the Norwegian Petroleum Directorate director Bente Nyland is handing over her office to her successor Ingrid Solvberg, she is presenting the report "The Future is in the North".

In the report she expects that 8.3 billion standard cubic meters (sm3) of hydrocarbons remain to be produced on the Norwegian shelf. And that 5.4 billion of this will be produced in the Barents Sea in the North. One third of the total recoverable resources on the entire Norwegian shelf, which is estimated at 15.6 billion sm3.

Harvesting of resources at sea, hunting and fisheries, as well as other sea traffic in this area have traditions that are hundreds of years long and frighten few in Norway.

In spite of the high north latitude, the Gulf Stream ensures that the Barents Sea has little or no sea ice and less harsh climate than other similarly located Arctic regions in the North, of crucial importance to those operating in the region.

Equinor has successfully developed and operated the Snøhvit gas field and the Hammerfest liquefied natural gas (LNG) plant since 2007. And the Vår Energi Goliat oilfield has likewise been producing for nearly four years. Equinor is now developing the Johan Castberg oil field. In the next few years OMV is expected to decide on the development of its Wisting oil field and Lundin on the Alta/Gohta oil field. Business is flourishing and conducted by the same mix of local, national and international companies as elsewhere in the world where oil and gas is produced. There are opportunities for everybody.


Source: Aker BP

Hammerfest is the energy town of the North. Here the NorSeaGroup operates the Polarbase supply base while ASCO operates the ASCO base. Hammerfest hosts a complete cluster of service providers to the offshore oil and gas industry with competing bidders within all disciplines and all kinds of services. Hammerfest is therefore dominating as far as technical services to the oil industry in the

Equinor has used the West Hercules drilling rig to explore for hydrocarbons in the Barents Sea.

Source: Ole Jørgen Bratland, Equinor

High North are concerned.

With few exceptions Norwegian national service providers prefer to commute their human resources from their Southern headquarters to the North. While British and other international contractors are more known for bringing their technologies with them and recruit, train and employ local labor. That contributes to more local content and is very much appreciated in the region. Examples of such companies are ASCO, Swire and Score.

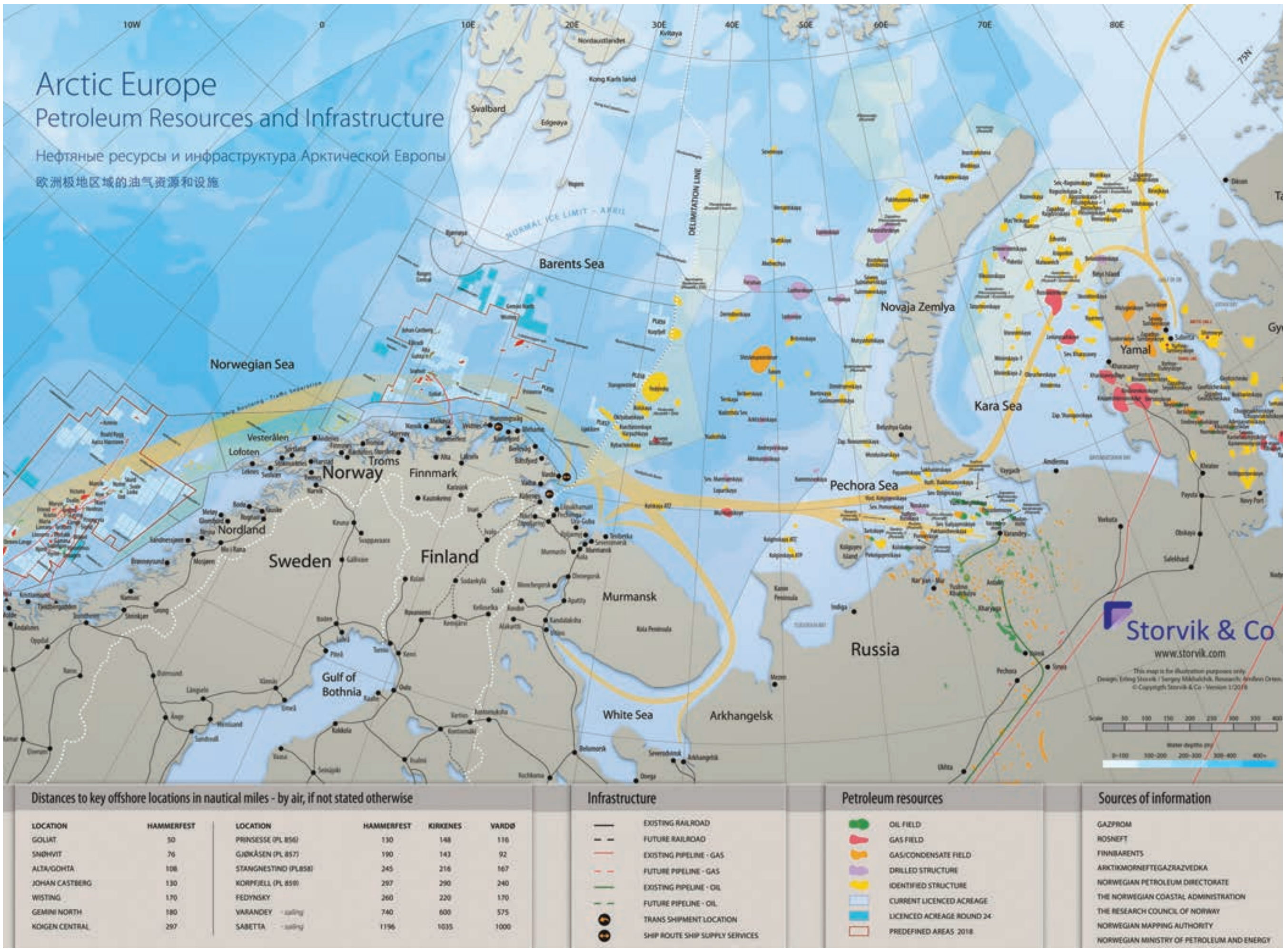
Hammerfest has established and maintains strong connections with other arctic stakeholders like Scotland, Aberdeen, Canada, St. Johns and Halifax, Russia and China. Cooperation includes energy city competence, technology transfer, transport and logistics, maritime services to vessels and alternative energy sources. A strong force in this cooperation is the Lord Provost of Aberdeen and president of World Energy Cities Partnership – WECP, Barney Crockett. And in Hammerfest, Port Director Per Åge Hansen.

The Northern Norwegian Sea is operated from Sandnessjøen and comprises the field centers Aker-BP-operated Skarv, Equinor-operated Norne and the largest spar platform in the world, the Equinor-operated Aasta Hansteen. Smaller satellite fields are developed with subsea technology and tied in to these field centers.

