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World Trends and Technology for Offshore Oil and Gas

GLOBAL E&P REPORT

- COVID-19 impact
- Energy Transition
- Brazil's Buzios field
- Port Fourchon supplement

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International Edition
Volume 80, Number 4

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GLOBAL E&P REPORT

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COVER: While the offshore oil and gas market has entered into a new period of uncertainty, some projects are still moving forward. Earlier this year, the *Liza Unity* FPSO hull arrived in Singapore for topsides integration work ahead of planned startup offshore Guyana in 2022. *(Photo by Lim Weixiang, courtesy SBM Offshore).*

DEPARTMENTS

showcase

Allseas

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NEW WEBCAST

Floating Production Market Outlook

In this presentation, David Boggs, managing director of Energy Maritime Associates, discusses the status and forecast for the floating production market including recent awards and deliveries.
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BPA WORLDWIDE BUSINESS
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Coronavirus pandemic spreads uncertainty

DAVID PAGANIE, *CHIEF EDITOR*

AT THE TIME of this writing, the novel coronavirus (COVID-19) had spread to more than 200 countries, areas, or territories, impacting communities, disrupting supply chains, and striking fear in investors. Rapid containment measures to mitigate the spread of the virus had resulted in drastic reductions in transportation and other economic activity, leading to lower estimates for oil demand and downward pressure on oil prices.

Meanwhile, geopolitics exacerbated the situation for the oil and gas industry, as OPEC+ (OPEC and its non-OPEC allies) had failed to agree on extending oil production cuts beyond March 31, to stabilize oil prices. This triggered a breakdown in the group and led some members to threaten an increase in production, in a bid to compete for market share.

This heightened concern of a supply surge – while economists were estimating falling demand for oil – sunk oil prices to an 18-year low in mid-March. As of late March, oil prices were trading in the mid-$20/bbl range – down by about 60% from the 2020 peak in early January. Operators quickly responded with plans to cut E&P budgets, while some oilfield service companies activated employee furloughs and staff reduction plans.

For more on the COVID-19 impact, and a new forecast for offshore E&P, see page 17. For continuing news and analysis, visit *Offshore's* website: www.offshore-mag.com.

Stay well.

David Paganie

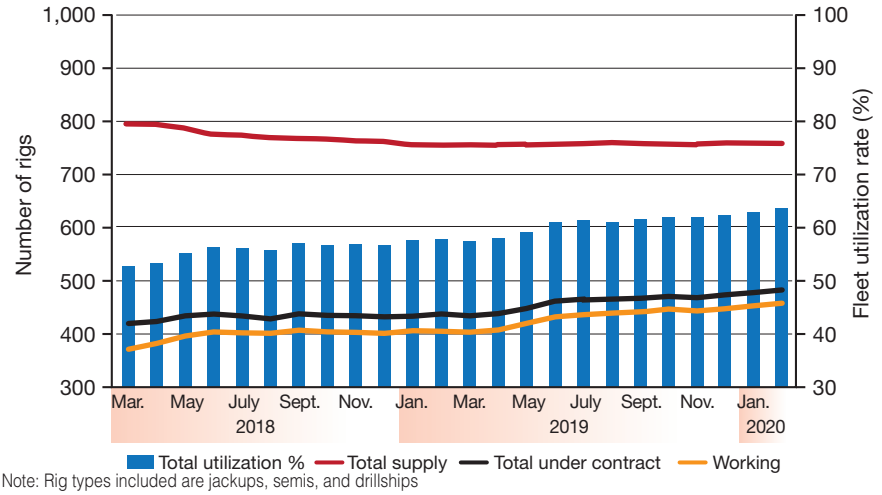
To respond to articles in Offshore, or to offer articles for publication, contact the editor by email (dpaganie@endeavorb2b.com).

Worldwide offshore rig count and utilization rate

First, there is the good news that the offshore drilling market has, again, improved a bit more over the last month. The total number of jackups, semis, and drillships under contract grew by five units from 478 in January to 483 rigs through February. Meanwhile, the global fleet has shrunk by two units to a total supply of 758 rigs. As a result, utilization improved from 62.9% in January to 63.7% in February. Meanwhile, the number of rigs working has also improved, climbing by six units from 453 in January to 459 in February. However, the bad news is that likely all these figures will suffer in the coming months due to impacts from the plummeting oil price and COVID-19, but the question is by how much.

– Justin Smith, Petrodata by IHS Markit

WORLDWIDE OFFSHORE RIG COUNT AND UTILIZATION RATE
MARCH 2018 – FEBRUARY 2020



Note: Rig types included are jackups, semis, and drillships

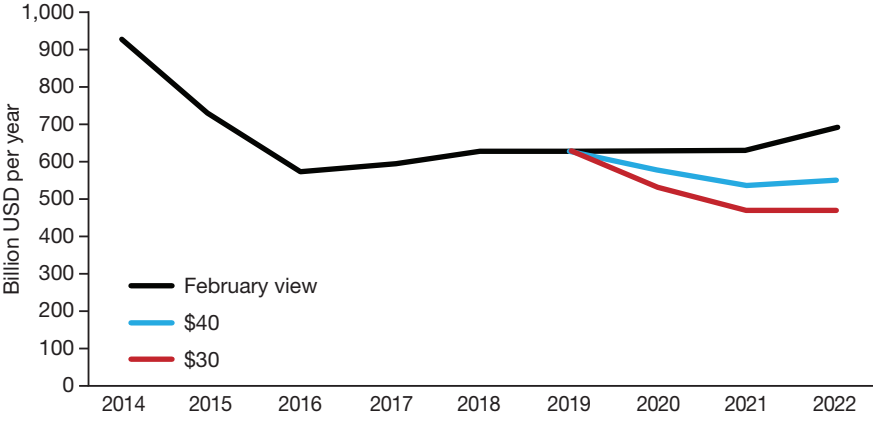
Source: IHS Markit RigPoint

Deep cuts expected in OFS market

If the current $30/bbl environment continues, capex/opex commitments could be scaled back by $100 billion this year and by a further $150 billion in 2021, according to Rystad Energy. This development could force some service companies out of the market altogether, it adds.

Rystad has forecasted flat oilfield service purchases this year, but now anticipates a reduction of 8% if oil averages $40/bbl, rising to 15% in a $30/bbl scenario. And if the current dispute involving OPEC+ countries continues, with no further production cuts agreed until 2021, there could be further spending reductions next year of 7% at $40 oil and 11% at $30 oil.

YEARLY OILFIELD SERVICE PURCHASES BY BRENT OIL PRICE SCENARIO

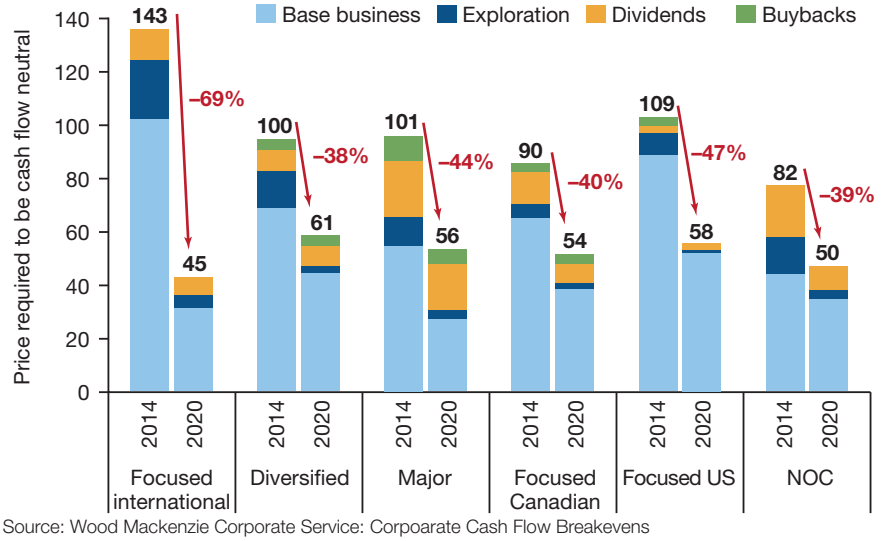


Source: Rystad Energy ServiceCube

Widespread upstream cutbacks likely

The global oil and gas industry is back in survival mode as the oil price rout deepens. According to Wood Mackenzie, although corporate financials are in better shape than during the 2014/2015 crash, room for further maneuver is limited. In contrast to the previous oil price collapse, debt and equity markets are virtually closed for US independents, and upstream M&A liquidity too is limited - to survive, there will need to be swift and sharp cuts in investment. Since the week of March 9, more than one-third of the companies the consultant covers in its Corporate Service have cut capex by 30%, and further cuts will be needed if low prices continue.

CASH FLOW BREAKEVENS HAVE FALLEN DRAMATICALLY SINCE 2014



Source: Wood Mackenzie Corporate Service: Corpoarate Cash Flow Breakevens

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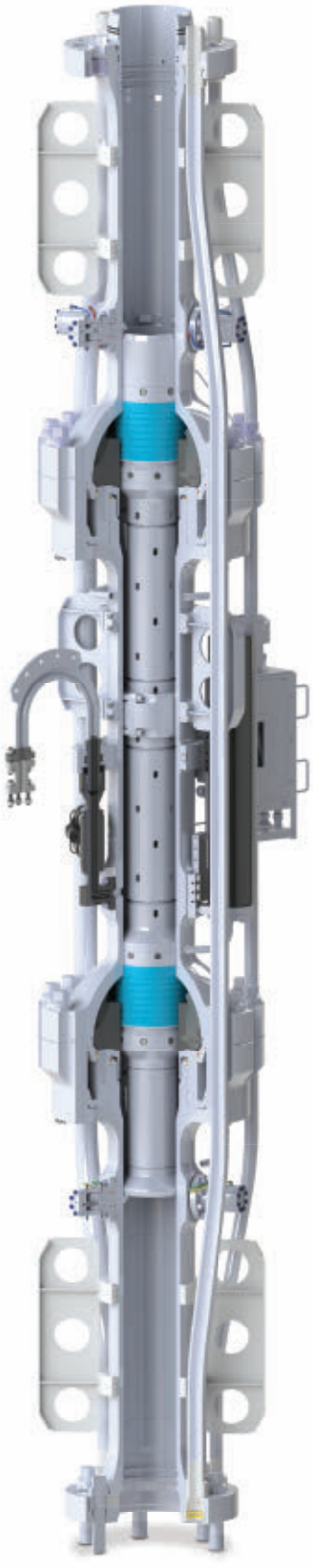

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NORTH AMERICA

Stena Drilling has signed a contract with China's CNOOC to drill up to three exploration wells this year in the Flemish Pass basin off Newfoundland this year, according to Rystad Energy. The drillship *Stena IceMAX* will operate at $299,000/d on the 1144 and 1150 licenses, the consultant claimed.

◆◆◆

Talos Energy and its co-venturers in block 7 offshore Mexico have settled on the main elements of a full-field development of the Zama oil discovery. According to Premier Oil, these comprise two processing, drilling and accommodation platforms connected to an FPSO, with oil offloaded to shuttle tankers. They hope to submit their proposals this summer, assuming they can strike a deal on unitization of the field with Pemex, which operates an extension of Zama in an adjoining block.

SOUTH AMERICA

Apache Corp. plans to proceed with drilling of a third prospect offshore Suriname once operations have concluded on the Sapakara West-1 well. This follows the company's play-opening Maka Central oil discovery in offshore block 58 earlier this year. However, Apache is scaling back planned activity in other regions such as the North Sea, following last month's oil price fall.

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Petrobras plans to offer its full equity interest in Merluza and Lagosta, two producing fields in the shallow-water Santos basin off southern Brazil. Merluza's PMLZ-1 fixed platform has handled gas and condensate from the field since 1993, and has also received Lagosta's production since April 2009. Combined output from the two fields last year was 3,600 boe/d.

PGS has been acquiring a new GeoStreamer X 3D seismic survey over a 14,500-sq km (5,590-sq mi) area in the presalt, deepwater Campos basin. The *Ramform Titan* is towing what the company claims is the largest acquisition spread ever deployed in Brazilian waters, comprising over 140,000 m (459,316 ft) of multi-stream sensors. Some of the data will be relevant to acreage due to be offered late this year under Brazil's 17th Bid Round.

WEST AFRICA

Maersk Decom - a joint venture between Maersk Drilling and Maersk Supply Service - will P&A seven exploration and appraisal wells at the Banda and Tiouf fields offshore Mauritania for Tullow Oil. The fields are respectively 53 km (33 mi) and 84 km (52 mi) from the shore, in 1,200 m (3,937 ft) of water. Offshore execution, involving a drilling rig and two support vessels, should start early in 2021.

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Aker Energy has provisionally contracted Yinson Holdings Berhad to supply, operate and maintain an FPSO for the deepwater Pecan field development in Ghana's Deepwater Tano Cape Three Points block. This will be Yinson's second floater in Ghanaian waters following the *John Agyekum Kufuor*, which has operated for Eni since 2017.

◆◆◆

Keppel Shipyard has completed a fasttrack modification/upgrade program on the FPSO *Abigail-Joseph*. Yinson Nepeta Production commissioned the project, which included life extension work and installation/integration of topsides modules. The vessel, designed to process 50,000 b/d oil and to compress 34 MMcf/d of gas from connected wellhead platforms, will operate for First E&P at the Anyala-Mudu field in the shallow-water OML 83/85 license offshore Nigeria.

◆◆◆

Tower Resources has moved closer to drilling the NJOM-3 appraisal well in the Thali production-sharing contract off Cameroon, after agreeing to farm out a 24% interest to Brisbane-based OilLR. Tullow aims to start drilling in June followed by first production in 2021.

New Age has contracted TechnipFMC to undertake front-end engineering design (FEED) for the IM gas condensate field development in Cameroon's offshore Etinde permit. New Age, which will manage reservoir engineering and subsurface aspects of the FEED, plans an unmanned wellhead platform with pipelines connected to an onshore gas processing/export center.

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BW Energy has brought onstream the first two wells of the Tortue Phase 2 development in the Dussafu Marin permit offshore Gabon. Both are tied back to the FPSO *BW Adolo*; two more wells are due to be tied in ready for start-up by June.

◆◆◆

BP has awarded TechnipFMC an integrated EPCI (iEPCI) contract for the Platina field development in block 18 offshore Angola, in water depths of 1,200-1,500 m (3,937-4,921 ft). TechnipFMC will supply and install subsea trees, a production manifold, subsea controls, rigid steel pipelines, umbilicals and flexible jumpers, with some of the assembly/manufacture performed at the company's plants in Angola.

Eni's latest appraisal well on the Agogo oil discovery in Angolan block 15/06 suggests overall oil in place of around 1 Bbbl. The drillship *Libongos* drilled Agogo-3 in 1,700 m (5,577 ft) of water, 23 km (14.3 mi) from the block's West Hub FPSO *N'Goma*. Deviation of the well through a thick sub-salt sequence confirmed an oil-charged and connected reservoir.

MEDITERRANEAN SEA

In the Adriatic Sea off eastern Italy, Eni has extended its lease of Ocean Power Technologies' PB3 PowerBuoy by 18 months, following over a year of continuous operation for an offshore AUV charging pilot project. The PowerBuoy will be redeployed this summer to supply power to an unmanned, decommissioned gas production platform off the Abruzzo coast. This is part of a wider program that includes assessing life-extension methods for oil and gas platforms nearing the end of their productive lives.

◆◆◆

Energean has agreed to acquire Total's 50% operated interest in block 2 offshore western Greece. Work on the license to date has identified a large hydrocarbon-prospective structure analogous to the Vega field across the median line offshore Italy, operated by Energean's soon-to-be subsidiary Edison E&P. Hellenic Petroleum

is the other partner in block 2.

CASPIAN SEA

Azerbaijan International Operating Co. has contracted Worley to support production operations on the Chirag platform in the Azeri sector. Worley will manage a project to install new gas-lift flowlines and production manifolds.

MIDDLE EAST

McDermott has started construction of its new fabrication site at the King Salman International Complex for Maritime Industries and Services in Ras Al-Khair, Saudi Arabia. The 1.2-MM sq m (13-MM sq ft) facility with covered assembly shops will be capable of manufacturing platforms and modules for offshore and onshore projects for Saudi Aramco and others in the region, and will also feature a 580-m (1,903-ft) reinforced bulkhead providing marine access.

Schlumberger has opened a well completions manufacturing center at the King Salman Energy Park for production of equipment including liner hangers, packers, and isolation valves. The first-phase development extends over 105,000 sq m (1.13 MM sq ft).

◆◆◆

Saudi Aramco has contracted Nexans to supply and install 180 km (111 mi) of 230-kV submarine cables for the Marjan increment development project offshore Saudi Arabia. Nexans' factories in Halden and Rignan, Norway will respectively manufacture the composite power and fiber optical cables, with the company's new flagship vessel *Aurora* due to start installation in February 2022.

◆◆◆

Heerema Marine Contractors' *Aegir* vessel has installed the new living quarter platform for Qatargas' North Field Bravo expansion project offshore Qatar. The vessel collected the 1,000-metric ton (1,102-ton) jacket and the 3,000-metric ton (3,307-ton) topsides in two separate voyages to the N-KOM yard in Qatar, then performed the offshore lifts, all within a 10-day period.

The *Aegir* preparing to install the North Filed Bravo living quarters. *(Courtesy Heerema Marine Contractors)*

Rystad Energy expects investments in the North Field to exceed $50 billion, if Qatar is to meet its goal of expanding the associated liquefaction capacity by 49 MM metric tons (54 MM tons) to 126 MM metric tons annually (139 MM tons). The consultant recently predicted that approval for the project's first stage would be deferred until the first half of 2021.

ASIA/PACIFIC

Cambodia's first offshore oilfield development remains on track for start-up around mid-year, according to operator KrisEnergy. The production barge *Ingenium II* has been undergoing upgrades at two sites in Singapore, and construction is progressing on minimum facilities wellhead platform topsides and jacket at the PT Profab 1 yard on Batam Island, Indonesia.

◆◆◆

Fugro will acquire an extensive marine survey for INPEX Masela to support the Abadi LNG-related field development in the Masela block offshore Indonesia. Results from the geophysical/geotechnical program will inform the FEED for the offshore production facilities and subsea pipeline to the onshore LNG terminal. Seafloor challenges at the location are said to include slope stability, faulting and carbonate sediments.

◆◆◆

Jadestone Energy has decided to delay development of the Nam Du and U Minh gas fields offshore Vietnam, as part of a review of its 2020 capital program.

AUSTRALIA

ConocoPhillips has awarded the three outstanding subsea contracts for the Barossa gas/condensate project, 300 km (186 mi) north of Darwin in the offshore NT/RL5 petroleum permit. Aker Solutions and National Oilwell Varco will respectively supply the umbilicals and flexible risers, while Subsea 7 will transport and install the umbilicals and 36 km (22 mi) of infield flowlines in water depths of 230-270 m (754-886 ft). The development plan calls for an FPSO connected to six subsea production wells, infield facilities and a gas export pipeline tied into the Bayu-Undan pipeline system that supplied gas to the Darwin LNG complex.

Santos, which has agreed to acquire ConocoPhillips' operated interest in the Barossa joint venture, has also sanctioned phase two of its Van Gogh Infill Development in the Exmouth basin off Western Australia. This will entail the Valaris *MS1* drilling three horizontal/dual-lateral oil production wells (starting early next year) and a subsea tieback to existing infrastructure. The Van Gogh field is tied into the FPSO *Ningaloo Vision*.

◆◆◆

Esso Australia has started drilling two new subsea production wells for the West Barracouta gas field development in the Gippsland basin offshore Victoria. The company will control the subsea infrastructure from the Barracouta platform over 5 km (3 mi) distant: West Barracouta's gas will flow to the Longford onshore gas complex via a connection to the existing Barracouta pipeline.

Equinor's licenses offshore South Australia. *(Courtesy Equinor)*

◆◆◆

Equinor has dropped plans to drill the Stromlo-1 well in the Ceduna basin offshore South Australia, after concluding the project would not be competitive with other exploration opportunities in its global portfolio.

