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MAGAZINE | **SUMMER 2023**

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Contents

Summer 2023
Volume 16 Number 02

Front cover

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Comment

Summer 2023

Emily Thomas, Deputy Editor
emily.thomas@palladianpublications.com

Woodside Energy has recently made headlines with the ambitious announcement that it plans to develop the Trion oilfield, located in the Gulf of Mexico, without impacting its emissions reductions targets.[1] The company will invest US$7.2 billion to recover 479 million boe, with the drilling of 24 planned wells to commence in 2026 and first oil scheduled for 2028. Despite being met with some scepticism, Woodside maintains that its plans are consistent with limiting global temperature rise to less than 1.5°C. Wood Mackenzie's Emission Benchmarking Tool also suggests that the project will have a low emission intensity compared to other oil resource projects. At an average intensity of 12 tCO_2e/1000 boe, the project is set to fall below the deepwater average.[2] An analyst at the company noted that emission intensity is largely attributed to production and processing infrastructure, and that "Woodside will implement reduction initiatives such as high-efficiency compressors, heat recovery mechanisms, and low-pressure vapour capture."

Industry trends show that Woodside is not alone in its pursuit of more responsible and sustainable operations. As Wood Mackenzie reiterates in this issue's Regional Report on the upstream sector in Continental Europe, decarbonisation and emissions cuts are a key focal point for operators and new projects awaiting approval, and rightly so, according to a recent report from the IEA. The report outlines the immediate steps that the industry needs to take to allow energy and climate goals to be met, claiming that in 2022, production, transport and processing of oil and gas emitted the equivalent of 5.1 billion t of CO_2.[3] As part of the IEA's Net Zero Emissions by 2050 Scenario, the emissions intensity of the former must fall by 50% by 2030.

One avenue that the industry is exploring on the journey to net zero is the leveraging of software and artificial intelligence to enhance operational efficiency, reduce emissions, and drive positive change, all of which are themes underpinning this issue of *Oilfield Technology*; on P.31 for example, Freewave Technologies discusses the possibility of IoT sensors monitoring how operations are affecting the environment, allowing companies to improve their performance and minimise environmental damages. Also within the issue, Rajant Corp. highlights the importance of investing in new equipment and technologies to be best placed for greener processes, while GlobalLogic considers how the upstream industry can remain profitable and competitive, and simultaneously move towards sustainable business models. This is an undeniably tricky balancing act, however GlobalLogic sums it up well by saying: "The demand for energy and the demand for greener operations do not need to be at odds." Instead, advances in technology can be leveraged to help reshape the upstream industry's environmental landscape.

1. www.woodside.com/docs/default-source/asx-announcements/2023-asx/woodside-approves-investment-in-trion-development.pdf?sfvrsn=3a57fbb6_5
2. www.woodmac.com/press-releases/woodside-announces-trion-field-fid-mexicos-first-deepwater-oilfield-development/
3. www.iea.org/news/new-iea-report-highlights-the-need-and-means-for-the-oil-and-gas-industry-to-drastically-cut-emissions-from-its-operations

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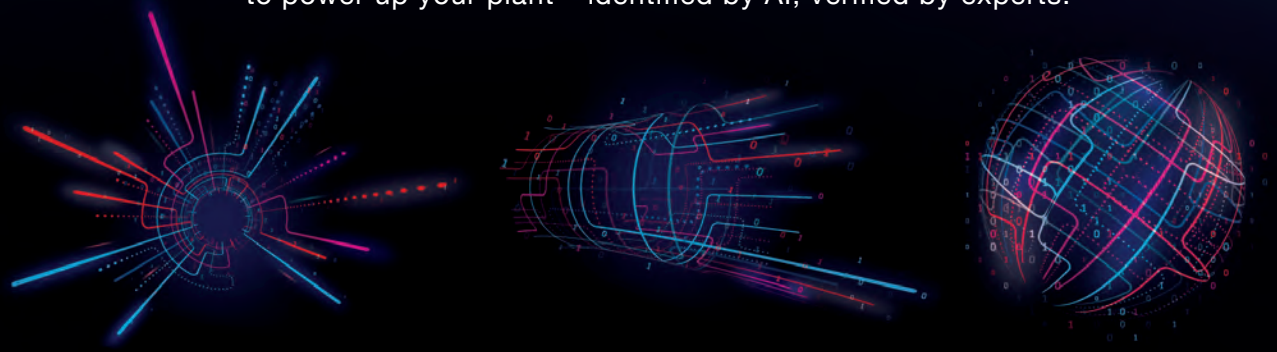

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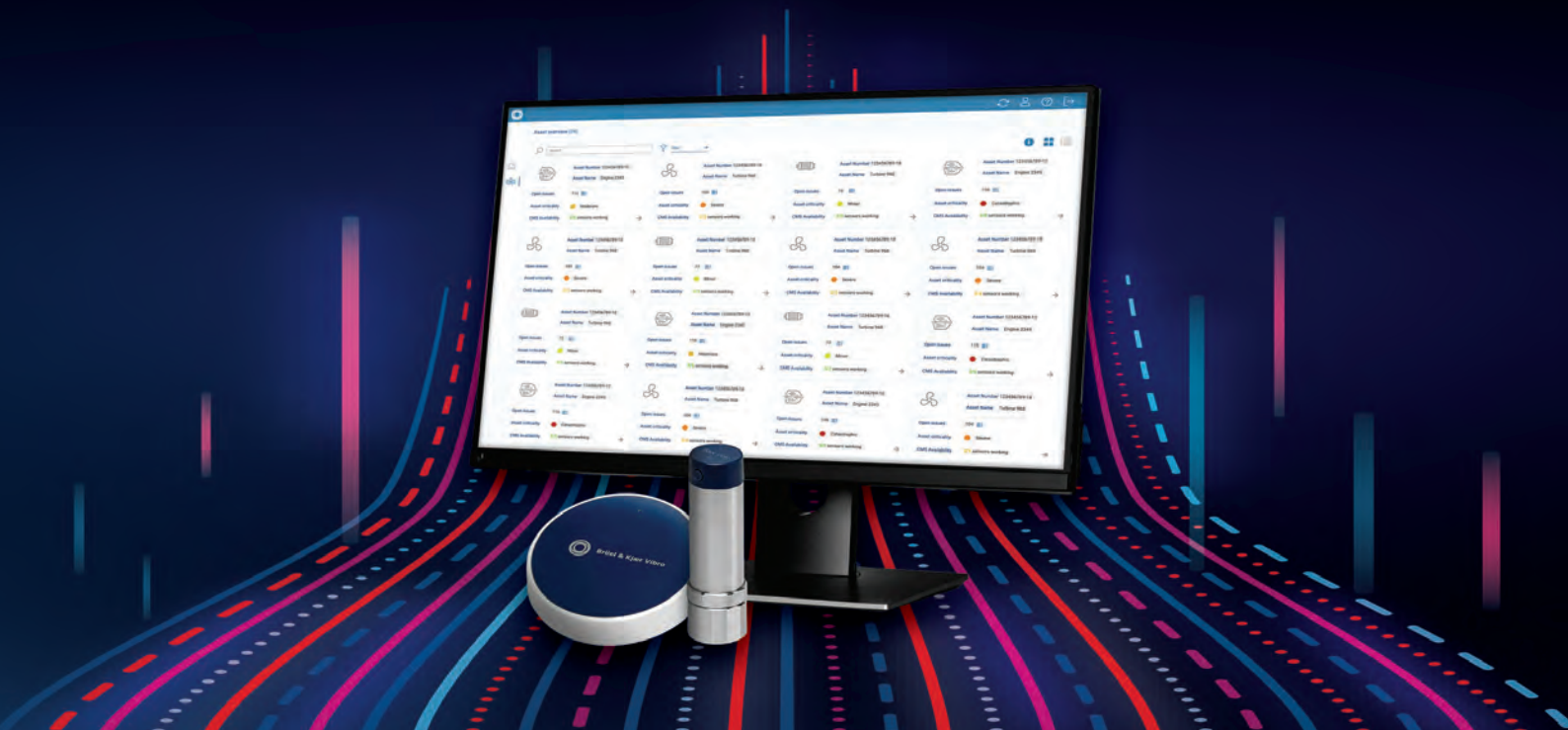


World news

Summer 2023

ADNOC Drilling secures offshore jack-up contracts

ADNOC Drilling Company has confirmed the award of five 10-year contracts, totalling approximately US$2 billion, in support of ADNOC Offshore's growing drilling operations.

The contractual conditions, particularly the duration, were agreed with the client in light of the strength of the offshore jack-up market with higher day rates. The contracts supporting drilling operations across five fields in ADNOC's offshore portfolio, are for the charter of five high-specification, premium jack-up rigs along with all required manpower and equipment.

The rigs will commence activity progressively from the end of 2023, with significant revenue expected in 2024 and first full-year revenue contribution from 2025. The revenue associated with these contracts is included in the company's full year 2023 and medium-term guidance.

Abdulrahman Abdulla Al Seiari, Chief Executive Officer of ADNOC Drilling, commented: "We are pleased to have been awarded these important contracts. Long-term contracts like these are the backbone of our business model, providing clear line of sight on future earnings. As we continue to grow our fleet, our shareholders will benefit from the opportunity to be directly invested in ADNOC's accelerated production capacity growth, which is driving faster revenue growth and progressive, long-term shareholder returns while responding to the world's rising energy demand."

The five rigs have been acquired as part of the company's fast-tracked rig fleet expansion programme, designed to enable the delivery of ADNOC's accelerated production capacity growth to responsibly meet rising global energy demand. The new rigs, SALAMAH1, AL SAADIYAT, AL SILA, RAMHAN and YAS, will be among the most capable, high-specification rigs working in the Arabian Gulf.

Each of the five rigs will be equipped with a battery energy storage system to increase efficiency and reduce emissions. The hybrid power technology system stores energy in its batteries to use when there is a need for continuous power or to provide instant extra power when there is an increase in demand.

The new rigs are central to ADNOC Drilling's rigorous decarbonisation strategy and the company's commitment to support ADNOC's target to reduce greenhouse gas intensity by 25% by 2030, as well as the UAE Net Zero by 2050 strategic initiative.

The US$2 billion contract award follows more than US$11.5 billion in long-term contracts announced since the beginning of 2022.

Halliburton and Nabors to collaborate on new well construction technologies

Halliburton Company and Nabors Industries have announced an agreement on leading well construction automation solutions. Under the agreement, Halliburton and Nabors will collaborate together on their technologies including the Halliburton Well Construction 4.0 digital surface and subsurface drilling technologies, the LOGIX Autonomous Drilling Platform, the Nabors SmartRos universal rig controls and automation platform, and RigCLOUD high-performance digital infrastructure platform.

Initially deployed in Iraq, the companies' technologies automate well construction services from planning to execution across both subsurface and surface equipment and environments. Halliburton and Nabors will engage with further opportunities to expand projects for other customers in countries across the globe.

Steve Haden, Senior Vice President, Halliburton Project Management, said: "Halliburton's and Nabors' efforts will make it easier for customers to deploy Halliburton's automation solutions that can enhance rig capabilities, lower well construction costs, and reduce operational risks."

"This agreement brings together the drilling process automation and digital solutions of Nabors with Halliburton's sub-surface expertise, resulting in a unique combination that will drive well construction efficiencies through repeatable and consistent outcomes," said Subodh Saxena, Senior Vice President, Nabors Drilling Solutions.

In brief

Nigeria

A discovery in shallow water by TotalEnergies in Nigeria is the biggest the country has seen in a decade. Estimated resources could be in excess of 300 million boe.

Addressing TotalEnergies' discovery at Ntokon in the shallow water Niger Delta, Gail Anderson, Director of Upstream Research at Wood Mackenzie, said: "Ntokon is likely to be Nigeria's biggest shallow water discovery in a decade. Despite the lack of exploration in recent times, this discovery shows that there is still plenty of running room in the shallow water Niger Delta."

Based on analogous net pay of shallow water discoveries in the Tertiary Agbada formation of the Niger Delta, and above-average recovery from high quality reservoirs, Wood Mackenzie estimates that the field could hold resources in the range of 300 to 400 million boe.

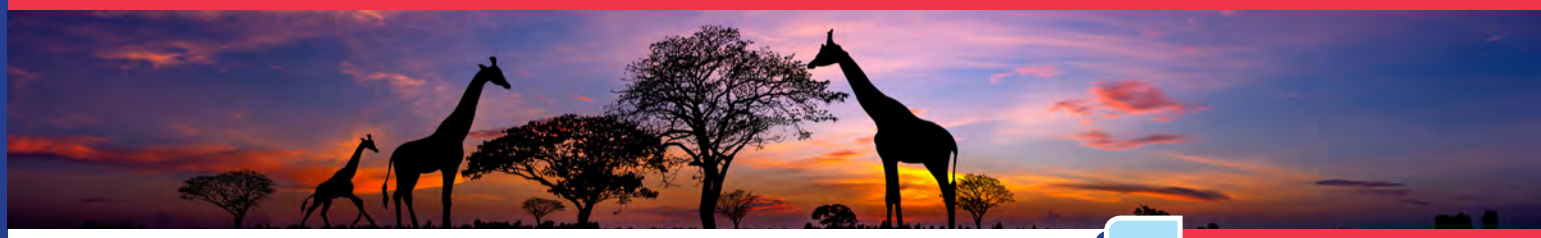
The discovery was made on shallow water block OML 102, which is part of a joint venture between operator TotalEnergies (40%) and NNPC Limited (60%). Ntokon will be developed as a tie-back to the Ofon field, 20 km to the northeast, on the same block.

Romania

OMV Petrom has announced the discovery of new crude oil and natural gas resources in the Oltenia and Muntenia regions of southern Romania. Cumulatively, the discovered deposits hold over 30 million boe of recoverable resources, equivalent to around three quarters of OMV Petrom's 2022 production.

Exploration drilling and testing of these three wells took place between June 2022 and April 2023. The company has invested around €20 million in the exploration drilling campaign.

Cristian Hubati, member of the OMV Petrom Executive Board, responsible for the exploration and production activities, said: "Romania has been producing crude oil and natural gas for over 150 years, and under these conditions, identifying new resources requires a significant effort."



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Diary dates

05 – 08 September 2023

Gastech Exhibition & Conference
Tampines, Singapore
gastechevent.com

17 – 21 September 2023

24th World Petroleum Congress
Calgary, Canada
24wpc.com/world-petroleum-congress

02 - 05 October 2023

ADIPEC 2023
Abu Dhabi, United Arab Emirates
adipec.com

16 – 18 October 2023

SPE ATCE 2023
Texas, USA
atce.org

Web news highlights

- OMV Petrom and Romgaz announce largest gas project in the Black sea
- SBM Offshore completes financing of Alexandre de Gusmão
- Keir Starmer softens stance on UK oil and gas
- We1-1 has reached total depth in Guyana

To read more about these articles and for more event listings go to:

www.oilfieldtechnology.com

Baker Hughes awarded subsea contract in Africa

Baker Hughes has been awarded a major contract by Eni and its partner Petroci for the Baleine Phase 2 project in Ivory Coast, Africa's first Scope 1 and 2 net zero emissions development.

This award, which includes eight deep water trees, three Aptara manifolds, the relevant subsea production control system, and flexible risers and jumpers, strengthens Baker Hughes' presence in West Africa and unlocks considerable growth potential in the country.

The company will deliver a configured-to-order product portfolio across subsea production and flexible pipe systems, designed for optimum cost effectiveness, installation and life-of-field value. These deepwater trees and manifolds, supplemented with subsea production controls and flexible pipe systems, provide efficiency and cost-effectiveness under demanding conditions. Their modular design aids in reducing lead times, vital for the economic feasibility of such projects.

Maria Claudia Borras, Executive Vice President, Oilfield Services & Equipment at Baker Hughes, said: "This collaboration between Baker Hughes and Eni is Africa's first development project with clear Scope 1 and 2 carbon reduction goals and will deliver innovative technology that will enhance the energy security in Ivory Coast. Ensuring that energy is locally available is an increasingly profound challenge, and we applaud the efforts of Eni and companies like it to shape an abundant energy future for Africa. We are proud of the confidence placed in us to accelerate the execution of this important project."

TGT Diagnostics launches resource to locate and characterise flow in oil and gas wells

TGT Diagnostics has announced the launch of its latest acoustic platform, ChorusX, a new diagnostic resource specifically designed to locate and characterise flow in oil and gas wells. This acoustic array platform enables energy companies to find and map fluid flow throughout the well-reservoir system with greater ease and precision, helping them to keep wells safe, clean, and productive.

Ken Feather, TGT's Chief Marketing Officer, commented, "Understanding flow dynamics in the well system is the key to unlocking better well and reservoir performance, and acoustic techniques have become an indispensable means of achieving that goal. ChorusX is the result of two decades of intensive research, innovation, and extensive field experience in applying the power of sound to flow diagnostics in thousands of wells. Eight high-definition array sensors, extreme dynamic range recording and a unique phase analysis engine work in concert to deliver uncompromising levels of clarity, precision, and certainty to analysts and well operators."

TCO announces the installation of a new injection valve

TCO has announced the successful development and installation of the API 19CI Qualified FNR (fall through protection, non-return, retrievable) injection valve.

The installation, for a major Norwegian Operator, is the first API 19CI qualified retrievable injection valve to be successfully installed on the NCS. The API 19CI specification, which was released in 2019, states the requirements for chemical injection devices intended for use in the worldwide petroleum and natural gas industry.

This includes requirements for specifying, selecting, design verification, validation testing, manufacturing, quality control, testing, and preparation for shipping of chemical injection devices.

The FNR injection valve allows operators to retrieve and change the valve or Anti-U-Tube mechanism during the well's lifetime, which can save operators the potential costs of recompleting a well due to CIV failure.

The FNR injection valve has a pressure rating of 10 000 psi and can operate at temperatures up to 150ºC, making it suitable for various applications.

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World news Summer 2023

Eni and Vår Energi to acquire Neptune Energy Group

Eni S.p.A. has announced that, along with Vår Energi ASA, it has reached an agreement to acquire Neptune Energy Group Limited.

Neptune is a leading independent exploration and production company with a world-class portfolio of gas-oriented assets and operations in Western Europe, North Africa, Indonesia and Australia. The portfolio is competitive in terms of cost, and low in operational emissions. Neptune was founded in 2015 by Sam Laidlaw and is currently owned by China Investment Corporation, funds advised by Carlyle Group and CVC Capital Partners, and certain management owners.

Eni will acquire assets comprising Neptune's entire portfolio other than its operations in Germany and Norway. The German operations will be carved out prior to the Eni transaction and the Norwegian operations will be acquired by Vår directly from Neptune under a separate share purchase agreement.

The Vår transaction will close immediately prior to the Eni transaction with the proceeds from the Norway sale remaining with the Neptune Global Business purchased by Eni. Vår is a company listed on the Oslo Stock Exchange and is 63% owned by Eni.

Valeura Energy completes Nong Yao field infill drilling campaign

Valeura Energy has announced the successful completion of its Nong Yao field infill drilling campaign and recent increases in oil production.

The company has drilled two horizontal infill wells on its Nong Yao oilfield at Licence G11/48 in Thailand, in which it holds a 90% operated working interest.

Drilling operations were executed safely, below budget, and ahead of schedule. The wells encountered approximately 1000 and 700 ft of net oil pay in their horizontal sections, respectively, confirming pre-drill reservoir simulation results. The wells have come onstream at a combined initial gross rate of approximately 1350 bpd.

The impact of the new Nong Yao wells, in addition to contributions from the company's Jasmine oilfield drilling programme earlier in 2023, has resulted in aggregate oil production rates from the company's portfolio during the 11 days of June averaging 23 700 bpd (net to the company's working interest), an increase of approximately 16% over average 1Q23 rates from the four assets.

The Borr Mist drilling rig is now on location at the Manora oilfield where the company plans to drill three wells aimed at increasing production from the field and by extension, adding to the economic life of the asset. Upon completion of operations at Manora, anticipated in early August 2023, the rig will move to the Wassana field for the company's five-well infill drilling programme.

Sean Guest, President and CEO, commented: "Our Nong Yao drilling campaign has been a success and the results bolster our investment thesis that our assets offer the potential to add further value through increased production and new reserve additions through targeted infill drilling."

TETRA Automated Drillout System to enhance wellbore management

In four months of incident-free operation, the TETRA automated drillout system, which was deployed to Appalachia and used in unconventional gas wells, drilled out more than 2300 plugs without the need to pull a screen. The operation reduced the time for rig-up/rig-down by 40%, reduced risk exposure by 33.3%, and damages per plug by 64.5%, from US$48 to US$17.