The oil companies and the Norwegian Petroleum Directorate (NPD) are managing their interests in the Barents Sea and the Northern Norwegian Sea from offices in the town of Harstad.

Exploration on the Norwegian Shelf and in the Barents Sea is profitable. The NPD's resource report for exploration shows that every 1,000 kroner invested in exploration in the Barents Sea has given 2,100 kroner in return.

On the Russian side, oil and gas resources are enormous in size. Production is dominated by the Novatek LNG production in Sabetta, Yamal, with an annual production



Source: Storvik & Co

close to 20 million tons of LNG and more to come. Dry gas is also produced at the peninsula and transported by pipeline. Oil from the Timan Pechora region is exported through the Varandey terminal at the Pechora coast. Oil is also produced from the Prirazlomnoje field and Kolguev in the Pechora Sea.

At this time with Western sanctions we see that Chinese capital and contractors have gained a solid position in the Russian petroleum industry.

The Russian activities have from time to time also led to activities on the Norwegian side. In the form of ship-to-ship transfer from ice class tankers to conventional tankers of crude oil, condensate and LNG in Kirkenes and Honningsvåg, North Cape. Vardø Port is serving vessels in the sea route by transfer of crew, technical equipment etc. While Kirkenes is serving Russian fishing vessels and Chinese exploration vessels working on the Russian shelf.

Transport and logistics

The Northern aspect also includes two international transport routes. The Northern Sea Route (NSR) is a shipping lane between the Atlantic Ocean and the Pacific Ocean along the Russian coast of Siberia and the Far East.

The distance from Northern Europe to China and vice versa, is approximately 40% shorter than via the Suez Canal or 60% shorter via the Cape of Good Hope.

With accelerating energy and mineral resources in the Northern Region, effective alternative transportation solutions between Europe and the Far East will be of increased importance.

During the favorable ice season, the Arctic region has a transport advantage to the fast growing regions in the Far East. Voyages increase annually and expectations for this alternative sea route are high.

The New Silk Road is another newcomer.

The Narvik Port is today exporting to the world mar-

Source: Roar Lindefjeld and Bo B. Randulff, Equinor

kets some 20 million tons of iron ore annually, transported from Kiruna in Sweden by the Ofoten railway. This volume is expected to increase in the years to come.

Narvik Port is now promoting the New Silk Road – a new fast transport corridor both ways between China and North America. The backbone of this transport corridor is a "nonstop" container block train between Xi-an, China and Kouvola, Finland with a total travel time down to nine days. The other parts of this route are made up by rail Kouvola - Narvik and sea transport Narvik - North America.

The environment

The world, and in particular the younger generation, is calling for efforts to eliminate climate threats. Few dispute the necessity of this.

Many even require to discontinue oil and gas production. In our mind time has not come for that yet. We have to fight the threats by technology rather than passivity. A stop now would reduce economic growth and our capacity to lift people out of poverty and secure safety, welfare and democracy for the people of the world. Gas is the key to a better environment. In the first phase, gas should replace coal which will reduce pollution by 50%. In the next phase, flexible use of gas should be used to fill the gap between renewable energy sources and the energy demand. Finally, gas produced with carbon catch and storage will be used to produce nonpolluting hydrogen.

Policies and tools to promote economic development and reduce poverty must take ecological limits and climate change into account and ensure an integrated approach to different kinds of activities and environmental pressures. Ensuring sustainable use is a priority for Norway and vital for ocean-based activities in Norway and the world as a whole. Growth in the blue economy may include both steps to improve the environmental performance of existing industries – by deploying new technologies – and the development of new ocean-based industries that have less environmental impact.

Norway's oil and gas production is a world leader in clean production and is continuously improved by new technologies, such as carbon capture and storage, renewable energy sources and electrification based on renewable energy production.

As an example of environmental issues in the North, government this summer reported that they are evaluating to establish offshore wind power outside Hammerfest with a view to supply clean energy for the operation of the Hammerfest LNG plant at Melkøya. The Port of Hammerfest is also active in this work by establishing shore-to-ship power supply systems and alternative energy sources for ship propulsion purposes.

OPTIMIZING RECOVERY

BP's Mad Dog field in the deepwater Gulf of Mexico is a good news story that keeps delivering, and the reservoir management team aims to keep it that way.

BY JENNIFER PALLANICH

When discovered in 1998, the field in Green Canyon blocks 825, 826 and 782 was thought to hold 1 billion barrels of oil in place. Production began in 2005 from the original Mad Dog truss spar. Known as the A-Spar, it was equipped for simultaneous production and drilling operations. Later appraisal and delineation programs combined with improved seismic data shot the resources estimate up to 5 billion barrels of oil in place. BP and partners BHP and Chevron planned a second floating platform, initially dubbed Big Dog, to serve the field. In 2013, they scrapped the $22 billion project as uneconomic and in 2016 sanctioned a $9 billion plan known as Mad Dog 2.

When Mad Dog 2 goes online in late 2021, it will rely on a host of reservoir management strategies to squeeze out as much oil as possible from the reservoir. BP has used techniques like LoSal EOR Technology, immobile proppant, downhole flow control and ocean bottom node monitoring at other fields, but this is the first time all the strategies have been planned into a project from the outset.