JEREMY BECKMAN
LONDON

SUBSEA TIEBACKS HIT COST TARGETS

Most new Norwegian offshore projects in recent years have come through close to budget, according to the Norwegian Petroleum Directorate. The NPD's review of 66 projects between 2007 and 2018 found that for just over 80%, costs ended up within or below the 20% uncertainty range cited in the plans for development and operation (PDOs). Cost control proved easier with subsea tiebacks, with 90% completed in line with or below the PDO estimate. Platform-based developments were less successful: while 70% were within the estimated cost range, others incurred cost overruns. Typically, project completion dates were around 3.5 months longer than planned, the report added, with delays generally greater for platform developments. On the plus side, the general shake-up of the industry since the previous oil price slump of 2014 brought improvements in supply chain resources and capacity.

OKEA has confirmed that the Yme redevelopment project in the Norwegian North Sea remains on schedule for first oil in the second half of 2020. The company said it was working with operator Repsol and the other partners to mitigate the impact that travel and other restrictions caused by the COVID-19 virus may have on the project.

PREMIER WINDS DOWN HUNTINGTON

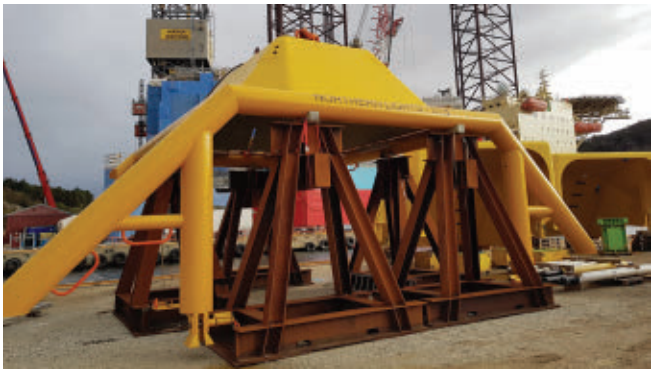
Premier Oil expected to lift the final cargo this month of oil from the Huntington field in the UK central North Sea, and has submitted a draft decommissioning plan for removal of the Sevan-designed circular FPSO. Since the company became operator in 2016 through acquiring the original developer, E. ON E&P UK, Premier has managed the reservoir to help defer cessation of production.

Last year the company also trialled Ocean Power Technologies' (OPT) PB3 PowerBuoy at the field. The equipment proved its ability to harness wave energy to power site monitoring systems designed to protect the subsea infrastructure following the departure of the FPSO. Premier said it would continue working with OPT and the Oil & Gas Technology Centre in Aberdeen to further develop the PowerBuoy for other decommissioning programs.

NORTHERN LIGHTS WELL CONFIRMS CO_2 GOALS

Equinor has completed three successful exploration/appraisal wells in the Norwegian North Sea for different purposes. The two wells drilled by the semisub *West Phoenix* 11 km (6.8 mi) southeast of the Gudrun field proved oil in the Sigrun East prospect - recoverable resources could be up to 17 MMboe. Both wells were a follow- up to appraisal drilling on the Sigrun discovery in 2018, with Equinor seeking to clarify to clarify the commerciality of the area.

The 31/5-7 Eos well south of the Troll field was drilled 2,500 m (8,202 ft) subsurface to assess the suitability of the reservoir in the Johansen formation for storing CO_2 (carbon dioxide) as part of the 'Northern Lights' project (co-supported by Shell and Total). Early analysis of the data was encouraging, according



Northern Lights template prior to installation in the North Sea. *(Courtesy Equinor)*

to Geir Tungesvik, Equinor's SVP for Project Development, with Eos proving the presence of a sealing shale layer and good-quality reservoir sandstone. This was the first well on exploitation license 001: an investment decision could follow this spring, and if the project progresses to a development, the well will be retained for injection and storage of CO_2.

OGA URGES LOWER CARBON STEP-UP

UK North Sea companies are playing their part in delivering a low-carbon future, said Andy Samuel, chief executive of the Oil & Gas Authority (OGA) at the recent IP Week 2020 conference in London. "I'm encouraged by what's happening in the North Sea, but I think we can go a lot quicker," he suggested. While the North Sea operators Samuel had consulted were "all doing something, none were top quartile," he said. "We have to level up performance throughout the industry, and that means finding out who is doing best on reducing flaring and the intensity of carbon emissions from production platforms, [offshore] electrification, and carbon capture storage."

The OGA's data shows the UK North Sea has cut its emissions by 13% since 2014, he continued. "But we also need to get after electrification of facilities west of Shetland and in the Outer Moray Firth." Samuel added that the UK offshore had abundant reservoirs and aquifers potentially suited to carbon capture and storage (CCS), and the OGA was tracking 61 potential sites in the North and East Irish Seas. "CCS is also an enabler for blue hydrogen…but let's get on with it."

JOG TO HEAD BUCHAN AREA STUDY

Various operators of discoveries in the Greater Buchan Area in the UK North Sea have agreed that Jersey Oil & Gas should lead a joint integrated studies agreement assessing the technical and commercial requirements for a collaborative development of the area, which holds proven oil and gas resources of over 200 MMboe. One goal is to determine whether collaboration could cut development costs for all concerned in a new production hub, potentially supported by electrification measures. The main fields in the Greater Buchan Area are Buchan, J2, Glenn, Verbier, Avalon, and Leverett.

BRUCE BEAUBOUEF
HOUSTON

Topsides and hulls work moves forward on Anchor, Whale

WHILE GLOBAL PANDEMICS and falling oil prices are taking the steam out of upstream capex, two Gulf of Mexico operators are moving forward with their deepwater development plans.

Chevron has contracted Wood to deliver engineering design for its Anchor deepwater development in the Gulf of Mexico.

The scope of the project included the preliminary front-end engineering and design (FEED), FEED, and now entails detailed design of Anchor, a wet tree development that will use a semisubmersible floating production unit (semi-FPU).

Anchor is the industry's first deepwater high-pressure development to achieve a final investment decision.

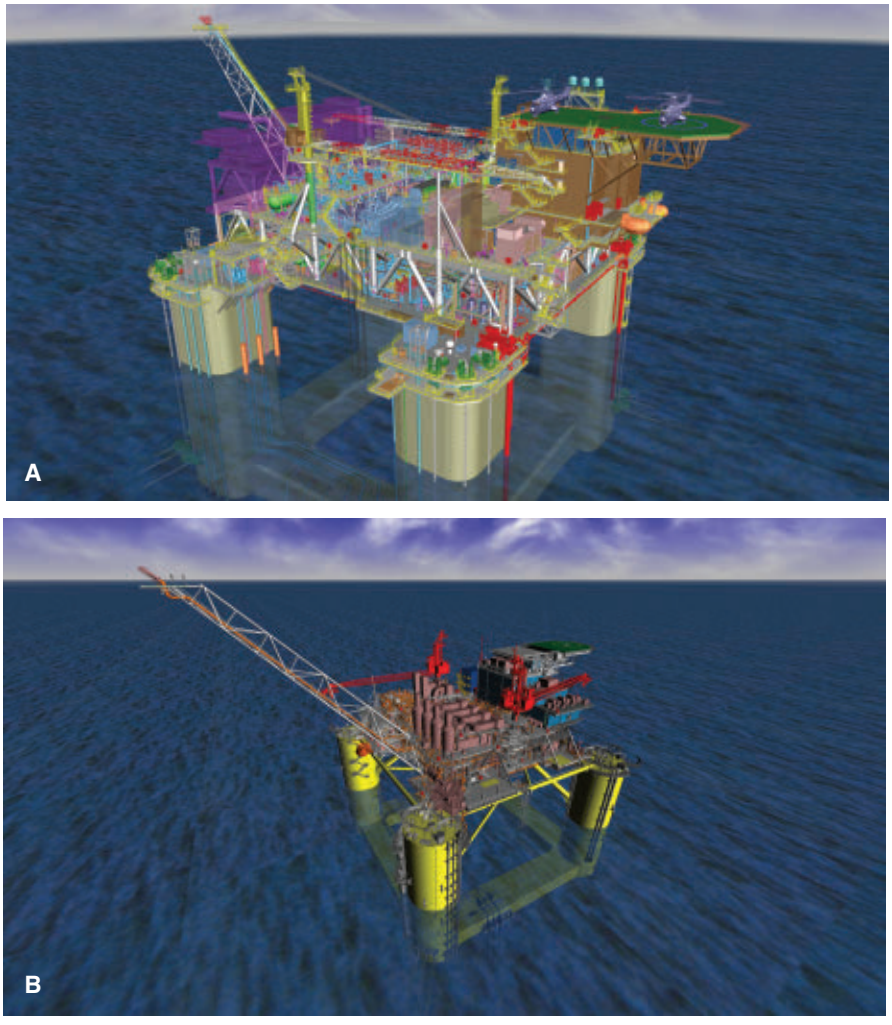
The project will be led by the company's engineering teams in Houston, with the contract awarded under an existing 10-year master services agreement with Chevron.

Under the scope of work, Wood is delivering a fully integrated design for the topsides and subsea system, incorporating risers, production flowlines, export pipelines, and flow assurance analysis.

KBR has been awarded the FEED contract for the semi hull; South Korea's Daewoo Shipbuilding & Marine Engineering (DSME) will build the semi hull; and US-based Kiewit will build the topsides.

OneSubsea, which signed a 20-year subsea equipment and services master contract with Chevron in July, has a contract to provide engineering and qualification for subsea equipment on the field.

The Anchor discovery is in Green Canyon block 807, located about 225 km (140 mi) offshore Louisiana in more than 1,500 m (4,921 ft) of water.



Chevron has contracted Wood to deliver detailed engineering design for its Anchor deepwater development, including a semisubmersible floating production unit (a) while Shell has contracted Sembcorp Marine Rigs & Floaters Pte. Ltd. to build and integrate the topsides and hull of an FPU for the Whale field. (b)

With an operating pressure of 20,000 psi, it is one of the first ultra-high-pressure projects in the world. The semi-FPU is expected to have a production capacity of 75,000 b/d of oil and 28 MMcf/d of gas, with the potential for future expansion.

Meanwhile, Shell has contracted Sembcorp Marine Rigs & Floaters Pte. Ltd. to build and integrate the topsides and hull of an FPU for the Whale field in the Gulf of Mexico.

The agreement precedes a final investment decision (FID) for the full Whale project, which is expected to be made next year by Shell. It paves the way for the Whale FPU

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to move ahead and take advantage of synergies from Shell's Vito FPU, currently under construction at Sembcorp Marine's Tuas Boulevard Yard. Shell has stated that Vito will apply a new, simplified host design and subsea infrastructure. In addition, the development assumes a break-even oil price below $35/bbl.

The Whale FPU comprises a topsides module and a four-column semisubmersible floating hull, with a combined weight of 25,000 metric tons. Slated for completion in 2022, it will operate in the Alaminos Canyon block 772.

Like the Vito FPU, the entire Whale FPU topsides will be integrated and commissioned on ground level at Tuas Boulevard Yard in order to minimize work-at-height risks for the workers, Sembcorp Marine said. The completed FPU topsides will then be raised and attached to a 51-m (167-ft) tall hull, using a pair of gantry cranes that can lift up to 30,000 metric tons.

The cranes will enable the company to integrate the topsides and hull in one lift, according to William Gu, Sembcorp Marine Head of Rigs & Floaters.

SUBSEA 7 TO ENGINEER MURPHY'S DEEPWATER GOM TIEBACKS

Murphy Exploration and Production Co.—USA has contracted Subsea 7 to provide the subsea installation services for the Samurai and Khaleesi/Mormont developments in the Green Canyon area of the Gulf of Mexico.

This contract covers the tieback of seven subsea wells to the King's Quay FPS that will be moored about 282 km (175 mi) south of New Orleans.

The project scope includes engineering, procurement, construction, installation, and commissioning of all subsea equipment including PLETs, PLEMs, umbilicals and distribution hardware, production and export flowlines and jumpers, as well as the wet tow in the Gulf of Mexico to the fields and mooring system installation of the semisubmersible FPS.

Project management and engineering will start immediately at its offices in Houston. Fabrication of the flowlines and risers will take place at the company's spoolbase in Ingleside, Texas, with offshore operations occurring in 2021.

Craig Broussard, vice president for Subsea 7 US, said: "Subsea 7 will provide a single point contract for the SURF and mooring work scopes on this project, which allows for improved management of the interface risk."

SHELL MULLS MARS CRUDE OIL PIPELINE EXPANSION

Shell Midstream Partners LP expects to take final investment decisions on expanding its Mars crude oil pipeline system in the Gulf of Mexico in the first half of the year, according to a Reuters report.

Shell has seen significant interest from oil producers as the 600,000 b/d system nears capacity, and the company is working toward finalizing agreements with them for additional capacity on the system, executives said in a conference call with analysts. "Our outlook, as always, on the Gulf of Mexico remains bullish," said Chief Executive Kevin Nichols. Production in the area has grown 9% year-over-year, and is up over 57% since 2014, Nichols added.

The company does not want to comment on the specifics of expected added capacity or what it would spend on the project on the Mars corridor, a 260-km (163-mi) crude oil pipeline originating approximately 209 km (130 mi) offshore in the Gulf of Mexico. It transports crude from the Mississippi Canyon-area to Clovelly, Louisiana.

"When we get to the point of definitive agreements and bringing it online, which is estimated around mid-2021, we'll give guidance in customary fashion at that point," said Steven Ledbetter, vice president of commercial for Shell Midstream.

Shell also said Amberjack Pipeline Co. has signed a dedication and connection agreement with Chevron's Anchor project, which is expected to produce oil in 2024. The project is expected to open up 75,000 b/d of crude oil production, which will be transported on the Amberjack pipeline. Amberjack Pipeline Co. is a joint venture between Shell Midstream Partners and Chevron Pipe Line Co.

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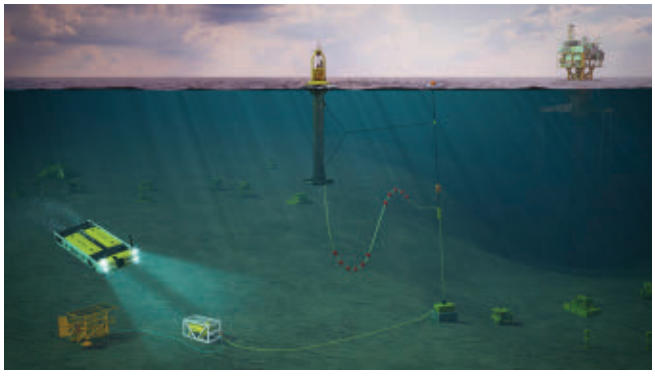
TRIO ADVANCING AUV RESIDENCY

Ocean Power Technologies Inc. (OPT), Modus Seabed Intervention, and Saab Seaeye are developing a solution for carbon-free subsea autonomous underwater vehicle (AUV) residency. This system is designed for autonomous offshore operations with the OPT PowerBuoy power and communications platform at its core. Via an integrated mooring and subsea power/data transmission cable, a PowerBuoy can provide carbon-free power to a seabed docking station to recharge an AUV while enabling secure data transmission to and from shore-based operations anywhere in the world.



The PB3 PowerBuoy wave energy converter is pictured with single point mooring integrating power and data transmission connected to a subsea battery solution and AUV charging station. *(Courtesy Ocean Power Technologies)*

The autonomous resident AUV system concept has been jointly submitted for US government development and demonstration project funding consideration.

George Kirby, OPT president and CEO, said: "We believe a self-contained system powered by an OPT PowerBuoy and exempt from existing ocean infrastructure has the potential to revolutionize the industrial use of AUVs and make long-term residency a cost-effective reality.

"Modus Seabed Intervention's experience with advanced technology development efforts in subsea docking with Saab Seaeye's market-leading hybrid AUV [HAUV] enables autonomous offshore operations and we believe it is a natural fit for our environmentally sound PowerBuoy ocean power and communications technology."

The ongoing electrification of offshore applications finds underwater vehicles increasingly used for defense and security surveillance, as well as for seafloor mapping and asset maintenance in oil and gas. Increasing the length and variety of missions an AUV can undertake can lower costs and risks, and true autonomous control with access to data in real time is a goal for operators, the company said.

An autonomously powered interactive docking station independent of traditional infrastructure offers efficiency in routine operations and facilitates timely response to ad hoc events (extreme weather, subsea equipment failure) more rapidly than possible with surface-based vessels.

In addition, Eni has extended its lease of OPT's PB3 PowerBuoy for an additional 18 months.

Following more than one year of continuous maintenance-free operation as part of an AUV charging pilot project offshore Italy in the Adriatic Sea, the leased PB3 PowerBuoy will be redeployed to provide power to systems on an unmanned, decommissioned gas production platform.

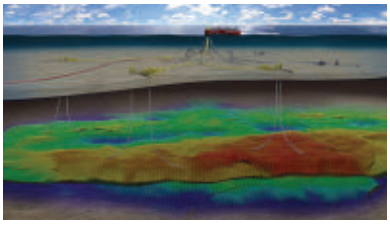
The offshore platform conversion project is exploring the potential of future ecologically sustainable life-extension strategies for oil and gas platforms at the end of their productive phase. The project will assess the value of the platform to the ecosystem if left in place, as well as the viability of integrated aquaculture farming, recreational, and other uses.

The system will be relocated off Italy's Abruzzo region coastline in July 2020.

Deployed in December 2018, the PB3 PowerBuoy has demonstrated its capability as a charging and communications platform to enable the long-term remote operation of Eni's Clean Sea AUV, the company said. Since being deployed it has produced more than two megawatt hours of electricity.

BAROSSA SUBSEA CONTRACTS AWARDED

ConocoPhillips has awarded the main outstanding contracts for the subsea infrastructure for the Barossa project off northern Australia. According to partner Santos, these are the last major facilities commitments ahead of a final investment decision, expected in 2Q 2020.



The Barossa gas project will be developed via an FPSO, six subsea production wells, in-field facilities and a gas export pipeline. *(Courtesy ConocoPhillips)*

Subsea 7 will transport, install and pre-commission 36 km (22 mi) of in-field flowlines, along with the subsea umbilicals and risers, in water depths of 230-270 m (754-886 ft). The company expects to execute the offshore campaign during 2022-23, using various reel-lay and heavy construction vessels.

Aker Solutions will provide the umbilicals and National Oilwell Varco Denmark the flexible risers.

Barossa will be developed via an FPSO, six subsea production wells, in-field facilities and a gas export pipeline tied into the Bayu-Undan to Darwin pipeline system that supplies gas to Darwin LNG.

Santos holds a 25% interest in the Barossa joint venture along with partners ConocoPhillips (37.5% and operator) and SK E&S (37.5%). Santos is also a joint venture partner in Darwin LNG with an 11.5% interest. Last October, Santos agreed to acquire ConocoPhillips' Northern Australia and Timor-Leste portfolio including its interests in Darwin LNG, Bayu-Undan and Barossa.

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COVID-19 TO DELAY MOST FPSO DELIVERIES

Out of a global total of 28 FPSO vessels that are under construction, 22 are being built at shipyards in China, South Korea, and Singapore. Rystad Energy expects the outbreak of COVID-19 to cause extensive staffing and supply shortages in these countries that will in turn delay project deliveries by at least three to six months.

If the pandemic escalates, the delays could increase to nine or even 12 months, especially considering the restricted time windows for heavy transport, installation, and hook-up, the consultant said. The average development time for an FPSO is 36 months, meaning that companies could face a 30% delay.

Audun Martinsen, Rystad Energy Partner and Head of Oilfield Service Research, said: "Although operators and contractors are looking into ways to make up for some of the time that will be lost by fasttracking other stages of development, we anticipate first oil or gas for these projects will face clear delays."

At present, 28 FPSOs are under development globally, 15 of which are being built in China. Seven are under construction in COVID-19 hotspot South Korea as well as in Singapore, while six additional vessels are being constructed elsewhere.

Many Chinese workers received a holiday extension in early February after the Chinese New Year, aimed at limiting the spread of the coronavirus. However, even as workers return to the yards, Rystad expects projects may still have to contend with 30% to 50% fewer work hours.

Construction progress may also be slowed by supply delays, as the delivery of bulk materials, modules, and equipment is hampered by transportation restrictions both within and outside of mainland China. According to the consultant, the plant utilization rate in China's equipment manufacturing sector has fallen to less than 10%.

In addition, project management will face severe issues as travel bans restrict contractors, engineering firms, certification companies, and E&P officials from accessing shipyards.

Experts do not yet know when the effects of the pandemic will ease, but one thing remains clear: the virus is not limited to Chinese fabrication yards – it affects the entire global service industry.

As the virus has caused reduced industrial activity and travel restrictions in China and beyond, much of this year's global expected oil-demand growth will be lost, according to Rystad.