Inception of the equipment began when a major operator of unconventional gas wells in Appalachia approached TETRA seeking a safer plug-drillout solution requiring less time. The main challenge of a standard drillout operation is the exposure to hazards with workers having to manually adjust valves, pull screens for cleaning, and change line connections around equipment under very high pressures. Another challenge is the logistic complexity of engaging multiple service providers, opening the drillout operation to potential miscommunication, mistakes, nonproductive time, and costly inefficiency.

At the operator's request, TETRA engineers designed an integrated, single-skid, drillout system that is remotely operated via the TETRA BlueLinx™ automated control system. The new system eliminates manual control of valves and pulling junk-catcher screens, thus reducing both exposure to HSE risk and the time needed to conduct drillout. The system provides remote control of the valves, manifold, junk-catchers, and emergency shutdown, as well as real-time monitoring of flowrates, pressures, pressure differentials, plug weights, tank levels, and other metrics.

The TETRA drillout system also enhances wellbore management during drillout, enabling pre-programmed valve sequencing, consistent pressures and flowrates without large swings when switching sides of the dual system, and the flushing of plug parts from junk-catchers at a chosen flowrate.

THREE60 Energy win European well decommissioning contract

THREE60 Energy has been awarded a well decommissioning contract to plug and abandon multiple offshore wells in Europe.

The new contract will see the company permanently decommission 13 injection, production and observation wells, creating new jobs for the company in the UK and Europe.

THREE60 Energy, which has geographical hubs in UK, Norway and Malaysia, will utilise its well decommissioning team to deliver the plug and abandonment designs, prepare operational planning and supervise the offshore execution, which includes the management of the jack-up rig and well abandonment subcontractors.

Nick Ford, Wells UK Managing Director at THREE60 Energy, said: "With our strong track record of offshore delivery and well abandonment we bring almost 20 years of the technical skills, capabilities and experience needed to successfully deliver this significant well decommissioning project offshore Europe."

Walter Thain, CEO at THREE60 Energy, said: "This contract clearly demonstrates the opportunities available for supply chain companies globally, especially within decommissioning, and is a great example of transferring our competency and capability across multiple geographies. We're excited to continue growing our decommissioning delivery and play a key role in decarbonising the future as part of the wider energy transition."


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Beyond the core North Sea countries of the UK and Norway, Europe boasts a diverse upstream sector, from the Netherlands to the Black Sea and East Mediterranean.

This Continental Europe region currently produces about 1.5 million boe/d of oil and gas. The energy shocks after Russia's invasion of Ukraine have highlighted the importance of the continent's own upstream sector.

But, in recent years, it has been a region of contrasts. In mature locations, output is declining, energy mixes are transitioning, and the social and environmental licence to operate has weakened. Yet, at the region's geographical frontiers, major developments and high-impact exploration have still made progress. The current outlook reflects this well.

Upstream has moved up the policy agenda amid security of supply pressures

Russia's invasion of Ukraine and the subsequent risks to European gas supply have called into question the continent's reliance on imports. Some European governments have therefore re-evaluated the role of their domestic upstream gas sectors.

In parts of Continental Europe, the upstream sector has become the black sheep of the economic family in recent years. This has eased since 2022 for gas, although not for oil. The region does not speak with one voice, even among EU members, but there are clear steps in favour of gas-led upstream policies.

Italy is a prime example. After a change in government in 2022, the country wants to double domestic gas production to almost 600 million ft^3/d by supporting offshore activity. That is very ambitious, even with the relaxation of some upstream regulatory restrictions. The most important pillar of Italy's gas supply recovery will be Eni and Energean's Cassiopea development, offshore Sicily. This is on track to launch in 2024.

In contrast, a country where gas production is decreasing is the Netherlands. This is because of the managed wind-down at the giant Groningen gas field.

Ashley Sherman, Wood Mackenzie, UK, provides an outlook for Europe's upstream oil and gas sector and considers how the industry will navigate the energy transition.

Continental Europe: An upstream outlook

Groningen was Europe's core swing supplier in previous decades, but those days are long gone.

Political and social concerns about recurring earthquakes have taken precedence over energy security risks, with the Dutch government repeatedly re-emphasising its commitment to phasing out Groningen. 2023 is intended to be its last year of sustained, albeit now small-scale, operations. A decision will be made in June on whether to extend this into 2024.

Regulation: Windfall taxes have grabbed the headlines, including EU-wide measures

Europe has been at the forefront of the recent energy windfall tax debate. For governments, there is a very delicate balance between encouraging new upstream investment, to boost security of supply, and taking a fair share of additional profits in higher prices.

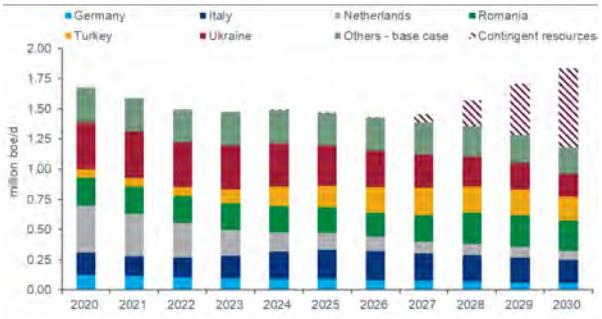

Figure 1. *Continental Europe's production (liquids and marketed gas) (source: Wood Mackenzie).*

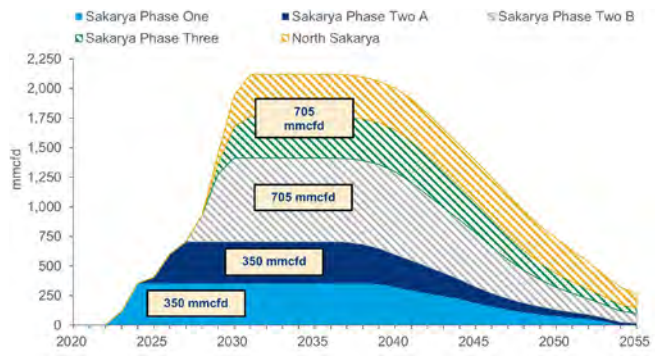

Figure 2. *Turkey - Sakarya megaproject gas production (source: Wood Mackenzie, TPAO public disclosure).*

Figure 3. *Cyprus - resources discovered to date (source: Wood Mackenzie, operator disclosure).*

In late 2022, many EU member states adopted a temporary solidarity contribution on 'surplus profits'. However, there was more variation than initially expected in how countries applied the EU charge – by rate and timeframe. Backdated changes understandably frustrated investors, with several legal cases ongoing to challenge the legislative process at either a national or EU level.

'Smart' approaches to windfall taxation may be what is needed to provide predictability irrespective of the prevailing price. It is a mixed bag in Continental Europe at present.

Romania is a prominent example. The country introduced the EU levy at a comparatively high rate of 60% for 2022 – 23, rather than the 33% minimum. After investor-friendly offshore reforms in 2022, this once again increased the country's tax burden. Romania already has a permanent gas windfall tax and a producer price cap that extends to 2025. In May, the country had to amend its terms for the EU solidarity contribution to reduce the impact on OMV Petrom, its leading operator, and the firms involved in a newly producing Black Sea project, the Midia Gas Development.

Black Sea: A year of gas megaproject milestones in Turkey and Romania

Russia's full-scale invasion of Ukraine has brought insecurity to the Black Sea. Upstream operators continue to scrutinise all discretionary investment, while the international service sector applies a risk premium to Black Sea work. However, Wood Mackenzie is confident that the highest-profile exploration and development projects can proceed.

In April, Turkey commissioned Phase One of its deepwater Sakarya gas megaproject. The giant field was discovered in 2020, and state-owned TPAO, the operator, achieved first gas on an extremely impressive schedule. A fast-tracked lead time of less than three years from discovery has few peers globally for a project of this scale.

Turkey's deepwater Black Sea resources are of huge political importance. Sakarya redefines the scale of the country's upstream sector, bringing its first deepwater output and a fundamental shift in domestic energy security. To date, Turkey has relied almost entirely on gas imports to meet its demand. Sakarya Phase One will put a sizeable dent into the country's energy import bill, which reached an eye-watering US$97 billion in 2022.

Phase One will ramp up to its plateau of 350 million ft^3/d (3.7 billion m^3/yr), increasing Turkey's national gas output nearly tenfold. But a larger Phase Two would be the real gamechanger, enabling Sakarya to cover almost 30% of Turkey's gas consumption by 2030. A full Sakarya development, including a third phase, is under evaluation to grow future production capacity to 2.1 billion ft^2/d (21.9 billion m^3/yr) by the late 2020s.

The path to Black Sea gas commercialisation has been far less smooth outside of Turkey, most notably in Romania. Its Neptun Deep fields were discovered in the early 2010s, but a development is only set to reach a final investment decision (FID) later this year. This would enable large-scale gas production from 2027 at the earliest.

After ExxonMobil's US$1.1 billion exit in 2022, Neptun Deep is now operated by OMV Petrom (50%), in partnership with state-backed Romgaz. Cost pressures are in the spotlight, with escalation likely from a previous US$4 billion estimate because of industry inflation and elevated Black Sea rates.

Approval for Neptun Deep will be bittersweet, coming five years after the development was first deemed FID-ready. Reforms to Romania's controversial Offshore Law in 2022 removed key blockers, although chronic fiscal and regulatory challenges persist from windfall taxes and gas price caps.

East Mediterranean: Cyprus seeks to advance its gas development plans

Cyprus represents the European section of the prolific East Mediterranean gas play. In the last decade or so, more than 14 trillion ft^3 of gas has been discovered, however no upstream projects have yet reached FID.

2022 was another successful year for Majors-led exploration in Cyprus. Eni and TotalEnergies announced two more large gas discoveries on Block 6: Cronos and Zeus. Each was reported to have 2 – 3 trillion ft^3 of gas in place.

Attention has now firmly turned to appraisal and progress towards clarifying the 'how' and 'when' of gas commercialisation.

At Aphrodite, Cyprus' earliest discovery, a Chevron-led consortium started drilling the crucial Aphrodite-3 appraisal well in May. This should take about three months. Other appraisal probes, on other discoveries, should follow by this time next year.

The Aphrodite well is a critical milestone to derisk the field's proposed multi-billion-dollar development. The most likely concept involves the tie-back of subsea wells to infrastructure in Egypt, for gas delivery to an onshore LNG liquefaction plant.

More generally in Cyprus and the East Mediterranean, evaluation of floating LNG (FLNG) development concepts has gained momentum. For example, there is a giant gas resource cluster across Cyprus' Block 6 and Block 10. The former is licensed to Eni and TotalEnergies, and the latter to ExxonMobil and QatarEnergy. Synergies and the co-development of at least some of these discoveries makes sense to accelerate the schedule and optimise costs. Economies of scale would be benefitial to help manage exposure to high upfront capital costs and prevail above-ground risks.

For the development of Cyprus' vast discovered gas resources, commercial challenges still need to be overcome. Moreover, geopolitical tensions, and the risk of Turkish interference, are never too far away in the East Mediterranean. Turkey and the breakaway Turkish Republic of Northern Cyprus voiced their typical strong opposition to the ongoing well at Aphrodite. Direct interference is a risk if Cypriot development plans mature.

How does Continental Europe fit into the energy transition?

Upstream decarbonisation and emissions cuts are front and centre for regional operators, including for any new projects awaiting approval. Leading European upstream firms are also well-placed to accelerate the regional transition, be that thanks to their subsurface expertise and infrastructure portfolios for carbon capture and storage, or offshore working practices for wind power.

Countries across Continental Europe must search for the optimal balance between energy security, economic advantage and climate goals. Some, including Denmark, France and Spain, have already announced time-bound commitments to end upstream activity. However, this is still only realistic for nations with minor production, where upstream revenues are not a major economic contributor. Emerging producers further east, like Turkey and Romania, do not want to miss out on the economic benefits that domestic oil and gas extraction can provide.

Maintaining a social licence to operate will be paramount. As Groningen's tumultuous path to cessation in the Netherlands shows, that can be lost at surprising speed, and once gone, it is unlikely to be regained.

EXPLORING NATURAL TECHNOLOGIES

Jennifer Knopf and Neil Lawrence Tobin, Vink Chemicals, Germany and UK, discuss natural gas hydrogen sulfide mitigation technologies and consider the benefits of alternative scavengers.

Hydrogen sulfide (H_2S) is often present in crude oil and gas. Generated by thermochemical or biogenic breakdown of organic matter, it is an extremely hazardous, colourless, highly toxic, flammable and corrosive gas. It poses a danger to personnel, damages the integrity of industrial equipment and devalues marketed hydrocarbons. It is a leading cause of workplace gas inhalation death in the US, second only to carbon monoxide.[1] It has a familiar 'rotten egg' smell at a very low concentration, but injury and death can occur at gas phase levels as low as 500 ppm.[2] It is heavier than air and collects in low-lying, poorly ventilated areas. Industrial H_2S based corrosion is reported to cause over US$1 billion worth of damage per year. [3,4]

H_2S in the supply chain

H_2S can be an issue in natural gas along the entire supply chain: production systems, offshore platforms, FPSOs, gas/petrochemical/crude processing plants and storage facilities, and vent gas/wastewater treatments. It is critically important to remove H_2S, not just for personnel protection, but also to ensure the integrity of compressors, separators, pipes and pumps, and particularly to avoid sulfide

GAS H_2S MITIGATION

Table 1. H_2S removal techniques in natural gas.

Method	Description/benefits/drawbacks
Venting and flaring	Venting or flaring of lighter ends (generally methane with H_2S) has been practiced across the industry. Successive stages of separation of oil, water and gas results in gases rich with H_2S that are not permitted in pipework. H_2S laden gases are flared at platforms or wells but this risks environmental penalties due to the conversion to other toxic pollutants (SO_2). These practices are targeted for reduction through on-site direct use or energy conversion that would indirectly require the use of H_2S capture technology in some form. Treating rather than flaring is becoming a more common refinery application as limits on SO_x emissions become tighter.
Nitrogen stripping systems	These systems are used at the platform in the oil industry to remove H_2S. After the stripping process, the H_2S is usually flared.
Chemical removal methods	**Absorbents** – Known as a regenerative process, meaning that they can be recycled and used again, amine alcohols (MEA, DEA) are typically employed. The amine (in water) 'captures' the H_2S, and is then heated to gas off concentrated H_2S to flare it afterwards. These products are used to treat large volumes of sour fluids. **Scavenging** – Non regenerative H_2S scavengers react directly with H_2S to create a reaction product. Most chemicals are non-regenerative in these systems and spent reaction product is sent to waste after use. **Inorganics** – Gas scrubbing systems remove H_2S from gas streams in an amine treating unit. The H_2S gas from the regenerated amine is converted to sulfur through the Claus process. This is performed under license and requires installation of capital equipment. **Solvents** – A range of formulated solvents are also used for the extraction of H_2S (along with CO_2).
Fixed bed adsorbents	Molecular sieves, metal oxide and carbon-based sorbents are technologies used by a number of operators looking for sub ppm levels. These systems are fixed beds of absorbent material where sour gas is pumped into the top and sweetened gas exits at the bottom. Gas with heavier loads may need some pretreatment. Metal oxide beds take up significant space and require two sets of beds to maintain operation during servicing. The media is non-regenerative and requires significant time and labour to charge with fresh media. Mol sieves are regenerative solid beds that remove H_2S by adsorption instead of chemical reaction.

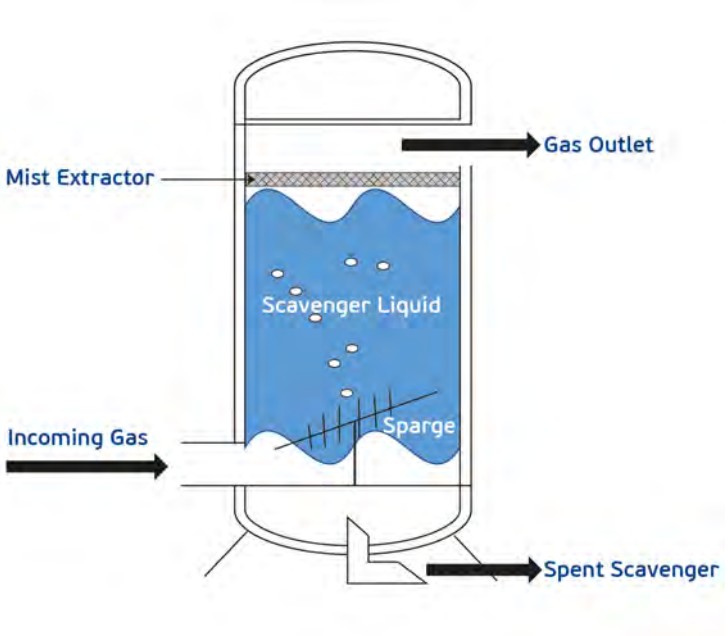

Figure 1. *Bubble tower schematic.*

stress cracking. Natural gas high in H_2S is known as sour gas, and removing it is known as gas sweetening. Adsorption, absorption, oxidation, membrane processes and scavenging are removal methods with various merits and drawbacks.[5] H_2S must be removed to a permissible level before it is transported for storage or use. The level depends on the specific end use and the relevant local regulations. Gas to be sent to processing stations in the EU and USA must have a limit of <10 ppm, and often <4 ppm. Gas transported to transmission pipelines must be H_2S free.

H_2S removal methods in natural gas

Continuous injection

Gas pipeline streams can be treated by injection of scavenger directly into the wet gas, before condensation, to make sure that H_2S/scavenger reaction products can be separated and removed from the system through the condensed fluids.

Injection location and the product selection must be carefully considered for direct injection to be efficient and successful. The installation consists of a chemical injection pump/skid, and an injection spray point (typically a quill, atomiser, fog nozzle or static mixer) through which the scavenger is dispersed. Atomising creates a fine fog-like mist and greatly increases the scavenging efficiency due to the fine dispersion of liquid throughout the gas. Using a quill can result in the scavenger dropping through the gas to the bottom of the pipework, resulting in less contact with the H_2S molecules. Little capital expense is required for direct injection but poor application can result in overdosing/excessive scavenger consumption and increased waste.

Liquid batch process (bubble towers)

A batch contact tower (also known as a bubble tower) is a tower-like vessel that is constructed inline between the well and the transfer sales point. It is filled with a specific volume of the liquid scavenger solution and the gas is 'sparged' or percolated up from the bottom of the tower. The treated gas exits at the top and the spent chemical and waste reaction product exit at bottom drain points.

Proper design is important for optimum operation. The gas enters the bottom of the vessel, and travels upward through the treatment mixture, and perforated baffles within the system increase the gas-chemical contact and H_2S removal efficiency. The gas then rises out of the liquid pool and enters a head space in the upper section of the tower. Gas exits the tower at this point in older designs. In improved bubble tower designs, gas undergoes a second stage reaction where a combination of fresh and recycled chemical is sprayed into the gas through atomising nozzles. Waste chemical byproducts can be disposed into produced water tanks.

Space is premium with bubble towers and they can be expensive to install in existing production systems. They are suitable for smaller well volumes where consumption of scavenger is relatively low: they have high tolerance for varying levels of H_2S and flexible inlet range, however, most triazine-based systems cannot economically treat over 2000 ppm H_2S. Removal of reaction by-products and solids build up is vital to ensure process longevity between refills. The H_2S removal efficiency of basic contactor towers can reach up to 80%. As a result, much less chemical is used and

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Table 2. Test conditions.	
Column diameter/height (cm)	7.5/52.8
Temperature (°C)	36
Chemical fill (%)	87.91
H_2S in gas mixture – balanced with nitrogen (ppmv)	14
H_2S in gas mixture (g/L)	0.0198
Gas flow rate (L/min)	0.997
Total H_2S gas (g/day)	28.3561
Scavenger concentration %	30
KPI ppm H_2S in the gas (after exceeding 10 ppm, the H_2S scavenger solution needs to be exchanged.)	< 10

Table 3. Mass H_2S scavenged by mass neat chemical (g/kg). stabicor S 100 was able to scavenge 2.7 times the amount of H_2S than MEA-triazine before exceeding the KPI. *Amine scavenging capacity not included.

	stabicor S 100	MEA-triazine
Gas flow rate (L/min)	1	1
Time when H_2S exceeded 10 ppmv (min)	6604.5	3075.5
Total test gas volume (L)	6604.5	3075.5
H_2S in test gas at 20°C (mol)	3.7912	1.7655
H_2S mass (g)	128.9	60.03
Neat chemical mass (kg)	0.55	0.69
Mass H_2S scavenged by mass neat chemical (g/kg)	234	87,3
Theoretical H_2S that can be scavenged* (g/kg)	366	311
% Consumption of scavenger when KPI of 10 ppmv exceeded	64	28

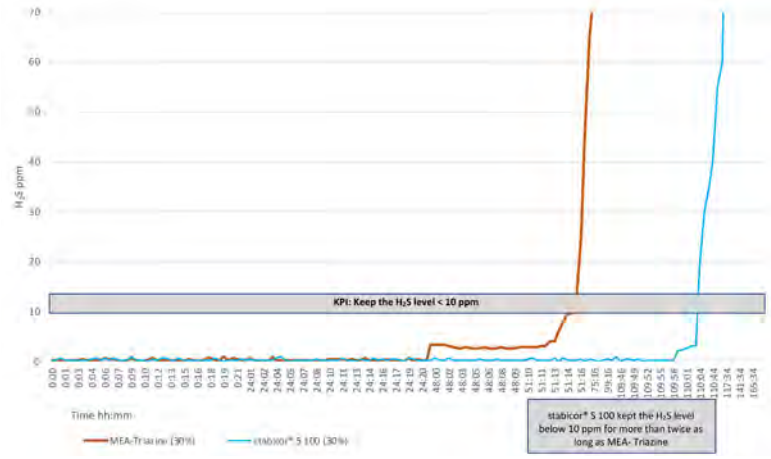

Figure 2. *H_2S concentration vs time: MEA- triazine vs stabicor S 100.*

Table 4. Case study for stabicor S 100 applied in contact towers in several fields in North America. By changing the scavenger product from MEA-triazine to stabicor S 100, the treatment was improved in terms of cost-performance and favourable maintenance procedure.