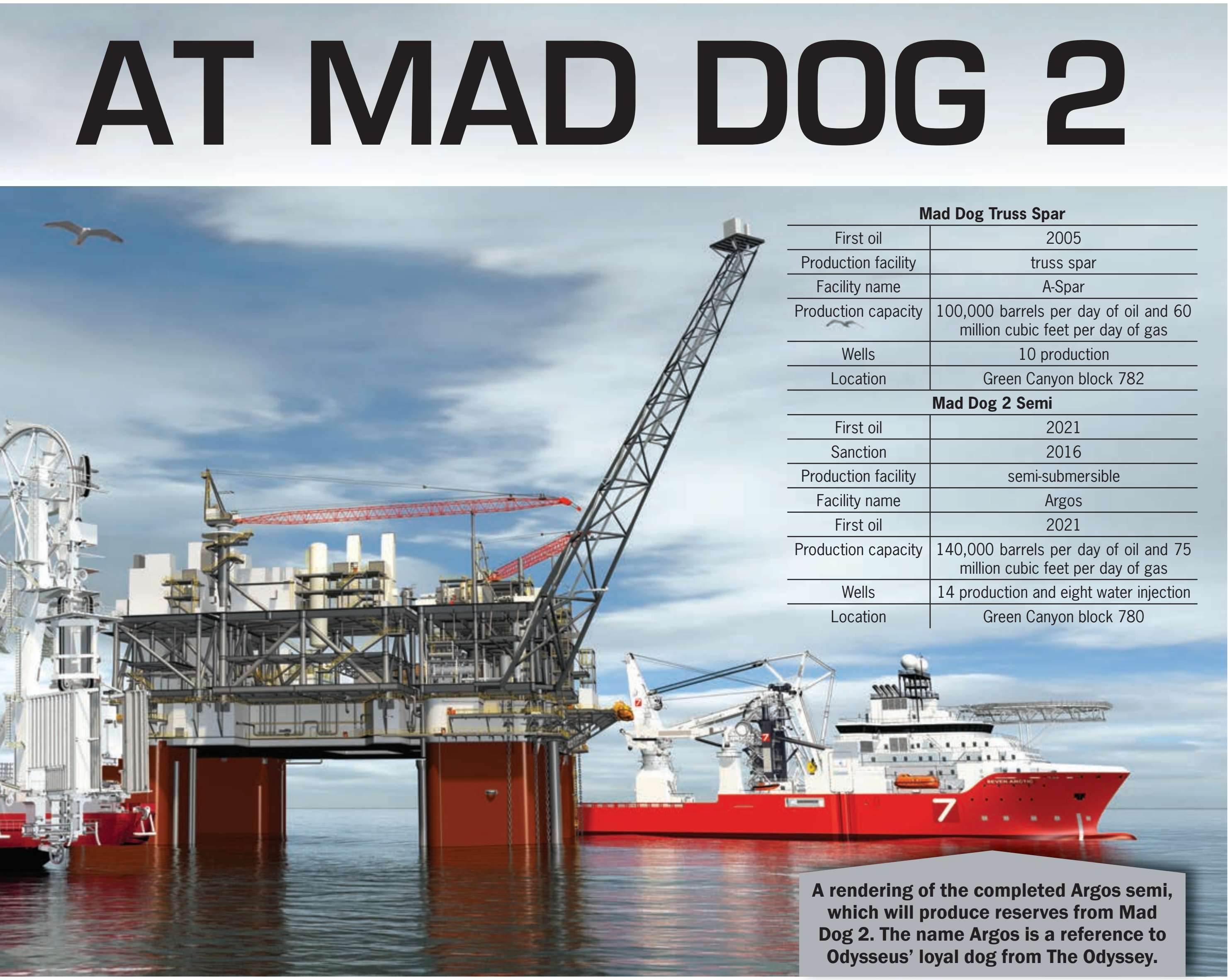
"There's a huge amount of oil here. We have to do more to optimize it," says Colin Bruce, manager of the global modeling team in BP's upstream technology division. "We're standing on all the embedded knowledge that BP has and applying it all to Mad Dog 2."

Emeka Emembolu, vice president reservoir development for the Gulf of Mexico, says Mad Dog is one of the largest undeveloped Miocene fields in the Gulf of Mexico. Of the 5 billion barrels of oil in place, so far 250 million barrels have been produced. Most of that, Emembolu says, has come from the northwest and northeast portions of the reservoir. The 10th producing well began production in 2019 and pushed the spar past its previous capacity of 80,000 b/d. A recent debottlenecking effort provided additional capacity closer to 100,000 b/d, and BP is taking advantage of that, he says.

"We may get 350 million barrels out of the existing spar," which was designed to produce a field holding 1 billion barrels of oil in place, Emembolu says. "That's not a material proportion of the currently understood resources. That is part of the driver for the Mad Dog 2 facility."

He says that in some ways the A-Spar has functioned

AT MAD DOG 2



Mad Dog Truss Spar	
First oil	2005
Production facility	truss spar
Facility name	A-Spar
Production capacity	100,000 barrels per day of oil and 60 million cubic feet per day of gas
Wells	10 production
Location	Green Canyon block 782
Mad Dog 2 Semi	
First oil	2021
Sanction	2016
Production facility	semi-submersible
Facility name	Argos
First oil	2021
Production capacity	140,000 barrels per day of oil and 75 million cubic feet per day of gas
Wells	14 production and eight water injection
Location	Green Canyon block 780

A rendering of the completed Argos semi, which will produce reserves from Mad Dog 2. The name Argos is a reference to Odysseus' loyal dog from The Odyssey.

Source: BP

like a prolonged, scaled-up well test ahead of Mad Dog 2.

With the combination of reservoir management techniques like waterflooding and infill drilling, the potential exists to produce between 500 million barrels and 1 billion barrels with the Argos semi-submersible at Mad Dog 2, Emembolu says. The Argos semi is designed to handle 140,000 b/d and 75 million cubic feet per day of gas from 14 production wells. It will help extend the life of the super-giant Mad Dog oil field beyond 2050.

The reserves lie in three Miocene sands, and BP has located a Paleogene structure under that. While that is not part of the current development plans, Emembolu says, producing that structure could be a future project.

Seeing clearly

Improved seismic technology, such as full wave inversion and ocean bottom node surveying, have helped BP understand just how vast the Mad Dog reservoir is.

According to Emembolu, it's been difficult to see the Mad Dog reservoir because of the large salt dome over it.

Emembolu says comparing 3D seismic data of the area from the late 1990s with current images "makes you wonder how anyone actually found oil there. We can see a lot more about the structure now."

Using full wave inversion, BP discovered additional resources at two other deepwater Gulf of Mexico fields – Thunder Horse and Atlantis.

"We're in the process of doing that at Mad Dog," Emembolu adds.

In 2017, BP carried out an ocean bottom node survey on the Mad Dog field. BP placed 2,600 recorders 400 meters apart on the seabed in 4,500 feet of water.

That survey "has shown pretty spectacular images beneath that salt," says Glyn Edwards, Mad Dog reservoir manager team leader. "We're starting to be able to see fluid contact."

And 4D seismic provides even more of a window into the reservoir.

"So much of the oil industry has been poking holes in the ground and seeing what's happening," Bruce says.

Paul Johnston, Mad Dog reservoir development area manager, says that while 4D seismic has been used before, the effective application of it under a complex salt body is new.

4D data will allow BP to monitor the waterflood visually, Bruce says.

Edwards says his team is considering a 4D mixed acquisition reprocessing technology trial to see if they can see water movement or reservoir pressure changes between a 2005 towed streamer survey and the most recent 2018 ocean bottom node survey.

"If we can see fluid movement under salt, it would be the next big seismic breakthrough for reservoir management," Edwards says.

Multiple models

BP uses an ensemble process for modeling. The suite of models, Edwards says, presents a range of potential futures, making it possible to capitalize on upsides and mitigate downsides.

The Mad Dog reservoir management team has around 3,000 history models that match data with different subsurface descriptions.

"If you only have one model, you convince yourself you know what's going on. It can lead to a difficult conversation with higher management if it doesn't play out that way," Edwards says.

Emembolu likens the approach to the probabilistic hurricane path projections meteorologists distribute.

"We use a lot of different models, weighted in different ways," Edwards says. "This way we don't bind ourselves to any particular outcome."