Lower oil prices have resulted in oil and gas companies scaling down their flexible investment budgets, especially shale operators in the US as well as some offshore exploration and production players.

"Our current assessment forecasts that COVID-19 could result in global E&P investments falling by around $30 billion in 2020 – a significant hit to the industry," Martinsen concluded.

ANYALA-MADU FPSO SETS SAIL FOR NIGERIA

Keppel Shipyard has delivered what it claims is the world's fastest brownfield FPSO modification and upgrading project safely and on time. The FPSO *Abigail-Joseph* was delivered to Yinson Nepeta Production Ltd., a wholly-owned subsidiary of Yinson Holdings Berhad.

The FPSO *Abigail-Joseph* was delivered in less than seven months. *(Courtesy Keppel Corp.)*

The project was delivered in less than seven months, according to Chris Ong, CEO of Keppel Offshore & Marine.

Keppel's scope included refurbishment and life extension work, engineering and procurement, fabrication and installation of new structures including the helideck and riser balcony, as well as the installation, integration, and completion of topsides modules.

Chartered by First Exploration and Petroleum Development Co. Ltd. on a firm seven-year contract with options to extend, the FPSO will be deployed at the Anyala-Madu field in OML 83/85 offshore Nigeria.

The FPSO *Abigail-Joseph* has a processing capacity of 50,000 b/d of oil and 60,000 b/d of liquid. It also has a gas compression capacity of 34 MMscf/d and a storage capacity of not less than 550,000 bbl of oil. It is designed for 15 years of operations without dry docking.

LANKHORST ROPES TO MOOR SECOND LIZA FPSO

SBM Offshore has contracted Lankhorst Offshore to supply the deepwater mooring lines for the FPSO Liza Unity for ExxonMobil's Liza Phase 2 oil field development offshore Guyana.

Twenty Cabral 512 deepwater mooring lines will be used for the FPSO *Liza Unity* offshore Guyana. *(Courtesy SBM Offshore)*

The FPSO Liza Unity will be spread moored at a water depth of 1,600 m (5,249 ft) with 20 Cabral 512 deepwater mooring lines with a minimum breaking strength of 12,300 kN. Each mooring line measures 2,320 m (7,612 ft) in length. When deployed the mooring line will comprise a chain top segment, polyester rope middle segment and chain bottom segment, connected to a suction pile anchor.

According to Lankhorst, the ABS class approved Cabral 512 rope construction features a specially designed filter, preventing ingress of sand while the mooring lines are pre-laid on the seabed ahead of the FPSO arriving on station.

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Drillers taking a pause to assess impact of pandemic, price shock

A NUMBER OF OFFSHORE OPERATORS and drilling contractors are pausing their campaigns to assess the impact of falling oil prices, and to addressing staffing issues related to concerns about the growing coronavirus pandemic.

Since the week of March 9, more than one-third of the companies covered by Wood Mackenzie have cut their capex by 30%. Further cuts will be needed if low prices continue, the consultant says.

"Balancing the books at $30/bbl in 2020 is possible for many companies. But tough decisions would be required," says analyst Roy Martin. "Over $75 billion in 2020 discretionary E&D capex and $80 billion of shareholder distributions [could] be cut – breaking a few promises to investors."

Evercore ISI recently reported on Maersk Drilling's reactions to market changes. With regard to the pandemic, Maersk is working through various day-to-day logistics and other challenges on its drilling rigs. Government guidelines are changing quickly, but the company benefits from a high degree of local content and quickly established various barriers on its rigs to reduce risk. For example, Maersk extensively reviews crew movements, and has implemented fewer rotations to reduce the risk of infection. The company had a few suspected cases but none were positive.

With the collapse in the oil price, operators are taking a deep breath, reviewing their portfolios, and re-prioritizing their projects in the new oil price paradigm. It is still early days, Maersk officials say that they expect their customers to put some opportunities on hold, to reduce costs. A few select projects that have progressed far may still be possible, but more and more projects are likely to be put on hold as the standoff drags on.

By mid-March, operators were already putting on the brakes in a number of regions throughout the world.

Shelf Drilling said that a contract for the jackup *Shelf Drilling Tenacious* will terminate early in September, 16 months ahead of the originally scheduled date, under a mutually agreed arrangement with Dubai Petroleum. The contract started in the Middle East in early 2018.

Oryx Petroleum has postponed a planned exploration well this year in the AGC Central license area offshore northwest Africa. Last year the company had requested an extension of the first renewal period of its production-sharing contract (due to end on Oct. 1, 2020) due to negotiations between Senegal and Guinea Bissau on the accord for their jointly-administered AGC area. Oryx said it expected the amendment to be finalized in the next few months. Due to the deferment of drilling, the company has cut its budget for activities on the license this year by $3 million.

MOL Norge has discovered oil and gas in the central Norwegian North Sea. The semisubmersible *Deepsea Bergen* drilled the Evra/Iving well on production license 820S, 8 km (5 mi) northwest of the Balder and Ringhorne fields and around 200 km (124 mi) west of Stavanger. *(Courtesy Lundin Petroleum)*

Panoro Energy reported that it would cut its planned capex offshore Gabon this year by 40% to soften the impact of the recent oil price collapse.

The Dussafu joint venture, led by BW Energy, has decided to temporarily postpone the start of the Ruche Phase 1 development process until conditions improve.

Currently four wells (DTM-2H, DTM-3H, DTM-4H and DTM-5H) are producing into the FPSO *BW Adolo* at a gross rate of 20,000 b/d. The DTM-6H well, approaching the end of drilling and completion operations, will come onstream by June.

In an attempt to limit the spread of the COVID-19 virus, international travel restrictions currently in place are limiting movements of essential personnel, subcontractors, and equipment to and from Gabon.

These and the increasing global restrictions will likely impact the planned timing of the DTM-7H well and the subsequent firm exploration well. As a precaution, the Dussafu partners have decided not to exercise options for additional exploration wells.

EnQuest said that it has been reassessing its North Sea assets and related spending plans in light of the current lower oil price. It now looks as if production will not re-start at the mature Heather and Thistle/Deveron fields in the UK northern North Sea, which collectively generated about 6,000 boe/d last year.

TOTAL TAKES MAJOR STAKE IN OFFSHORE WALES FLOATING WIND PROJECT

Total has signed an agreement with developer Simply Blue Energy to acquire an 80% stake in the floating wind project Erebus in the Celtic Sea, offshore Wales.

The facility, which will be installed in a water depth of 70 m (230 ft), will have a 96-MW capacity.

The WindFloat floating foundation for offshore wind turbines is said to cut environmental risk and cost. *(Courtesy Simply Blue Energy)*

Total said the UK was the world's largest offshore wind market, and that although most developments to date have been in shallow waters, based on fixed bottom technology, floating wind offshore appears set for strong growth.

This technology has the potential to open access to locations farther offshore, which have less impact on the landscape, as well as stronger wind resources.

According to Simply Blue, the WindFloat floating foundation for offshore wind turbines cuts environmental risk and cost. This is due to its relatively simple assembly and installation requirements, with all heavy lifting operations performed in a protected environment on dry land (i.e. at the port) using onshore cranes and transportation methods such as tugboats, instead of more costly offshore installation vessels.

"Total has the appropriate skills to meet the technological and financial requirements that determine the success of future floating offshore developments," said Patrick Pouyanné, chairman and CEO.

SIEMENS GAMESA TO PROVIDE TURBINES FOR TWO GERMAN OFFSHORE WIND FARMS

Ørsted has conditionally named Siemens Gamesa Renewable Energy as the preferred turbine supplier for two offshore wind power projects in the German North Sea.

At both the 900-MW Borkum Riffgrund 3 and the 242-MW Gode Wind 3 sites, Siemens Gamesa will deploy its new SG 11.0-200 DD offshore wind turbine. A five-year service and maintenance agreement is included in the preferred supplier award.

The SG 11.0-200 DD offshore wind turbine features a 200-m (656-ft) diameter rotor using the 97-m (318-ft) long Siemens Gamesa B97 IntegralBlade.

The award is subject to certain conditions including Ørsted's final investment decision, which itself is subject to the projects receiving final grid dates and final consents from German authorities.

The Borkum Riffgrund 3 project will be the largest offshore project in Germany to date, according to Ørsted.

The final number of turbines for both projects remains to be determined. Ørsted expects the installation of Gode Wind 3 to begin in 2023, with commissioning being completed in 2024. The installation of Borkum Riffgrund 3 is expected to begin 2024, with commissioning being completed in 2025.

MORAY EAST PILES INSTALLED

DEME Offshore has completed foundation piling operations at the Moray East offshore wind farm in the UK.

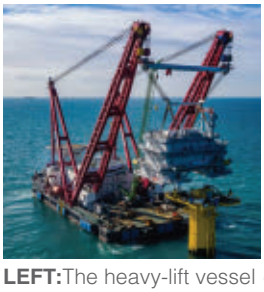
The company's installation vessel ***Apollo*** installed 309 piles in what was said to be a complex and varied seabed geology.

The company developed a piling template that was designed to integrate with the jackup legs of the ***Apollo***. It also developed an underwater drilling tool to cope with hard and rocky layers and relief drilling to install the piles in these challenging conditions.

As part of the second stage of offshore works, the company's newbuild installation vessel ***Orion*** will integrate 103 jacket foundation structures and three topside modules.

SEAMADE SUBSTATIONS INSTALLED OFFSHORE BELGIUM

Scaldis' heavy-lift vessel ***Gulliver*** has installed the two 1,200-metric ton (1,323-ton) substations for the SeaMade offshore wind farm in the Belgian North Sea.



LEFT: The heavy-lift vessel *Gulliver* installing one of two substations for the SeaMade offshore wind farm in the Belgium North Sea. **RIGHT:** One of two 1,200-metric ton substations for the SeaMade offshore wind farm. *(Courtesy DEME)*

The substations transform the wind energy that is produced to 225 kV, which in turn allows the electricity to be brought to shore via Elia's Modular Offshore Grid. DEME's cable installation vessel ***Living Stone*** installed the export cable which transmits the electricity to shore.

ABB TO POWER JAPAN'S FIRST SUPER-SIZE WIND TURBINE INSTALLATION VESSEL

Japan Marine United Corp. has contracted ABB to provide power and control technologies for the wind turbine installation vessel it is building for Shimizu Corp. This is the first self-elevating wind turbine installation vessel built in Japan.

ABB will deliver a closed ring configuration for the vessel's DP operations, as well as delivery and system integration of generators, high voltage switchboard system, the variable speed drives and motors for main propulsion and bow thrusters, and the power and energy management system. The 28,000-gross tonnage vessel is expected to be delivered in 2022.

Offshore industry braces for rough year ahead

Wind energy, decommissioning markets may offer some refuge

MATTHEW FITZSIMMONS, EMIL VARRE SANDOY, *RYSTAD ENERGY*

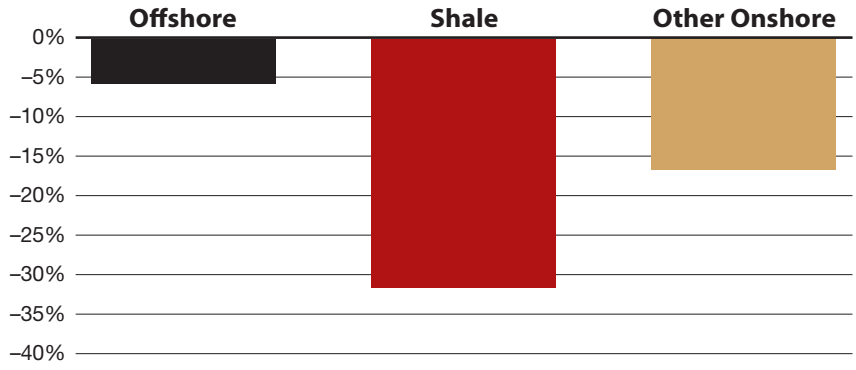
OFFSHORE EXPLORATION and production (E&P) investments have declined year by year since the oil price crash in 2014, as operators both scaled down activity and focused on cutting cost to make projects robust and commercial in the new price environment. The year 2018 marked a new low point, with offshore investments falling to $150 billion, down 55% from the previous peak in 2014. However, both oil prices and E&P companies' revenues recovered significantly during 2018. Paired with the low activity and cost levels, the upstream industry made more money when Brent oil prices hovered around $70/bbl than they did amidst $110/bbl prior to the late 2014 crash. In fact, E&P enjoyed all-time high free cash flow in 2018.

With the operators flushed with cash and given a positive market sentiment, Rystad Energy was early to predict a new offshore investment cycle starting in 2019 with increasing investments levels. Now that 2019 is history, we can conclude that the beginning of the foreseen rebound in offshore investments indeed materialized, as greenfield commitments grew by more than $30 billion. This marked a long-awaited turning point for many players in a market that endured very challenging conditions over several years.

Entering this year, Rystad Energy expected the rebound to continue and even to gain momentum in 2020, estimating capital investments to grow by 9.2% year-on-year to $165 billion. However, the picture changed completely during the first quarter of the year, as the market was hit by two significant shocks. Firstly, the Covid-19 virus broke out in China, before spreading to other countries in all corners of the world, evolving into a pandemic. This took a severe toll on the global economy, with an immediate negative impact on oil and gas demand. Secondly, the OPEC+ group failed to reach an agreement on further production cuts, triggering a breakdown of the collaboration and leading several members to increase production in a bid to compete for market share. Practically overnight, the market was awash with oil and a huge supply shock was inevitable. Brent crude prices collapsed from around $60/bbl to the low $30s, spawning vast uncertainty regarding future prospects.

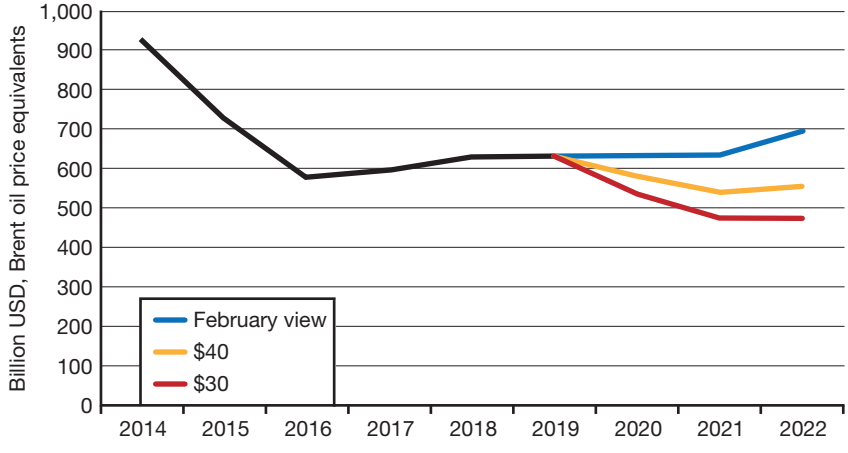
With these new market conditions, Rystad Energy now expects a fairly flat

REDUCTION IN 2020 INVESTMENTS AFTER COVID-19 AND OIL PRICE DROP IMPACTS



Source: Rystad Energy ServiceCube, March 2019

YEARLY OILFIELD SERVICE PURCHASES BY BRENT OIL PRICE SCENARIO



Source: Rystad Energy ServiceCube, March 2020

development in offshore investments in 2020 at $153 billion, growing by only 1.0% compared to 2019 levels, as companies will scale back activity and delay projects in response to the ongoing challenges. Investment levels this year are expected to remain relatively high as a large portion of the spending is related to ongoing and already sanctioned projects, so the sensitivity to recent market developments is quite low. However, the slowdown is expected to really make its mark next year, as Rystad Energy now forecasts offshore investments to decline significantly by 10.0% compared to 2020, driven by project delays.

HIGH UNCERTAINTY REGARDING THE NEAR-TERM FUTURE

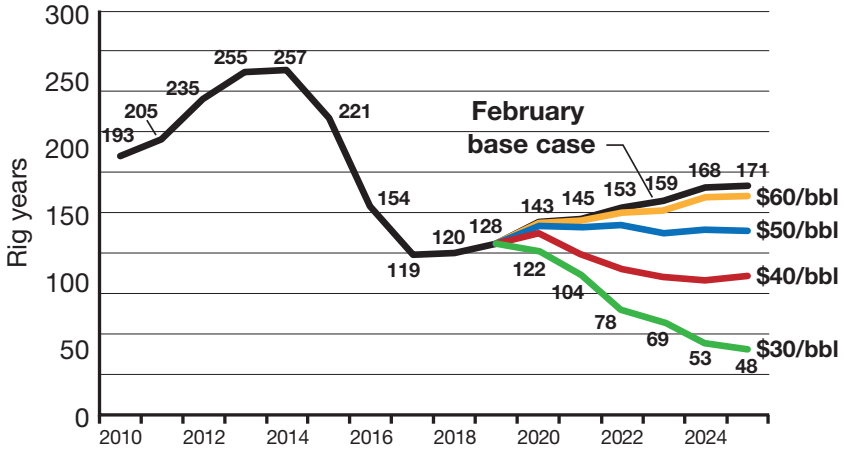
High uncertainty is the most significant characteristic of the prevailing situation in the upstream industry. Rystad Energy's current forecast is based on an average Brent oil price of $40/bbl in 2020 and $53/bbl in 2021, assuming both that OPEC manages to reach a new agreement on production cuts by mid-2020 and that the Covid-19 virus outbreak is brought under control during the course of the year. Under such a scenario, oil supply would be reduced and global demand would start a slow recovery, resulting in rising oil prices from the second half of 2020 and through 2021.

However, the volatility in the market is currently so high that revisions of the base case assumptions are to be expected. Market conditions could develop in either direction compared to the Rystad Energy base case, but the downside risk currently seems to be greater than the upside.

OIL PRICE SLUMP PUTS FLOATER DEMAND AT RISK

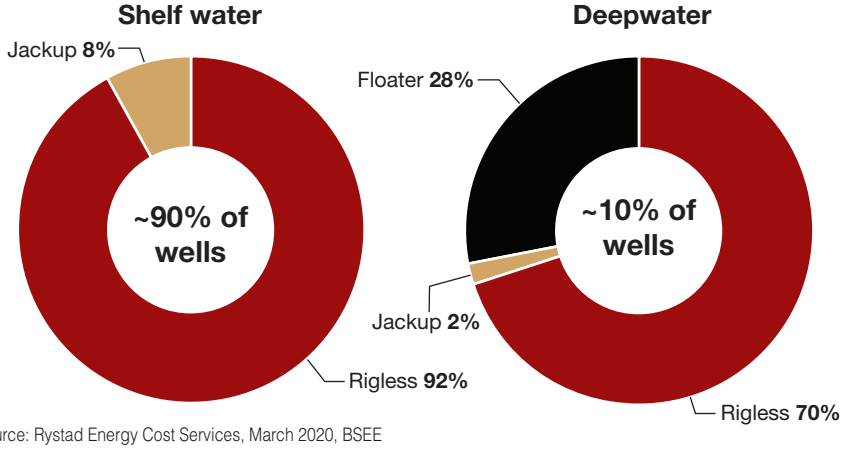
Before oil prices collapsed in March, Rystad Energy forecasted that global demand for floating drilling rigs would grow by 12% this year, to 143 rig-years, versus 128 rig-years in 2019. If the oil price were to average $40/bbl this year, demand could slide to 135 rig-years – still representing a 5% improvement over 2019 – whereas an average of $30/bbl would likely cut 2020 rig demand by 5% to 122 rig-years. This means that as much as 15% of the intra-year demand for floaters is at risk. This would be on par with the decline of 14% that the market experienced in 2015, although that drop was from much higher initial activity levels and amidst cost structures and project portfolios that had not been scrutinized as we have seen in recent years since the previous downturn. Given these differing circumstances, we believe that the current project portfolio on the E&P side is more competitive than it was five years ago – which means the rig market is more robust now than during the previous downturn.