	Field 1	Field 2	Field 3
Treated gas per day in MMSCFD	0.05	0.05	0.05
H_2S level in ppm	15.000	2.000	2.000
KPI H_2S in ppm	<10	<10	<10
Volume H_2S scavenger in L	200	80	80
Exchange of scavenger solution after X days	8	8	8

OPEX may be significantly decreased. In the second stage polishing step, up to 95 – 99% H_2S reduction can be reached.

Selection of scavenger

Scavengers must have the following characteristics:

- Rapid reaction – little contact time can be available between entry point and exit point.
- Non-reversible reaction.
- Selectivity for H_2S and no other species.
- Non-corrosive and low toxicity – for both scavenger and reaction products.
- Sufficient solubility of the byproducts in an appropriate solvent.

Monoethanolamine (MEA) triazine (hexahydro-1,3,5-tris(hydroxyethyl)-s-triazine) also known as MEA triazine or HHT, is the most widely used scavenger in the industry. It reacts quickly and irreversibly with H_2S to form a dithiazine (5-hydroxyethylhexahydrodithiazine – DTZ). The major drawback is that DTZ reacts further with excess H_2S to form a largely insoluble and sticky polymer (amorphous dithiazine) that can only be removed through expensive mechanical means.

The oxazolidine derivative stabicor® S 100/MBO (3,3'-methylenebis(5-methyloxazolidine)) is a new generation of non-triazine based H_2S scavengers.[6,7] It offers the same benefits as triazine, while increasing the consumption of H_2S/the weight of scavenger, and reduces the polymeric by-product deposition. It is 99% active, meaning that product, transportation, freight, and storage costs can be reduced and can also be diluted with numerous types of solvents before use. The higher scavenging chemical capacity allows for longer residence times in the contact tower and consequently longer exchange intervals can be achieved.

In this article, Vink Chemicals discusses the application details in bubble tower set ups, and considers laboratory performance and field test results on the use of this alternative H_2S scavenger.

Experimental lab data

The following experimental detail describes how scavenger products were tested in a contact tower simulation for H_2S breakthrough evaluation. The lab tower was filled to the required volume with a diluted mixture of H_2S scavenger with solvent. The liquid and the gas headspace were deaerated using oxygen-free nitrogen prior to starting the tests. The scavenger solution was heated to the test temperature, then the start time was recorded and sparging of the test gas was commenced at the specified flow rate. The mass of H_2S gas in contact with the scavenger was calculated from the gas flow rate and the duration of the test. The H_2S concentration of the outlet was continuously monitored using a digital H_2S in-line monitor. Automatic datalogging and the

gas flow stopped once the H_2S concentration of the outlet gas exceeded the KPI of the 10 ppmv breakthrough condition, which is usually the natural gas specification. At this point in the field, the scavenger chemical is replaced due to quality, safety, and operational reasons.

Results

The alternative scavenger was able to maintain the H_2S level below 10 ppmv for around 110 hours. At this time, the H_2S reaction product started to precipitate from the solution and the H_2S level increased quite quickly back to baseline. After approximately 168 hours, the H_2S concentration was measured at 6000 ppmv. In contrast, the industry standard H_2S scavenger kept the level below 10 ppmv for around 51 hours. Solid formation started at this point. After this, H_2S levels increased slowly back to the baseline. stabicor S 100 was able to meet the KPI of H_2S content below 10 ppmv for twice as long as MEA-triazine.

Discussion

Although the active ingredients of the alternative and industry standard scavenger present a similar chemical stoichiometric capacity, stabicor S 100 displayed more favourable kinetics and a more economical performance. This scavenger maintained a H_2S level that was below KPI level for a much longer time but when the chemical capacity was mostly depleted, a quick increase back to baseline was detected. In contrast to this, MEA-triazine kept the H_2S level at the outlet 'moderately low' for a long time but not consistently below the required KPI < 10 ppmv. Under field conditions, this translates into the need to exchange the only semi-consumed scavenger solution (one third consumed) resulting in a significant waste of resources. The formation of solids has been observed with all scavenger products. It has been shown that the formation of solids with stabicor products can be reduced by using polar solvents such as alcohols or glycols. Feedback from the field has shown that solids formed by the alternative scavenger products have different, more beneficial physical properties, resulting in easier and less costly maintenance and cleaning.

An alternative scavenger: Case study

- Goal: Improved H_2S mitigation of three fields in North America, each producing 0.05 MMSCFD high H_2S containing dry gas. Less solid formation should be seen, cleaning should be easier, and treatment should be cost-effective. The current product is based on MEA-triazine, which shows undesirable behaviour in terms of solids formation, resulting in uneconomic treatment.
- Solution: Application of a dilution of stabicor S 100 in methanol.
- Result: Successful reduction of H_2S to desired KPI, showing a cost-effective treatment due to extended residence time of the scavenger solution. No (low) significant solid formation led to easier cleaning of the contact tower.

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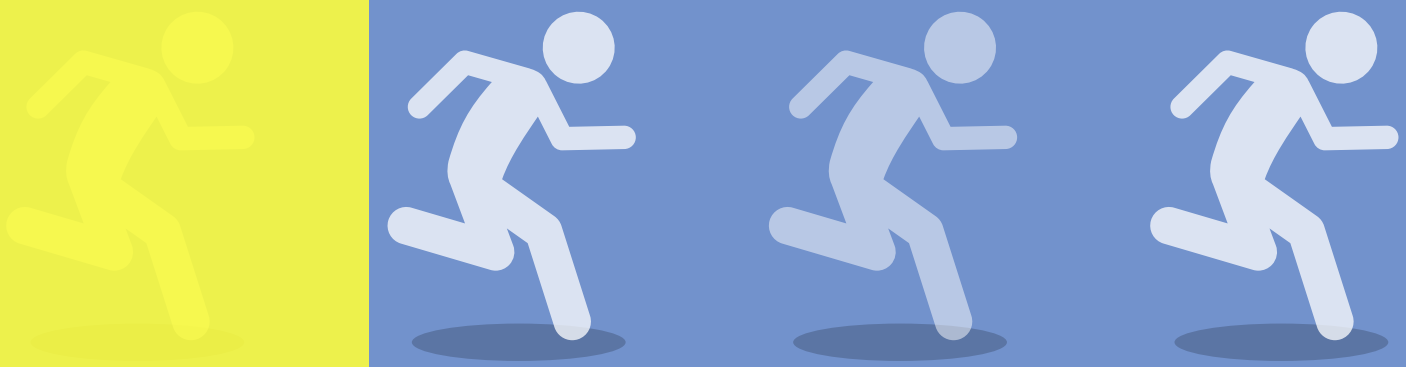
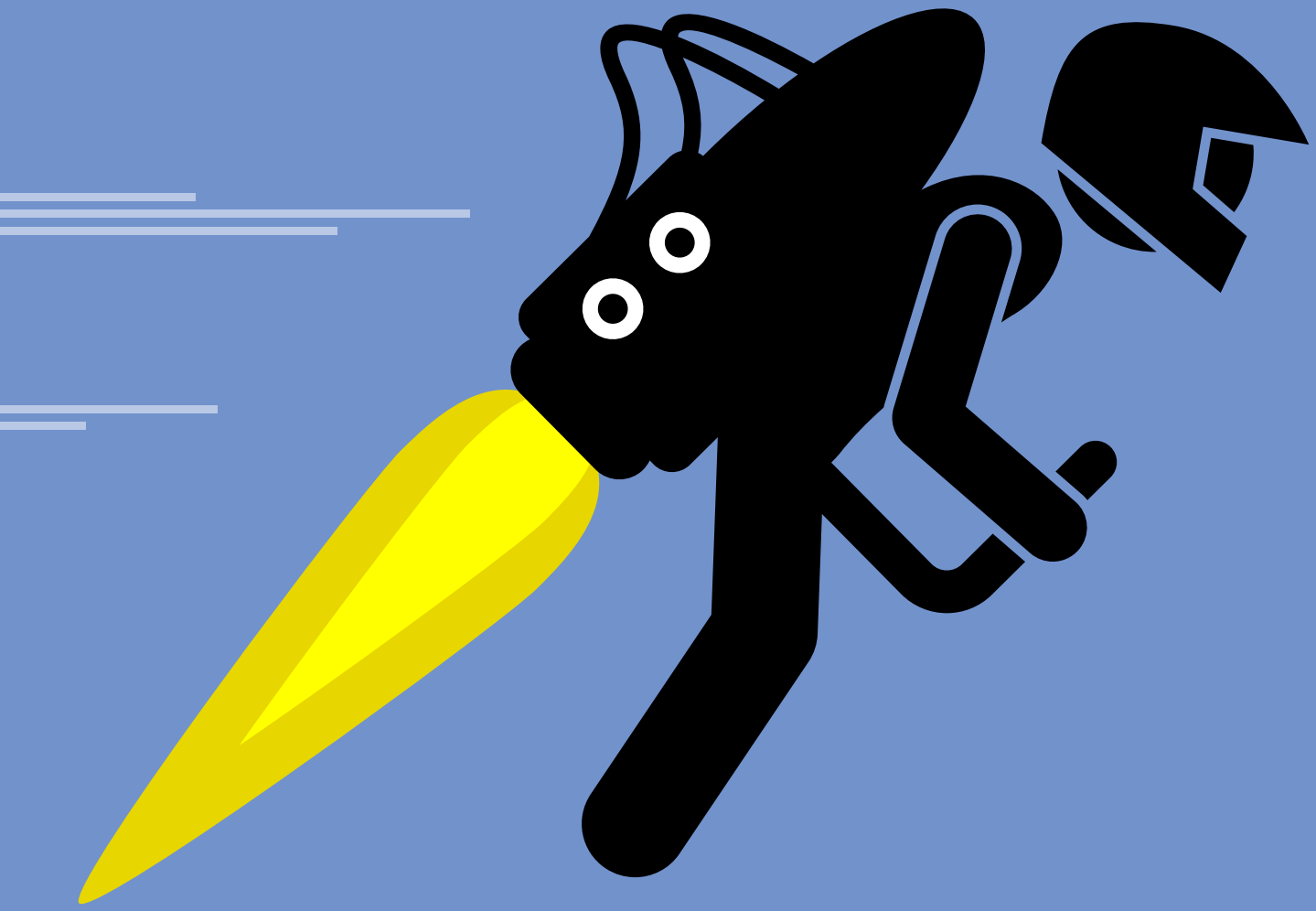
Gerald Woodward, Parker Hannifin, UK, evaluates the benefits of upgrading offshore filter systems in the fight against rising carbon emissions.

UPGRADING OFFSHORE FILTER SYSTEMS





Offshore gas turbines (GT) need protection from the harsh environments in which they are installed. Filtration solutions are used to remove contaminates from the airflow and safeguard turbine performance and output. However, units that have been installed for many years are not benefitting from the advances in filtration technology that will provide enhanced protection for these valuable machines. Although the prospect of upgrading filtration systems offshore may appear challenging, there are many benefits to be gained and filter manufacturers can offer the experience and expertise needed to ensure a smooth upgrade project.

Why operators should upgrade filters

First generation filtration technology typically offers efficiency levels of around M6/F7, which, compared to current technology, offers a medium level of protection, filtering particulate sizes of about 1.0 µm – 3.0 µm. However, the latest EPA filtration units have efficiency ratings of E10-12. This means they can provide protection from particles as small as 0.3 µm. Even a change to F8-9 filters will handle particles between 0.3 µm and 1.0 µm. But why is this important and what will it mean for the gas turbine?

Ignoring environmental factors (temperature, pressure, etc.) a GT operating with maximum compressor efficiency will deliver rated power over a long period of time, typically around one year before maintenance is deemed necessary. However, when particulates stick to the turbine blades, they change the turbine's aerodynamics and reduce its efficiency. GTs are very sensitive to this, hence the need for air filtration.

It has long been the accepted practice to perform either an online or offline wash to remove contaminants that have reached the GT internals, although the downtime incurred with this process inevitably costs money and results in lost production time. As filter technology has advanced, however, improved filtration efficiency has extended the time between water washes and has helped maintain higher levels of GT performance over longer periods. Considering current climate issues, the resulting reduction in fuel consumption, and hence carbon emissions, make filter upgrades more appealing than ever.

Legacy filtration systems

M6/F7 rated filters, such as the Altair System2 and Aquila, are designed for use offshore and have recorded millions of hours of operation across thousands of installations. These filters protect against highly corrosive wet and dry salt particulates. Today's technology, with higher efficiency ratings, can provide even higher levels of protection. This will improve the performance of the GT, increase power, reduce fuel consumption, and as such lead to fewer carbon emissions.

Figure 1. *An offshore filterhouse undergoing an upgrade.*

Figure 2. *An EPA rated GT filterhouse.*

A 30 MW LM2500 + turbine has a heat rate/fuel consumption of approximately 9227 KJ/kWh and rated power of 30 000 kW. Based on 8000 operating hours per year, the CO_2 produced at 0.056 kg/MJ means, without any degradation, this GT will produce 30 000 kW X 8000 h X 9227 kJ/1000 X 0.056 kg/MJ, which equates to 124 million kg (124 000 t) of CO_2/yr. A GT performance chart typically demonstrates how GT performance is affected over time. As more particulate becomes attached to the compressor blades, turbine performance degrades, resulting in either lower power output or increased fuel consumption and increased carbon emissions per generated unit of power.

When looking specifically at power output, older technology filter systems may result in a graph with multiple 'saw tooths' within a year, and resulting degradation of X%. If a degradation of 10% over a time of 2000 h is assumed, this equates to a loss of 12 million kWh/yr.

Improved performance and reduced emissions using the latest filtration technology

Switching to a higher efficiency filter designed for offshore use, featuring strong hydrophobic properties, has been proven to significantly reduce the rate of performance degradation. By offering a high level of protection from contaminates, the result means machines can run cleaner with reduced pressure loss, increasing power output and lowering carbon emissions, as well as reduced overheads and lost production time with fewer offline washes required.

But what does this mean in terms of emissions? If a clean GT compressor produces approx. 0.56 kg/kWh of CO_2, the performance of the GT with an old technology filtration system will degrade (and require multiple washes), resulting in an increase of emissions to approx. 0.54 kg/kWh. This means that an upgraded filtration solution could result in a 4.6% improvement in CO_2. That is a saving of 5580 t CO_2/yr on the 30 MW GT.

Choosing the right partner for filter upgrades

While significant ongoing cost savings and reduced overheads can be the result of upgrading to higher efficiency filtration solutions, any new system will need to fit into the existing envelope, and better still the same footprint of the inlet filter house. This makes upgrading quite challenging. Operators need a supplier they can trust, that understands the existing structure, footprint, and everything about the filter house, and has experience in successfully completing such projects. From surveying the existing filter house to delivering a new solution and ensuring smooth operations, experience and understanding of the operator's needs are essential.

The use of computational fluid dynamics (CFD) and a filter testing regime that allows for the extreme conditions experienced offshore will help ensure that the new filter system will perform as expected.

Going beyond filtration efficiency: Selecting a filtration solution that will work reliably to reduce emissions

The only true measurement of filtration performance is the performance of the GT in real-world conditions. Every environment has unique challenges, and every aspect of the filtration system needs to be designed to maintain GT efficiency; providing reliable, predictable performance, and minimising carbon emissions is key.

It is crucial to look to suppliers that carry out extensive filter testing against high levels of moisture and salt.

Salt is one of the most damaging and challenging threats to GT reliability and for an offshore installation, the threat is greater than ever.

Salt is hygroscopic in nature. It can attack a turbine as both a particulate and a liquid, making it particularly important to capture and retain in a filtration system. The average salinity of oceans around the world is about 3.5%, predominately due to the presence of sodium chloride or 'common salt'. As waves churn the surface of the seas, air becomes trapped in the water. This rises to the surface as bubbles which explode into the atmosphere and expel small sea water droplets, forming salt aerosols which are carried by the wind. Aerosols are also directly produced from the mechanical disruption of wave crests.

To ensure that a filter system offers adequate protection, testing levels need to allow for both input concentration, aerosol size distribution and aerosol physical state, whether droplet or particle. If significant quantities of salt are allowed to pass through to the GT, its aerodynamic efficiency may reduce, and there is greater risk of permanent damage to the machine, resulting in reduced power output, increased downtime, and higher maintenance costs.

With the moisture offshore, salt becomes a sticky substance that may clog filters and adhere to compressor blades, severely affecting aerodynamic performance and placing turbine internals at the peril of corrosion. One of the keys to prohibiting salt corrosion in an offshore environment is to effectively handle moisture, requiring filters with good hydrophobic design.

It is also vital that the new filters can withstand the rigours of an offshore installation, and that this goes beyond just filtration efficiency levels. With aerosol salt sprays, best in class hydrophobic properties are needed to ensure that both water and salt are handled efficiently and reliably. Indeed, filters that use hydrophobic and advanced fibre coatings have been proven to improve turbine performance between wash cycles, thereby reducing the amount of carbon released into the atmosphere. It is also paramount that the filter is designed to avoid air bypass.

Air bypass effectively renders the filter useless as air finds the path of least resistance, avoiding the filtration media and carrying contaminates with it to the turbine internals. Filters with robust ABS frames designed to handle the harsh offshore conditions and downstream protective grids that will help the filter to withstand high burst pressures, will help to ensure this does not happen.

Improved pleating and packing of the filter media will also provide more efficient filtration and better overall performance of both filters and compressors.

Conclusion

As we all strive to reduce carbon emissions and limit the impact essential oil and gas operations have on the environment, an upgrade to GT inlet filters offers many benefits. The data around GT performance over time and Parker's experience in such projects shows that operators have a lot to gain.

To ensure a smooth and successful project, operators should select an experienced partner with practical people that can solve operational challenges. Getting this right means that the benefits of modern filtration solutions can be embraced, and carbon emissions can be reduced without the need to necessarily change out the whole filter house, delivering a swift return on investment and a greener pathway for the future.

Many operating environments within the energy industry are in remote places where it is difficult to deploy a solid network connection via fibre optic cabling. At the same time, production wells and today's drilling equipment can quickly generate thousands of data points per second. Refineries are now home to hundreds of thousands of sensors that create numerous terabytes of data, and most of this is simply thrown away because moving it to where it can be analysed is seen as too difficult or costly.

This is where satellite technology comes in. The commercialisation of satellite technology is helping to fill the gaps where terrestrial connectivity cannot reach. According to estimates, if the sector was to make use of advancing connectivity to optimise drilling and production throughput and improve maintenance and field operations, it could add up to US$250 billion of value to the industry's upstream operations by 2030. An additional US$70 billion could also be unlocked using low-Earth orbit (LEO) satellites and next-generation technologies such as cloud-based applications.[1] By combining these technologies, the higher bandwidth and lower latency that allows for the optimisation of remote operations can be achieved.

Connectivity from above the clouds

There are nearly 4000 satellites currently in LEO, and this is where satellites are commonly used for communications.[2] With the number of satellites expected to grow exponentially, there has never been a better time to embrace and implement LEO and cloud connectivity.