EOR solution

The Mad Dog spar doesn't have capacity for water injection, but in 2021, BP will undertake a project to take water from Argos to inject in the northern section of the Mad Dog field, Johnston says. The North West Injection project will include future water injectors down dip of the Western Flank producing A-spar wells. The project takes water from the Argos facility, yet the production benefit is seen at the A-spar, according to BP. The pressure support benefit is expected to increase production well past the current cessation of production of the A-spar in 2039, enabling even more future development options.

The Mad Dog 2 semi is designed to inject 140,000 b/d of LoSal EOR.

LoSal EOR "is a key enabler for getting the recovery factors out of the field that we anticipate getting," Emembolu says.

BP developed the LoSal EOR technology after research showed injecting water with low levels of salinity meaningfully increased production rates. BP first deployed the LoSal technology at Clair Ridge last year, and has said the use of the technology was expected to yield an additional 40 million barrels at that field.

At Mad Dog 2, BP will reduce the salinity of seawater and inject it through one of eight water injection wells to tease out more oil from the reservoir.

According to Emembolu, LoSal will do more than just boost production rates at Mad Dog 2. It also mitigates souring and scaling as the field matures.

Tracing a path

BP will use a combination of reservoir simulation, 4D seismic, downhole flow control and tracers to understand and manage the waterflood and the interactions between the spar and production semi, which will be about 6 miles away from each other.

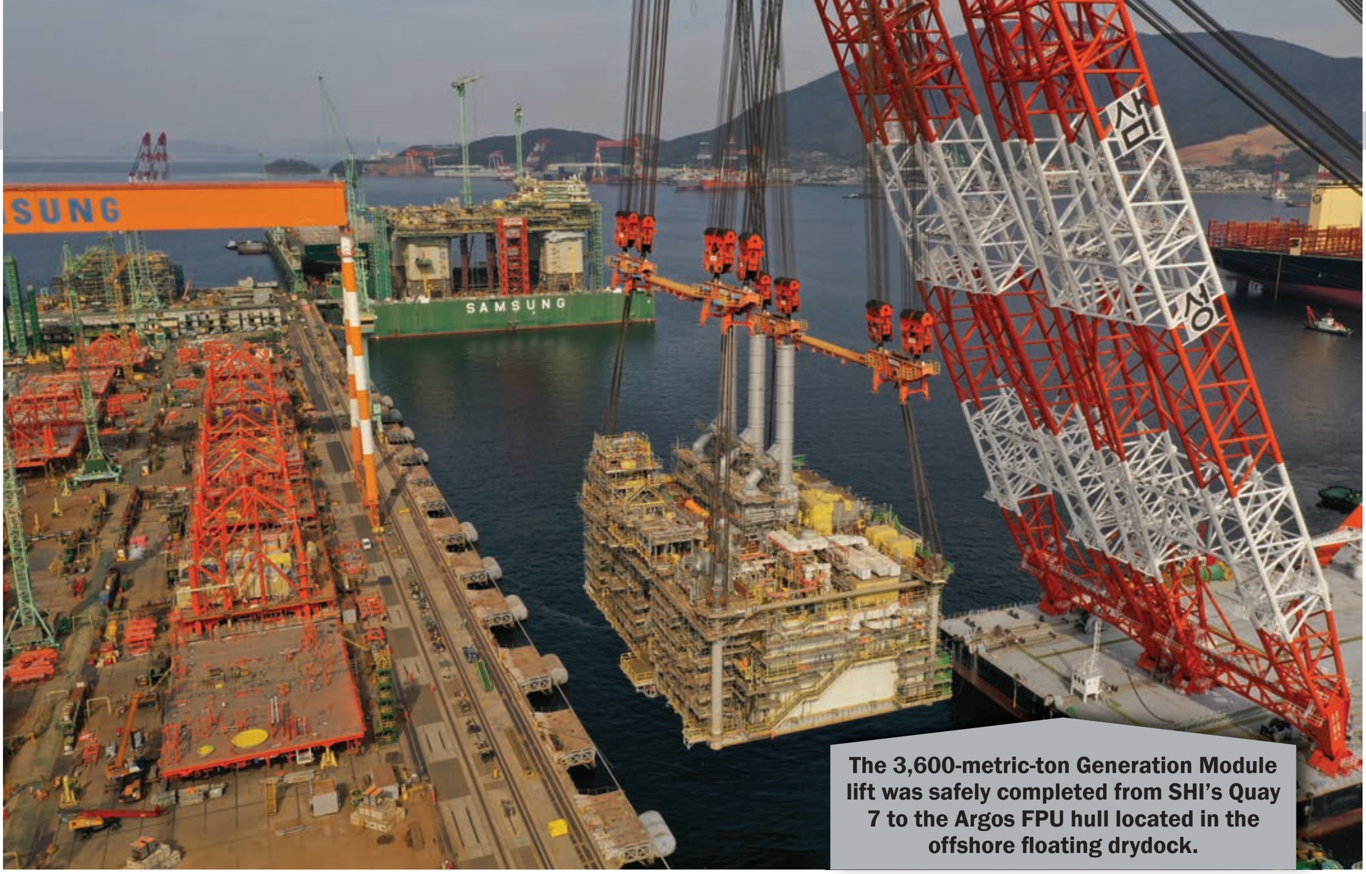
"The spar does communicate somewhat into the southern area where Mad Dog 2 will be, but it's not a strong communication," says Edwards.

The key interaction, Edwards adds, is around pressure depletion.

"The waterflood will maintain reservoir pressure, so that will help to moderate the effect," Edwards says.

Tracers will allow BP to see what water injection wells connect to which producing wells and immobile proppant will maximize the lifetime of those injectors.