FLOATER RIG DEMAND SCENARIOS BY OIL PRICE



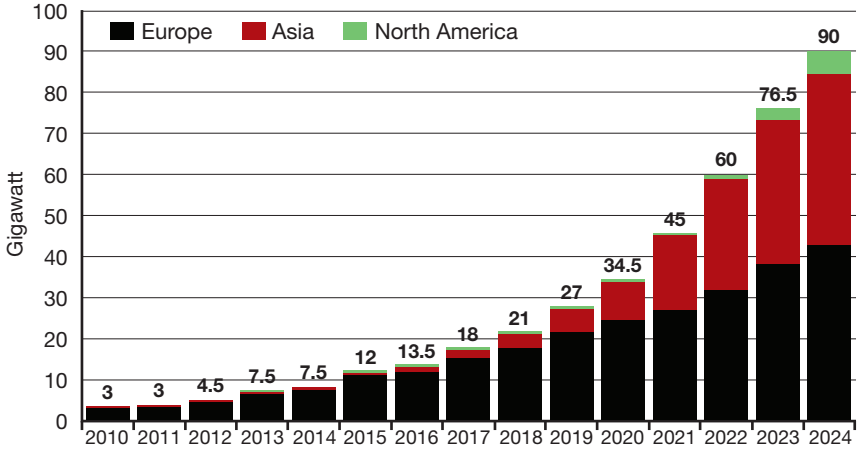
Source: Rystad Energy ServiceCube, March 2020

WELL P&A METHOD BY WATER DEPTH IN GULF OF MEXICO



Source: Rystad Energy Cost Services, March 2020, BSEE

OFFSHORE WIND INSTALLED BASE EXTENDS FROM EUROPE TO ASIA - NORTH AMERICA NEXT



Source: Rystad Energy WindCube, March 2020

By evaluating the type of drilling programs that lie behind the overall floating rig demand forecasts for 2020, Rystad Energy anticipates that 24 rig-years are at risk in the exploration drilling segment and another eight rig-years are at risk within development drilling in light of the ongoing oil price crash. It is possible that all final investment decisions on new projects that had been anticipated this year could be cancelled or delayed. Although most of these projects have very low breakeven levels, operators will be much more cautious about moving ahead with additional sanctioning activity this year given the heightened market uncertainty. Exploration will probably be cut back as operators seek to reduce risk and save cash in the current environment. Exploration carries a double risk – there is no guarantee of success, and even if new discoveries are made, they may not be commercially viable in a world of oversupply. This makes exploration the top target for oil companies looking to cut costs and minimize risk.

OPPORTUNITIES EMERGE FOR DECOMMISSIONING PROSPECTS

While lower oil prices will spell work reductions for most sectors, the decommissioning market could see an uptick of activity. Looking at the maturity of producing fields in the main offshore regions, the Gulf of Mexico and Northwest Europe display the largest percentage fields nearing the end of their production lives, followed by Southeast Asia and South America. While the decommissioning markets in the Gulf of Mexico and Northwest Europe are already consolidated due to the numerous decommissioning projects already in place, South America and Southeast Asia may not be prepared to face the boom in decommissioning activity in coming years due to a lack of regulation and experience.

Across offshore decommissioning expenses, well plugging and abandonment (P&A) represent the biggest cost for operators, with over 45% of decommissioning work focused on well abandonment. In the Gulf of Mexico, most P&A activity is done with rigless equipment as this saves up to 50% in costs. In addition to vessel rates being significantly lower than rig rates, the set-up time for a rigless P&A spread is also much shorter, with an average of four to eight hours, whereas a rig can take 72 to 96 hours to get ready to work. In addition, the rigless approach allows for simultaneous operations on multiple wells, generally two to four wells at one time. However, rigs are still needed in some situations, for instance to handle complicated wells. During the past 10 years, about 90% of P&A operations in the Gulf of Mexico have been done rigless, leaving only 8% of the wells for the jackup market. Looking solely at P&A work on deepwater wells, on the other hand, drilling units are required in 30% of the cases.

SUPPLIERS COULD SEEK REFUGE IN OFFSHORE WIND

Offshore wind farms are being erected with increasing speed, which in turn with drive the growth of the global market for wind turbine operations and maintenance (O&M). As offshore wind turbines age and experience wear and tear, they are bound to generate demand for repairs and maintenance services. This will unlock opportunities for oilfield service companies to leverage their offshore expertise by entering this market.

Following on the heels of Europe and Asia, North America is poised to be the next hotspot to drive demand for O&M services within offshore wind. The region has set ambitious targets and is expected to develop its offshore wind capacity potential to beyond 5 gigawatts by 2024. While the offshore wind supply chain in the US is still immature, it will not be so for long. Global offshore wind operator Orsted, for instance, has secured funding to open training centers in the US in a bid to establish a workforce trained in operating and maintaining offshore wind projects.

The offshore wind O&M market presents a golden opportunity for maintenance focused companies within oilfield and marine services. These companies must consider the best use of their own capabilities and develop sector-focused solutions to capitalize on an offshore wind market that is set to grow exponentially.

Asia/Pacific lowers offshore expectations in new era of uncertainty

Gas projects, frontier wells at risk of deferment

JEREMY BECKMAN, *EDITOR, EUROPE*

GROWING OPTIMISM across Asia/Pacific's offshore sector was swiftly flattened by last month's turn of events. There were no immediate reports of project casualties, but as elsewhere, major new investments in greenfield developments involving gas or LNG look set to be pushed back as companies take urgent actions to preserve their balance sheets.

A resurgence in exploration drilling led to the region delivering five of the world's top 20 discoveries last year, according to Wood Mackenzie, including PTTEP's HP/HT Lang Lebah gas find in shallow water off Sarawak. The consultant's APAC team had expected around 200 exploratory wells throughout the region this year, but numbers could now drop by up to 30%, Asia Pacific Vice Chair Gavin Thompson predicted.

Most explorers would likely delay planned campaigns with no rig commitment, or if the well economics at $35/bbl failed to meet company thresholds. This would knock up to $1 billion off the previously anticipated exploration spending this year of $4.5 billion. Thompson added that only around 16% of future APAC prospects breakeven below $35/bbl, and most of those are smaller, near-field structures.

Prior to the oil price slump, Wood Mackenzie had singled out as wells to watch Total/Woodside's Shwe Nadi, targeting gas in Myanmar's deepwater Moattama basin; Eni's Dan-Day-1X in Vietnam's Song Hong basin; Repsol's Remcong-1X in deepwater in Indonesia's North Sumatra basin; BP's Ironbark, a potentially large gas structure in Australia's North Carnarvon basin; and OMI's pursuit of oil with the deepwater Tawhiki-1 well in New Zealand's Great South basin. One well that has gone ahead is CNOOC's recent play-opening Kenli-6-1 offshore China, thought to be the first oil discovery in the Laibei lower uplift region of the shallow water southern Bohai basin.

PFLNG DUA. (Courtesy Petronas)

Across Asia/Pacific, nearly $35 billion of pre-final investment decision (FID) and development expenditure now appears to be at risk for 2020-2022, Thompson said, with spending on producing field facilities likely also under scrutiny. Two of the largest projects targeting FID this year are backfill LNG investments offshore northern and western Australia: in Wood Mackenzie's calculations, Barossa (operated by Santos) and Scarborough (Woodside) account for 52% of APAC's unsanctioned project spending and 48% of reserves.

Before the oil price crash, both companies had been seeking to farm down equity to reduce their capex commitments, with Santos agreeing to sell a 25% interest in the existing Bayu-Undan field development in the Timor Sea and the Darwin LNG complex to South Korea's SK E&S for $390 million. Santos' goal is to achieve increased partner alignment for Barossa and Darwin LNG, which would receive the field's production.

The impact of recent developments on Asia/Pacific's existing upstream supply could be softer: Thompson singled out China as the key market, a country which produces 3.7 MMb/d, representing more than 60% of the 6 MMb/d produced throughout the region. In his view, China's output remains safe for now, although more capex will be needed to sustain development drilling on various mature field projects.

Thompson expected most other Asian NOCs to follow China's lead, not altering their spending plans for 2020 despite lower prices as their governments typically rely on these enterprises for their tax revenues, employment and energy import decisions. But while Petronas and India's ONGC have reportedly confirmed that they will not change direction this year, PTTEP may face greater challenges in its transition to operatorship of the Erawan gas field offshore Thailand, Thompson said.

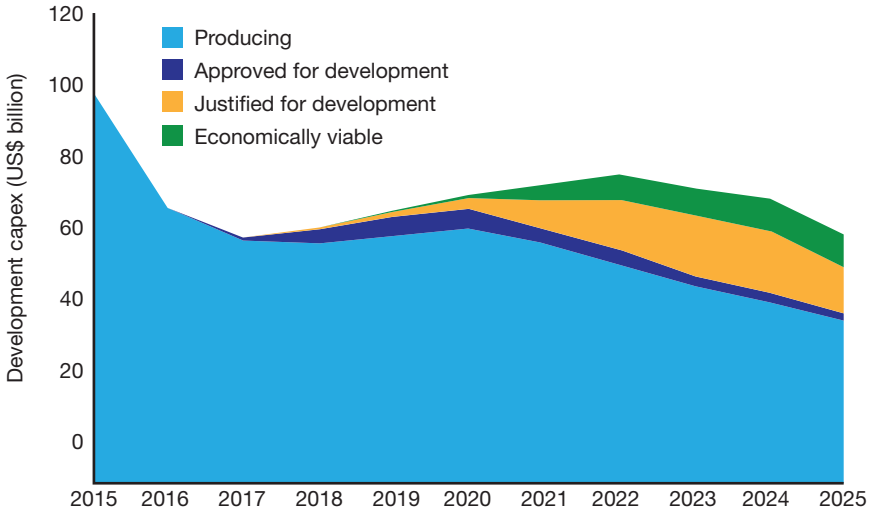
Earlier this year Petronas' second floating LNG facility *PFLNG DUA* departed the Samsung Heavy Industries shipyard in South Korea. The 393-m (1,289-ft) long vessel

ASIA/PACIFIC

Reserves	
Remaining Reserves (Million bbl)	91047
Production	
Current Production levels	4252
Liquids (kbbl/d)	1371
Gas (kbbl/d)	2881
Production platforms	
# Producing fields Total	467
# Tie backs	36
# Floating production	43
# Fixed production	388
Drilling Rigs	
# Floaters Demand 2019	9
# Jackups Demand 2019	32
Infrastrcture	
# Active Wells	11738
# Active XMTs	202
# Installed XMTs (2019)	21
Active SURF lines (km)	5714
Field sanctioning 2019-2021	
# Fields to be sanctioned	63
Subsea tie back	14
Floater	12
Fixed	37
Oilfield Service Purchases 2019 (MUSD)	
Maintenance and Operations	7906
Well Services and Commodities	2952
Drilling Contractors	2443
Subsea	1299
EPCI	4016
Seismic	628

Source: Rystad Energy UCube, DCube, WellCube

CLOSE TO $35 BILLION OF SPEND AT RISK IN 2020-2022



Source: Wood Mackenzie Lens

was due to be moored in 1,300 m (4,265 ft) of water at the Rotan gas field, 140 km (87 mi) offshore Kota Kinabalu, Sabah, with capacity to produce 1.5 MM metric tons/yr (1.65 MM tons) of LNG.

Thompson said sustained lower oil prices would bring down LNG contract prices in Asia, thereby boosting the case for gas. But the opposite might happen in India, where the lower oil price could slow the shift from oil to gas in the nation's industrial sector, as heating oil, LPG and naphtha compete with contracted and spot LNG.

A report by Rystad Energy earlier predicted that Indonesia's oil and gas production would probably fall this year, despite the government's projections of a combined 8% increase. Indonesia's upstream task force SKK Migas was targeting oil production of 755,000 b/d in 2020, while Rystad was predicting 718,000 b/d, due mainly to a decline in output from mature assets, partly offset by projects in the ramp-up phase adding 10,000 b/d. Rystad's Senior Upstream Analyst Prateek Pandet said that out of the eight fields to come onstream this year, only Malacca Strait Phase 1 is an oil play. Rystad also forecast a decline in Indonesia's gas output to 5,870 MMcf/d.

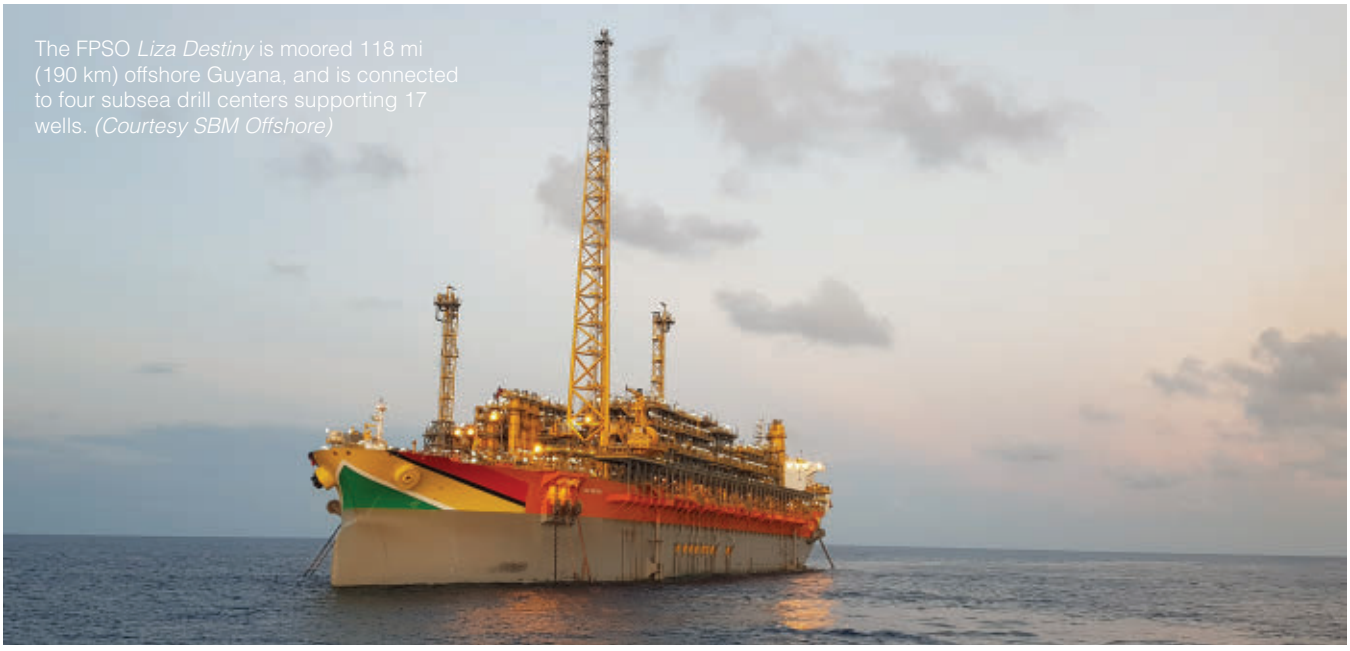
For the government to meet its targets, state-owned Pertamina faces pressure to stem the decline at the offshore Mahakam field since it took on operatorship in 2018, Pandet said. Eni's Merakes gas field, due to start up this year, should lift the country's gas production, although not significantly until at least 2021.

Thom Payne, Head of Offshore Research in Singapore at Westwood Global Energy Group, said Japan's INPEX, "had already gone back to the drawing board" on its Abadi LNG project in Indonesia's Arafura Sea, would probably push the FID with partner Shell to 2022 at the earliest. Payne, speaking to *Offshore* just at the outset of the oil price slump, predicted slow progress on other potential LNG projects in the APAC region. "The capex-intensive nature of these offshore LNG developments has seen operators attempt to farm down to reduce their capex-burden even before the price crash, in the current sub $40 environment projects like Equus, Scarborough, Crux and even Santos' Barossa all look very challenging."

In Payne's view, the spread of COVID-19 will likely impact crew changes for offshore drilling rigs and platforms, "adding extra layers of bureaucracy in a region with an already diverse regulatory environment." Discretionary spending in the current environment will be at significant risk, if any higher-profile exploration wells do go ahead, these will most likely be those with firm rig commitments offshore Western Australia, he said. "We have already started to see some E&Ps push for cancellation of offshore rig contracts, but most at risk for rig managers are the $300 million of contract options across Southeast Asia and Australia that were due to be exercised in 2020."

The impact of COVID-19 on APAC's ambitious offshore wind targets is yet to be seen but to date developments are advancing at a brisk pace. "China has huge wind plans involving significant volumes of turbines," Payne said, "but there is also a high requirement for local content which has slowed down the market in the recent past."

Elsewhere, Taiwan is well on the way to meeting its 2030 capacity target of 15 GW with the recent full commissioning of the 128-MW Formosa 1 development in January which will soon be joined by a further 2.5 GW of sanctioned capacity at Formosa 2, Changua 1 & 2a, Yunlin and Xidao and Changfang.



The FPSO *Liza Destiny* is moored 118 mi (190 km) offshore Guyana, and is connected to four subsea drill centers supporting 17 wells. *(Courtesy SBM Offshore)*

E&P activities rising across Latin America

Guyana, Brazil leading the way

JESSICA STUMP, *ASSISTANT EDITOR*

SINCE THE PREVIOUS DOWNTURN, the emergence of Guyana and the resurgence of Brazil played a major role in the industry's recovery, especially the FPSO market. The FPSO boom in South America is mainly the result of large investments in deepwater exploration and field development. Between 2015 and 2019, oil and gas companies invested about $8.1 billion in exploration and development activities offshore Guyana, according to Rystad Energy. Before the sudden oil price collapse and the COVID-19 pandemic, the analyst said companies were preparing to spend more than $53 billion in the country's coveted Stabroek block in the coming decade.

Operator Exxon Mobil Corp. and partners Hess Corp. and CNOOC have discovered more than 8 Bbbl of recoverable oil in the deepwater Stabroek block and brought the country's first offshore development project onstream on Dec. 20, 2019. According to ExxonMobil, Liza Phase 1 is currently ramping up and will produce up to 120,000 b/d of oil in the coming months, using the FPSO *Liza Destiny*.

The FPSO *Liza Unity*, which will be used for Liza Phase 2, is at Keppel Shipyard in Singapore for topsides integration and installation. The FPSO will have a processing capacity of 220,000 b/d of oil, 400 MMcf/d of gas, 250,000 b/d of water injection, and storage capacity of 2 MMbbl of crude oil. It will be spread moored in water depth of about 5,249 ft (1,600 m). ExxonMobil has re-engaged TechnipFMC and Saipem for the second phase's subsea umbilicals, risers and flowlines (SURF). Production is expected to start by mid-2022.

ExxonMobil, Hess, and CNOOC have made 16 discoveries in the Stabroek block offshore Guyana. *(Map courtesy ExxonMobil)*

Front-end engineering design (FEED) is under way for a potential third FPSO, *Prosperity*, to develop the Payara field in the same block. Pending government approvals and project sanctioning, Payara could start as early as 2023. Both FPSOs are based on SBM

LATIN AMERICA

Reserves	
Remaining Reserves (Million bbl)	155999
Production	
Current Production levels	4594
Liquids (kbbl/d)	3440
Gas (kbbl/d)	1154
Production platforms	
# Producing fields Total	192
# Tie backs	28
# Floating production	56
# Fixed production	108
Drilling Rigs	
# Floaters Demand 2019	27
# Jackups Demand 2019	4
Infrastrcture	
# Active Wells	1961
# Active XMTs	1169
# Installed XMTs (2019)	66
Active SURF lines (km)	11853
Field sanctioning 2019-2021	
# Fields to be sanctioned	35
Subsea tie back	11
Floater	19
Fixed	5
Oilfield Service Purchases 2019 (MUSD)	
Maintenance and Operations	11377
Well Services and Commodities	2592
Drilling Contractors	3387
Subsea	5253
EPCI	4296
Seismic	993

Source: Rystad Energy UCube, DCube, WellCube

Offshore's Fast4Ward program, a newbuild, multi-purpose hull combined with several standardized topsides modules.

Four drillships in Guyana continue to explore and appraise new resources as well as develop the resources within approved projects, ExxonMobil said. A fifth drillship is expected to be deployed later this year. By 2025, the operator expects at least five FPSOs to be in service on the block producing more than 750,000 b/d.

Other companies have found success in Guyanese waters. Tullow Oil and partners Eco (Atlantic) Oil & Gas and Total's Jethro and Joe discovery wells on the Orinduik block proved two different oil plays in the Cretaceous and Tertiary intervals. Samples from Jethro-1 and Joe-1 indicate mobile heavy crudes, similar to the commercial heavy crudes found in the North Sea, Gulf of Mexico, the Campos basin offshore Brazil, Venezuela, and Angola, according to Eco.

Offshore Suriname, Apache Corp. and Total's large Maka Central oil discovery in block 58 proved a working hydrocarbon system in the shallower Upper Cretaceous Campanian interval and the deeper Santonian interval.