Global cloud infrastructure spending is expected to reach US$118 billion by 2025, as more and more businesses realise the extensive list of benefits cloud services offer.[3] Historically, data has been stored on archive or at a physical location which, understandably, presented challenges to the industry in terms of data storage and access, which was far too slow for a fast-paced industry like oil and gas.

Storing data in the cloud eliminates the need for physical storage space and accelerates the speed in which data can be accessed. IT resources can be quickly spun up to servers as needed, meaning a secure cloud connection can be deployed in minutes, allowing for improved business agility and flexibility. Businesses do not need to overprovision for the likes of electricity and are only charged for the cloud capacity that is used by their services, meaning cost savings can be achieved and can lead to improved total cost of ownership (TCO). By migrating to the cloud, organisations can focus their IT resources on tasks that clearly benefit the business, allowing for faster innovation throughout industry operations.

This migration can also increase the quality of data being saved within the cloud. Previous information systems were not sufficiently built to handle a high quality and quantity of data. Significant issues were often encountered when moving old software to the cloud, but a complete overhaul is now no longer required to action this migration. With the latest satellite technology on the market, assets are now integrated automatically, streamlining and optimising a previously time-consuming process.

Utilising LEO connections

By combining this migration of data to the cloud with LEO satellite connections, more operators can connect to the global cloud using orbiting antennas that are quite literally above the clouds. LEO satellites sit in close proximity

With the number of satellites expected to grow exponentially, there has never been a better time to embrace and implement LEO and cloud connectivity, says **Sandro Delucia, Speedcast, UK.**

The perfect pairing for remote operations

to the Earth's surface (500 – 1600 km). These satellites do not simply sit at an attached point but are in constant motion. The advantage of being closer to the Earth is that signals can travel more quickly between satellites and receivers on the ground, reducing latency and delivering gigabit per second connections. This provides the scalability and sustainability required to not only meet requirements but transform oil and gas operations where connectivity speeds are much greater than current market solutions. It is thought that LEO will cut costs in operations and capital expenditure by at least 20% from extraction to final distribution.[1] This is due to the higher bandwidth, quicker speeds and lower latency offered by LEO, enabling automation in the form of predictive maintenance and IIoT devices/sensors.

Direct-to-cloud acquisition through LEO also plays a crucial role in speeding up the processing of essential data, and reducing overhead costs where logistics are concerned. Engineers may require essential data from a remote site, such as when the workforce carries out seismic surveys or other operations. Fibre optic technology can help to transfer this data from a remote site to a land-based office environment, but can only include one terabyte of data within one transmission. This can mean it takes days or weeks for information to fully arrive at the data centre. LEO solutions can instead compress and transfer this data within minutes, placing it directly into the hands of the team requiring it. This can then be loaded into a cloud storage service which has almost unlimited space, allowing the archiving of data to save costs on storage. This information is then sent to be processed, giving engineers the tools to stay informed on the current activities of operations, and help them to be proactive in their decision-making.

Always-on connectivity for optimal communication and operations

Remote operations in the oil and gas sector must depend on real-time connectivity and information to provide the digitalisation, satisfaction, safety, and profitability required for success. The energy industry needs to leverage modern technology like LEO, cloud, and new business models, as they play a central role in achieving business aims.

No longer is communication just between people; it is between people and machines, and now includes the rise in Internet of Things (IoT) and machine-to-machine (M2M) technologies. Oil and gas rigs rely on these devices to manage and transmit data from equipment sensors and secure networks, sending information back to offices or personnel elsewhere, so that any malfunctions are promptly identified, and remedial action can be taken immediately. With these new applications, such as drones and other IoT devices on oil and gas rigs, comes the need for these devices to be reliable, safe and secure. Ensuring the safety and reliability of devices is vital to improving worker safety. Working in such remote areas, particularly with operating machinery, can prove a danger to personnel, and therefore the reliance on secure device monitoring is paramount to reducing safety incidents and keeping workers safe and well.

The increased availability of satellite connectivity is going a long way to optimise operations, but this can only come about as long as these LEO services fully prove their potential. Geographic coverage, performance, licensing, and the success of business models are still up in the air. To this end, businesses are increasingly utilising a hybrid approach for their operations, mixing LEO and traditional connectivity offers services such as GEO-based solutions to achieve the required information rates and uptime that energy companies demand.

A 'cloud centric' approach for operations

The modern oil and gas industry depends on LEO technology to ensure the technological applications that are revolutionising the sector can be run efficiently and effectively. However, with the huge amounts of data these applications generate, this means that the data cannot be stored and processed by existing, traditional methods; hence the expanding adoption of the cloud.

It is well known that traditional storage networks are notoriously difficult to manage. All businesses found within a network will likely have different approaches to security, and this makes it difficult to implement a single overarching strategy that can encompass each entity. Yet the prevalence of cloud-centric networks has been proven to significantly simplify networks and the management of systems. Deploying a cloud-centric network model enables the entities involved to use a central dashboard and system across all networks, eliminating the need to configure and manage the different aspects separately. Pairing this with the benefits that satellite connectivity brings over standard terrestrial networks, the combined technology provides the lower latency and higher bandwidth that aids in improving safety, increasing profitability, reducing production outages, and accelerating decision-making across global oil and gas projects.

Figure 1. *Utilising satellite technology can help operators deploy strong network connectivity to the most remote of sites.*

A fusion of technologies and expertise

Using the latest cloud-based solutions as networking infrastructure can help enable seamless connectivity between sites, ensuring that all sensitive data is encrypted as part of a strong security makeup that scales well and does not require the same level of human resources to maintain. Doing so provides organisations with a service that incorporates a centralised management system with built-in automation to establish a reliable, trusted platform for operations.

Cloud migration and LEO connectivity are critical for achieving real-time updated business performance and efficiency. For a smooth management and migration process across both, businesses can achieve effective analysis, planning and execution by working with reliable providers.

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Esben Thorup, Horizon56, Denmark, presents a digital transformation roadmap for drilling operations based around people and technology.

The digital transformation of drilling operations

In an industry where many seem to be focusing purely on technology for technology's sake, there is now a huge opportunity to prioritise user-centric value to leverage digitalisation for operational enhancement.

In most other sectors, technology is used to solve problems and make workers' lives easier. So why does this so infrequently apply to operators and platform workers within the upstream industry?

For operators to extract value, it is necessary to change mindsets and address the disconnect between the needs of offshore crew and those seeking onshore project improvements.

In pursuit of this, modern day rig management must now share the overall vision for extracting value with everyone involved, including the offshore teams themselves. Only by achieving this can operations fully bridge the gap between planning and execution.

A 'people business' in need of digitalisation

Well construction remains a people business with limited automation, but it is a business that needs urgent digitalisation to propel it into the future.

Many of the larger players currently undergoing digital transformation are talking about using technology without involving the end users. The typical stance is that technology alone can drive a business and its strategy, but this approach is rarely effective.

In the vast landscape of ever-growing available technology, oil and gas technology vendors start by outlining the problem that they are trying to solve and how technology can be used to address it. However, with many in the industry pointing to a lofty vision of digital connectiveness and big data to make everything better, the conversation should really be framed with the question: 'What operational pain-points does this product resolve?'

The road for progression in oil and gas is admittedly unclear. Many struggle with terms like 'digital well construction ecosystems' or 'autonomous drilling operations', what they can achieve, and towards what timeline they are possible.

As with all industry solutions to a problem, if you are not clear on what you want to do, your strategy may be doomed to fail.

Promise vs reality

Many technology vendors in the oil and gas industry offer impressive prototypes and presentations, but fall flat at providing evidence of their potential value creation, and this causes frustration over the speed of progress towards digitalisation that provides real impact.

Figure 1. *Solutions should provide drilling supervisors with operational transparency, progress tracking and the ability to specify and drive operations from their desk.*

Figure 2. *Activities driving drilling operations should be granular and accessible by the entire rig crew.*

Mindsets need to change in certain areas and the demonstrable impact of new ways of working need to be widely disseminated to incentivise some of the industry's 'old guard' to do things differently.

The industry also needs to address the frequent disconnect between the incentives of offshore crew, who are at the front line of operational and performance improvements, as opposed to those in charge of onshore improvement projects.

Humanising digital transformation is key for digitalisation to propel industry into the future, and as one of the few remaining industries lagging behind with digitalisation, the oil and gas industry is under increasing pressure to modernise in a collaborative way.

Often, when engaging in multi-well campaigns, where the rig, crew and operator work together long-term, there is a clear reduction in well construction time of 10 – 50% when comparing the first to the last well. This happens because the crews from the oil company, rig contractor and third-party service companies work together as one team, gradually improving processes and incorporating lessons learned.

However, when an operation ends and a new one begins – with new partners – momentum must be built from scratch. This suggests that the oil and gas industry struggles to efficiently harness, standardise and leverage lessons learned and best practices from one rig to the next.

In drilling environments, pervasive digitalisation can potentially deliver the systems necessary to communicate this knowledge effectively – and this needs to be delivered in real time, to simplify and enhance the working lives of offshore crews around the world.

Under pressure

The oil and gas industry faces pressure from numerous directions. Volatile oil prices, an increasing number of short-term rig contracts, and reallocation of resources towards green transition areas have crystalised the need to accelerate digitalisation in oil and gas.

With ageing rig crews across the industry, there is also the danger of an impending skills shortage, so it is necessary to get ahead of the curve and rapidly reimagine operational models.

The digitalisation opportunity

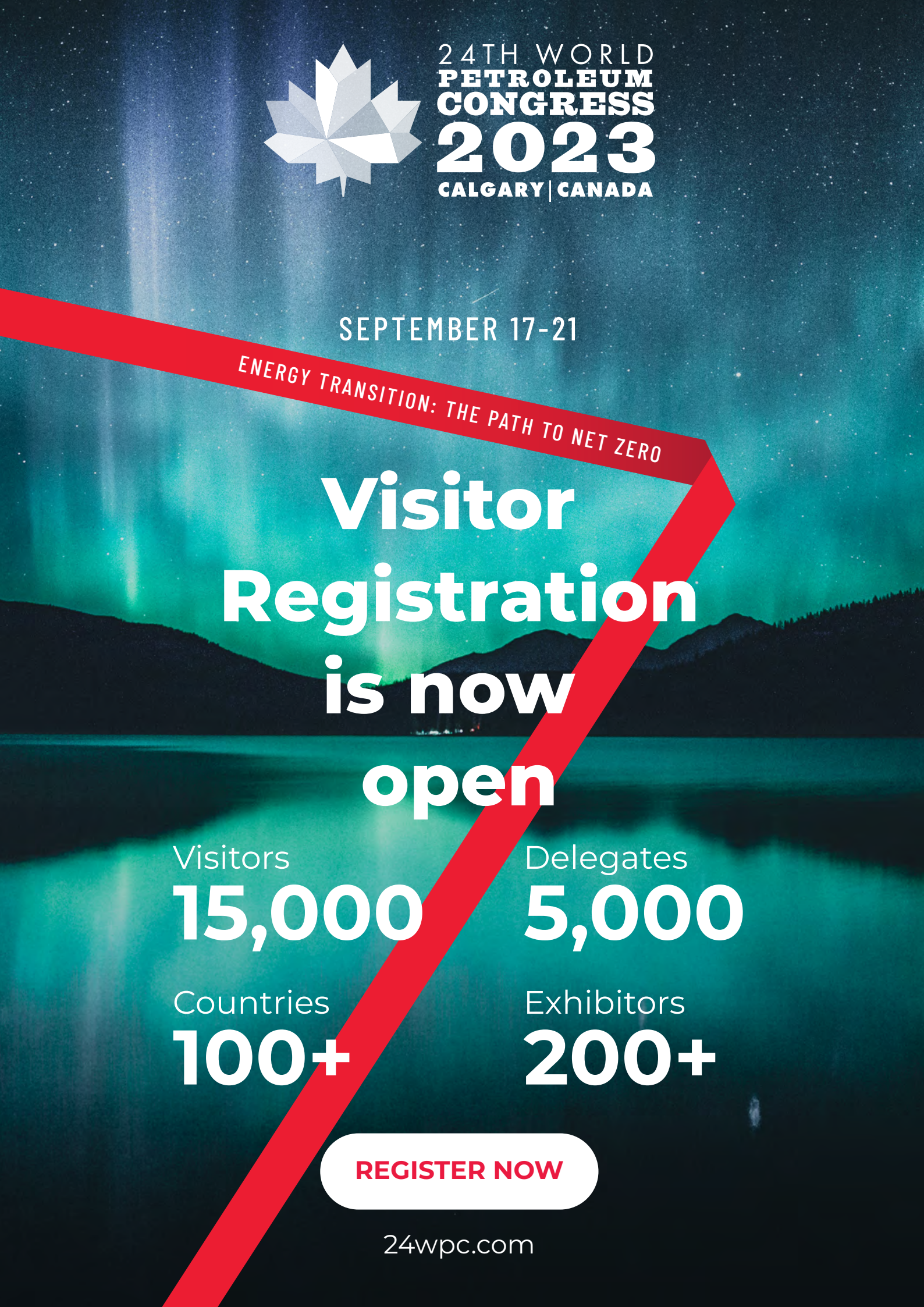
There is a tangible and extensive opportunity here. By leveraging digital technologies, it is possible to share role-specific, granular information across campaigns, so crews begin with the same level of expertise as those completing. But to achieve this, it is necessary to digitalise the information flow in the well construction process to include:

- Digitalised real-time well program information.
- Digitalised well execution systems coordinating across work centres.
- Real-time transparency of operation and defined workflows.
- Role-based instruction based on drilling operations broken down to individual role level, providing specific instructions.
- Performance management – lessons learned must be internalised and best practice data must be captured, standardised and tagged.

Collaboration and innovation are key

Building a system purely to serve the contractor or operator will not change the need for collaboration. From a technical point of view, no company can digitalise offshore drilling on its own. Interoperable systems and industry-wide collaboration are required, supported by innovative commercial models to incentivise it.

By attacking this together, the industry will move forward, delivering benefits of significantly improved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operational efficiency and reduced emissions, while providing better working environments.

Although it will not be easy, it is necessary to develop solutions that work together in an ecosystem with defined interfaces. A commitment to collaboration and innovation is required, but technology vendors also need to help the industry to evolve, collaborate and work more efficiently.

Many engineers are using silo and spreadsheet-based approaches that waste time and money, while missing the benefits of capturing lessons learned.

The technology is there to use collaborative processes and workflows that can be built quickly and cost-effectively. So, with a pressing need for innovation and digitalisation, let us consider one of the key factors holding back digitalisation: the need to digitise and standardise data flow within and between organisations.

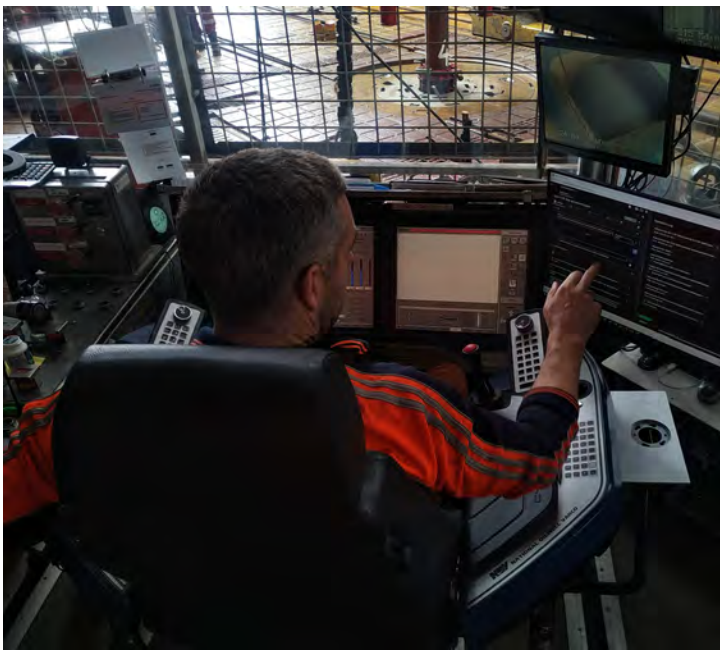


Figure 3. *Solutions must be intuitive for the driller to use and manage information flow to other parties and systems, in-turn avoiding paper, mails, phone calls and reporting.*

Figure 4. *Remote teams and operations centres require real-time access to the plans, progress and problems of drilling operations to allow them to be a part of the team, and proactively provide support.*

The current digital systems will bring offshore drilling into the future. But how can we deploy big data given the heavy focus on heritage processes using legacy paper-based methods? The oil and gas sector will not see significant benefits from digitalisation until it gets the fundamentals right – and digitised, standardised data flows between involved parties are a critical factor in this.

There is no shortage of companies offering sophisticated big data and artificial intelligence (AI) based solutions for well construction optimisation, but there is little evidence of impact in practice.

PDFs and paper

Many solutions are too advanced or narrowly focused, considering the somewhat analogue state of the industry and the fact that they lack user-centricity. Information is mostly shared between organisations via PDFs attached to e-mails, with no standardisation.

For example, drilling rig crew instructions come largely on paper print outs, with most reporting based on information that is input manually. There are no end-to-end data flows or defined interfaces between parties. So, we see advanced solutions, such as automated drilling, dependent on information that is manually input.

Standardising the well construction information

A critical challenge comes with each major industry player pursuing their own digital strategy, so there is limited standardisation in exchanging information or data in the well construction processes – an essential part of the foundation for digitalisation.

With a lack of standardisation, it is common to see advanced digital solutions focused on optimising very specific, micro key performance indicators (KPIs) (such as tripping or drilling speeds), without considering the bigger picture. The manual processes, training and resources required to integrate very targeted digital solutions do not necessarily help deliver the total well in an efficient, safe and predictable manner.

Simply put, the information most central to well construction, the drilling instructions and reporting on work completed, is not yet digitised. Reporting is typically based on manual inputting, and lacks quality as a consequence.

For the broader digitalisation of well construction to succeed, it is critical that this information flow is digitalised and standardised. It is also essential to unlock the big data opportunities of combining well-design data with drilling equipment data and down-hole data.

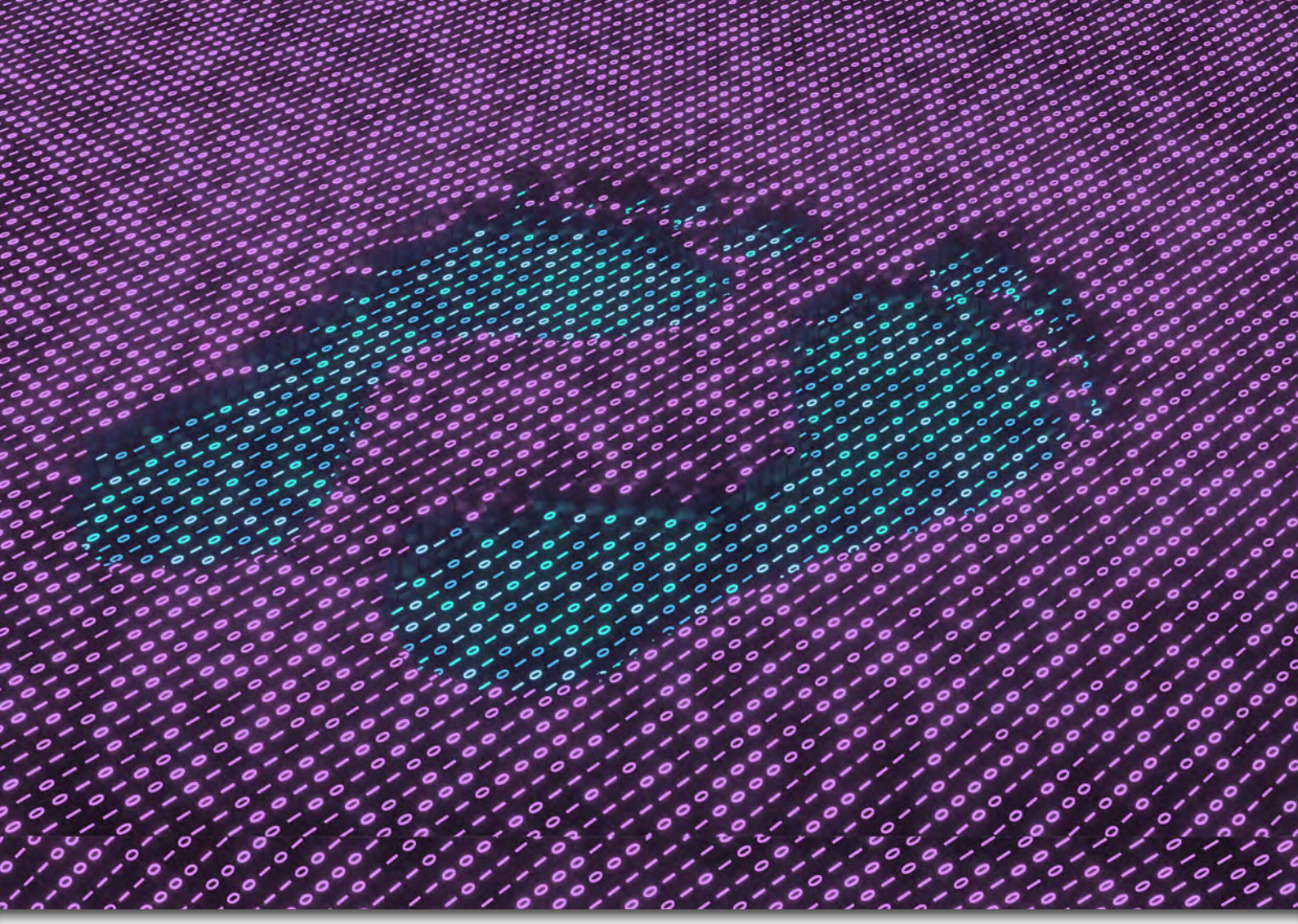
The fundamentals

For the offshore drilling industry to accelerate digitalisation, it is essential to re-focus on fundamentals such as establishing basic digital information flows between all parties. Developing big data analytics programs and advanced AI models is wasted effort.