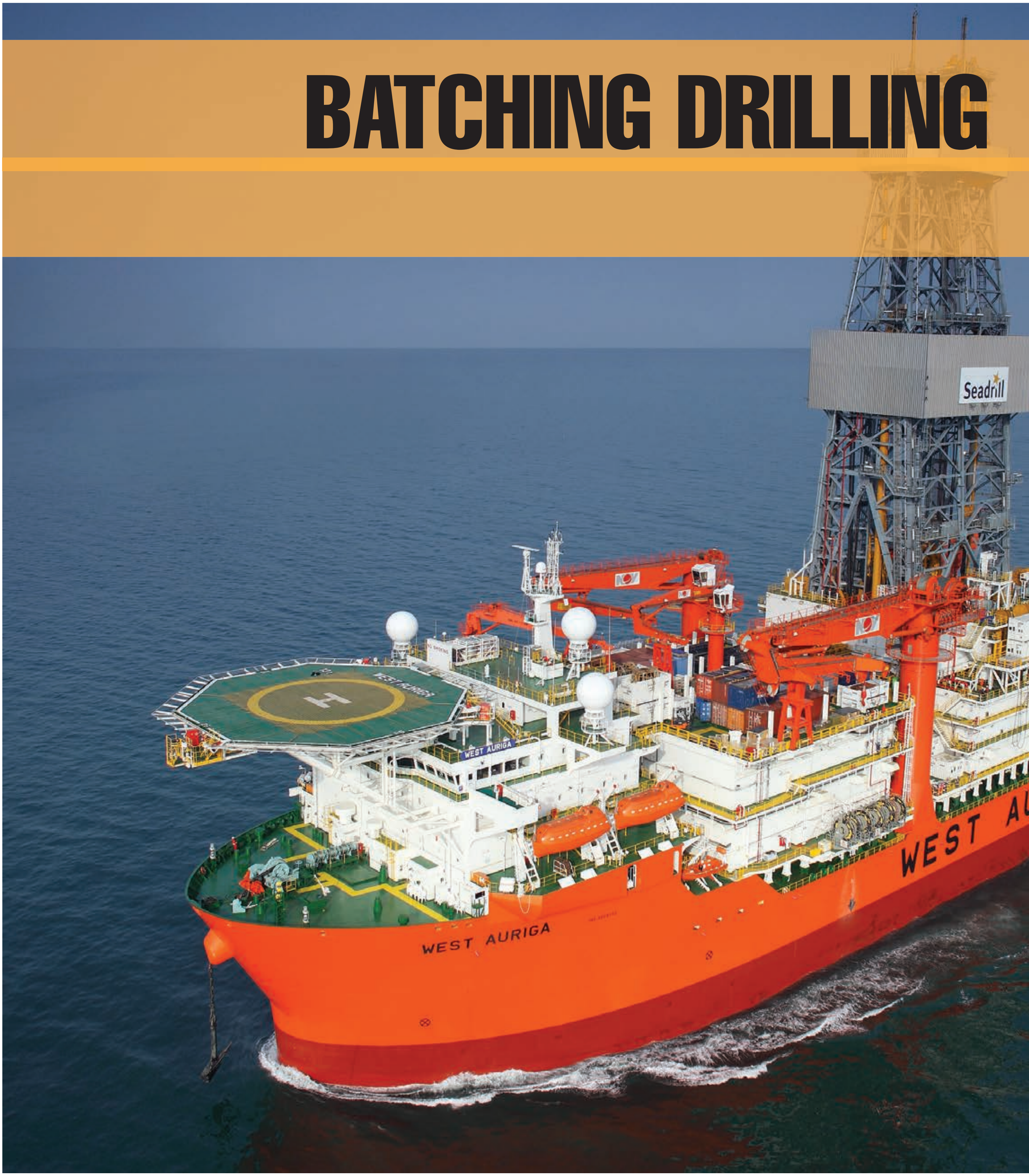
"What makes Mad Dog 2 unique is the utilization of immobile proppant, individually traced LoSal water injection with downhole flow control from the onset," Johnston says. "It's the aggregation and incorporation of all these techniques from the get-go to maximize the success."



The 3,600-metric-ton Generation Module lift was safely completed from SHI's Quay 7 to the Argos FPU hull located in the offshore floating drydock.

Source: BP

BATCHING DRILLING



Source: Seadrill

The West Auriga, under contract to BP through October 2020, batch drilled the wells and will carry out some of the batch completions

OPERATIONS AT MAD DOG 2
to save rig time

By Jennifer Pallanich

With the Argos semisubmersible due to begin production from BP's Mad Dog field in late 2021, the drilling team needed to ensure the drilling campaign stayed on schedule.

BP did this by dedicating and integrating experienced drilling engineers and geoscientists to plan, monitor and respond during the execution.

Overall, BP plans to develop Mad Dog 2 in the Gulf of Mexico with 14 production and eight injection wells. Of those, BP has promised to have eight production and two injection wells teed up when the facility arrives at the field in June 2021.

"We can't maximize the efficiency of the facility if all the wells aren't drilled," says Paul Johnston, Mad Dog reservoir development area manager. "We're trying to manage an early arrival of the facility."

As of mid-November, Johnston says, the team is set up to deliver nine production and four injection wells on time if completions go as expected.

"We have completed the predrills," says Emeka Emembolu, vice president reservoir development for the Gulf of Mexico.

The drilling campaign targeting the Miocene sands has "gone well," Johnston says. "We've taken a big step toward making sure these wells are ready in time for when the facility to shows up."

Seadrill's West Auriga, under contract to BP through October 2020, batch drilled the wells and will carry out some of the batch completions. Another rig will begin a contract in the second quarter of 2020 to finish the completions program.

The wells will produce oil and gas to the Argos semi, which will be moored in 4,500 feet of water in Green Canyon block 782. Argos nameplate production is 140,000 barrels per day of oil and 75 million cubic feet per day of gas.

"Will we have that capacity in the ground? We think so. Do we know how these wells are going to flow? No. We'll have to turn them on," Johnston says. "We haven't done the completions. It's oil and gas, lots of things can happen. But we feel comfortable that we may have an extra well in the bank from what we've promised. It's an insurance policy if a well doesn't show up the way we expect."

The Mad Dog 2 project has been a long time coming. BP originally found what was thought to be a pool of 1 billion barrels of oil in place at the Mad Dog prospect in the deepwater Gulf of Mexico in 1998. First oil to a truss spar followed in 2005. Seismic, appraisal drilling and production data increased the reserves in place estimate to 5 billion barrels of oil by 2011. Between 2014 and 2016, BP drilled three wells aimed at lease retention and delineating the reservoir. BP and its partners, BHP and Chevron, sanctioned the Mad Dog 2 project as a standalone production facility serving 14 production and 8 injection wells and first oil targeted for 2021.

While the spar is equipped to handle both drilling operations and production, "the efficiency of drilling from a spar is a lot lower than drilling from a dedicated drill unit," Emembolu says.

Beyond that, the spar limits step-out options. Using a drillship provides flexibility in addition to time and cost savings, Emembolu adds.

One of the themes for Mad Dog 2 has been price reduction. An earlier plan to develop the reserves, dubbed Big Dog, would run $22 billion. The current plan more than halved the price tag to $9 billion.

The Mad Dog 2 team has used efficiencies such as using a dual derrick rig, stack hopping and rebasing well design along with an integrated performance model to slim down drilling costs. In a September speech, Bernard Looney, BP chief executive, upstream, said, "Well-drilling is down by an average of $46 million per well on Mad Dog 2."

Effectively, says Glyn Edwards, Mad Dog reservoir manager team leader, the team has saved a year of rig time while still delivering the same number of wells.

"Wells were repeatedly going faster," Johnston says. One of big challenges and big successes of the project to date, he says, has been managing the pace of activity to design and safely drill the wellbores through an evolving understanding of a complex geological environment.

Johnston says the drilling team has had "fantastic" learning from one well to the next.