John J. Christmann IV, Apache's CEO and president, said: "Preliminary formation evaluation data indicates the potential for prolific oil wells. Additionally, the size of the stratigraphic feature, as defined by 3D seismic imaging, suggests a substantial resource."

Drilling is under way of the second exploration well on block 58, Sapakara West-1. Despite the recent downturn, Apache said it will proceed, as planned, to a third exploration prospect.

Petrobras and its partners have sanctioned the second phase of the Mero project in the ultra-deepwater Libra block in the presalt Santos basin offshore Brazil. Designed and constructed using SBM's Fast4Ward program, the FPSO *Sepetiba* will have a processing capacity of 180,000 b/d of oil, 12 MMcm/d of gas, 250,000 b/d of water injection, and storage capacity of 1.4 MMbbl of crude oil. Delivery is due in 2022. It will be spread moored in 6,562 ft (2,000 m) water depth and link up to 16 wells. Other partners in the Libra consortium are Shell, CNOOC, and CNPC. Pré-Sal Petróleo manages the Libra production-sharing contract.

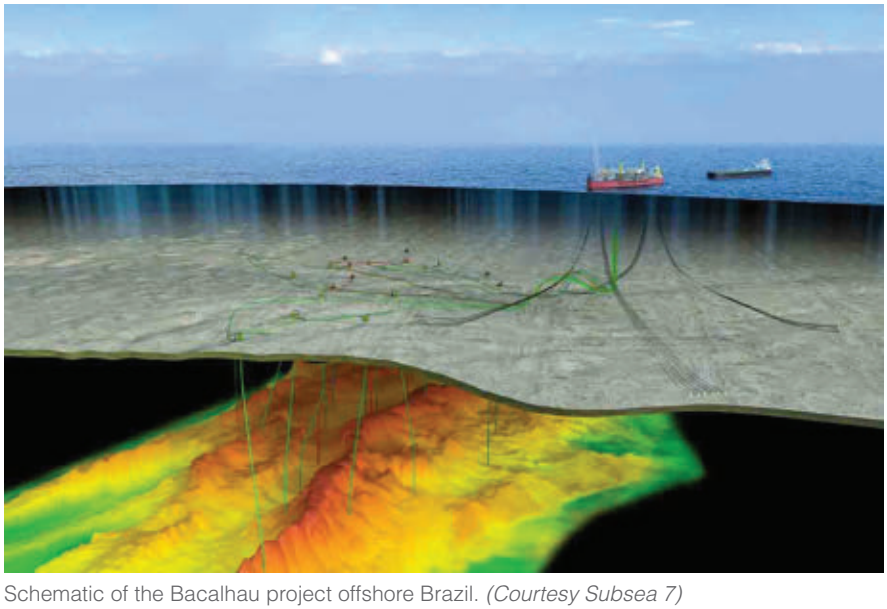
Equinor has awarded FEED contracts for the Phase 1 development of the Bacalhau (ex-Carcará) area in the presalt Santos basin offshore Brazil. MODEC, which started pre-FEED work for the FPSO in late 2018, will handle the full FEED, with the Subsea Integration Alliance (SIA) between Subsea 7 and OneSubsea responsible for the SURF FEED.

The contracts are based on a two-step award. FEED and pre-investment are under way, with an option to progress to the execution phase under a lump sum turnkey contract that includes engineering, procurement, construction, and installation for the entire SURF and FPSO scopes. Both are subject to a planned investment decision late in 2020. First oil should follow during 2023-24.

The Bacalhau field is 115 mi (185 km) from the coast of the State of São Paulo in water depths of around 6,726 ft (2,050 m).

According to Equinor, the FPSO will be Brazil's largest to date with a production capacity of 220,000 b/d.

MODEC will be responsible for the design and construction of the FPSO, including topsides processing equipment, hull and marine systems, with SOFEC supplying the spread-mooring system. This will be the second application of the company's M350 hull,



Schematic of the Bacalhau project offshore Brazil. *(Courtesy Subsea 7)*

a newbuild double-hull design said to accommodate larger topsides and larger storage capacity than conventional VLCC tankers, also providing a longer design service life. Dalian Shipbuilding Industry Co. in China will construct the hull.

Margareth Øvrum, Equinor's executive vice president, Development and Production Brazil, said the company planned to grow its production offshore Brazil to 300-500,000 b/d by 2030.

Equinor operates Bacalhau with a 40% interest, in partnership with ExxonMobil 40%, Petrogal Brasil 20% and Pré-sal Petróleo SA.

Oil companies are advancing exploration and development projects throughout Latin America.

Last summer, Eni became the first international operator to produce oil offshore Mexico following the country's Energy Reform. Early production started from the Mitzón 2 well on the Miztón field in Area 1 in the Campeche Bay. This was the initial development on the concession which also contains the Amoca and Tecoalli fields: total in-place resources are estimated at 2.1 Bboe (90% oil). The company acquired Area 1 under a competitive bid round in September 2015.

Production from the Miztón field platform, in 111 ft (34 m) water depth, is exported through a multiphase pipeline to Eni's onshore receiving facility (ORF) in Sanchez Magallanes, State of Tabasco.

Following separation at ORF, the wellstream continues to Pemex's San Ramón plant for treatment.

Eni expects the early production phase to deliver up to 15,000 b/d of oil with full-field production to begin in early 2021 via an FPSO, building to a peak of 100,000 boe/d.

According to Eni CEO Claudio Descalzi, production began less than two and a half years after the company's its first well in the concession and in less than a year since the government approved the project.

The plan for Area 1 also includes two additional platforms on the Amoca field and one on the Tecoalli field.

Eni's Saasken oil discovery in block 10 in the Sureste basin is estimated to have 200-300 MMbbl of oil in-place. The company and partners Lukoil and Capricorn plan to appraise the discovery and initiate studies for a commercial development.

Talos Energy will likely submit the development plan for the offshore Zama field to Mexico's government this summer, according to partner Premier Oil. Last June, the block 7 joint venture agreed on the main elements of a full-field development to maximize overall recovery from the Zama field, where reserves are thought to be in the range 670-970 MMboe. They propose two processing, drilling and accommodation platforms connected to an FPSO, with oil offtake by tankers.

Premier stressed that approval for the plan would be subject to an agreement on unitization of the field between the block 7 partners and Pemex, operator of an adjacent block containing an extension of Zama. Discussions are progressing in accordance with the Mexican regulatory process. But if no accord is forthcoming, an independent expert will be appointed during 2Q to determine the initial tract participation of the field, in compliance with the government-approved pre-unitization agreement process.

BHP has selected SBM Offshore USA Inc., Technip USA Inc. dba Genesis North America, and McDermott Inc. to deliver an early engineering study for a semisubmersible floating production unit for the deepwater Trion field off Mexico. BHP is the operator and holds 60% interest, and Pemex holds 40%.

Offshore Trinidad and Tobago, BHP has sanctioned the Ruby oil and gas project in block 3 (a). The development will focus on resources in the Ruby and Delaware reservoirs and will involve tiebacks of five production wells to existing processing facilities. BHP estimates recoverable resources at 13.2 MMbbl of oil and 274 bcf of natural gas. It anticipates start-up during the 2021 calendar year, with peak output of ~16,000 b/d and ~80 MMcf/d. Partners are Heritage Petroleum and the National Gas Company of Trinidad and Tobago.

Bahamas Petroleum Co., which has been preparing to drill its first exploratory well offshore the Bahamas, said if current negative developments forced a postponement of Perseverance #1 from the planned spud date in June, the next practical window would be from mid-October onwards. This is after the peak-risk period of the hurricane season in the Gulf of Mexico area. The company stressed that this is not its planning objective, but that it needs to put in place a realistic "back-up" plan to meet its primary license obligation of an initial exploration well in 2020.

E&P activity gains momentum offshore Eastern Canada

Range of new discoveries underpins growing industry interest

BRUCE BEAUBOUEF, *MANAGING EDITOR*

BUOYED BY A SERIES of recent discoveries, momentum for a new wave of E&P spending offshore Eastern Canada has been growing for the past six months. Recent events – namely the rapid growth of the COVID-19 pandemic and the even more rapid implosion of oil prices – may call some of this development into question.

Nevertheless, the region is poised to host a number of new drilling and field development activities in the near future. According to one report, deepwater areas off Newfoundland and Labrador are expected to bring in a new $4-billion wave of offshore oil and gas exploration in the next few years.

"There's an unprecedented level of interest for offshore East Coast Canada," said Jim Keating, executive vice president of Offshore Development at Nalcor Energy, which holds minority equity rights in three upcoming offshore projects.

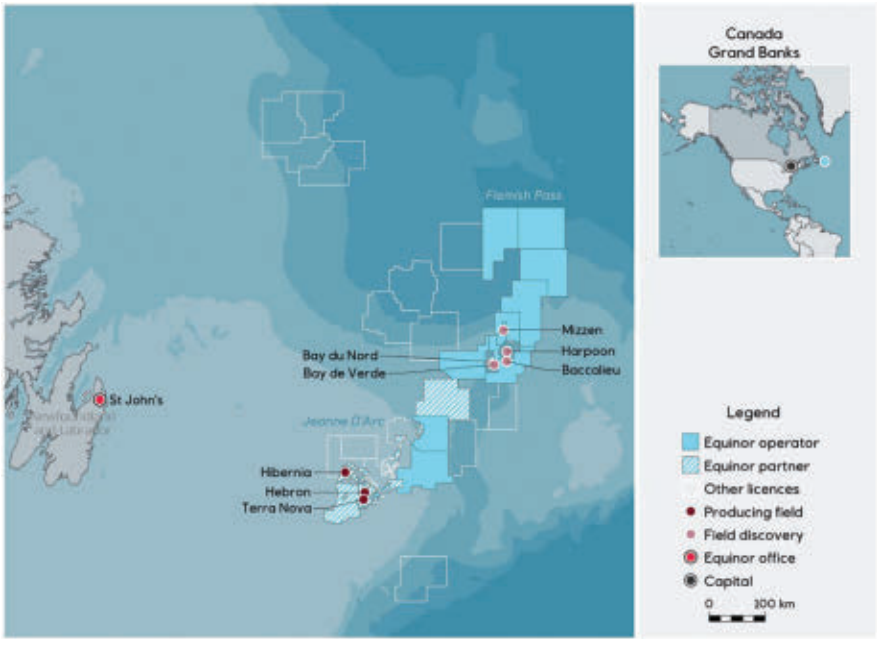
Keating gave his views at the Newfoundland and Labrador Oil & Gas Industries Association (NOIA) conference held last fall. The new interest is due to new geoscience work and changes in how offshore bidding is conducted, he said.

The first wave will crest by 2021, with the oil majors such as ExxonMobil, Chevron, Equinor, and CNOOC committed to spending $1.7 billion. That activity has begun, with ExxonMobil set to start drilling on a prospect identified through Nalcor's long-running geoscience program.

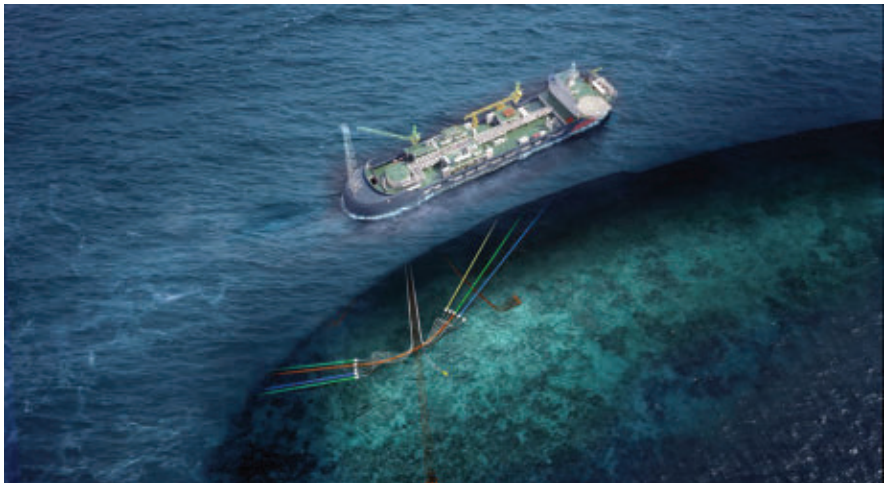
By 2022, BP Canada, Navitas Petroleum, Nexen Energy and Husky have committed to spending $763 million.

And further out, to 2024, BHP, Equinor and Suncor, plan to invest $1.4 billion in exploration.

Keating described this as "bow wave" of investment as eight oil companies, with 10 exploration plans, launch almost concurrent exploration campaigns in Canadian offshore frontier areas.



Canada's Grand Banks region is home to both its long-standing offshore oil and gas developments as well as its upcoming E&P projects. *(Courtesy Equinor)*



The Bay Du Nord development plan calls for 10 to 30 wells connected to five to 10 subsea templates, which will be tied-back using flowlines to an FPSO. *(Courtesy Equinor)*

"I think we're going to peak [in drilling activity] pretty soon in the next two or three years," Keating told NOIA conference attendees. He noted that eight or more exploration wells could be drilled in the near term, and many more in future years.

EASTERN CANADA

Reserves	
Remaining Reserves (Million bbl)	16979
Production	
Current Production levels	306
Liquids (kbbl/d)	304
Gas (kbbl/d)	2
Production platforms	
# Producing fields Total	10
# Tie backs	5
# Floating production	2
# Fixed production	3
Drilling Rigs	
# Floaters Demand 2019	1
# Jackups Demand 2019	0
Infrastrcture	
# Active Wells	109
# Active XMTs	92
# Installed XMTs (2019)	0
Active SURF lines (km)	407
Field sanctioning 2019-2021	
# Fields to be sanctioned	1
Subsea tie back	0
Floater	1
Fixed	0
Oilfield Service Purchases 2019 (MUSD)	
Maintenance and Operations	826
Well Services and Commodities	481
Drilling Contractors	332
Subsea	141
EPCI	1151
Seismic	148

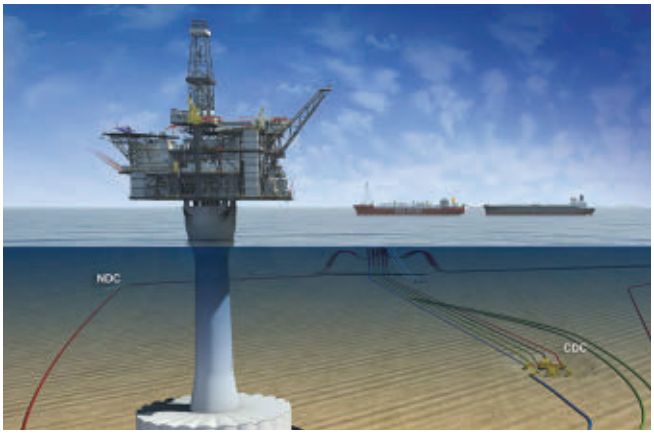
Source: Rystad Energy UCube, DCube, WellCube

Much of the interest has been driven by the findings of a recent study which identified an additional 3 Bbbl of oil and 5.8 tcf of gas potential offshore Newfoundland. That study, the 2019 Oil and Gas Resource Assessment conducted by Nalcor Energy and Beicip-Franlab, in partnership with the government of Newfoundland and Labrador, was released last October.

The report found an overall resource potential of 52.2 Bbbl of oil and 199.6 tcf of gas in the region. It also found that the area had over 650 leads and prospects identified; eight new entrants in the past three years; and $4 billion in exploration work commitments.

Keating added: "In addition to the 2D multi-client seismic we collected with TGS and PGS over the area, we partnered with Fugro in acquiring a high resolution multibeam survey which identified a number of seep-like features coming from the ocean floor. Subsequent coring of these anomalies confirmed hydrocarbon presence which is an important insight in this frontier basin due to the limited number of wells and no discoveries to date in the area."

The province already has four oil-producing projects: Hebron, Hibernia, Terra Nova, and White Rose. The primary operators are ExxonMobil, Husky Energy and Suncor with Chevron and Equinor also involved.



West White Rose will be developed through a fixed drilling platform consisting of a concrete gravity structure and an integrated topsides facilities. *(Courtesy Husky Energy)*

Operations are located roughly 338 km (210 mi) off the island of Newfoundland in water about 100 m (328 ft) deep. Other companies including China's CNOOC, BP, Australia's BHP Group and Navitas Petroleum hold exploration licenses.

The province's four oil production areas have produced an estimated 1.9 Bbbl of oil since 1997. Current production is about 257,000 b/d.

The companies have proposed 10 drilling projects with perhaps 100 wells in the next two to four years in deeper offshore water farther from the island of Newfoundland, according to Canada's Financial Post publication.

WEST WHITE ROSE

One notable project is Husky Energy's West White Rose project, with first oil expected by 2022. It would be the province's fifth oil project. Husky Energy is leading development on behalf of the West White Rose project partners which include Suncor Energy and Nalcor Energy. The White Rose field and satellite extensions are in the Jeanne d'Arc basin, 350 km (217 mi) east of Newfoundland and Labrador in approximately 120 m (394 ft) of water.

The West White Rose project will be developed through a fixed drilling platform consisting of a concrete gravity structure (CGS), built by the SNC-Lavalin- Dragados-Pennecon General Partnership (SDP), and an integrated topsides facilities. SDP will be constructing the CGS in the Argentia Graving Dock, located on the Argentia Peninsula approximately 130 km (81 mi) from St. John's.

BAY DU NORD

Perhaps the most notable upcoming project is the Bay Du Nord field development program. It includes the development of the Bay du Nord, Bay de Verde, Bay de Verde East and the Baccalieu fields located in the Flemish Pass basin of the Atlantic Ocean offshore Canada.

Equinor Canada (formerly Statoil Canada) and Husky Oil Operations (Husky Energy) jointly own the project with 65% and 35% interests respectively, with the former serving as the operator.

The Bay du Nord project is currently in the initial stage of planning and development. The development activities for the project are expected to begin in 2020, while first oil is targeted for 2025.

The Bay du Nord project is located in the Flemish Pass region, approximately 450 km (280 mi) offshore east-northeast of St. John's, Newfoundland, Canada. The project development area, spanning 450 sq km (174 sq mi), includes the exploration licenses (EL) 1125, 1126, 1143 and 1154, as well as the Significant Discovery Licenses (SDL) 1047, 1048 and 1055.

The water depth around the proposed project area ranges between 1,000 m and 1,200 m (3,280 ft and 3,937 ft).

The Bay du Nord oil field was discovered during an exploration drilling program conducted in the Flemish Pass area in 2013. The exploration and appraisal drilling program was extended for a period of 19 months from 2015.

A total of nine exploration and appraisal wells were drilled during the drilling program, which led to the discovery of the Bay de Verde and Baccalieu fields.

The Bay du Nord oil field and the Baccalieu field are estimated to hold mean recoverable resources, ranging between 300 and 600 MMboe (approximately 47.7 MMcm of crude oil). The fields contain

Equinor has appointed DNV GL to oversee design review activities for the Bay du Nord oil field development project, which will feature an FPSO and associated facilities. *(Courtesy Equinor)*

light crude with a 36° API and a low gas-to-oil ratio.

The initial development will focus on the Bay du Nord oil field and the Baccalieu field in the SDL 1055 and EL1143. A conceptual plan was created as part of the initial development plan, which may be modified following further studies and design optimization.

The proposed development plan includes the drilling of between 10 and 30 wells using five to 10 subsea templates. The drilling program will be carried out over a period of three to five years. The drilling activity is expected to be conducted using either a semisubmersible drilling unit or a drillship.

The subsea templates, including individual satellite wells, will be tied-back using flowlines to an FPSO.

The development plan proposes the use of pressure support through water and produced gas injection to recover the oil. The production life of the project is expected to range between 12 and 20 years.

The proposed FPSO will be moored offshore in a fixed location and will have the capacity to handle crude oil production, storage and export, gas management, water injection, produced water management and other waste management.

The FPSO will have a design life of 30 years and an estimated production capacity between 94,000 and 188,000 b/d of oil. It will also have a crude oil storage capacity ranging between 143,000 m^3 and 191,000 m^3 (between 0.9 and 1.2 MMbbl).

The water production rate of the FPSO will range from 30,000 m^3 a day to 50,000 m^3 a day.

The future development plans for the Bay du Nord project are expected to extend the core life of the field to a maximum of 30 years. Potential development plans include the drilling of an additional 20 development wells, installation of up to five subsea templates, as well as drilling of satellite wells.