Innovation is also required, as well as an exploration of ways to use digital tools in collaboration to help build the digital foundation required. This is key to increasing total well construction efficiencies and hitting sustainability targets.

As we move beyond ‘Industry 4.0’, which was previously about automation, we can start looking at what ‘Industry 5.0’ will look like, and the new ways of working that will emerge once we have caught up digitally.

Cemented around a foundation involving the human approach, the industry will finally be positioned to reap the full potential of digitalisation and automation.



TAKING THE NEXT STEPS WITH TECHNOLOGY

Dennis Stipati, FreeWave Technologies, USA, discusses the ways in which IIoT is benefitting energy companies now and in the future.

The Industrial Internet of Things (IIoT) is increasingly transforming the US$5 trillion oil and gas industry, from drilling platforms to transporting oil and natural gas. IIoT, a network of internet-connected physical objects used in industrial applications, gives the ecosystem of upstream, midstream and downstream companies a smarter, faster and more cost-efficient way to utilise data to improve operations.

To fully optimise IIoT capabilities, more oil and gas companies are moving to edge computing solutions, which bring data closer to the source of production. Those companies using

edge computing have lower latency and data storage issues, and provide real-time visibility that improves decision-making in core business operations.

Usage of IIoT is on the rise

Research has found that IIoT continues to gain traction in the oil and gas industry. According to BIS Research, IIoT in the sector is predicted to hit nearly US$40 billion in 2023.[1] Another research firm, Stratview Research, released a report stating that the IoT market is expected to expand to a compound annual growth rate of about 10 from 2022 to 2029, with the market reaching more than US$22 billion at the end of the forecast period.[2]

The industry's demand for digital solutions has accelerated in recent years, amid ongoing pressures to reduce costs, boost revenues, improve efficiency, increase competitiveness and advance environmental and sustainability initiatives. A Cisco survey of oil and gas companies found that a majority of the respondents named data analytics for 'faster, better decision-making' as the top driver for IIoT investment.[3]

IIoT is benefitting energy companies now and in the future.

Improving operational efficiency

IIoT gives oil and gas companies a more efficient and effective process to handle various tasks without human intervention, such as monitoring the flow, pressure and temperature of oil and gas in a pipeline, and checking on inventory levels of onshore tanks. Performing these tasks remotely with IIoT significantly reduces time and costs, by limiting the need for workers to drive trucks at remote and hard-to-reach sites to measure tank levels and conduct similar manual tasks. IIoT replacing these kinds of manual processes has allowed energy companies to stay productive, lessening the impact of tight labour conditions.

Figure 1. *Oil and gas drilling operations are achieving greater efficiency with IIoT.*

Figure 2. *FreeWave provides solutions to a Faulconer Energy site.*

Predicting maintenance needs to prevent equipment downtimes

By installing IoT sensors in pipelines, drilling platforms, tanks and other places, companies can create real-time visibility in equipment performance. Integrating IIoT in equipment maintenance schedules allows sensors to instantly detect when pumps, valves and other parts are defective or due to wear out. One industry report on IIoT usage noted that a defective pump can cost a company as much as US$300 000 and a lost day of production.[4]

IIoT enables companies to replace parts before production breakdowns occur. The upstream industry would especially benefit from IIoT applications, as it loses billions of dollars in non-productive time. With IIoT, upstream companies can reduce non-productive time with real-time data used to minimise equipment failures.

Monitoring and measuring environmental impact

Over the years, companies have had to comply with stricter government regulations on the environmental impact of oil and gas operations, amid growing global concerns about climate change. These regulations have presented new and complex challenges for companies seeking to provide cleaner and more efficient energy solutions.

IoT sensors can monitor and measure operations affecting the environment, thus providing companies with valuable data, improving their performance as well as minimising possible environmental damage. Some companies have installed IoT sensors measuring the atmosphere at gas-producing facilities to determine if methane emissions – which accounts for an estimated 30% of the rise in global temperature – are complying with governmental regulations.

Improving worker safety and operational security

It is no secret that working on an oil rig or processing facility is one of the most dangerous occupations. Worker fatalities and injuries are caused by fires, explosions, falls, exposure to toxic chemicals, equipment-related accidents and other job hazards. According to the US Bureau of Safety and Environmental Enforcement, 19 fatalities and 106 injuries were reported at offshore oil sites in a five-year period (2015 – 2020).[5]

Companies using IIoT solutions can significantly reduce hazardous job conditions with sensors detecting the presence of flammable gas and toxic vapours, while preventing gas leaks and oil spills. Additionally, IIoT can augment security measures at oil and gas facilities. For years, the industry has used IIoT to protect its assets from theft, sabotage and other types of criminal activity. IIoT sensors and cameras allow companies to monitor facilities and equipment for potential security issues.

Recently, more energy companies are implementing new safeguards in their IIoT systems to strengthen their resiliency against potential cyber attacks, such as the one

that temporarily shut down the Colonial Pipeline in 2021, the largest cyberattack on an oil infrastructure in the US.[6] IIoT also can confirm the identities of employees at work sites, ensuring only authorised personnel access to facilities and equipment.

The future of IIoT in oil and gas

Technological advances like IIoT are making oil and gas companies more efficient in their operations, along with improving safety and security, and reducing damage to the environment. Playing a crucial role in companies' efforts in digitalising these activities, the industry's adoption of IIoT will continue to grow as better decision-making on the edge allows oil and gas companies to more efficiently handle the massive volume of data produced in global energy production.

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Fact and figures

- IoT-connected devices are predicted to expand from 15.4 billion in 2023 to 29.4 billion in 2030, according to Statista.[7]
- Global consulting firm McKinsey & Co. forecasted that IoT will have a total economic impact of between US$3.9 trillion and US$11.1 trillion in 2025 on various industries, including oil and gas companies.[8]
- Technological advances in the analytics industry have improved perception quality by using intelligent components such as sensors, smart devices and software, according to Precedence Research.[9]
- Expanding use of internet and cloud-based services for operating equipment, devices and recording data will support growth of IoT among North American oil and gas companies over the next several years, according to a Tech Sci Research Tech report.[10]
- The industry is ripe for edge computing implementation, which provides faster and more cost-efficient ways to collect and analyse data. According to a Cisco report, a typical oil platform produces up to 2 terabytes daily. Simply put, a single terabyte could hold 1000 copies of the Encyclopaedia Britannica while 10 terabytes could hold the entire printed collection of the US Library of Congress.[11]
- According to Gartner, internal IT roles in oil and gas companies will provide or support new digital business services.[12]


A NEW
CHAPTER FOR
OIL AND GAS

Al Rivero, Rajant Corp., USA, explains how next-generation technologies can allow organisations to closely manage and optimise unmanned remote operations, improve worker safety, and limit their impact on the environment.

Following the worldwide pandemic, the oil and gas industry has had to transition from a more 'hands on' approach to remote operations. The shift in the sector posed serious concerns and difficulties, with smaller crews on site requiring significant operational changes such as new technologies and more data to be shared to augment operations and make them more efficient. These increasing demands can easily outpace a network's capacity in a robust environment.

A significant change to operations comes with a cost, and companies must be sure of a return on investment (ROI), which is of particular importance in an industry characterised by substantial and constant price swings. In April 2020 for example, the oil price plummeted to US$40/boe, and two years later, with the war in Ukraine, the price skyrocketed to more than US$105/boe.

Not only this, but the industry must also evolve operations to conform with global expectations of greener processes and help to lower carbon and other harmful emissions. Directly and indirectly, the oil and gas industry accounts for 42% of global emissions, and companies in the sector must reduce these emissions by 90% by 2050 to achieve net neutrality. With sustainability at the forefront of regulation discussions, companies must invest in new equipment that instils confidence.

A key component to achieving these operational gains is the ability to access real-time data and analytics as part of a fully integrated picture of the oilfield. This will provide oil and gas operators with a clear view of the assets and personnel operating within it. However, this places a considerable amount of pressure on the communications network.

Investing in new technologies

Complex technologies, also known as the Industrial Internet of Things (IIoT), and capabilities such as mobile machine-to-machine (M2M) communication, real-time field intelligence, and predictive analytics, have all been introduced into the oil and gas industry. Ultimately, this has increased productivity and ensured that sites are safer for personnel operating in potentially dangerous oil rig and gas production environments. As more complex IIoT applications are introduced, operators must ensure that processes can operate seamlessly with new technologies.

Innovative technology, such as hands-free voice communication and wearable cameras, can provide a full-spectrum perspective that increases visibility and real-time insights into identifying disturbances and site monitoring of equipment, vehicles, and staff constantly on the move. This technology also ensures complete security of the production site, preventing unauthorised access.

Operators have also opted to utilise robotics in these challenging environments to combat the potential efficiency issues that human error can cause, such as downtime. Most importantly, deploying robotics to monitor and inspect hazardous industrial equipment removes worker safety risks by completely removing them from the operation. Robots have discrete sensing capabilities to identify and target maintenance needs more accurately.

The greatest challenge in supporting robotic and autonomous solutions is keeping them connected. Safety is a significant challenge in such an environment, requiring real-time optimisation and complete visibility. For example, oil rigs can be prone to heating up underground if the rig gets too dry, leading to potential burn up, and this poses a danger to remote site personnel and presents substantial repair costs.

While these additional assets add value, expanding interconnectivity puts pressure on the network that must ensure the security and authenticity of the communications traffic moving in, out, and across it. To achieve and maintain peak productivity and efficiency, mission-critical applications must run on a communications network that offers reliable, agile, and adaptable connectivity that can thrive in diverse, evolving, mobility-driven environments. Critical networks cannot afford downtime.

Figure 1. *With the ever-changing volatility in oil prices, oil and gas operators are realising the need for a network solution that is flexible and not rigid to optimise production efficiency while minimising expenses.*

Figure 2. *A typical remote and rugged oil and gas terrain needs constant observation. A reliable network is key to this, allowing operators to access real-time data and analytics to understand all aspects of the assets.*

Rugged environments block smooth wireless paths

Companies face daunting challenges when planning and implementing a communications network that provides site-wide mobile access to vital data, voice, and video. In the face of intense economic pressure, organisations are striving to maintain continuous operations, increase productivity, and cut operating costs while maintaining safety standards.

A typical remote and rugged terrain needs constant observation. This can cause issues in achieving a consistent network connection, as the core environment of an oil or gas production site can be unpredictable and often isolated. As a result of implementing more technology on-site, an enormous volume of data is produced by devices that enhance oil recovery and improve production. Effectively managing this data will become even more critical as the industry moves towards unmanned facilities.

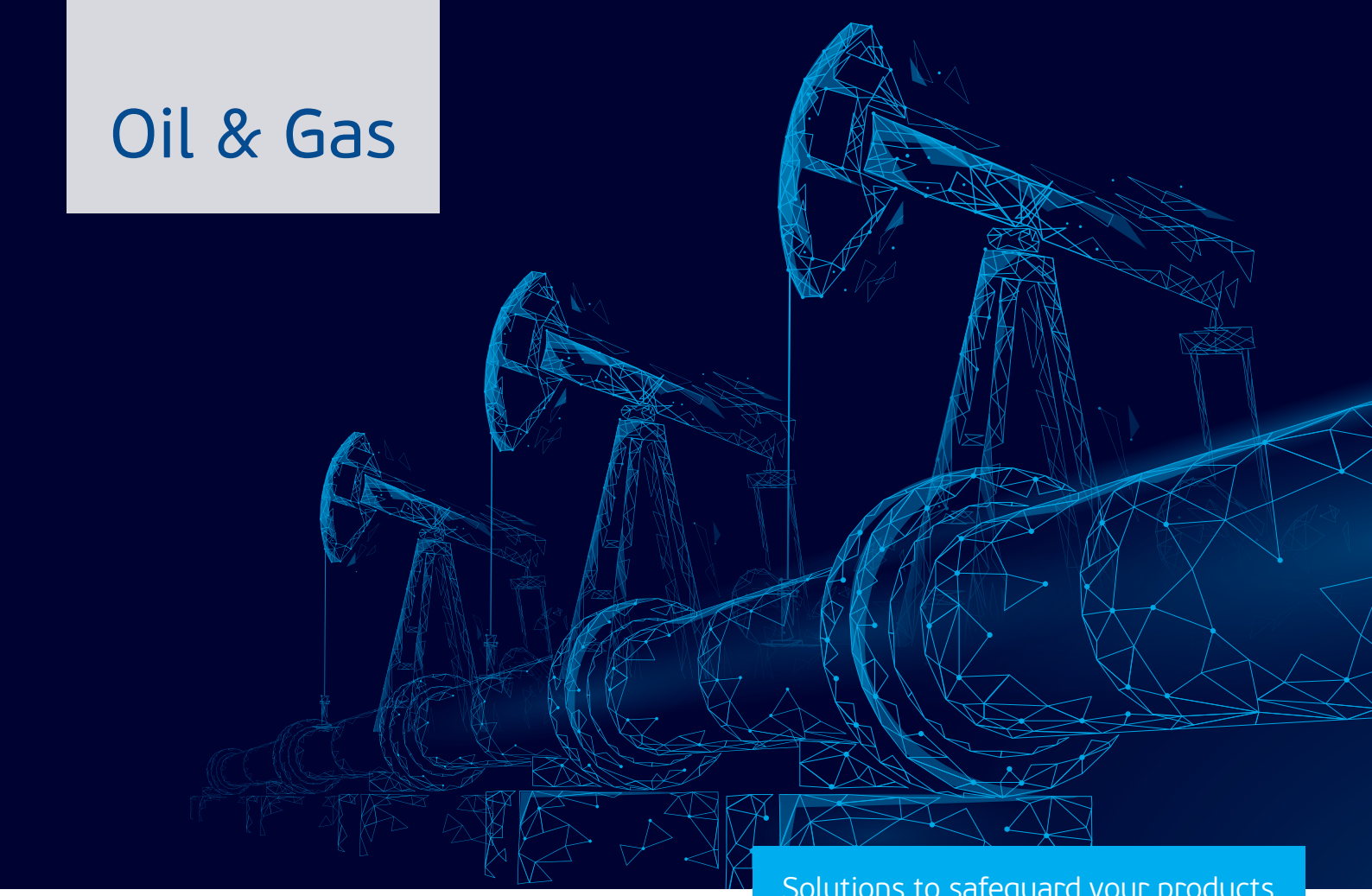
Operators often experience difficulties securing a reliable connection by conventional means, such as when deploying long-term evolution (LTE) or 5G technology. Public cellular networks often need to offer the levels of reliability, availability, latency, and security that mission-critical services in oil and gas require. As some mobile devices lack infrastructure capabilities, they can only connect to one access point at a time. This means that if an access point fails, all nodes connected to that access point are disconnected from the network. Access points therefore are potential areas of failure. In the case of root controller nodes, one device manages the routing for the entire wireless network. If the root node fails, the whole network subsequently goes offline.

After a reliable network is ensured, the subsequent action is to capitalise on the advantages of remote collaboration, which can bring significant societal, economic, environmental, and climate benefits. Real-time support provided by remote collaboration enhances operator efficiency and safety, offering specialised knowledge and skills to remote or underserved workers while reducing workplace accidents and fatalities without compromising performance.

Furthermore, remote collaboration generates considerable economic benefits by decreasing travel costs and time, improving productivity, and streamlining operations. Additionally, it minimises the need for travel and commuting, resulting in fewer carbon emissions and air pollution, benefitting industries that require frequent travel and on-site inspections while lowering their carbon footprint.

According to estimates provided by the UK government, avoiding a single travel event through alternative solutions like automation and remote support significantly reduces CO_2 emissions. Avoiding one employee's single international round-trip flight can reduce approximately

Oil & Gas



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This reliance on IIoT and M2M connectivity to improve productivity, streamline operations, and control costs, has created a demand for private wireless mesh networks.

Ensuring effectiveness

A high-capacity wireless network that supports reliable, real-time data delivery to and from the array of onboard sensors within these autonomous systems is paramount. It can aid in the precise diagnosis of equipment problems and provide efficient fixes. Wireless mesh networks are unique in delivering consistent, reliable coverage across any space, regardless of the environment's size, topography, physical obstacles, radio frequency traffic, and weather conditions.

Rajant's Kinetic Mesh network is dynamic, comprised of several communication nodes that can automatically identify and transmit data between them. These nodes can adjust to find the fastest and most stable connections. Mesh networks can scale up and down quickly by adding or removing nodes. The data travelling across the network can be rerouted depending on the bandwidth needs, signal strength, or competing traffic. Having a network with M2M connectivity is a bonus. With each mobile asset equipped with a mesh node, the mobile robots remain connected to the network with no dropouts.

Incorporating well and platform monitoring using cameras, smart meters, and sensors, the network integrates with WiFi or ethernet-connected devices to let operators monitor conditions and identify issues, often before they cause downtime or production delays. The network also allows real-time drilling activities to be monitored to help drive down non-productive time, which industry studies show equates to a loss of approximately one-third of an operation's average annual drilling budget.

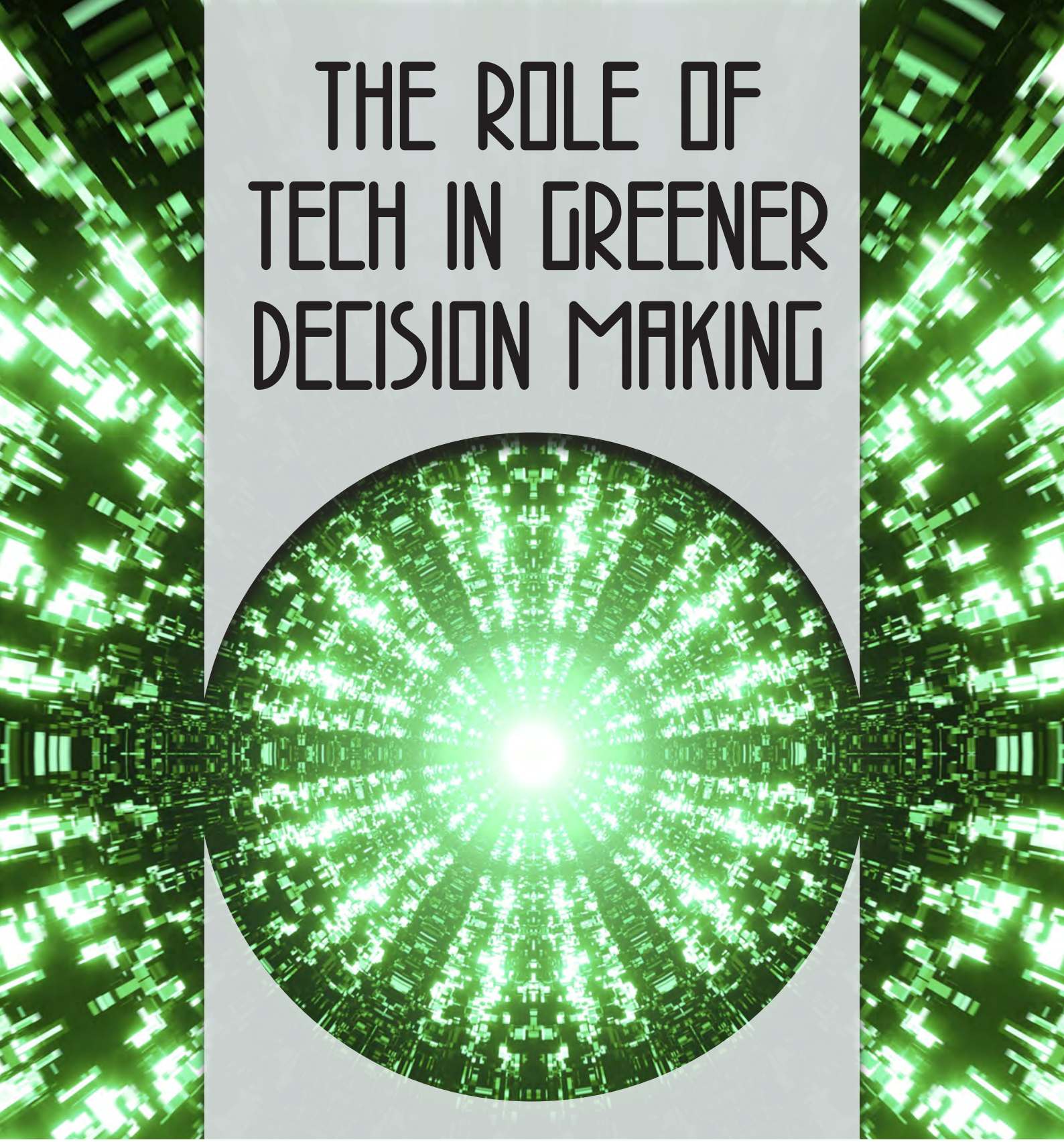
Efficient networks empower companies to utilise efficiencies through equipment health monitoring. Using equipment performance data and a predictive maintenance model, companies can keep equipment operating at peak efficiency and extend the service life of onshore assets. New technologies enable up to a 30% decrease in maintenance costs, amounting to 60% of overall operational expenditure.