And some of the learnings were counter-intuitive.

"One of the things we learned was we had to go slow to go fast," Johnston says.

The wells target naturally regressed Miocene sands that are weaker than the surrounding shales. Using the correct mud weight keeps the wellbore stable and prevents losses into the formation. But that alone wasn't the solution. BP found that by slowing drilling rates down in these sections, the drillers created a more stable environment for handling the pressures.

"We didn't see the losses we saw in earlier wells," Johnston says. "We went from 200 feet per hour to 70 feet per hour. It's slower, but it's safer. It's a good technique."

Another technique that saved time was removing a casing string by changing the overall casing design.

One of the efficiencies was a result of reevaluating the casing design. By reevaluating the pore pressure and drilling trajectories, the engineering team was able to safely deliver a design that had one less casing string in it than the earlier wells. This removed the flat time associated with running the string and had the added benefit of minimizing personnel exposure to handling equipment, Johnston says.

The West Auriga's dual derrick design further drove efficiency with the drilling campaign. The team was also able to move the blowout preventer during batch drilling without bringing it to the surface, to create further time savings.

Once Argos is online and receiving hydrocarbons, Johnston says, BP will study production data for six to 18 months to better understand the field and see which injectors support which producers. With that understanding, he says, the team will drill the remaining wells planned for the field.

"We have a model today, thousands of models. We don't really know which one's right. We'll learn from the wells and production data to see where future wells need to go," Johnston says. "You're not just drilling a well, you're drilling a well surrounded by geology. We'll take our best learnings from the subsurface and use that information to inform our forward path and what we do on the next well."

Mad Dog at a glance	
Water depth	4,500 feet
Location	Green Canyon 825, 826, 782
Field discovery	1998
Oil in place	5 billion barrels
Operator	BP, with 60.5% working interest
Partners	BHP Billiton (23.9%) and Union Oil Company of California, an affiliate of Chevron U.S.A. Inc. (15.6%)

CannSeal Unlocks Development of an Additional Reservoir by Restoring Integrity to an Unconventional Cement Packer Design

Source all images: CannSeal

Annular isolation technology specialist CannSeal aided the successful repair of an unconventional cement packer design, 4 ½" in 9 5/8" with limited cement. CannSeal's technology achieved the objective of reducing the gas leak to within acceptable limits, thereby facilitating development of an additional reservoir.

In order to unlock additional accumulation, the wellbore was sealed off and the A-annulus was filled with cement above the top of the additional reservoir. Two long formation, or reservoir sections, were then perforated below the estimated Top of Cement (TOC) in the A-annulus. When production started, the A- and B-annuli developed gas influx issues. Conventional methods of sealing could not be used due to the risk of filling the reservoir with sealant through the perforated sections.

The cement below the estimated A-annulus TOC was of unknown quality and the 4 ½" tubing was placed inside the 9 5/8" casing. Perforating through a thick cement sheet, while not damaging the outer casing on the low side, was vital to the project. CannSeal's criteria was to remove or reduce the gas leak to within acceptable limits.

The CannSeal IntegritySeal was run on wireline to perforate and inject epoxy in the cement above the top perforation interval. CannSeal's high viscous sealant forms a doughnut around the tubing in an open void, or fills large channels in a poor cement matrix. This process creates a plug independent of annular condition.

Cannseal's delivery tool is fitted with a g-sensor, which has the ability to show the tools relative orientation. As a result, eccentric centralizers were used to point the perforation gun in the desired direction. This allows selective penetration with max reach topside to occur, while not damaging the second casing in the eccentric annulus. The CannSeal heater tool was used in order to increase the epoxy materials cross linking, establishing a strong plug.

A total of three epoxy injections was completed (31,6L ea.) throughout the job. The injections were placed in close proximity, and the CannSeal heater tool was deployed to increase the strength of the plug material. This enabled it to withstand high delta pressure in an anticipated large open void in the event there was no cement. Orientation of the tool was successful despite a low clearance, making the concept viable for larger casings in the future.

The aim of lowering the gas leak rate was successfully achieved. A month after the treatment was completed the situation was reported to be similar, with the pressure build reduced to a minimum.

CannSeal's Chief Executive Officer, Bengt Gunnarsson, said CannSeal is a problem solver for operators who experience unexpected well integrity issues. "Without a successful barrier repair, on this occasion it would not have been possible to develop this additional reservoir through conventional methods.

"Committed to innovation and global growth, we are proud to share success stories like this. Following the recent launch of our mobile mixer, we are now able to reach more markets faster than ever before."

The launch of CannSeal's new mobile mixer was a strategic investment for the company. Facilitating the company's proprietary epoxy resin to be mixed on-site, the mobile mixer opens up new markets independent of location as it removes constrictions associated with storage and curing.

Chase the Right Metrics for Better Production Results

By Jennifer Pallanich

Oil and gas companies track and incentivize a variety of metrics, but these actions can inadvertently lead to lower production levels and affect lifting costs.

If there's an incentive for fast drilling instead of precisely placed wellbores that maximize contact with sweet spots, the wellbore will miss out on potential production of hydrocarbons, says John Clegg, Weatherford's drilling fellow.

Or a wellbore might have a lot of tortuosity, which in a lateral can lead to problems with sand choking production, hurting output rates. Or unwanted tortuosity can cause premature and expensive damage to production equipment such as rods or pumps.

"If you're measuring once you've drilled the well, it's too late," he says. "You'll suffer for perhaps the next 10 years with lower production and lack of ultimate recovery."

Clegg calls that a big problem.

"We need a completely different set of KPIs for how we value what we're doing while we're drilling," he says.

In short, he says, it's time for the industry to "change the way it thinks about drilling well costs" and incentives programs that can influence immediate outcomes like cost per foot or days of drilling without considering later outcomes like production levels.

"It's one of those things everybody knows, but nobody seems to know how to address," he says.

One challenge is to figure out what those KPIs are. One possibility is value per foot of wellbore, which he acknowledges "is not simple to measure." Another is simply looking at cost per barrel instead of cost per foot, he says.

More valuable wellbores are smoother and more precisely placed so they offer more exposure to the reservoir for higher overall drainage of the reservoir while minimizing the chance for sand to choke down production levels, he says. They are also easier to drill, easier to cement – improving integrity – and easier to complete, as well as improving the reliability of production equipment, he says.

In the long run, high-producing wellbores produce more of the original resources in place. Through that higher production, they lower the overall cost per barrel.

Technology holds another key to the puzzle, Clegg believes. A rotary steerable system like Weatherford's Magnus can maintain inclination and azimuth angles until a driller intervenes. As such, it can optimize production by drilling a smoother well.

Taking that technology one step further, it might be possible with "a lot of development" to automate geosteering by teaching it to "find the sweet spots," he says.