CALL FOR NOMINATIONS

In January, the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) issued a Call for Nominations (Areas of Interest) NL20-CFN01 – Eastern Newfoundland. This call for nominations will assist the C-NLOPB in selecting a sector for introduction into the scheduled land tenure system. The approximate timing for subsequent announcements is as follows:

- Sector Identification: April 2020
- Call for Nominations (Parcels)
  - Opens August 2021
  - Closes November 2021
- Call for Bids (pending Board approval and ratification by the federal and provincial governments)
  - Opens March/April 2022
  - Closes November 2022.

Majors, independents champion gas, carbon capture for energy transition

London conference explores creative approaches to tackling emissions

JEREMY BECKMAN, EDITOR, EUROPE

GAS WILL HAVE a major role to play in the pursuit of lower-carbon energy, according to senior executives speaking at the recent IP Week 2020 conference in London, organized by the Energy Institute. Despite the steady ascent of renewable energy - in certain cases to power offshore production - gas remains the cleanest option, many stressed, to meet the needs of the developed and developing worlds.

Earlier this year BP's new CEO Bernard Looney revealed the company's new goal of 'net zero' emissions by 2050 from its upstream production, and Britain's government has set a similar timeline for the UK to become 'carbon neutral.' Sinead Lynch, UK Country Chair for Shell, speaking at IP Week's initial plenary session on Defining the Industry's Role and Delivering Low Carbon Energy, said her company supported this goal, but cautioned that the transformation would be harder if all major players were not aligned.

"The public debate on climate change has become increasingly polarized," she said, "with tens of thousands of people taking to the streets, and the topic dominating the agenda at this year's Davos economic forum. Governments must provide economy-wide carbon pricing mechanisms, and there is also a need for radical improvements in energy efficiency and low-carbon technologies. The oil and gas industry is investing in hydrogen, wind and solar energy, but just putting in all these measures will not be enough."

Shell, she pointed out, was investing in restoring wetlands and forests for carbon capture and storage, but added that the industry "needs to be more transparent about what it is doing and how it is doing it - and to listen harder to society's expectations…Those who produce energy need to work with those who use it on the best ways to deliver energy efficiency."

Sinead Lynch of Shell and Mathias Rigas of Energean (2nd and 3rd right) speaking at IP Week 2020. *(Images courtesy Energy Institute)*

Equinor recently committed to a 50% reduction in its emissions by 2030 in order to help contain the rise in global temperatures, said Al Cook, the company's EVP, Global Strategy & Business Development. "This is a massive challenge - it is solvable, but not without our industry being involved, and working on it with governments and consumers. Progress has been underpinned by fossil fuels, which currently satisfy four-fifths of the world's energy demands, but are also responsible for two-thirds of emissions. While we need to eliminate these, that should not be at the expense of the progress of the last 200 years."

Cook claimed there were reasons to be optimistic. "Although emissions grew by 3%/yr to 2010 as China and India industrialized, there has been much less growth since, and that is due in part to the industry's success in reducing emissions. The US has cut its emissions by 15%, or 1 billion tons, over the last decade, and in the UK, emissions are now down to levels seen in the last century, with the government introducing a carbon price of £40/ton. Business has responded by turning more to gas and renewable energy over coal."

Equinor is one of the leading investors in offshore wind power in Europe: the company's Dogger Bank wind farm project off the Yorkshire coast of eastern England will be the world's largest, Cook said. The company is also helping to drive the emergence of floating offshore wind power: its HyWind development is 30 km (18.6 mi) offshore northeast Scotland, "a long way from land, where the wind blows more strongly," he pointed out. In addition, Equinor is involved in projects in the UK and

TOP: Andrew Inglis (left) of Kosmos Energy. **BOTTOM:** Arnaud Breuillac of Total.

Norway to capture carbon dioxide (CO_2) from natural gas and from industrial emissions onshore, for storage in reservoirs beneath the North Sea.

Mathias Rigas, CEO of Energean Oil & Gas, spoke of the role the Eastern Mediterranean is playing in the energy transition to gas and renewables. Energean has an E&P presence in eight countries in the region with 800 MMboe of reserves, mostly gas, and started its commitment to be a net zero player three years ago. "We will be reducing our carbon intensity by 70% over the next three years," he claimed.

In Israel, the Energy Ministry has pledged to shut down coal-fired power across the country, Rigas said, replaced with gas-powered energy supplied from its deepwater fields. Energean is investing $1.7 billion to put in place some of that infrastructure for its Karish/Tanin development. To the west offshore Greece, the company has various blocks and Eni, ExxonMobil, and Repsol are also coming in to explore for gas, "helping the Greek government to meet its target of fully gas-fired power for the country." In addition, the East Med subsea pipeline project will connect Greece and other European Union countries to gas from deepwater fields off southern Cyprus and elsewhere in the region.

"Italy has banned exploration and committed to renewables providing 30% of the country's energy needs by 30%," he continued, "the rest supplied by fossil fuels. My question to the government is, do you want to produce this or import it? I don't see anyone yet willing to give up their current lifestyles. Egypt is the total opposite of what's happening to the north: the government there is promoting oil and gas…and turning the country from an importer to an exporter of gas. So today, countries in Europe are importing gas from North Africa…

"In Egypt, is climate change a priority? The answer from the government is 'yes, but we still need to heat and feed 30 million people.' In the western world we are very comfortable, but a lot of people in the rest of the world aren't, and it's our responsibility to help them and to do this sustainably."

Andrew Inglis, CEO and Chairman of Kosmos Energy, said his company had "a great gas portfolio for the future," notably as BP's partner in the deepwater Tortue/Ahmeyim LNG project off Mauritania and Senegal. "It's about making the transition from oil and gas, and how you do you support it? The big challenge is how to manage frontier exploration against allocation of capital in a perceived 2° [global warming] world?

"As an oil company, you look at a long-term opportunity now, then plan to shoot seismic in the middle of the decade followed by a well at the end of the decade and field development by 2035. Does frontier infrastructure investment deliver the returns that today's investors are looking for…and how will stranded assets ultimately compete for capital? The industry will undoubtedly continue to need oil and gas in future, but those assets will have to be low-carbon.

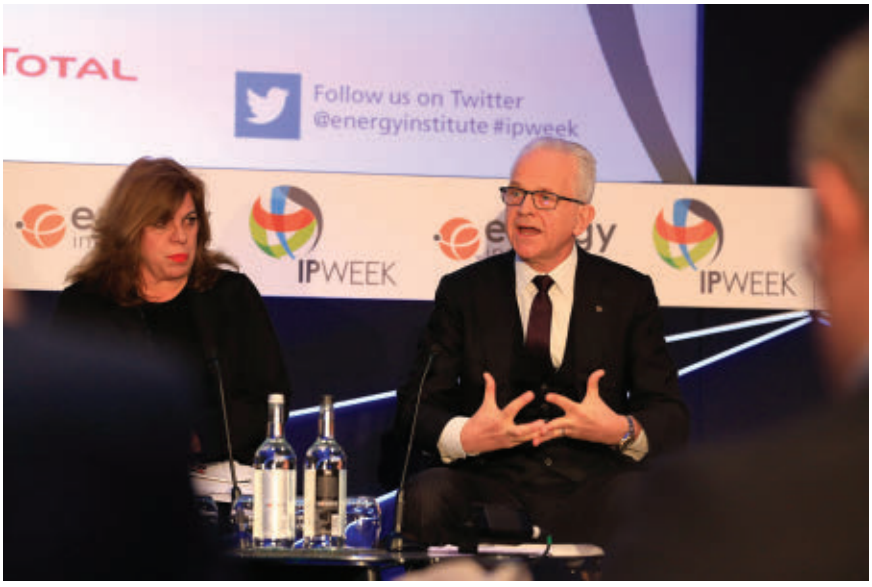
"To meet the requirements of a 2° world, there will be a need for more renewables and more gas. The challenge with transporting that gas is that it takes more energy to do so. So…how do you provide low-cost and low-carbon gas? Offshore Senegal and Mauritania, we are looking at renewables as a power source for production of the gas - and at

the same time, we are giving these countries the opportunity to rapidly grow to a low-carbon future."

Although Kosmos lacks the resources that the supermajors can pour into developing alternate energy sources, the company is playing its part, Inglis said, by supporting projects involving reforestation in Ghana and wetlands reclamation on the US Gulf Coast. And the Gulf of Mexico's experience as a low-carbon, low-cost production industry thanks to natural aquifer drive is relevant to what the world needs today, he suggested.

Arnaud Breuillac, President E&P at Total, said his company's ambition was to be "the responsible energy major" while at the same time delivering clean and affordable energy. At the same time, oil and gas will still contribute at least 50% of the world's primary energy needs by 2040, he predicted, adding that current production would have to be replaced via continued exploration.

Last year, demand for LNG worldwide grew by 13%, he said, while emissions were flat compared with levels in 2018. A big factor was the growing substitution of coal with gas-fired power, he said. "For Total, gas is a cornerstone of our strategy, which is why we're investing mainly in LNG projects - but we also need to be cost-effective and low in terms of energy intensity...all our investments worldwide include a carbon price of $40/ton of CO_2 equivalent."



Phillip Hemmens of Eni.

The industry needs to keep investing in lower-carbon technologies, Breuillac maintained. Total is involved in five projects in this regard in the North Sea: this region, with its combination of depleting reservoirs and a comprehensive subsea pipeline network, is very well suited to subsurface carbon and capture storage, he suggested. The company is targeting a reduction of CO_2 emissions from its production operations to below 40 MMt-equivalent by 2025, he added. "While some fields only need low energy to produce gas or oil, we can do a lot with other fields to reduce their energy consumption."

Patrick Allman-Ward, CEO of UAE-based Dana Gas, opened IP Week's second-day presentations on 'Strategies for Delivering a Low-Carbon Future.' The best pathways, he said, "are those that allow us to reach the COP21 targets most cost-effectively, while meeting the world's energy needs. Being prescriptive is not the way - we need to intensify low-carbon electrification with more renewables, but with no solution for the intermittency of renewables, the world will continue to need gas."

Allman-Ward supported carbon pricing which, in his view, "unleashes the creativity the industry needs to reduce carbon." He also advocated continued replacement of coal with gas as one of the best ways of reducing pollution. However, he was critical of the steep increase in recent years in gas flaring from production of unconventionals in the US, due mainly to debottlenecking.

Last year Russia's Novatek drilled two of the world's largest offshore gas discoveries in the Arctic Ocean. CEO Mark Gyetvay said the oil and gas industry had made a significant effort to clean up its business yet was not receiving due recognition. "Too many company managers are apologizing for being in oil," he said. "At the same time there is no dialogue, only shouting and yelling from one side. The energy transition is real, but there are also many people worldwide with no access to basic energy.

"We have to do everything possible that the industry can do to make this transition. Companies are spending [to that effect] - my company's contribution is to produce 70 MMt of LNG by the end of the decade, and we are one of the lowest in terms of intensity/per kilogram of carbon emitted."

Phillip Hemmens, SVP Northern Europe for Eni, said his company saw gas as playing a significant role in a low-carbon future. "The issue is global, but the objectives have to be regional. The pathway to low-carbon will also have many technological twists, turns and uncertainties, and we will have to try many things to get there. But someone in the industry told me that for the same reason, this is the most exciting time in his 30-year career, and we should look at it that way.

"Parts of the world have reached energy intensity and want to reduce emissions, while others do not have so much energy. In Europe, by 2040 the target is to reduce emissions by 1.4 gigatons, but by that point, emissions will have risen in the Middle East and Africa by respectively 0.7 and 0.6 gigatons, due to demographics and their energy needs - so effectively, we will end up with a status quo. The answer, therefore, is to reduce CO_2 across Asia and the Asia/Pacific region.

"OECD nations need to accelerate their transitions to lower-carbon economies while non-OECD countries need

to maximize energy for their people through the right energy mix, which Eni would say is gas. Equinor's approach to carbon capture and storage [offshore northwest Europe] is also an indicator of how the industry should move forward. We shouldn't worry if it's blue or green hydrogen, the main thing is that the carbon is captured. If that process is seen to work in northern Europe, we could convince Italy's government to do the same."

David Eyton, Group Head of Technology at BP, said his company sees digital solutions as one of the key ways of lowering emissions. BP, he said, is looking to apply digital technologies to improve production integrity, optimize energy distribution, and improve energy efficiency. "So far we've only scratched the surface," he said, "but this will be a big part of what we invest in in the future...

"Along this digital journey, just getting access to the data, curating it properly, is very important to the quality of service we provide to our customers. The next stage will be to do analytics on the data to discover its true value - where we're going is towards increased prediction and intelligence. We also need to improve the quality of Edge computing, and we're still learning a lot about artificial intelligence.

"As for carbon capture and storage, some of the big decisions we will take in the UK will concern what scale we build the required infrastructure to allow others to tie into it in future. And there need to be discussions between industry and government not just on CO_2 generated in the UK, but elsewhere."

Jean-Luc Guiziou, Managing Director, Total E&P UK, said his company remained committed to investing in the North Sea, "which we believe can create value and which we see as fit for the energy transition." Aside from the traditional challenges the sector brings in terms of safe operations and controlling costs to deliver affordable energy, reducing North Sea greenhouse gas emissions is a growing priority for the company, he explained.

Total has implemented systems at its UK sites (and elsewhere) to monitor CO_2 emissions, Guiziou said. "By raising the awareness of the workforce on our sites about emissions, we can harness any new ideas they may come up with. We are also developing our digital capabilities: we believe 20% of our CO_2 reductions can be derived through our digital initiatives." Under another program involving BP and Shell, the company is investigating electrification of its UK central North Sea assets, Guiziou said.

The *P-77*, which started operations in March 2019, was the fourth floater to come online at the field within the space of just 11 months. *(Images courtesy Petrobras)*

Subsea, downhole innovations driving deepwater Búzios development

Riser, injection configurations supporting high-output wells

JEREMY BECKMAN, *EDITOR, EUROPE*

PETROBRAS HAS WON this year's Offshore Technology Conference Distinguished Achievement Award for Companies for its innovations at the deepwater Búzios field development in the presalt Santos basin. Production started in April 2018 through the FPSO *P-74*, and output has continued to grow as further platforms have come onstream over different parts of the field. Over the past few years the company has developed and applied new downhole, subsea, and seafloor technologies to address conditions including ultra-deepwater, sub-salt reservoirs, high reservoir pressures, and large volumes of carbon-dioxide (CO_2) in the wellstream.

Petrobras discovered the field (then known as Franco) in the Cessão Onerosa Transfer of Rights (TOR) region in 2010. Búzios is a giant, extending over an area of 850 sq km (328 sq mi) and in water depths ranging from 1,700-2,100 m (5,577-6,890 ft), 180 km (112 mi) from the Rio de Janeiro State coast. The oil is relatively light, in the range 26-28° API. The company submitted its proposal for the Declaration of Commerciality in December 2013 to Brazil's National Petroleum, Natural Gas and Biofuels Agency. At the time, this estimated total recoverable reserves at 3,058 Bboe.

Following start-up, production rose rapidly as Petrobras brought online three more FPSOs within the space of 11 months. Like the *P-74*, the *P-75*, *P-76*, and *P-77* are all conversions of former VLCCs, each with an oil production capacity of up to 150,000 b/d. Petrobras has since commissioned MODEC to construct a fifth floater which is due to enter service during the second half of 2022. Production should continue to climb through the remainder of the decade as more floaters are added, due to the company securing a 90% operated stake in additional volumes

at Búzios under Brazil's latest Transfer-of-Rights area auction, in partnership with China's CNPC and CNOOC.

Offshore spoke to Petrobras' project team about the challenges associated with a development of this scale.

***Offshore:* Following the initial exploration and drilling campaign were the size of the in-place reserves and the field's areal extent in line with the company's expectations, and what is Petrobras' current estimate of the recoverable resource?**

Petrobras: Since the Declaration of Commerciality (2013), with the drilling of new appraisal wells and new acquisition and processing of 3D seismic covering the entire field, the estimates of the areal extension and the volume in place have not changed significantly. However, the total recoverable volume is estimated to be much higher than the original contracted volume, which makes Búzios the world's largest deep and ultra-deepwater field to date.

***Offshore:* Why did the government/ANP create the TOR regime?**

Petrobras: The Cessão Onerosa Transfer of Rights (TOR) is a legal regime regulated by a contract signed with the federal government in 2010, by Law 12.276. According to the contract, Petrobras acquired the right to produce up to 5 Bboe in the areas assigned, equivalent to a $42.5-billion capital increase subscribed by the government of Brazil.

***Offshore:* How does the composition of the oil and gas, the subsurface setting and the quality of the reservoir compare with other giant presalt Santos basin fields, and how many wells are currently in production at Búzios?**

Petrobras: In terms of reservoir quality Búzios and Libra have similar porous thicknesses, greater than those noticed in Lula. We are currently producing 16 wells, four connected to each floater, with well productivity of up to 60,000 b/d. Total production from Búzios is currently around 600,000 b/d and all the produced gas that is not used as fuel gas is reinjected into the reservoir. Our forecast is to start exporting gas in 2020, at a rate of 3.5 MMcm/d.

The *P-75*, the second FPSO to come onstream at the field.

***Offshore:* Is the company considering further 3D seismic acquisition over the field to take advantage of the latest developments in subsurface imaging techniques? And does it plan any further drilling?**

Petrobras: Yes. Petrobras is continually looking for new seismic imaging technologies, mainly with azimuth richness and broadband technology, aiming to a better characterization and monitoring of Búzios' reservoirs. A well campaign has been planned in the Búzios field area where new production development projects will be implemented.

***Offshore:* Can Petrobras cover all the operating costs associated with the currently operating wells and production facilities, and what could future development phases entail?**

Petrobras: The two Chinese partner companies will only participate in the consortium after the production-sharing contract becomes effective. The implementation of seven more FPSOs is under evaluation for the Búzios field. If all are installed, there will be total of 12 FPSOs.

***Offshore:* On which parts of the field are the four existing FPSOs, and has production so far been in line with expectations?**

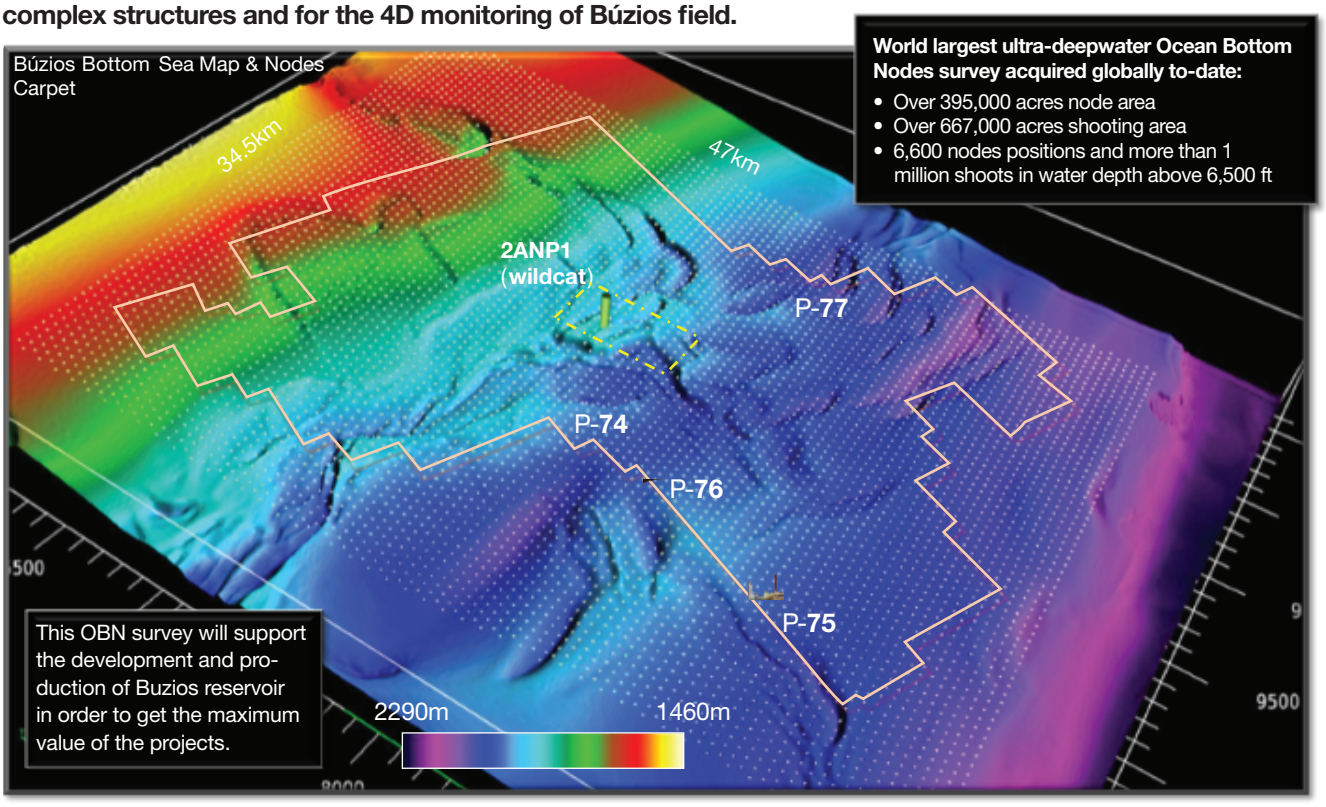
Petrobras: Three FPSOs were installed in the central area and one in the southwest area of the field. The productivity of the wells is similar among the four modules and is confirming the estimated production curves for the projects.