A mission-critical network provides operational confidence

More services, assets, and technologies are connected to onshore oil and gas projects than ever before, with augmented reality, drones, and robots playing a critical role. For many workers, the operational insights enabled by these technologies are indispensable, which elevates the importance of reliable network connectivity. Next-generation technology allows organisations to deliver business-critical field intelligence securely and reliably to closely manage and optimise unmanned remote operations, improve worker safety, and limit their impact on the environment.

Enhanced connectivity enables these technologies to drive value for oil and gas enterprises, as well as supporting a global movement towards a cleaner environment. With a reliable network, oil and gas leaders can analyse their current operations for inefficiencies and take proactive steps to ensure sustainability, and compete and thrive in this new era of oil and gas.

THE ROLE OF TECH IN GREENER DECISION MAKING



Gaurav Rohella, GlobalLogic, UK, explains how innovative technology could help the upstream sector make more environmentally friendly, sustainability focused decisions for intelligent operations.

The energy sector is caught in a balancing act. Oil companies, beholden to investors and other stakeholders, are under pressure to remain profitable and competitive while addressing energy security and moving to net-zero business models. They must step up production to meet incessant demands for greater and faster output due to macro factors influencing the market. At the same time, they must make operations more

environmentally friendly, in line with climate change targets. It is a monumental task, but a task that technology can help with.

Sustainability challenges

Oil consumption is soaring as the global population grows exponentially and developing economies harness oil for transportation, manufacturing, and power generation. Demand is set to increase by an expected 1.8 million bpd in 2024 to reach a total of more than 101 million bpd. Despite pressure to limit the use of hydrocarbons, alternative fuel sources have little market share, so it falls to traditional energy to fulfil requirements.

The oil sector is concurrently juggling the increasing demand with an overload of local, national and international environmental and sustainability regulatory and legislative burdens. These burdens stem from global blueprints such as the United Nations Environment Programme and Sustainable Development Goals. The resultant obligations are defined in legally-binding targets, such as reaching net-zero greenhouse gas emissions by 2050, as laid out in European Climate Law.

These divergent diktats of greater demand and tighter environment and sustainability controls add to the list of longstanding challenges that upstream oil E&P must mitigate to ensure energy security. Unsurprisingly, topping that list is heightened industry risk, from natural disasters, attacks on infrastructure, fluctuating geo-political tensions, economic instability and competition from alternative sources.

As younger, more eco-conscious generations of consumers, stakeholders and workers enter the system, pressures are changing in line with new expectations. Shifting customer, investor and employee demands encompassing sustainable policies and practices have resulted in a magnified emphasis on health, safety and environment (HSE) considerations and tighter environment, sustainability and governance (ESG) controls.

Alongside rapidly increasing demand, broadening legal and regulatory oversight, industry risk mitigation, and shifting expectations is the more recent inclusion of challenges associated with diversification. In response to sustainability-related challenges, big oil is increasingly shifting focus from traditional E&P activities towards meeting customer demands. Emerging from this approach are new revenue streams – like renewables, biofuels and advanced chemicals – and alternate business models such as energy-as-a-service and power-as-a-service – all with their own set of pains.

Overcoming sustainability challenges

Overcoming the sustainability challenges associated with the aforementioned rapidly increasing demand, growing list of regulatory and legislative burdens, industry risk mitigation, shifting expectations, and diversification, is not easy.

There are no magic wands that will, in one swipe, eradicate all of these issues. Experience does, however, teach us that there are approaches, tools and solutions that can help enterprises manage these challenges.

If adequately leveraged with a combination of logic and function, such approaches, tools and solutions can reduce the stress these challenges cause. This article considers the ways design and Internet of Things (IoT) can help.

IoT technologies

IoT is, according to Microsoft, the network of physical objects that contain embedded technology to communicate and sense, or interact with, their internal states or the external environment. But IoT is not just about connected devices, it is about the information those devices collect and the powerful, immediate insights that information garners.

IoT fuels intelligent operations underpinned by advanced analytics and embedded system management. Deploying IoT in conjunction with machine learning (ML), artificial intelligence (AI), and automation creates integrated information technology (IT) and operational technology (OT) solutions. The power of IoT to provide and optimise data-driven insights in real-time also means that is central to greener decision making. The key upstream uses of IoT include the following.

Condition-based monitoring (CBM) and predictive maintenance

Predictive maintenance technologies listen to enterprise assets such as pipeline monitors, fleets of vehicles and on-site machinery, to assess conditions in real-time. CBM anticipates changes in asset

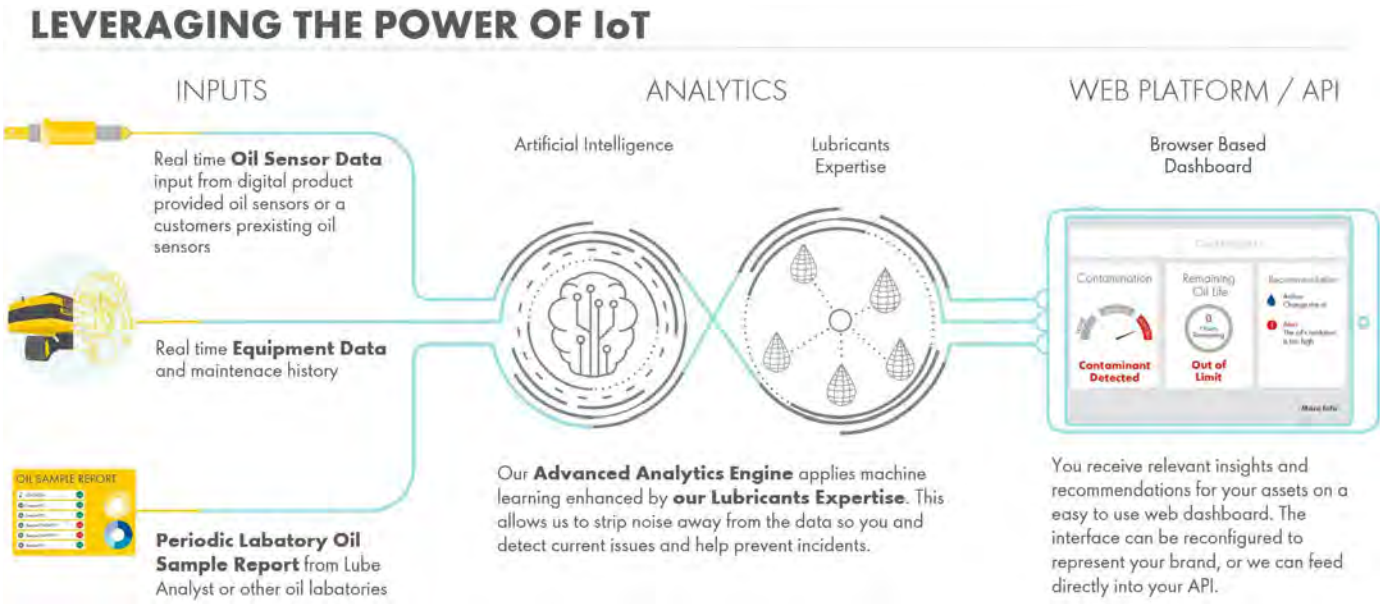


Figure 1. *Illustrative condition-based monitoring reference view for lubricants.*

condition and schedules maintenance when and where needed to avoid failures.

Digital twins

A digital twin is a virtual copy of a physical asset, process, system or environment that looks and behaves exactly like its real-world counterpart, much like a pilot training flight simulator. Digital twins take in data and replicate processes to predict performance outcomes and problems such as corrosion in real-world scenarios.

IoTH

IoT products operate in the world alongside real-life workers and bring another layer of HSE challenges. Internet of things and humans (IoTH) conceptualises the relationship between IT, OT and people. It is also a logistical paradigm and solution-oriented management methodology that harmonises interactions between human and non-human workers in the field.

Hydrocarbon accounting

Hydrocarbon accounting performance measures track oil resources, reserves and production in order to monitor the volume and sustainability of resources. These automated blockchain enterprise solutions provide accurate, repeatable, auditable records in line with regulatory reporting standards.

Open subsurface data universe (OSDU) platforms

The digital transformation of E&P workflows is now a reality, but disparate information across data silos and domain teams slows the exploration to production lifecycle. OSDU platforms allow all applications to access all data so knowledge flows freely across a single standardised solution.

IoT and greener decision making

Understanding how IoT, and technology more widely, contributes to sustainability efforts in the upstream oil sector boils down to one critical factor: IoT facilitates greater production, making operations more intelligent with fewer resources. It achieves this by giving decision makers the insights they need, when they need them, so they can make fully informed, operationally and friendly sound choices.

Intelligent asset maintenance conserves resources

Whenever industrial machinery breaks down, productivity takes a hit. It also results in unplanned maintenance costs. Historically, the industry overcame this with regularly scheduled equipment checks and servicing. Whilst this approach negates the problem of reactive repairs, it is inexact. In contrast, CBM and predictive maintenance lower the cost burden and save many person hours, as they prevent work from being done to perfectly functioning assets.

Predictive modelling reduces downtime

By modelling future outcomes, technologies such as digital twins reduce the likelihood of wasting resources through poor planning and errors. They arm decision makers with insights, analysis and simulations of present and future conditions. Digital twins also improve safety training, quality assurance and quality control. In conjunction with IoTH, downtime resulting from accidents and mistakes in the field is significantly reduced.

Real-time monitoring leads to operational efficiencies

The real-time overview of all operations, such as that provided by OSDU platforms, gives users an integrated, centralised source of truth, so on-the-spot decisions are based on complete datasets. This means resources can be deployed where and when needed in response to current demands. Operational efficiencies, such as the reduction in storage costs derived from just-in-time (JIT) management, are optimised.

Improved accuracy increases compliance and benchmarking activities

Manual tools and fiscal meters, like custody transfer points, are error-prone and open to manipulation and misrepresentation. When it comes to industry benchmarking and regulatory reporting, decisions based on inaccurate data can be costly for both sustainability efforts and the bottom line.

IoT with blockchain integration enables companies to boost the integrity of recording and reporting. It does this by systematising and consolidating records from oil producers, shippers, suppliers and operators from installation throughout the lifecycle, from upstream, midstream and downstream.

Blockchain is also essential in helping implement the creation and tracking of carbon credit systems to help offset the carbon dioxide and other environmental effects resulting from oil production.

IoT and greener decision making in practice

As a leading indicator of equipment health, monitoring and responding to oil quality is essential in preventing avoidable failures and deterioration. Improved asset performance and reliability associated with oil monitoring also helps reduce loss through premature disposal – cutting costs and the carbon footprint.
In light of this, the UK's largest oil company engaged GlobalLogic to deliver an application that improves the intelligence gained from oil condition monitoring.

The company had a minimum viable product (MVP) they wanted to transition into a scalable digitally-enabled solution. GlobalLogic was, therefore, tasked with leveraging the power of IoT to put real-time insights into the hands of large industrial companies. The end goal was to optimise equipment health, lower maintenance costs, and increase operational efficiency.

GlobalLogic moved the basic design from a few inflexible screens to a detailed customer-centric integrated, centralised, all-operations dashboard. The dashboard mirrored values and parameters relevant to their specific oil use. This enabled onsite engineers to gain a comprehensive understanding of numerous equipment located at multiple sites.

The application, developed as a scalable navigation system on Microsoft Azure, included scope to become an integrated platform. A tracking system for oil samples was one notable feature. This system identified when a sample should be taken, whether the sample gave the client the correct information, and whether it made sense in the context of other data already in the AI/ML model.

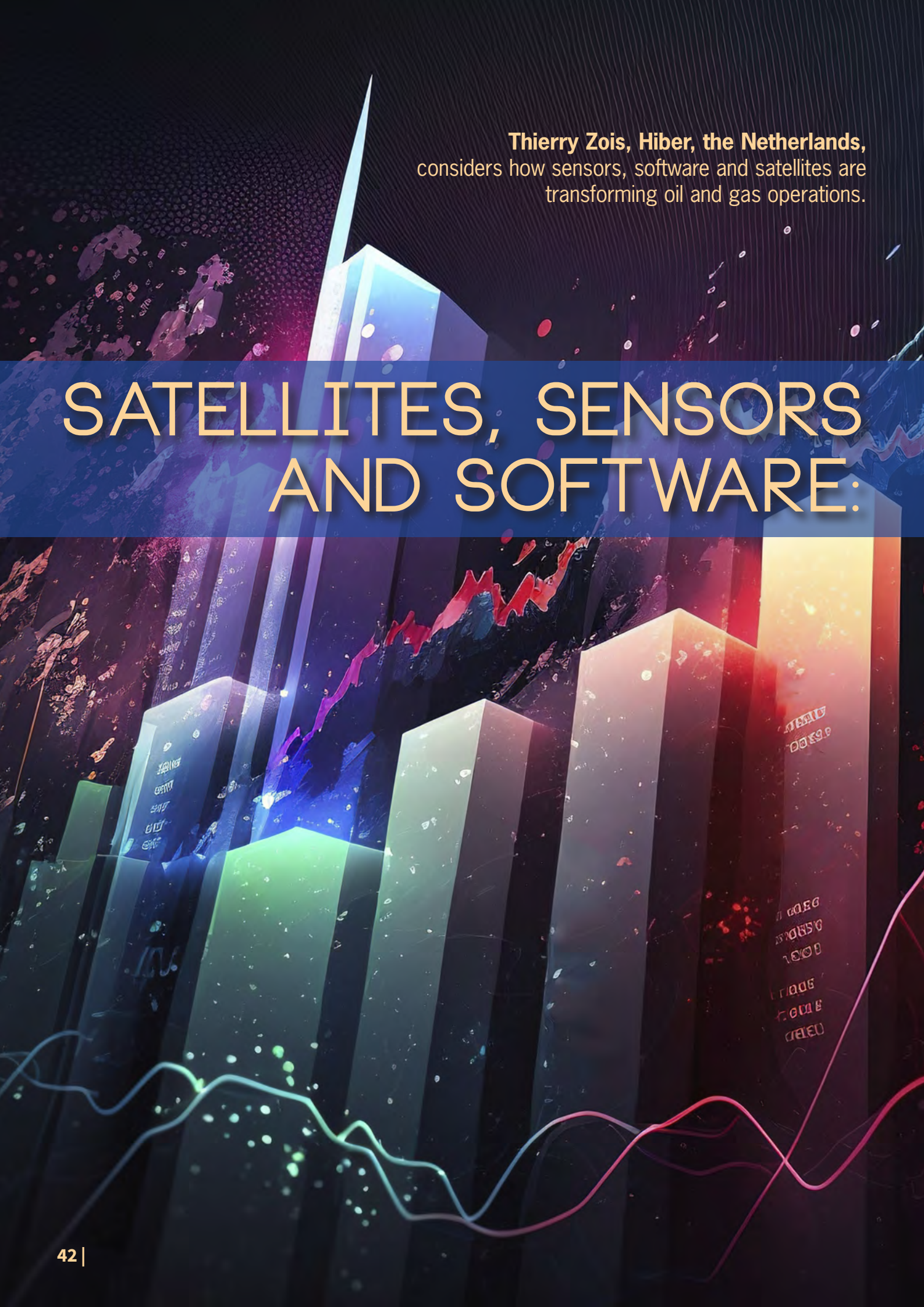
The user interface reflected this functionality and flagged the sampling process status. It also incorporated checks and balances, thus ensuring regular and precise data collection, with notifications sent directly to the app and customer email. In short, the technology facilitated better, greener decision making with efficiency and sustainability at the core.

GlobalLogic's solution also helped the client gain added revenue from upselling lubricants to new and existing customers and sectors and led to an efficiency gain of around 15 – 18%.

The case study above demonstrates that technology, particularly IoT, exists to help the upstream oil sector make more environmentally friendly, sustainability-focused decisions. Ultimately, it means the demand for energy and the demand for greener operations do not need to be at odds.

Thierry Zois, Hiber, the Netherlands,
considers how sensors, software and satellites are transforming oil and gas operations.

SATELLITES, SENSORS AND SOFTWARE:



A MODERN TAKE ON WELL MONITORING

Well monitoring has always been a necessary pain: a vital but often difficult and expensive part of oil and gas operations.

Today, technology can cut out some of the pain points. Modern monitoring systems provide accurate and reliable data so remote engineers can spot potential problems at wellheads, such as an increase in temperature, flow or pressure, and take action. It means fewer potentially hazardous journeys for engineers, lower travel costs, and a reduced risk of oil and gas leaks.

But there are still challenges; older, wired monitoring systems may not measure everything and can be unreliable – for example, a slight twist in the wire could break the whole monitoring system. Newer systems have been improved, but are expensive and take time to install. Plugging in a wired system to monitor annuli is by no means straightforward. Depending on the size, it can cost up to tens of thousands of dollars per installation, and can take several weeks or even months to set up on larger projects, often forcing a halt in production. Such systems also still rely on having a reliable power and communications infrastructure.

Despite wired technology being around for decades, it is only viable for the largest producers or for high-producing wells in accessible locations.

So, it is not a surprise that around 90% of the world's estimated 4 million oil wells are still monitored manually, with all the associated well-visit costs, concerns about the safety of crews, and patchy data on well integrity and performance.

Satellites, sensors and software transform well monitoring

One solution to this challenge is a satellite-enabled well-monitoring technology that uses a combination of sensors, software and satellite connectivity to provide a constant stream of data on the integrity,

temperature, injection rate, pressure or flow rate of wells. One such solution is HiberHilo, which can make it cost-effective for producers to digitally monitor any well.

This solution connects sensors on the annuli on wellheads via a wireless, solar-powered gateway to satellites, and then on to an API or secure online mobile or desktop dashboard, which can be monitored from anywhere in the world. Multiple wellheads with different sensors can be connected to the same gateway within a five-mile radius. These sensors regularly relay data back to the dashboard, providing a 24/7 view of the status of any well.

For producers of all sizes, satellite-enabled well monitoring offers four major benefits. Firstly, these systems are simple to use and installation takes just a few hours. Secondly, they are also significantly more affordable than wired systems, and available via a monthly subscription, which means zero CAPEX. Subscriptions may include all of the hardware (sensors, connectors and gateway) needed to monitor wells, as well as the data connectivity from the sensors to the gateway, the satellite connectivity, and the integration into a producer's data systems. Thirdly, because they are battery and solar powered, a local power source is not required. Lastly, due to long range wireless satellite connectivity, they can gather data anywhere.

Monitoring any well anywhere

Digital well monitoring – especially in remote locations – brings distinct advantages to producers across a range of well types and use cases.

For producing wells, digital monitoring can ensure that they are set up to meet local regulations. The technology can provide the data needed to monitor and check annuli, stay compliant, and better target maintenance.

With natural flowing wells, it is essential to monitor the pressure, temperature and flow to get a clear picture of how the well is performing.