John Clegg, Weatherford

"Rotary steerable systems in their recent incarnation have been expensive to work with," Clegg says, so there is still widespread use of steerable motors. He says the industry "has to bring down the overall cost of using rotary steerable systems."

If access to rotary steerable systems becomes ubiquitous, he says, automated geosteering becomes more likely.

"Without better KPIs, we cannot justify the development of the technology we will need to maximize value of the well," he says. "Right now, we are not measuring the right things and we are not incentivizing the right behavior."

Rotary steerable systems like Weatherford's Magnus offering are a technology that improve the quality of a wellbore.

Source: Weatherford

Ensuring Riser Readiness

Source: Baker Hughes

at Lower Cost and Risk

As drilling costs keep coming down for land-based wells in unconventional plays, offshore drillers face increased pressure to lower their costs. A key focus area: maintenance budgets for marine drilling risers. Instead of the traditional five-year, calendar-based inspection interval for risers, can drillers use a condition-based monitoring (CBM) methodology to extend the interval to beyond five years?

A longer interval would cut down on the frequency with which risers have to be shipped to shore for inspection and returned back to the rig to go back into service. Reducing trips makes more effective use of transport vessels, maintenance crews and reduces the overall carbon footprint. Ultimately, a CBM program helps drillers become more cost-competitive and lowers their drilling cost per foot.

Achieving these goals was the ultimate aim behind the development of the Baker Hughes DrillCERT program, an API-compliant certification program that can extend required maintenance intervals based on condition rather than time. DrillCERT is a digital inspection solution that incorporates data collection from sensors and asset management from web-enabled devices.

The process begins by performing ultrasonic scans of the riser joints and the auxiliary lines that carry mud back and forth. The scans look for any decreases in wall thickness and any anomalies or a previously unseen defect.

The collected data is entered into a CBM analytical model, where it is compared to baseline riser usage and manufacturing data. The baseline data sources include rig data, manufacturing data on the riser string's metallurgy, weld integrity and the surface finish of the riser pins and boxes. Based on the physical condition of each riser joint and the current operating conditions, the program delivers an assessment of how long the riser can remain in service before it must be pulled for maintenance or replacement. Often, this assessment extends the full riser inspection and service cycle to an average of eight years.

If an anomaly in wall thickness or welds is observed, further analysis is performed to determine the root cause, which could include excessive movement due to waves, aggressive chemistries in the drilling mud that might contribute to corrosion, or the presence of high concentrations of acid gases such as H2S.

Assessments are conducted on an annual basis and incorporate many other services in addition to riser inspection. These include inspections of buoyancy on joints to look for damage or stress. If the inspection uncovers a riser pin with scratches and wear, the DrillCERT team will polish the pin and make any other necessary repairs as a standard part of the DrillCERT program.

At the end of the inspection and repair process, a certificate of service (COS) is issued to the driller stating that the riser is certified for use per API standards, including API 53 and API 16Q. The driller does not have to concern themselves with trying to get their risers re-certified and ready to drill on a five-year interval. The DrillCERT process ensures that each riser is in good working order and always ready to drill, while lowering the driller's total cost of ownership.

The cost savings to the driller extend beyond the longer riser maintenance interval. The program allows the riser inspection and repair to be conducted on the rig floor itself, rather than shipping it to shore and incurring longer out of service intervals and high transport costs. Drillers also enjoy the benefit of selectively deploying work crews only when they are needed, which lowers manpower costs and improves safety metrics.

The DrillCERT service is applicable on drillships, semisubmersibles and other offshore platform designs as well, providing the entire offshore drilling community with greater assurance and cost control for their riser maintenance programs.

Understanding Market Needs Can Shape Control Valve Design

By David Nemetz, President, and Brett Robinson, Sales & Strategic Accounts Manager – Business Development, Gilmore, a Proserv Company

When it comes to smooth, safe drilling, you'd be hard-pressed to argue that the blowout preventer (BOP) stack isn't the key to the whole operation. A series of mechanisms to regulate pressure levels in a well and prevent blowouts, which could potentially endanger personnel and the environment, let alone halt production, is unquestionably vital equipment.

This sizeable unit weighs more than 300 metric tons and subsea stacks can be over sixty feet in height, consisting of multiple ram and annular preventers, and a myriad of critical pipework. The BOP is essentially one vast valve whose basic role is to shut in a well when required, sometimes within minutes, if a control problem, such as a kick, occurs during the drilling process and threatens a blowout.

But within the BOP stack are many further integral smaller parts, from valves to actuators, which must function reliably. The BOP stack is basically tens of millions of dollars' worth of kit designed to enable drilling activities but in effect – the system is only as reliable as its least reliable component. In the challenging subsea environment, BOP stacks are inevitably more complex and involve even more components than surface stacks.

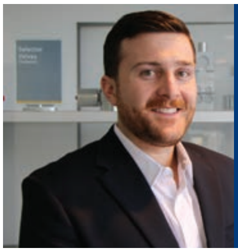
At Gilmore, we develop a range of hydraulic flow control valves and regulators to perform a variety of critical tasks topside, subsea and downhole. For instance, on BOP stacks, our products play multiple roles, including helping to alleviate pressure kicks encountered while drilling and initiating the closure of the BOP when issues arise.

We recognize that if a key subcomponent fails then the whole BOP stack will most likely need to be pulled, such is the crucial nature of this piece of the drilling infrastructure. A stack pull represents a major intervention to the entire operation, which could be forced to shut down for up to a fortnight, depending on water depth.

Source all images: Gilmore

A technician works on a new regulator in Gilmore's Houston facility.

David Nemetz, President, Gilmore



Brett Robinson, Sales & Strategic Accounts Manager – Business Development, Gilmore

Costly stack pulls

The financial penalties of such an outcome are severe for operators. Even during a scheduled outage for preventative maintenance, costs can easily run into several million dollars, but with an unplanned shutdown, requiring investigation, diagnosis and repair, producers are immediately hit by the substantial daily rental costs of drilling rigs, offshore support vessels and other service providers. That is without factoring in lost production from the well over that period.

For drilling contractors and original equipment manufacturers (OEM), operating in increasingly competitive markets where margins are slim, downtime is a significant problem. Contracts are handed out largely based on good uptime ratios and if a critical valve was to fail on a BOP stack, necessitating a pause in drilling rig operations, then this could mean the difference between winning or losing the next potential contract.

Such insights can only come from being close to the market and listening to customers. At Gilmore, we understand the driving issues and requirements of our end users, and so, consequently, our own design and manufacturing strategy is governed by prioritizing the serviceability, durability and reliability of our products.

Drillers fundamentally demand valves that will develop few failure issues and will be easy and quick to maintain when they carry out their regular servicing schedules. Ideally, they want to be able to "set it and forget it" and then focus on other aspects of their day-to-day operations.