***Offshore:* Has the company made any requests for changes to MODEC for the fifth FPSO, based on experience to date? And does Petrobras envisage a standard design for the future platforms?**

Petrobras: No. The FPSO for Búzios 5 was already contracted with the design adjustments that Petrobras considered necessary. The contracting strategy and project design to be adopted for the field's next FPSOs are under evaluation.

BÚZIOS: LARGEST 3D OBN ACQUISITION IN ULTRA-DEEPWATER

OBN survey is a fit-for-purpose solution for better illuminating and imaging complex structures and for the 4D monitoring of Búzios field.



***Offshore:* Petrobras has highlighted five major technical advances in its development of the field to date. Can you supply some background, starting with what the company claims to be the first-ever application of an optimized, 20-line torpedo mooring system for FPSOs in ultra-deepwater?**

Petrobras: This development involved reducing the number of mooring lines per FPSO from 24 to 20, shortening the mooring radius and using the largest torpedo piles ever deployed by the industry. Each pile is anchored by its own weight, through gravitational force, launched from a certain height from the seabed to ensure a sufficient (minimum) penetration for resisting FPSO lateral movements. Petrobras developed the design in partnership with Brazilian universities.

Optimization of the mooring system reduced the radius by around 15% and raised the angular clearance between the bow and stern mooring clusters by around 15% as well, allowing connection of additional risers at preferential points closer to wells (i.e. portside for wells on the east of the platform, headed to the south in the Santos basin).

Through early engagement with our suppliers we achieved on average a reduction of 37 mi [59.5 km] in flexible and umbilical lines per module for the full life-cycle needs: in other words, this number is related to wells already in operation and to future tie-in opportunities. A higher reduction came when mooring optimization allowed positioning of the FPSO closer to the wells, or through altering the point of connection of certain risers and significantly reducing the length of their associated flowlines. These situations depend on the wells' positions and on seabed characteristics, such as geological hazards. Our suppliers' participation was of paramount importance in re-designing the riser configuration and reducing both the risers' length and the amount of buoyancy modules, thereby saving material and installation costs.

***Offshore:* Another reported technical first is the application of 8-in. flexible production risers in ultra-deepwater to manage hydrogen sulfide (H2S) and carbon dioxide (CO_2) in the field's gas. Is this an in-house design, and can you explain how it works?**

Petrobras: This is a technology developed by TechnipFMC that involves interconnection of the annular flexible riser sections. And with a vacuum and monitoring system installed on the platform, it allows continuous suctioning of the annular, thereby mitigating condensation of water vapor, and can also identify potential annular flooding.

The Búzios field is also the first development to employ large-scale flexible lines of 8-in. ID (risers and flowlines) for oil production installed in ultra-deepwater, allowing flow rates above 60,000 b/d, representing a new world record for

Búzios features what are said to be the largest torpedo piles ever deployed by the industry.

offshore wells. These high production rates allow for a full FPSO ramp-up with only three wells. The solution has since been applied to other ultra-deepwater projects for high-productivity wells.

The system facilitates the integrity management of the flexible line along its entire length, from the top to the well, allowing verification of the annular flooding at different stages of life of the flexible line (handling, installation and operation). In addition, it allows access to the annular flexible line from the topside, lessening the need for ROV interventions for inspection of the annular flexible line.

Offshore: **Another reported highlight of the project is the first use of simultaneous Water-Alternating- Gas (WAG) manifolds to receive oil and gas independently from the FPSO, and distributing these to selected wells to increase recovery.**

Petrobras: The WAG manifold is being used at Búzios and on some of our other projects for water or gas injection. The innovation is the possibility of simultaneous injection of both fluids (water, gas) by the manifold. As one of the interconnected wells manifold injects gas, the other well can inject water simultaneously.

Offshore: **Can you explain what is meant by "the first intensive use of intelligent completions in a 'total fluid loss' scenario"?**

Petrobras: The scenario is only applicable to the well construction phase, when the intelligent completion system can be installed while having major fluid losses to the formation. The solution developed to overcome this situation includes the use of a lower completion system that is compatible with MPD (Managed Pressure Drilling) techniques and is capable of delivering downhole remote control and monitoring of the production (intelligent completion).

This new solution can be used in other presalt projects that might require the installation of intelligent completions in wells prone to heavy fluid losses.

Offshore: **Finally, Petrobras highlighted what it claims was the world's largest 3D ocean bottom node (OBN) survey in deepwater in order to acquire an accurate image of the Búzios reservoir.**

Petrobras: The NODES survey began in October 2018 and lasted one year. It will contribute greatly to improved reservoir characterization, also serving as a base survey for future 4D acquisitions, with a tremendous potential to add value to the field, both for implementation of new projects and for and production management. Furthermore, it will play a major part in definition and managements of the future Surplus of Rights projects. This and the other four technological breakthroughs are readily available to other players in the offshore industry.

New rotary steerable system designed to optimize wellbore quality

JOHN CLEGG, *WEATHERFORD*

IT CAN TAKE AS LITTLE AS two weeks to drill a horizontal well, but it may be expected to produce for years or even decades. Therefore, any problems that are introduced and any imperfections that are inadvertently left behind when drilling the well can have adverse impacts on production that linger for orders of magnitude longer than the time to drill. And these impacts on production are in addition to the problems that can accrue in drilling and completions if the well is drilled sub-optimally.

The following will look at some of the ways in which the quality of drilling can impact on the whole life value of the well, and how technology can help to optimize it.

The industry has been drilling directional wells for a century now. Some of the first directional wells were used for onshore-to-offshore drilling at Huntingdon Beach, California, in the 1930s. Since then the ability to drill basic directional wells, then horizontal wells, and now the complex wells seen today, has evolved rapidly. Alongside it, the ability to drill wells more and more quickly, at higher and higher rates of penetration, has also grown. Drilling the well is merely the means to the end. As result, how far and how fast we can drill are not the only key performance indicators (KPIs) for success. Ultimately, initial production and ultimate recovery need to be maximized. How can we do this, and are there other KPIs we can look at along the way, to help and guide us?

Tortuosity is a measure of high frequency deviation from plan. In 2018, Ashok and others from the University of Texas at Austin published work[1] on what they called Tortuosity Index (TI). It was influenced by work published 10 years earlier on the tortuosity of veins in the human eyeball. This TI is intended to serve as a measure of the total tortuosity in a well, which can be compared with the intended curvature – the well plan – to determine a quality measure for how the well was drilled. A student internship at the same university, also reported in 2018, studied 6,000 real wells and clearly showed the negative impact of high TI on economics. Wells with a higher TI saw an increase in average drilling cycle time per section, an increase in the average rod pump failures per well and, significantly, a decrease in initial production.

In what has become a seminal paper from 2012[2], Stockhausen and others showed what can happen when a directional well is drilled with a steerable motor. Alternating slide-rotate-slide intervals can lead not only to significant tortuosity

The Magnus RSS was designed from the outset with wellbore quality in mind. *(Images courtesy Weatherford)*

in the well, with regions of higher than anticipated dogleg in the slide sections, but also, incidentally, to significant TVD errors as the minimum curvature calculations we often use assume constant curvature between stationary survey points, which Stockhausen points out is often not the case.

Ashok and his colleagues are not the only ones to have documented the possible detrimental effects of tortuosity. In 2019, a paper by Apache[3] showed a beneficial impact on rate of penetration (ROP) resulting from lower TI, after sorting TI into bins. This demonstrates that there is not necessarily a trade-off between drilling the well quickly and drilling it smoothly.

Once the well is drilled, poor tortuosity causes problems. Monterrosa and others[4] published the results of modeling the impact of tortuosity on casing standoff. They clearly showed that poor tortuosity can lead to variations in casing standoff all the way down to zero, leading to zero cement thickness.

Poor tortuosity can cause problems with production equipment. For example, a paper from Ledroz et al in 2017[5] describes the case of an unfortunate electric submersible pump (ESP) that was landed in a highly tortuous section of a wellbore that was thought, from stationary surveys, to be smooth and straight. The ESP in question only worked for a week, before suffering a shaft failure "most probably related to excessive bending while operating..." This confirms what Stockhausen taught in that static surveys can give a false sense of security about the smoothness of a wellbore.

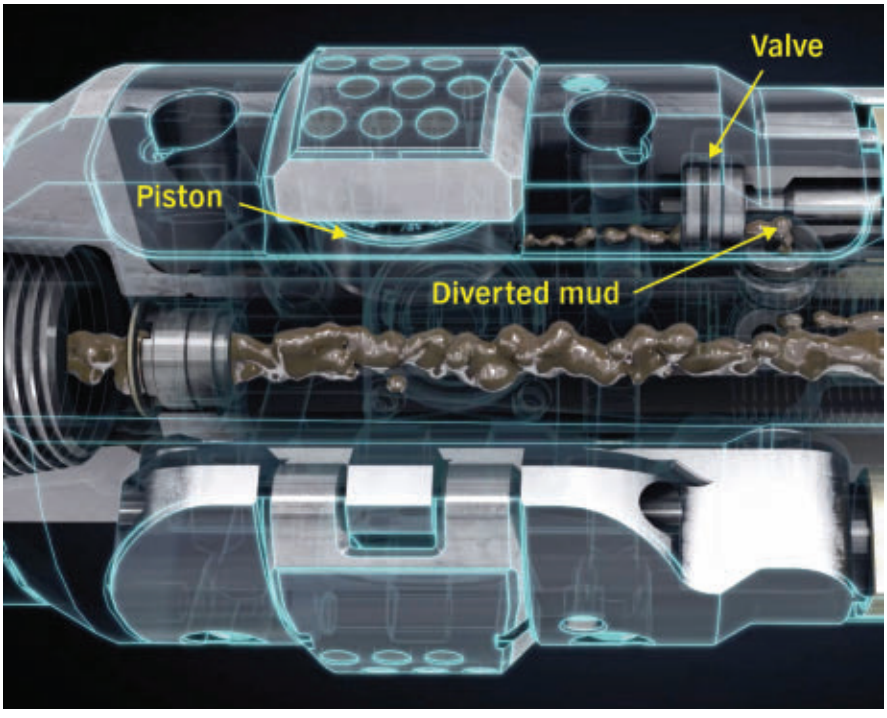
It is also possible that higher TI values can reduce overall production from a well. A study published by Shell in 2019[6] showed that in at least one formation, a correlation was observed between lower TI and higher production values, but without enough evidence to say that there is causation. Nonetheless, there are intuitive reasons why this might be the

case. For example, sumps filling with sand or water and holding back production, or reduction of effective diameter. There are some published models that show how this might happen.

There are many reasons why drilling wells with lower TI values and with higher wellbore quality can be advantageous: reducing drilling cost; reducing cost of completions and production; reducing maintenance of production equipment; improving cementing; and even increasing overall production from the well. The question then emerges – how can we drill less tortuous wells?

The author argues that a key requirement for drilling a less tortuous well is to use a directional system that is capable of not providing a bias to the bit – that's right, not providing a bias. A steerable motor is effectively a mud motor with a bent housing close to the bit, which is used to provide some bias to the drill bit. If the toolface of the bend is oriented correctly, when the motor is used in sliding mode the bit will drill approximately in the direction it is pointed, and a curve will be drilled. If the motor housing is rotated from the surface, the bias is effectively canceled, and the assembly will drill approximately straight. Unfortunately, wellbore quality is compromised because, among other things, the steerable motor drills an oversized hole when rotating (drilling straight) and a gauge hole when sliding (drilling the curve), and the transitions between the two modes add "speed bumps" which are illustrated in the Stockhausen paper[2]. As mentioned above, the same paper also illustrates how the slide-rotate-slide cycle introduces short sections of higher than expected dogleg into the well. So, arguably, the steerable motor was designed to optimize dogleg performance and not wellbore quality.

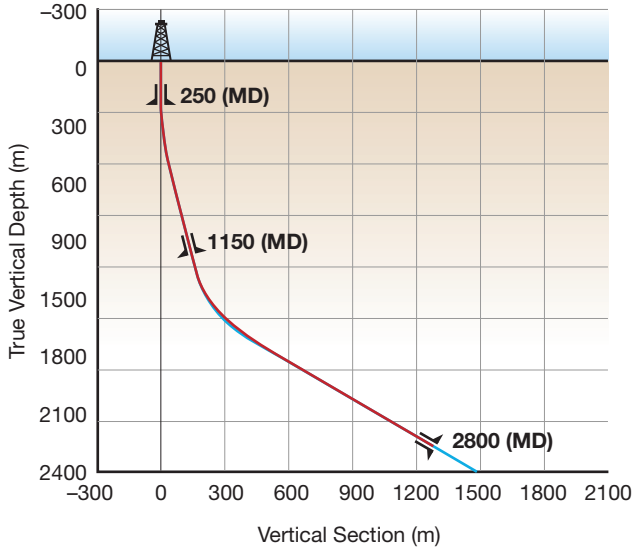
Similarly, many rotary steerable system (RSS) tools were designed to optimize dogleg, and did not take account of tortuosity and wellbore quality. In contrast, Weatherford's Magnus RSS[7] was designed from the outset with wellbore quality in mind.



A rotary control valve is used to determine when the pad is pressurized.

The Magnus tool has three steering pads, close to the bit, which are used when needed to apply a side force and deflection to the bit in order to push the bit sideways and thereby change the direction of the well. If maximum dogleg is required, each of these pads is extended once per revolution, resulting in a continuous lateral bias to the bit and thereby the desired build, turn, or drop. However, there are many instances where maximum dogleg is undesirable, and a lower dogleg is needed, or even when no bias is required at all. For example, when drilling out the casing shoe or reaming to bottom.

THE MAGNUS 1100 RUN IN THE GULF OF MEXICO

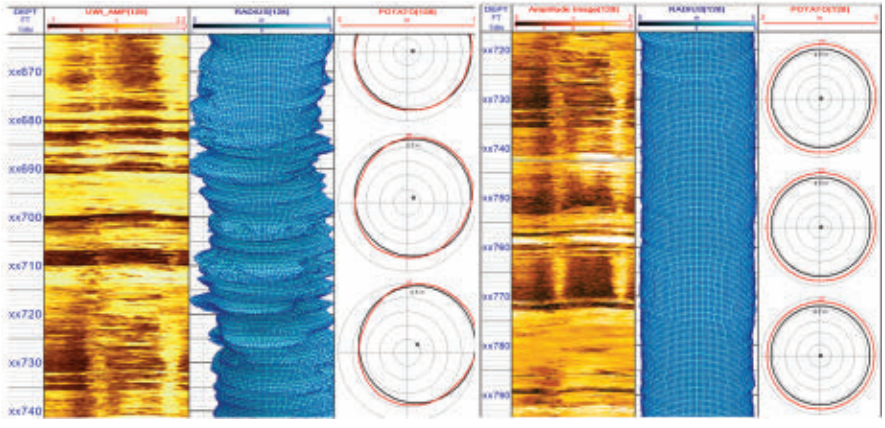


The tool meets this requirement by making each of its three steering pads independently addressable and controllable. Each pad is actuated by drilling mud, using the pressure drop between bore and annulus to act on a piston which extends the pad. A rotary control valve is used to determine when the pad is pressurized. If maximum bias is desired, each valve is opened once per revolution of the drill bit. If no bias is desired, all three valves can be parked in a closed position, effectively making the steering pads into an undergauge near bit stabilizer with no impact

on steering. And if a partial bias is needed, anywhere from 0% to 100% of maximum, valves share time between being open and closed on a cycle of a few seconds in order to achieve the desired bias percentage. Doing this on a short time cycle means that the curve, or tangent, drilled is as smoothly as possible and that any unwanted tortuosity, or hole enlargement, is eliminated.

In addition, the ability to drill straight, or to any dogleg up to maximum, enables the true "autopilot" mode. For example, the RSS can hold inclination by using near bit sensors and when necessary adjusting bias percentage, on the same short cycle described above, to overcome any natural tendencies of the BHA or formation. This enables the drilling of very straight and accurate tangent sections.

Since being introduced in 2018, Magnus has drilled more than 500,000 ft (152,400 m) in both onshore and offshore applications in North and South America, Europe, and the Middle East. In many cases, performance has been judged not only on the ability to get to target depth (TD) and on ROP, but also often on whether casing or liners can be run in hole after the section has been drilled, and sometimes on the ease of tripping out of hole. A recent example is an offshore run in the Gulf of Mexico with the Magnus 1100 tool in a 17½-in. hole. Kicking off below the shoe, the tool demonstrated its directional capabilities by provision more than 3.5°/100 ft dogleg to achieve the directional plan, and then drilled the whole of the 54.4° tangent in 100% auto-pilot mode while holding the desired tangent angle and with minimal tortuosity. Thus, the RSS enabled the achievement of the three customer drilling goals: drilling the section to TD; improving ROP by 10% when compared to offset wells; and successfully running 13⅜-in. casing to bottom.



Ultrasonic caliper taken at the same time as the Magnus tool was first tested onshore.

This case history is one of many and shows that it is possible to improve drilling performance at the same time as, and possibly even because of, a reduction in tortuosity and an increase in wellbore quality.

Further evidence for improved wellbore quality comes from an ultrasonic caliper taken at the same time as the Magnus tool was first tested, onshore USA. The blue traces show stacked "potato plots" which indicate the location of the center of the hole, and its shape and diameter, as drilling progresses. The very ribbed-looking well on the left was drilled with a steerable motor, while the much smoother looking well on the right was drilled with the Magnus rotary steerable.

To conclude, although high ROP can be achieved with modern drilling systems, we must also look at other indicators of drilling success including wellbore quality. The benefits of improved wellbore quality are manifest, and nowhere is it likely to be more important than when drilling an expensive offshore well. Achieving it is not at odds with achieving high ROP (in fact wellbore quality may enable higher ROP), and tools like Weatherford's Magnus RSS are available ideally positioned to help operators and drilling contractors to optimize it.