Digital monitoring of injection wells offers oil producers insights into injection rates and production output. This facilitates precise injection rates, reduces downtime, and provides the means to balance marginal costs against marginal revenue.

By installing the appropriate sensors on production tubing in artificial or natural lift wells, operators can monitor pressure and flow data to optimise production rates.

Across all of these use cases, near real-time alerts provide updates on pressure, flow and temperature, and downtime detection in minutes rather than hours or days, significantly enhancing the sustainability of oil production.

HIberHilo has also proven to be particularly suited to three specific use cases where, without satellites, well monitoring is expensive or unreliable.

Figure 1. *Installation of a HiberHilo sensor.*

Figure 2. *Example of a well in off-grid location.*

Late-life wells ready for decommissioning

Wells ready for abandonment need to be closely monitored for integrity issues. Equipping annuli with sensors to monitor pressure makes it easy to check well integrity, and implement more accurate plug-and-abandonment strategies that prevent the need for remedial work.

Shell tested HiberHilo on a well-abandonment project to evaluate the speed and ease of installation and compare the output of the sensor to an existing wired measurement system. The installation took less than three hours, with the sensors connecting to the satellites within 15 minutes. Shell was looking for accuracy levels within a 10% range of control data provided by the existing wired system. On average, the satellite data was 99.75% as accurate as that from the wired system. Shell agreed a deal to allow its subsidiary companies to transition to this satellite-based approach.

Marginal low-producing wells

The low cost and potential return on investment (ROI) makes the digitisation of well monitoring possible even for the lowest-producing wells and those in ageing oilfields that are often the most polluting. Where an operator has low-producing wells, it can be the difference between profitability or taking a real hit to the bottom line.

Dacian Petroleum is using HiberHilo to remotely monitor tubing pressure and other parameters at wells in southern Romania, helping it to reduce downtime and boost the productivity of marginal gas wells. Being alerted to issues, and scheduling interventions to mitigate the impact of technical faults, means Dacian can maintain optimal production.

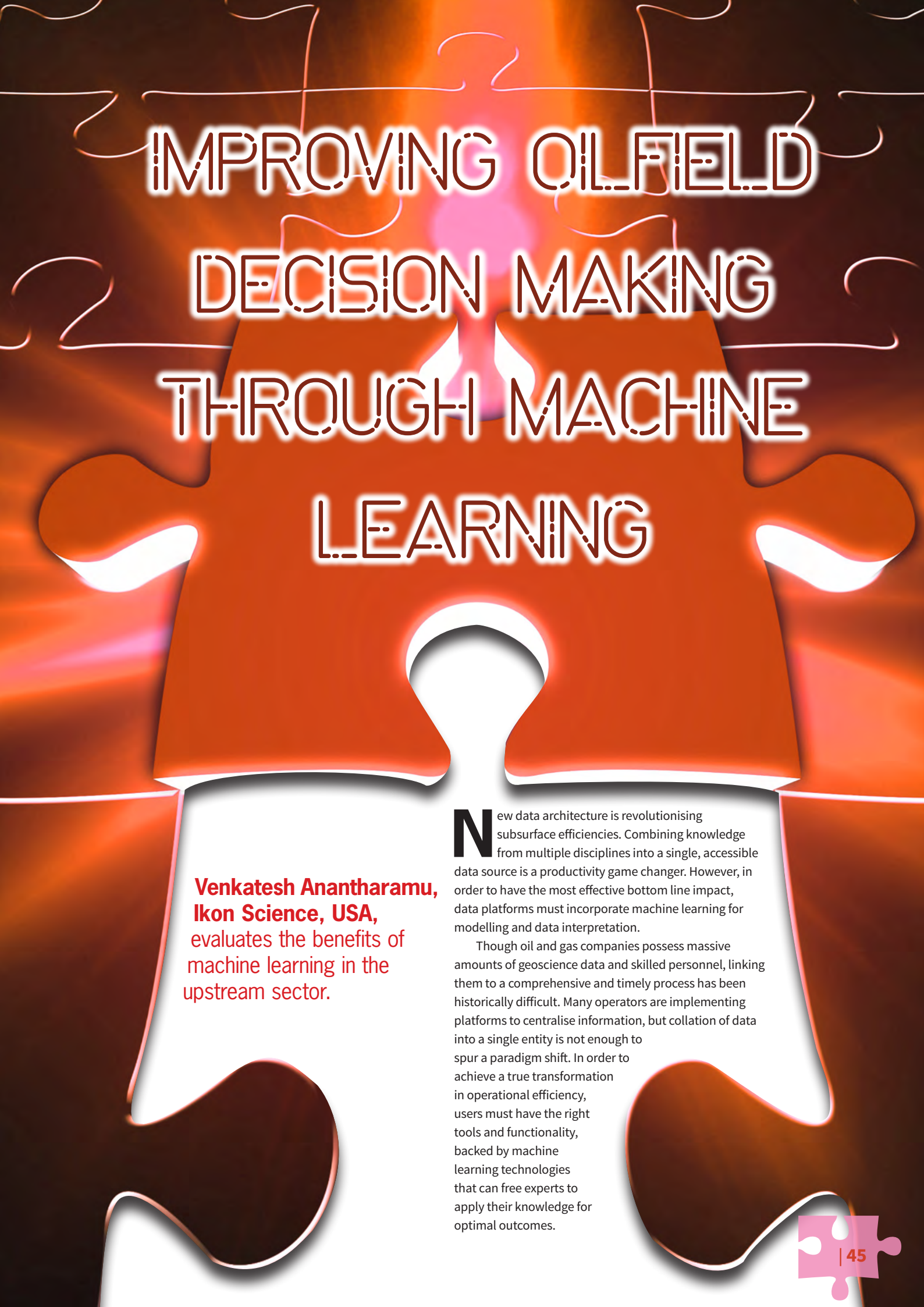
Wells in off-grid locations

Satellite connectivity allows for monitoring wells in remote locations, beyond the reach of cellular networks and local power infrastructure, or where sending engineering teams may be particularly hazardous and expensive.

In West Africa, Niger Delta Petroleum Resources (NDPR) is using HiberHilo to deliver real-time production data from wells scattered across the Niger Delta. NDPR previously sent several crews to monitor wells manually. Travelling to these remote wellheads in a dangerous region exposed the technical team to safety and security risks, while repeat monitoring trips increased operational costs.

Digital oilfields are the future

Connecting wells using low-cost satellite connectivity means oil and gas companies can gather data at almost every wellhead – completely digitising oilfields. It is an approach that makes well monitoring easy, affordable, and safe, with the key benefits of reduced downtime, optimised production, and improved sustainability.



IMPROVING OILFIELD DECISION MAKING THROUGH MACHINE LEARNING

Venkatesh Anantharamu, Ikon Science, USA, evaluates the benefits of machine learning in the upstream sector.

New data architecture is revolutionising subsurface efficiencies. Combining knowledge from multiple disciplines into a single, accessible data source is a productivity game changer. However, in order to have the most effective bottom line impact, data platforms must incorporate machine learning for modelling and data interpretation.

Though oil and gas companies possess massive amounts of geoscience data and skilled personnel, linking them to a comprehensive and timely process has been historically difficult. Many operators are implementing platforms to centralise information, but collation of data into a single entity is not enough to spur a paradigm shift. In order to achieve a true transformation in operational efficiency, users must have the right tools and functionality, backed by machine learning technologies that can free experts to apply their knowledge for optimal outcomes.

Data must be managed

Subsurface models are vital to operational decisions as an asset moves from exploration to production and beyond. As operators look to maximise returns in a safe and sustainable manner throughout the lifecycle of a drill site, having a thorough and accurate view of the subsurface is essential.

Subsurface projects typically build on existing studies or analogous areas to provide geological context and guide the construction of models. Teams distribute information to one another as the study progresses, with each performing individual workflows to add key elements. As new wells are drilled, the current model is revised to reflect additional information.

Though companies have decades of existing data and studies that can be leveraged for research, sprawling information systems and time pressures often lead to underutilising data history. Subsurface teams often save data in individual files, inadvertently keeping them isolated in individual silos. This process may occur over a period of many months and years, with participants coming and going.

The information exchanged between disciplines and applications often takes the form of manually produced data exports and written reports. Vital background information is often lost due to the lack of defined management practices and long evaluation timelines. As a result, subsurface teams spend countless hours recreating studies and searching for supporting documentation. The average geoscientist is estimated to spend almost three quarters of his or her time seeking out or performing quality control on existing information.

Digital transformation is significantly boosting efficiency in industries such as manufacturing, financial services and transportation. In order to minimise costs, effort and time, subsurface departments must follow their lead. Users must possess the tools and functionality to appraise and understand the vast amounts of information their files encompass. Applications, workflows and underlying processes must be designed to produce trust in that information. Without this context, future generations of geoscientists and subsurface engineers lack the key clues required to determine if data possesses the relevance and quality to be used repeatedly.

Artificial intelligence helping human intelligence

Once data is connected, the humans involved can work more effectively. However, connecting data only goes so far. Effective drilling starts with rock physics-based modelling and predictions that rely heavily on data interpretation to maximise the chance of productive well selection and minimise costs.

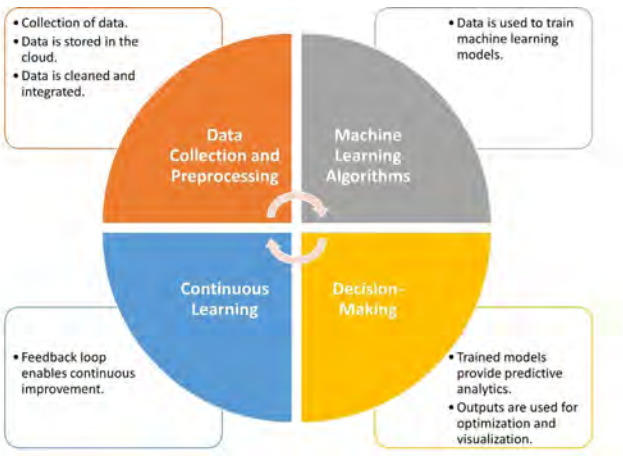


Figure 1. *The schematic representation illustrates the process of utilising machine learning techniques to enhance decison making in the oilfield.*

Machine learning can be used to streamline both rock physics and data interpretation significantly, freeing the non-machine participants to focus on analysing results rather than trying to obtain them.

Drilling teams rely on accurate interpretation of subsurface reservoir properties to begin determining where to drill. To estimate those from seismic data, one must start with well log data and calibrate rock physics models for each formation. This requires parameter selections such as mineral densities, elastic moduli, porosities etc. Historically, this required team members to experiment to find the best fit.

Machine learning, however, vastly simplifies the process. Artificial intelligence can automatically determine the best rock physics model for a given data set and then select as many parameters as necessary to fit the model to the data.

Based on geological and geophysical data, algorithms can be used to predict properties, including elastic moduli, permeability and porosity. Machine learning can ensure that users have a comprehensive understanding of factors such as minerology, microstructure and total organic carbon content in the rocks into which they propose to drill. Core samples, seismic data, well logs and much more can all be integrated to show patterns and relationships between rock properties. The result is a more accurate subsurface model, in a much shorter amount of time.

However, once property models are generated, geoscientists and other team members must interpret the data to move forward. Machine learning can also assist with this stage of the process. Multiple types of data must be tied together, compared and analysed. These tasks can be handled far more quickly if manual efforts are replaced with machine learning algorithms.

Technology cannot replace the expertise of actual geoscientists. Those who do not know what they are looking for in the data, or what the data is telling them, will not be able to accurately predict optimum drilling sites. However, machine learning can speed up the process of assembling that data into a whole, bringing together far more variables far more quickly than a manual process.

Machine learning models can be used to connect geoscience properties to rates of production, integrating geophysical data with information from drilling engineers, reservoir engineers and other disciplines. Teams can work more cohesively, spending less time on routine tasks and more time on in-depth analysis. What used to take weeks or months can now take days or hours, significantly reducing operating costs.

For drillers and their partners, this reduces time pressures to allow for greater focus on accuracy and safety. Improved productivity can minimise costs for exploration, drilling and production. As computational power continues to grow, the possibilities of machine learning for oil and gas grow with it.

Machine learning in the field

Some of the major and super major operators are tackling various challenges to improve their operations. One of the key challenges they are striving to improve is the quantitive interpretation of geophysical data. Traditionally, geophysical interpretations have been qualitative, relying on expert judgement and experience. However, there is a growing need to incorporate quantitative analysis methods and algorithms that enable a more rigorous and objective interpretation of the data. Machine learning enables quantitative interpretation by developing models that establish relationships between geophysical data and reservoir properties. Algorithms like random forests, XGBoosts or support vector machines (SVMs) can be trained on labelled data to predict reservoir

properties, such as porosity, minerology, or fluid saturation based on geophysical measurements. This allows for more objective and data-driven interpretations.

The operators also face the challenge of integrating data from multiple disciplines, such as geophysics, geology, and reservoir engineering. Each discipline provides valuable insights into the subsurface, and combining these diverse datasets can lead to a more comprehensive understanding of the reservoir. Machine learning techniques aid in integrating data from multiple disciplines by developing algorithms that can analyse and extract information from diverse datasets. For example, unsupervised learning algorithms like clustering or dimensionality-reduction techniques can help identify patterns and relationships across different data sources, enabling better integration and interpretation.

Oil and gas reservoirs are often found in complex geological settings, such as structurally complex regions, heterogeneous formations, and unconventional reservoirs. These complexities pose challenges in accurately characterising and modelling the subsurface. Machine learning can help handle complex geological settings by developing models that capture the complexities and variations in the subsurface. For instance, algorithms like Gaussian processes or deep neural networks can be used to model complex geologic structures and heterogeneity, allowing for more accurate reservoir characterisation and prediction.

Supporting operations as they evolve

Global efforts to manage carbon emissions and promote an expansion of energy sources have resulted in mature assets being appraised for reuse in parts of carbon capture and storage (CCS) or carbon capture, utilisation and storage (CCUS), as well as geothermal strategies. While this opens up the possibility of transforming abandoned wells from a cost centre to a source of revenue, this will also further increase the scope and responsibility of subsurface departments to optimise the efficiency of such endeavours.

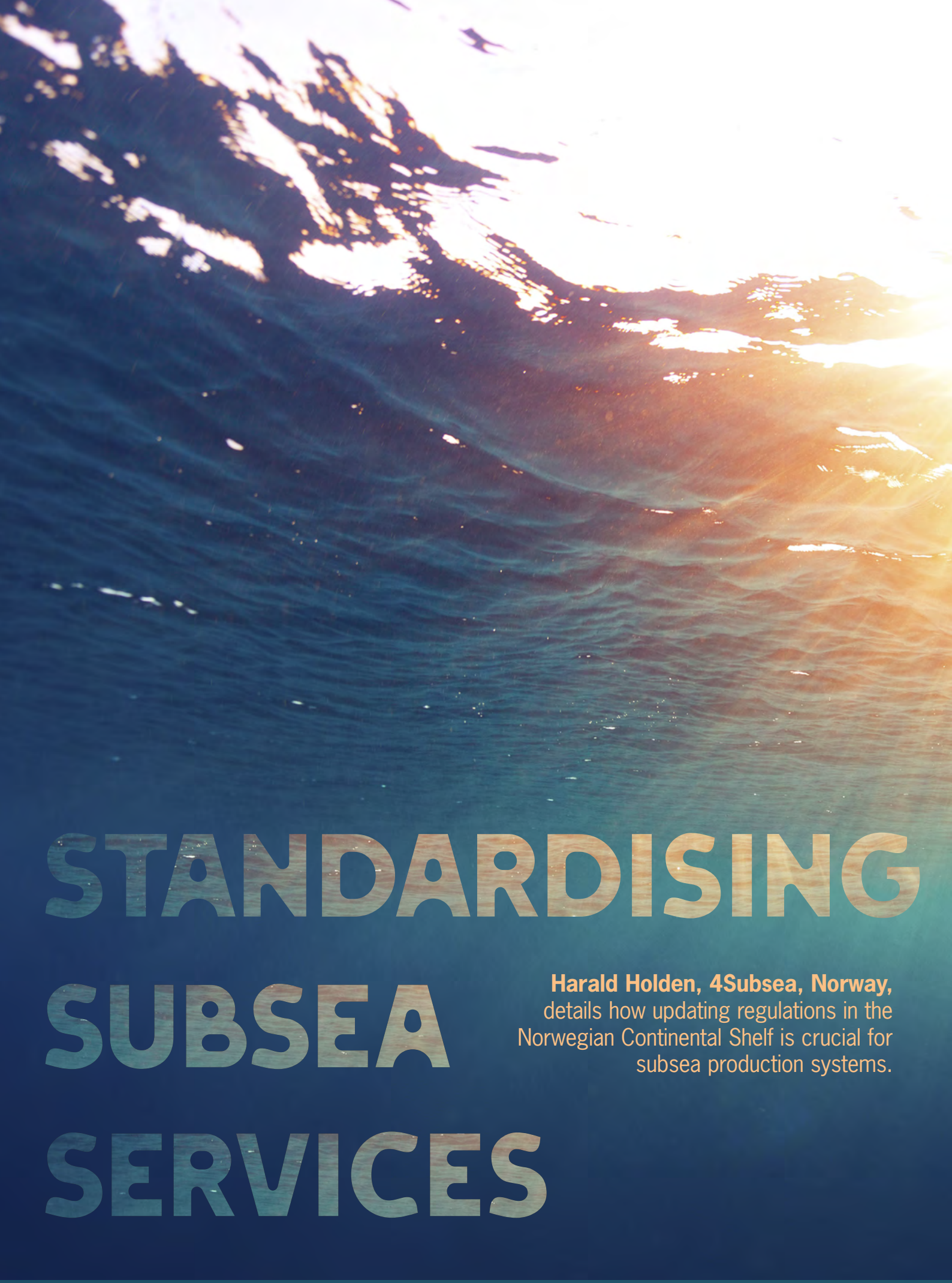
Accurately understanding the subsurface is absolutely essential to repurpose a mature oil or gas well safely and effectively. Successful management of the rich troves of subsurface data linked to old wells using machine learning will be critical in meeting new challenges and capitalising on new opportunities that can expand operations.

Conclusion

The needs of the oilfield will continue to evolve, and companies must evolve as well to remain competitive in the sector. As operators look to maximise returns in a safe and sustainable manner throughout the lifecycle of an asset, having a highly dependable and informed view of the subsurface is crucial.

Energy companies will keep working to reduce costs while increasing speed and production. Having the right subsurface tools is imperative to reach these goals. Combining a comprehensive, accessible data source that incorporates machine learning for input and connection will allow for better decision making in the field – and greater operational efficiency.

Overall, machine learning offers opportunities to enhance prediction and interpretation by automating processes, integrating data, improving accuracy, and enabling data-driven decision making. However, it is essential to note that successfully implementing a machine learning solution requires high-quality and diverse training data, appropriate feature engineering, and careful validation and calibration of models in collaboration with domain experts.



STANDARDISING SUBSEA SERVICES

Harald Holden, 4Subsea, Norway, details how updating regulations in the Norwegian Continental Shelf is crucial for subsea production systems.

For approximately 30 years, companies operating on the Norwegian Continental Shelf (NCS) have had to abide by specific regulations in relation to design loads on subsea structures and well equipment. However, as technology evolves and different challenges are posed, standards themselves must also move with the passage of time.

Norsok U-001 is a Norwegian national standard with requirements and recommendations that are supplementary to the ISO 13628 series of standards, which are applicable to the design, installation, and operation requirements for subsea production systems (SPS). The fourth edition of NORSOK U-001 was issued in 2015 and carried a significant revision of design drilling riser loads to be applicable to subsea structures and well equipment.

These maximum wellhead design loads were based on an analytical study followed by verification efforts, indicating a shallow water bias of ultimate limit state (ULS) and accidental limit state (ALS) design loads, as well as an overestimation of fatigue limit state (FLS) design loads. As for cyclic design wellhead loads, the

NORSOK U-001 fourth edition included informative design load histograms classified by blowout preventor (BOP) weight and water depth classes.

The standard, which is also used globally as it is designed for use in harsh environments, allows designers of SPS to standardise the equipment potentially years ahead of construction with little knowledge of the rig that it will be attached to. The cost-efficiency of such standardisation relies on the accuracy of the design loads, as over-conservative loads will lead to expensive over-conservative design. On the other hand, non-conservative design loads will lead to demand of expensive design modifications or load reducing measures during the final engineering and installation phase.

In 2021, the fifth edition NORSOK U-001 was launched with a wellhead load study conducted to establish normative maximum and cyclic loads for subsea wells.

Table 1. Key rig information.