Reliability and durability

For example, we cycle test and qualify our products beyond industry requirements, so as to offer concrete evidence of the kind of reliability and durability sought. Where the present industry API 16D standards necessitate manufacturers to cycle test one valve 1,000 times, we test two components 2,500 times each.

Feedback from the market and end users can be crucial to guiding future product development and strategy for flow control component manufacturers. In 2017, Gilmore became one of only two manufacturers to tie up with the Rapid S53 Reliability and Performance Information Database for the Well Control Equipment covered under API S53 and established by the IOGP and IADC.

This has provided hugely valuable commentary directly from operators and drillers out in the field about the type of issues they encounter. We have gained visibility about how our products are performing and also how the industry has been utilizing our valves. Previously, once an OEM acquired a valve, typically a manufacturer would have little awareness as to how that part would subsequently be used.

The information we have garnered from the S53 program, along with additional feedback from our customers, has shaped how we have designed and engineered our latest generation of hydraulic flow control valves.

We scrutinized how the materials used across our portfolio could be further enhanced so that our valves could become even more corrosion resistant when exposed to seawater and more durable.

Likewise, by accentuating serviceability and developing modular and standardized designs, it means we gain efficiencies on our inventory, reduce our lead times to customers and improve their own cost savings as maintenance cycles are so much quicker and less prone to human error.

Listening and testing

Seeking out the opinions of end users should be a priority for any valve manufacturer, and these can then guide product-testing methodologies. Our goal is to ultimately test as close to real life conditions as possible. We force flow rates of up to 300 gallons per minute through our products and use highly abrasive fluids, up to Nox (nitrogen oxide) class 10-12, so if any issues arise, then they occur in the testing facility and not out on the rig.

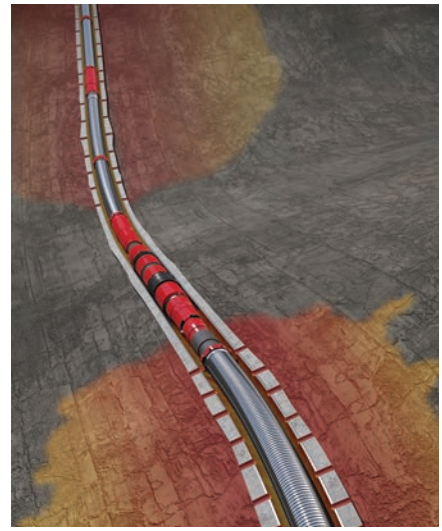
By understanding the needs and challenges of the customer, and adapting product designs accordingly, then engineering valves with greater durability and reliability becomes far more likely.

What will differentiate the successful sub-component manufacturer from the rest will be the ability to provide solutions that offer peace of mind to drillers and OEMs, with a greatly reduced risk of failure and costly downtime.

XSTMZ
Halliburton

Halliburton introduced the Xtreme Single-Trip Multizone (XSTMZ) system for completing wells in ultra-deepwater conditions up to 15,000-psi. Based on the existing 10,000-psi rated Enhanced Single-Trip Multizone (ESTMZ) system, XSTMZ's increased pressure rating allows operators to isolate and frac pack multiple zones at higher pump rates with larger proppant volumes. It also supports the ability to create zonal compartments for better stimulation of long pay zones that have high-pressure differentials between them. XSTMZ helps increase production and total recovery by driving down abandonment pressure and can save rig time by isolating and treating several intervals with a single trip.

A major operator looking to improve stimulation and gravel packing of long pay zones in Gulf of Mexico's Lower Tertiary has ordered the XSTMZ system to complete multiple reservoirs that are experiencing very large bottomhole pressure differentials due to the depletion of some of the reservoirs. The operator plans to begin installing the equipment needed to complete two wells in 2020.



Source: Halliburton

Offshore Work Class Robot
Taurob

Source: OGTC

Unveiled by the Oil & Gas Technology Center (OGTC), technology developer Taurob and industry partner Total, the OGRIP (Offshore Ground Robotics Industrial Pilot) robot is designed to be used primarily as a surveillance vehicle on offshore oil and gas platforms.

The partners announced that Equinor and Saft will join the joint industry project team, and that the next stage of the program will advance the OGRIP prototype to develop the world's first offshore work class robot (OWCR) for real world testing.

The OWCR has an improved chassis, enhancing the overall performance of ground robotics through the addition of active manipulation, to complement its current capabilities of surveying, inspection and observation.

AUV Batteries
Kraken

New pressure tolerant batteries from Kraken Robotics subsidiary Kraken Power GmbH helped Ocean Infinity's Kongsberg Hugin autonomous underwater vehicles (AUV) to perform several missions to greater than 5,000 meters and an unprecedented mission of over 100 hours without recharging, while running a full survey payload. As a result, Ocean Infinity is seeing an increase of almost 100% in energy capacity and can now operate increased survey ranges to nearly 700 line-kilometers per deployment.

Kraken's pressure tolerant gel encapsulation technology for lithium polymer batteries provides an attractively priced, environmentally friendly alternative to the oil compensated batteries currently used for subsea battery applications. Kraken's hot swappable batteries are modular and include an integrated battery management system within each battery module.

Source: Kraken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Well Intervention

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Inspection, Maintenance & Repair

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Subsea Processing

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Reservoir Management & Surveillance

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Brownfield: Projects and Life Extension Technology

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Production
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Date: September 19, 2019

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February 11-13, 2020
Aberdeen, UK
www.subseaexpo.com

FPSO Europe Congress
February 18-19, 2020
London, UK
www.fpsonetwork.com

Australasian Oil & Gas
March 11-13, 2020
Perth, Australia
www.aogexpo.com.au

SPE/ICoTA Well Intervention
March 25-25, 2020
The Woodlands, US
www.spe-events.org

OTC Asia
March 24-27, 2020
Kuala Lumpur, Malaysia
2020.otcasia.org

Eastern Mediterranean Offshore Conf.
April 8-10, 2020
Nicosia, Cyprus
http://www.emc-cyprus.com

Offshore Technology Conference
May 4-7, 2020
Houston, US
2020.otcnet.org

Global Petroleum Show
June 9-11, 2020
Calgary, Canada
www.globalpetroleumshow.com

Underwater Technology Conference
June 16-18, 2020
Bergen, Norway
www.utc.no

Subsea Well Intervention Symposium
August 11-13, 2020
Galveston, US
www.spe.org/events/calendar

ONS
August 31-September 3, 2020
Stavanger, Norway
www.ons.no

Gastech
September 8-10, 2020
Tampines, Singapore
www.gastechevent.com

ATCE
October 5-7, 2020
Denver, US
www.atce.org

OilComm
October 14-15, 2020
Houston, US
www.oilcomm.com

ADIPEC
November 9-12, 2020
Abu Dhabi, UAE
www.adipec.com

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