Parameter	Rig A	Rig B	Rig C	Rig D	Rig E
Dimensions (m)	116 x 97	119 x 97	92.5 x 67	90 x 70	104 x 65
BOP dry mass	150	149	149	209	168
LMRP dry mass	88	97	60	108	93
Stack dry mass (mT)	238	246	209	317	261
Tension at LFJ (mT)	118	120	68	182	144
LFJ type	5 ksi	0.6 ksi	3 ksi	2 ksi	2 ksi
LFJ stiffness (kNm/deg)[1]	125	61	38	88.3	88.3

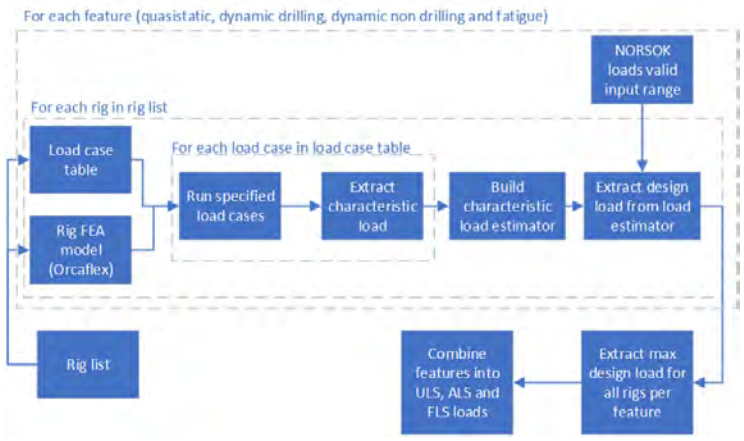


Figure 1. *Design load extraction process, showing how the ultimate limit state, accidental limit state, and fatigue limit state loads are established.*

Table 2. Proposed design load validity range for variable data.

Input parameter	Fatigue	Extreme drilling	Extreme non-drilling
Water depth	Three water depth ranges between 80 and 1500 m water depth.		
Stack height (distance from flex joint pivot point to BOP connector datum)	13.7 m		
Max drill pipe tension	150 mT		
Significant wave height (m)	8.5	8.5	10.5
Well rotational stiffness	2500 – 10 000 kNm/deg		
Wellhead inclination (deg)	N/A	1.5	1.5
Max subsea flex joint rotational (kNm/deg)[2]	125		
Max riser tension at subsea flexjoint (mT)	182		

NORSOK and its associated challenges

Use of standardised marine riser drilling loads was first introduced with the publication of NORSOKU-CR-001 in 1995, with updates in 1998, 2002, and 2015 before the latest iteration. Following changes to year-round operations and the use of fifth generation dynamically positioned semi-submersible drilling rigs, it was recognised that the existing standardised marine riser drilling loads were non-conservative, thus a well system load study was undertaken ahead of the 2015 update.

However, following industry use of the marine drilling riser design loads, it was observed that there was a shallow water under-estimation bias of ULS and ALS design loads and over-estimation bias of fatigue (FLS) design loads.

In response, for the study undertaken that led to the development of the fifth edition of NORSOK U-001, a different approach was taken. A representative selection of actual semi-submersible drilling rigs in use on the NCS were used as the basis for determination of marine drilling riser design loads, whereas previously a fictitious representative of a rig had been used.

Analysis methodology

The bending loads imposed by a subsea BOP when connected to a subsea wellhead can be affected by numerous factors, namely, but not limited to vessel motions, BOP dimensions, riser dimensions and configuration, well stiffness, and water depth.

The total load imposed by an operation with one rig will depend on each rig's unique combination of such factors. Some may be rig specific while others might change during or between operations. A design rig approach, where the most conservative combination of these parameters was selected, has previously proven to give over-conservative results. Therefore, it was decided to model five typical semi-submersible drilling rigs used on the NCS, from which the results were used to establish a design load.

For each of the rigs, a set of load cases were analysed with the purpose of establishing an estimator of the fatigue and extreme load as a function of the parameters that might vary from well to well. The estimator was then used to cover the range of these input parameters covered in the NORSOK standard. Each load case consisted of dynamic simulations of the response when subjected to wave loading of 154 sea states and quasistatic simulations to incorporate the effect of vessel offset and sea up to an offset of 13% of the water depth. Altogether, a total of 372 load cases were included, giving a total of more than 60 000 dynamic simulations. All models were built in accordance with the latest industry practice, and significant effort was made in accurately gathering the model input.

The purpose of the analysis was to establish design loads for subsea equipment covering the typical range of loads imposed by a subsea BOP from a semi-submersible rig that is connected to the well. To ensure that the calculated loads were representative of other rigs than just the five analysed rigs, a design load process was selected, as shown in Figure 1.

A parametrised riser analysis model was created for each of the selected rigs, while a range of load cases were selected to cover the variation of parameters that typically may change during or between operations. The different characters were extracted for each of the load cases and the

resulting characteristic loads were used to establish a characteristic load estimator:

$$L_{char} = f(P1, P2, \cdots, Pn) \quad (2)$$

Where:

L_{char} – Is the characteristic load (static extreme, dynamic extreme or fatigue)

$P1, P2, \cdots, Pn$ – Input parameters that can vary during or between operations, e.g water depth, LMRP overpull, drillpipe tension, flexjoint stiffness, well stiffness ++

Then a range of these parameters were selected as the NORSOK load validity range (see Table 3), and the design load for each rig was calculated using this load estimator. Finally, the the design loads were selected based on the maximum design load from the five rigs.

The new approach showed that the magnitude of the marine drilling riser design loads is primarily dependent on the height of the subsea BOP, as opposed to its mass, and other factors such as the response amplitude operators (RAOs) of the rig and riser tally. This moved away from a BOP mass classification as used in the fourth edition.

Different depths and accompanying hurdles

Normative ULS, ALS, and FLS marine drilling riser design loads are specified in NORSOK U-001. These design loads are specified for three water depth range classes: 80 to 250 m, 251 to 500 m, and 501 to 1500 m. A water depth range class approach was implemented to drive equipment standardisation. The choice of water depth range for each class also corresponded with the installed population of subsea development wells on the NCS.

The design loads were upper bound, based on loads from the most severe combination of variable operational input data.

Fatigue design loads, meanwhile, were specified as single load-bending moment ranges at the subsea wellhead datum, for example the hub face, for the corresponding water depth classes as for the ULS and ALS design loads. The single load-bending moment range (ΔMo) was selected rather than specifying bending moment fatigue load histograms to allow for direct and simple comparison of such histograms and with equipment single-load fatigue capacity, ΔMC.

For example, with an annual single-load bending moment range, the expected fatigue service life of a connecter will be one year if:

$$\Delta M_{o\,annual} \leq \frac{\Delta M_c}{(D_F)^{\frac{1}{m}}} \quad (1)$$

Where:

$\Delta M_{o\,annual}$ – is the ΔM_o value calculated from a histogram of an operation using the annual scatter diagram

ΔM_c – is the single-load fatigue capacity as defined in Annex B.6.4 of [1]

D_F – is the fatigue design factor

m – is the slope of the equipment MN-curve

Upon determination of a project relevant ΔMo, a bending moment fatigue load histogram can be established by multiplying a normalised load histogram by the single load bending value of ΔMo.

The changes made

Following the study, several recommendations were made.
In terms of ULS and ALS design loads, the variation of loads inter rigs are significant. Only one of the five rigs (stack mass of 317 t, slightly above 300 t) would end up in the 300 t BOP category from NORSOK U-001 fourth edition, thus supporting the removal of BOP mass classes in the fifth edition of NORSOK U-001.
Other findings include that there is potential for project specific design loads significantly lower than the fifth edition design loads.

For FLS design loads, a major shift is that reduction is observed in the fifth edition for most water depths below 700 m, while an increase is undertaken for depths above this.

Ultimately, the fifth edition of NORSOK U-001 is better equipped to help designers in the early phase, and the loads are better suited to what the equipment will see during the operational phase.
For engineers, surprises can be avoided when in the operational phase, with loads that are neither over- or non-conservative.

Table 3. Examples of ultimate limit state (ULS) and accidental limit state (ALS) wellhead design loads – BOP on wellhead mode.

Water depth ranges (m)	ULS			ALS		
	Bending moment Mw (kNm)	Shear force Qw(1) (kNm)	Tension(2) (kN)	Bending moment Mw (kNm)	Shear force Qw(1) (kNm)	Tension(3) (kN)
From 80 to 250	9289	678	-1472	13 382	977	3424
From 251 to 500	7354	537	-1472	12 217	892	3424
From 501 to 1500	6862	501	-1472	11 467	837	3424

Note 1: Shear force, $Q_w = M_w/H_{LFJ}$.
Note 2: Negative tension values means weight acting downwards. Based on worst case down weight (i.e. effective tension at lower flex-joint minus weight of BOP and LMRP).
Note 3: Positive tension values means a vertical force acting upwards. Based on effective tension at lower flex-joint minus weight of BOP and LMRP plus 450 t drill pipe tension. For vertical and horizontal well completions, it is assumed the drill pipe tension is reacted by the BOP stack (i.e. via a closed pipe ram on the landing string).

REAPING THE REWARDS OF A

RIGLESS APPROACH

Bård Marius Johansen, Odfjell Technology, Norway, outlines the benefits of a rigless approach to plug and abandonment and slot recovery.

The changing landscape of energy, whether across economics, emissions or supply challenges – or all three – necessitates an evolution of the oil and gas industry's approach to a range of standard operations.

This is particularly true of legacy assets, which in the face of shifting societal, governmental and environmental concerns, will often require either evolution of purpose or a shift into late-lifecycle decommissioning.

Both options carry a cost in terms of time and money, and volumes will accelerate as operators in the North Sea and around the globe prepare to meet the demands of security of supply, increasing demand and the ongoing energy transition.

Plug and abandonment (P&A) and slot recovery will, as a result, have a crucial and growing role to play in the decades ahead. Companies are beginning to invest the time and money required to bring innovation and fresh thinking to market, providing solutions, flexibility and increased options to an energy sector in transition.

Obligation and opportunity

The many thousands of wells drilled across the North Sea and Norwegian Continental Shelf over the last 50 years pose both a challenge and an opportunity for operators, and the scale, and stakes, are huge: in the UK alone, the government expects more than 2000 wells to be decommissioned over the next decade, at an average cost of nearly £8 million per well.

Whether for end of life, operational extension through new drilling, repurposing for lower carbon technologies, or some

combination of those three, infrastructure must be responsibly evolved from its original purpose in line with economics, environment and regulations.

Existing solutions, based on traditional drilling rigs or existing platform units, carry a high day rate and suffer from a lack of flexibility in terms of availability and responsiveness, with unexpected hurdles and/or delays quickly absorbing budget and inevitably pushing timelines to the right.

Arguably therefore, oil and gas needs to move away from big rig solutions and move towards tenable, effective and time-saving, but also cost-efficient, hardware and services.

Going rigless

Odfjell Technology has developed a rigless P&A solution and slot recovery, based on existing components across the company's service offering.

The well control package includes an integrated blowout preventer (BOP) stack, the BOP control unit, a choke manifold and the trip tank, in accordance with regulative requirements for operating offshore, both in the UK or at the Norwegian Continental Shelf (NCS). Tripping and pipe handling includes a jack positioned on top of the BOP, cherry pickers, pipe chute and pipe rack.

The unit is road transportable with a small footprint, and is designed for installation in the shortest period of time with the fewest number of lifts.

Such rigless concepts fits alongside, and bolster, existing oil and gas capabilities. Deployment of rigless P&A units for the less complex downhole P&A work can free up traditional drilling units for performing the more complex downhole operations. Well data and well barrier status collected with rigless operations, allows for an optimised planning of operation to be executed with the drilling unit, drastically reducing operation risk, improving operational efficiency and reducing time and cost.

Tromsø testbed

The operative principles of rigless P&A units as planned for offshore slot recovery and P&A operations, were proven earlier this year for a geothermal pilot project onshore in Tromsø, Norway. A modified version of the Odfjell Technology rigless intervention unit, in combination with a fit-for-purpose setup for pressure control and pipe handling was utilised to execute the pilot operation.

In close co-operation with Xrig and Halliburton, the company played a key role in the planning and execution of this project for Kvitebjørn Varme, the company operating the district heating facility in the city of Tromsø. The overall aim was to progress an underground heat storage concept developed by Ruden AS.

The project objective was to create a network of subsurface fractures between a centre injector well, and surrounding production wells placed in a circle around the injector. All wells had been pre-drilled down to 300 m depth. The rigless P&A unit was used to deploy a hydraulic stimulation assembly, sand jetting and fracturing the formation every 5 – 7 m from 270 m to 70 m.

With the fractures established, significant flow communication was confirmed between the injector well and the various producers by performing an injection test. The ideal downhole conditions were achieved for further testing of the Ruden AS heat storage concept.

The strategically important work in Tromsø identified and reinforced the capabilities of rigless P&A solutions across sectors, including geothermal and oil and gas. It also highlighted what can be achieved from close co-operation between well services, operations, and projects and engineering, and across borders from international partners.

Solutions in action

The duty of care demanded by legacy operations will require a commitment of time and money from the oil and gas sector, whether for permanent P&A of wells at the end of their lifecycle or for the slot recovery necessary to maximise existing infrastructure for future operations.

Rigless services, built on proven components and services, provide a dependable and cost-effective route that increases operator options and maximises the impact of existing technology. They also reduce emissions through time saved, transport logistics and related manufacturing.

These solutions extend to pre-P&A wireline, XT removal, production tubing removal and establishment of permanent reservoir barriers. With time, Odfjell Technology's unit will also be modified for covering the work scope including casing retrieval and removal, annual barrier establishment, permanent overburden barriers, environmental plugs and conductors and wellhead removal. Complete rigless solutions capable of performing the work scope typically involved as part of a P&A operation, are therefore in the pipeline.

The rigless approach has additional benefits, such as allowing for offline data collection on barrier status, for instance, or enabling development, testing and qualification of other next-generation P&A technologies at a low cost, in actual well conditions. Cost-effective alternatives to the more expensive and less flexible options represented by traditional offshore or onshore well capabilities are therefore available.

Slot recovery and permanent P&A represent both a challenge and an opportunity for the energy sector, and rigless solutions demonstrate a proven response. No one in oil and gas, or the wider energy sector, can afford to ignore a competitive edge.

Figure 1. *Rigless P&A unit.*

Dean Carey, Logan Industries, USA, explains how repairing and refurbishing equipment can be beneficial for customers, the industry, and the environment.

REFURBISH *or* REPLACE?

With a full-scale transition to solar and wind power unlikely in the medium-term, the oil and gas industry needs to continue to ensure it is operating in a way that maximises its environmental credentials. Responsible organisations in the industry are cognisant of the fact that they need to use their resources as efficiently as possible, and handle and dispose of their effluent in the proper manner.

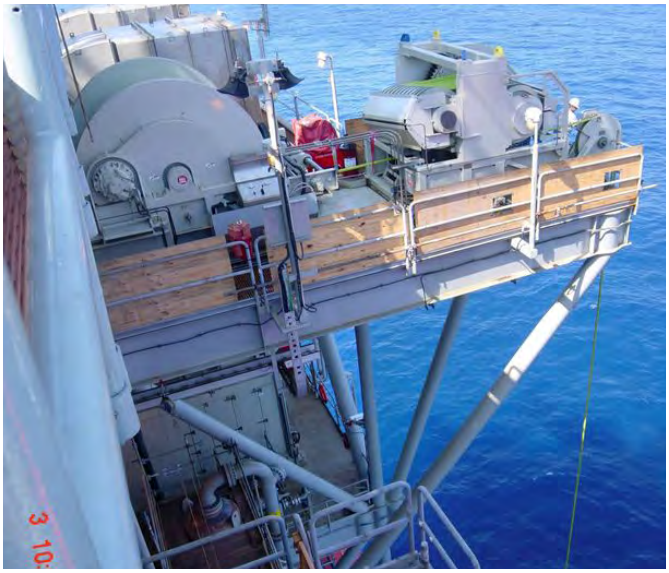


Figure 1. *The company found a consistent way of managing a soft rope traction winch over long duty cycles, allowing the overboard load to vary and keeping the storage tension on the surface constant.*

Figure 2. *Logan Industries' manufacture and repair facility located in Hempstead, just outside of Houston, Texas.*

Figure 3. *A custom-made, soft rope traction winch for Shell's Perdido platform was developed by Logan with many efficiencies in mind.*

To replace or refurbish?

When products reach the end of their life cycle, there are a couple of different options available to the equipment owners in order to disposition the product or equipment. They can either be thrown away and replaced with new products, or they can be repaired and refurbished and put back into service. Every day, companies must decide on the most commercially advantageous choice for a certain piece of equipment. Naturally, sometimes the solution is to just 'throw it away' because it has reached the economic end of its life cycle (meaning that the machinery is worn down past the point of commercial repair). It is the role of companies such as Logan Industries to recognise and advise when this is an appropriate business decision. Often, these business decisions go hand-in-hand with environmental responsibility. The refurbishment of a piece of equipment has both a commercial and environmental impact. With hydraulic machinery, it also sometimes makes commercial sense to choose to refurbish a piece of equipment that costs US$200 000 to buy new, and costs US$120 – 150 000 to refurbish. This is the commonly accepted view and is strictly commercial. There is, however, an environmental aspect that is often overlooked. By choosing to refurbish, the equipment owner is actively choosing not to source new raw materials or components or use the full energy load which would be required for building the equipment new again, thus relieving the overall environmental impact for new equipment.

Planning ahead for the best use of resources

Taking responsibility to fix issues before they cause problems later on is a field proven successful way of operating responsibly and is the most economical way of managing oilfield assets. Oilfield companies that are conscientious about forward planning and managing total cost of ownership of their assets will recognise that, typically, cutting corners to save money in the short-term on repairs will lead to bigger, more expensive problems that need to be fixed again down the road.

An example of this might be to apply a flash chrome on a hydraulic cylinder, which will likely last several years, but then fail and force a rebuild. If a more robust form of chrome is applied (hard chrome, nickel chrome, and others), the rod will likely last much longer and keep the cylinder in service, thus reducing the emergency maintenance downtime that is impossible to predict. As another example, when engineering a product, it is important to consider as many load scenarios as possible. From installation loads to normal working loads, to one-time major overloads, equipment should be designed not to break. This 'over-engineering' used to be common – industry veterans can attest that equipment is not made like it 'used to be.' This is primarily because it costs more to put more material into equipment. Therefore, it is important that products are not heavy and that all safety factors are considered. High strength steels should be chosen when there is any question of failure.

Another element to environmental conservatism is to manufacture technically sound equipment in the first place, so that it lasts longer, does not fail as often, and can be used for longer periods between refurbishments. Selecting cheap, substandard components can result in hours of repair fees over their lifetime.

Improving efficiency with custom design

Perdido, the world's deepest offshore platform located in the Gulf of Mexico, was a challenging deepwater project for both Shell and Logan Industries. Moored in over 8000 ft of water, it is Shell's second deepest oil and gas production hub. Logan created a custom design and build for Shell and played a part in helping to support the larger operation. A custom-made, soft rope traction winch was

developed to eliminate the need for vessels to come out to service the rig, saving Shell time and money. A lot of trust was put into this project, as it was the first time that Shell had ever used this type of soft rope winch system for its oil and gas production.

Creative and cost-effective solutions

Such creative solutions have helped keep the winch in service for an extended period of time while saving the customer time and money. Logan found a consistent way of managing a soft rope traction winch over long duty cycles, allowing the overboard load to vary and keeping the storage tension on the surface constant. Using a soft rope meant it was buoyant and lighter in weight than a typical steel wire. Periodic testing of the rope was performed to ensure excellent system operation. During each test, it passed all safe working load and break load test requirements.

The system's first major overhaul was 11 years after going into service. It is estimated that at least US$5 million has been saved during the course of this project due to the design efficiencies and longevity of the system. The machine has lasted approximately 14 years, and although it has performed many operations, it is still in service thanks to continued maintenance and attention to detail. With the newly tuned maintenance programme, any issues are now addressed at the 5-year mark, continuing the best practices that were set at the beginning of the project and that have been seen to protect the equipment, as well as the crew.

Summary

Aside from being a commercially wise decision, refurbishment enables equipment owners and purchasers to utilise the resources they already have more responsibly. A repair shop that actively engages with clients to clarify the bigger picture of their machine maintenance programme will help to balance short-term budgets with long-term goals. Repair shops can also help companies make good environmental decisions, ensuring that the right decision is made for the customer, the industry and the environment.

Figure 4. *Logan's work on Perdido was the first time that Shell had ever used this type of soft rope winch system for its oil and gas production.*

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