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2020 ROTARY STEERABLE DRILLING SYSTEMS DIRECTORY

Product trade name	Point-the-bit or Push-the-bit	Length (ft)	O.D. & I.D. (in.)	Hole size (in.)	Max DLS capability (°/100')	Automated closed loop deviation control (yes/no) (+/-degrees)	Build rate increment	Is deviation force continuous?	Max temp (°C/°F)	Max internal pressure (psi)	Other special pressure limitations	Does tool require configuration based on anticipated flow rate?	
APS Technology													
SureSteer-RSM (Rotary Steerable Motor) RSM675 (6-3/4"")	Push	Steering Section (14.5'), Power Section (17.2')	OD: 7.78 ID: 1.5	8.375" to 8.75" nominal	5.5	Yes, Inclination and MTF to within 0.1°	Configurable	Yes and variable	150/302	20,000	None	No	
SureSteer-RSS RSS475	Push	Steering Head - 10.6'	Nominal OD - 4.75"" Steering Pad Upset OD - 5.75"" ID 2.7 - 3.1""	6.0" to 6.75"	12.0	Yes, Inclination and MTF to within 0.1°	Configurable	Yes and variable	150/302 175/347 (option)	20,000	None	Yes	
Baker Hughes	**https://www.bakerhughes.com/**												
6.75" AutoTrak Curve (conventional motor can be added)	Continuous Proportional Steering	38 (fully inclusive of steering system & MWD) Steering head length = 9.3	OD: 6.75 ID: N/A	8.375 - 9.875	15	Yes Precise to within 0.2°	Build Force programmable from surface via downlink. Target inclination in 0.125° increments	Yes	150/302	20,000	None	Steering system: No MWD system: No	
9.5" AutoTrak G3	Continuous Proportional Steering	58 (fully inclusive of steering system & MWD/LWD) Steering head length = 8.2	OD: 9.5 ID: N/A	12.00 - 28.00	6.5	Yes Precise to within 0.1°	Build Force programmable from surface via downlink. Target inclination in 0.125° increments	Yes	150/302 (175/347 on request)	20,000 (25,000 & 30,000 on request)	None	Steering system: No MWD system: Yes	
6.75" AutoTrak G3	Continuous Proportional Steering	50 (fully inclusive of steering system & MWD/LWD) Steering head length = 7.2	OD: 6.75 ID: N/A	8.375 - 10.625	6.5	Yes Precise to within 0.1°	Build Force programmable from surface via downlink. Target inclination in 0.125° increments	Yes	150/302 (175/347 on request)	20,000 (25,000 & 30,000 on request)	None	Steering system: No MWD system: Yes	
9.5" AutoTrak X-treme (Adds Integrated pre-contoured drilling motor)	Continuous Proportional Steering	88 (fully inclusive of steering system, motor power section & MWD/LWD) Steering head length = 8.2	OD: 9.5 ID: N/A	12.00 - 28	6.5	Yes Precise to within 0.1°	Build Force programmable from surface via downlink. Target inclination in 0.125° increments	Yes	150/302 (175/347 on request)	20,000 (25,000 & 30,000 on request)	None	Steering system: No MWD system: Yes	
6.75" AutoTrak X-treme (Adds Integrated pre-contoured drilling motor)	Continuous Proportional Steering	76 fully inclusive of steering system, motor power section & MWD/LWD) Steering head length = 7.2	OD: 6.75 ID: N/A	8.375 - 10.625	6.5	Yes Precise to within 0.1°	Build Force programmable from surface via downlink. Target inclination in 0.125° increments	Yes	150/302 (175/347 on request)	20,000 (25,000 & 30,000 on request)	None	Steering system: No MWD system: Yes	Inc Othe depe
9.5" AutoTrak eXpress (Base level RSS service)	Continuous Proportional Steering	64.6 (fully inclusive of steering system & MWD) Steering head length = 8.2	OD: 9.5 ID: N/A	12.00 - 28.00	6.5	Yes Precise to within 0.1°	Programmable from surface via downlink from 0-6.5° /100 ft	Yes	150/302	20,000	None	Steering system: No MWD system: Yes	Inc Othe depe
6.75" AutoTrak eXpress (Base level RSS service)	Continuous Proportional Steering	58.2 (fully inclusive of steering system & MWD) Steering head length = 7.2	OD: 6.75 ID: N/A	8.375 - 10.625	8	Yes Precise to within 0.1°	Programmable from surface via downlink from 0-8° /100 ft	Yes	150/302	20,000	None	Steering system: No MWD system: Yes	Inc Othe depe

	Sensor distance (ft) Inc/Azm/GR/ Res	Control from surface (Downlink) (Y/ N)	If yes, tool control method	Rig time req'd to communicate change in target (minutes)	Minimum kickoff inclination (degrees)	Max RPM / WOB	Min flow rate (gpm)	Max flow rate (gpm)	LCM limits	Power source	Bit requirements	Integrated LWD?
	4' Inc/Mag ToolFacE	Y	Mud Pumps and Rotary	3.5 to 8 min	0	80 RPM, 50 klb	300	600	None	Alternator driven off motor	Per APS Bit Recommendations	No - Can be operated below any LWD/MWD
	Inc (RSS) - 14.1' Gamma - 17.2' MWD Dir - 21.6'"	Y	Mud Pumps and Rotary	3.5 to 8 min	0	200 RPM, 30 klb	150	350	None	Turbine Alternator driven by Mud flow	Per APS Bit Recommendations	MWD & LWD can be intergrated with steering head
	5.9 / 21.6 / 11.5 / NA	Y	Negative pulse from surface skid unit	While drilling ahead	0	400RPM 56 klbf	300	750	50 lb/bbl medium nutplug, Cedar Fiber	Turbine generator	Application specific	No
	Inc: 3.9 Others BHA dependent	Y	Negative pulse from surface skid unit	While drilling ahead	0	300 RPM 100 klbf	300	1,600	Steering system: None MWD system: 40 lb/bbl fine nutplug (higher conc. on request)	Turbine generator	Application specific	Yes
	Inc: 3.1 Others BHA dependent "	Y	Negative pulse from surface skid unit	While drilling ahead	0	400 RPM 57 klbf	200	900	Steering system: None MWD system: 40 lb/bbl fine nutplug (higher conc. on request)	Turbine generator	Application specific	Yes
	Inc: 3.9 Others BHA dependent	Y	Negative pulse from surface skid unit	While drilling ahead	0	300 RPM 60 klbf	530	1,600	Steering system: None MWD system: 40 lb/bbl fine nutplug (higher conc. on request)	Turbine generator	Application specific	Yes
c: 3.1 rs BHA endent	Y	Negative pulse from surface skid unit	While drilling ahead	0	400 RPM 36 klbf	265	660	Steering system: None MWD system: 40 lb/bbl fine nutplug (higher conc. on request)	Turbine generator	Application specific	Yes	
c: 3.9 rs BHA endent	Y	Flow rate change	While drilling ahead	0	300 RPM 100 klbf	300	1,600	Steering system: None MWD system: 40 lb/bbl fine nutplug (higher conc. on request)	Turbine generator	Application specific	No	
c: 3.1 rs BHA endent	Y	Flow rate change	While drilling ahead	0	400 RPM 55 klbf	200	900	Steering system: None MWD system: 40 lb/bbl fine nutplug (higher conc. on request)	Turbine generator	Application specific	No	

2020 ROTARY STEERABLE DRILLING SYSTEMS DIRECTORY

Product trade name	Point-the-bit or Push-the-bit	Length (ft)	O.D. & I.D. (in.)	Hole size (in.)	Max DLS capability (°/100')	Automated closed loop deviation control (yes/no) (+/-degrees)	Build rate increment	Is deviation force continuous?	Max temp (°C/°F)	Max internal pressure (psi)	Other special pressure limitations	Does tool require configuration based on anticipated flow rate?	
9.5" AutoTrak V (RSS for vertical drilling)	Continuous Proportional Steering	24 fully inclusive. Steering head = 8.2	OD: 9.5 ID: N/A	12.00 - 28.00	Vertical Drilling	Yes Precise to within 0.1°	Vertical Drilling	Yes	150/302	20,000 (25,000 & 30,000 on request)	None	No	3.9 NA
6.75" AutoTrak V (RSS for vertical drilling)	Continuous Proportional Steering	21 fully inclusive. Steering head = 7.2	OD: 6.75 ID: N/A	8.375 - 10.625	Vertical Drilling	Yes Precise to within 0.1°	Vertical Drilling	Yes	150/302	20,000 (25,000 & 30,000 on request)	None	No	3.1 NA
6.75" AutoTrak eXact (Can be integrated with pre-contoured drilling motor)	Continuous Proportional Steering	38 (fully inclusive of steering system & MWD) Steering head length = 9.3	OD: 6.75 ID: N/A	8.375 - 9.875	15	Yes Precise to within 0.2°	Build Force programmable from surface via downlink. Target inclination in 0.125° increments	Yes	150/302	20,000	None	Steering system: No MWD system: No	Inc Othe depe
4.75" AutoTrak eXact (Can be integrated with pre-contoured drilling motor)	Continuous Proportional Steering	39 (fully inclusive of steering system & MWD) Steering head length = 9.62	OD: 4.75 ID: N/A	5.75 - 6.75	15	Yes Precise to within 0.1°	Build Force programmable from surface via downlink. Target inclination in 0.125° increments	Yes	165/329	30,000	None	Steering system: No MWD system: No	Inc Othe depe
Gyrodata Product Line Manager: Chris Hartey chris.hartley@gyrodata.com www.gyrodata.com													
Well-Guide 10-300	Point	30 collar	OD:10.25 ID: 2.813	12.25 - 18.25	3	Yes inclination and azimuth to within 0.1°	0 to 100%	Yes	150/302	20,000	None	No	
Well-Guide 10-400	Point	33 collar	OD:10.25 ID: 2.813	12.25 - 18.25	3	Yes inclination and azimuth to within 0.1°	0 to 100%	Yes	150/302	20,000	None	No	
Well-Guide 7-100	Point	25 collar	OD: 7.25 ID: 1.9375	8.375 - 9.875	7	Yes inclination and azimuth to within 0.1°	0 to 100%	Yes	150/302	20,000	None	No	
Well-Guide 7-200	Point	28 collar	OD: 7.25 ID: 1.9375	8.375 - 9.875	7	Yes inclination and azimuth to within 0.1°	0 to 100%	Yes	150/302	20,000	None	No	
Well-Guide 4-100	Point	24 collar	OD:4.75 ID: 1.25	5.875 - 6.75	12	Yes inclination and azimuth to within 0.1°	0 to 100%	Yes	150/302	20,000	None	No	
Nabors Drilling Services Steve Krase Andy Biem Neil Bird													
OrientXpress Rotary Steerable Tool 700 Series	Hybrid	12.5	7.1 OD 1.6 ID	7 7/8" to 8 3/4	15	"Yes Inclination (+/-0.1) Azimuth (+/- 1 deg)"	Continuous	Yes	150°C	20,000	None	Yes (generator)	
National Oilwell Varco													
VectorEDGE	Push the bit	21	OD:6.5" ID: N/A	7-7/8" - 8 3/4	5	Yes (0.2)	1% and 1o TF	No	120°C / 248°F	30,000	Optimized for Drilling conditions	Yes	
VectorZIEL 800	Push the bit	30	OD: 8" ID: N/A	12 1/4" - 13 7/8	5	Yes (0.1)	5%	Yes	150°C - 302°F	20,000	None	No	
VectorZIEL 600	Push the bit	28	OD: 6.75" ID: N/A	8 1/2" - 9 7/8	8	Yes (0.1)	5%	Yes	150°C - 302°F	20,000	None	No	

	Sensor distance (ft) Inc/Azm/GR/ Res	Control from surface (Downlink) (Y/ N)	If yes, tool control method	Rig time req'd to communicate change in target (minutes)	Minimum kickoff inclination (degrees)	Max RPM / WOB	Min flow rate (gpm)	Max flow rate (gpm)	LCM limits	Power source	Bit requirements	Integrated LWD?
/ NA / / NA	Y	Flow rate change	While drilling ahead	0	300 RPM 70 klbf	300	1,600	Steering system: None MWD system: 40 lb/bbl fine nutplug (higher conc. on request)	Turbine generator	Application specific	No	
/ NA / / NA	Y	Flow rate change	While drilling ahead	0	400RPM 55 klbf	200	900	Steering system: None MWD system: 40 lb/bbl fine nutplug (higher conc. on request)	Turbine generator	Application specific	No	
: 5.9 rs BHA endent	Y	Negative pulse from surface skid unit	While drilling ahead	0	400 RPM 56 klbf	300	750	Steering system: None MWD system: 40 lb/bbl fine nutplug (higher conc. on request)	Turbine generator	Application specific	Yes	
: 4.8 rs BHA endent	Y	Negative pulse from surface skid unit	While drilling ahead	0	400 RPM 35 klbs	475	1,325	Steering system: None 40 ppb (114 kg/ m³) medium nut plug, cedar fiber	Turbine generator	Application specific	Yes	
	8 Inc/ Azm	Y	Rotary (or via mud motor)	12	0	150 RPM 70 klb	none	none (2.813 bore - no restriction)	None	Lithium batteries/ rotation	Best bit for formation - Prefer 0.5 x hole diameter passive gauge	No - Can be operated below any LWD/MWD
	8 Inc/Azm	Y	Rotary (or via mud motor)	12	0	150 RPM 70 klb	none	none (2.813 bore - no restriction)	None	Lithium batteries/ rotation	Best bit for formation - Prefer 0.5 x hole diameter passive gauge	Yes - integrated with Gyrodata MWD/LWD to give real-time near bit inc and azi
	5.5 Inc/ Azm	Y	Rotary (or via mud motor)	12	0	250 RPM 53 klb	none	none (1.9375 bore - no restriction)	None	Lithium batteries/ rotation	Best bit for formation - Prefer 0.5 x hole diameter passive gauge	No - Can be operated below any LWD/MWD
	5.5 Inc/ Azm/GR	Y	Rotary (or via mud motor)	12	0	250 RPM 53 klb	none	none (1.9375 bore - no restriction)	None	Lithium batteries/ rotation	Best bit for formation - Prefer 0.5 x hole diameter passive gauge	Yes - integrated with Gyrodata MWD/LWD to give real-time near bit inc, azi and gamma
	11.25 Inc/Azm/GR	Y	Rotary (or via mud motor)	12	0	250 RPM 30 klb	none	none (1.25" slick bore - no restriction)	None	Lithium batteries/ rotation	Best bit for formation - Prefer 0.5 x hole diameter passive gauge	Yes - integrated with Gyrodata MWD/LWD to give real-time near bit inc, azi and gamma
	Inc/Azi 6.8ft Azi GR 22ft	Yes	Flow	3 mins (while drilling)	0	400 / 60K	400	700	None	Turbine alternator driven by mud flow	Nabors specifications preferred	Integrated with Nabors AccuMP or AccuSteer
	N/A	Y	Rotary	Avg 5 min	3	300 / 50,000	300	700	40 ppb med nut plug	9	Application Specific	No
	6/6/6/30	Y	Mud flow via surface skid	Avg 6 min	0	400 / 56,000	520	1100	Steering system none, MWD, 50ppb med nut plug	Turbine Gemerator	Application Specific	Yes
	4/4/4/29	Y	Mud flow via surface skid	Avg 6 min	0	400 / 45,000	320	650	Steering system none, MWD, 50ppb med nut plug	Turbine Gemerator	Application Specific	Yes

2020 ROTARY STEERABLE DRILLING SYSTEMS DIRECTORY

Product trade name	Point-the-bit or Push-the-bit	Length (ft)	O.D. & I.D. (in.)	Hole size (in.)	Max DLS capability (°/100')	Automated closed loop deviation control (yes/no) (+/-degrees)	Build rate increment	Is deviation force continuous?	Max temp (°C/°F)	Max internal pressure (psi)	Other special pressure limitations	Does tool require configuration based on anticipated flow rate?	
VectorZIEL 400	Push the bit	26	OD: 4.75" ID: N/A	6" - 6 3/4"	8	Yes (0.1)	5%	Yes	150°C - 302°F	20,000	None	No	
VectorEXAKT 900	Push the bit	26	OD: 9" ID: N/A	14 3/4" - 17 1/2	Vertical Drilling	Yes (0.1)	Vertical Drilling	Yes	150°C - 302°F	20,000	None	No	
VectorEXAKT 800	Push the bit	25	OD: 8" ID: N/A	12 1/4" - 13 7/8"	Vertical Drilling	Yes (0.1)	Vertical Drilling	Yes	150°C - 302°F	20,000	None	No	
VectorEXAKT 600	Push the bit	25	OD: 6.75" ID: N/A	8 1/2" - 9 7/8"	Vertical Drilling	Yes (0.1)	Vertical Drilling	Yes	150°C - 302°F	20,000	None	No	
Sanvean Technologiies Scout Downhole													
9.625" Rotary Steerable Scout	Push	18.22	OD: 9.63 ID: 2.75	12.25 - 16.00	3	Yes +/- 0.1°	25%	Yes	150/302	20,000	None	No	
7.125" Rotary Steerable Scout	Push	14.11	OD: 7.13 ID: 1.63	8.5 - 8.75	6	Yes +/- 0.1°	25%	Yes	150/302	20,000	None	No	
Schlumberger +1-281-285-8500													
PowerDrive Archer 675	Hybrid-Point-the-bit	16.15	OD: 6.75 ID: N/A	8.375 - 9.675	15	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302	20,000	Optimized for Drilling conditions	Optimized for Drilling conditions	Inc 9.9 / GR
PowerDrive Archer 475	Hybrid-Point-the-bit	14.98	OD: 4.75 ID: N/A	5.875 - 6.75	18	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302	20,000	Optimized for Drilling conditions	Optimized for Drilling conditions	Inc 8.41 GR
PowerDrive Orbit 1100	Hybrid Push-the-bit	15.22	OD: 11 ID: N/A	20 - 28	2	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302	20,000 (35,000 Optional)	Optimized for Drilling conditions	Optimized for Drilling conditions	Inc 8.99 GR
PowerDrive Orbit G2 900	Hybrid Push-the-bit	13.94	OD: 9 ID: N/A	12 - 18.5	5	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302	20,000 (35,000 Optional)	Optimized for Drilling conditions	Optimized for Drilling conditions	
PowerDrive Orbit 825	Hybrid Push-the-bit	13.84	OD: 8.25 ID: N/A	10.625 - 11.625	6	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302	20,000 (35,000 Optional)	Optimized for Drilling conditions	Optimized for Drilling conditions	
PowerDrive Orbit G2 675	Hybrid Push-the-bit	13.43	OD: 6.75 ID: N/A	8.375 - 9.675	8	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302 (175/350 optional)	20,000 (35,000 Optional)	Optimized for Drilling conditions	Optimized for Drilling conditions	
PowerDrive Orbit G2 475	Hybrid Push-the-bit	13.38	OD: 4.75 ID: N/A	5.875 - 6.75	10	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302 (175/350 optional)	20,000	Optimized for Drilling conditions	Optimized for Drilling conditions	
PowerV 1100	Hybrid Push-the-bit	15.22	OD: 11 ID: N/A	20 - 28	Vertical Drilling	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302	20,000 (35,000 Optional)	Optimized for Drilling conditions	Optimized for Drilling conditions	
PowerV 900	Hybrid Push-the-bit	14.05	OD: 9 ID: N/A	12 - 18.5	Vertical Drilling	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302	20,000 (35,000 Optional)	Optimized for Drilling conditions	Optimized for Drilling conditions	
PowerV 825	Hybrid Push-the-bit	13.84	OD: 8.25 ID: N/A	10.625 - 11.625	Vertical Drilling	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302	20,000 (35,000 Optional)	Optimized for Drilling conditions	Optimized for Drilling conditions	
PowerV 675	Hybrid Push-the-bit	13.53	OD: 6.75 ID: N/A	8.375 - 9.675	Vertical Drilling	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302 (175/350 optional)	20,000 (35,000 Optional)	Optimized for Drilling conditions	Optimized for Drilling conditions	
PowerV 475	Hybrid Push-the-bit	13.5	OD: 4.75 ID: N/A	5.875 - 6.75	Vertical Drilling	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302 (175/350 optional)	20,000	Optimized for Drilling conditions	Optimized for Drilling conditions	
PowerDrive Xcel 675	Point-the-bit	24.93	OD: 6.75 ID: N/A	8.375-10.625	8	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302	20,000	None	Optimized for Drilling conditions	

	Sensor distance (ft) Inc/Azm/GR/ Res	Control from surface (Downlink) (Y/ N)	If yes, tool control method	Rig time req'd to communicate change in target (minutes)	Minimum kickoff inclination (degrees)	Max RPM / WOB	Min flow rate (gpm)	Max flow rate (gpm)	LCM limits	Power source	Bit requirements	Integrated LWD?
	4/4/4/27	Y	Mud flow via surface skid	Avg 6 min	0	400 / 16,000	230	300	Steering system none, MWD, 50ppb med nut plug	Turbine Gemerator	Application Specific	Yes
	6/NA/6/NA	Y	Mud flow via surface skid	Avg 6 min	Vertical Drilling	300 / 90,000	630	1500	Steering system none, MWD, 50ppb med nut plug	Turbine Gemerator	Application Specific	No
	6/NA/6/NA	Y	Mud flow via surface skid	Avg 6 min	Vertical Drilling	300 / 56,000	520	1100	Steering system none, MWD, 50ppb med nut plug	Turbine Gemerator	Application Specific	No
	4/NA/4/NA	Y	Mud flow via surface skid	Avg 6 min	Vertical Drilling	400 / 45,000	320	650	Steering system none, MWD, 50ppb med nut plug	Turbine Gemerator	Application Specific	No
	8.42, 9.67, NA, NA	Y	Rotary	3 Minutes	0	400 RPM/85 klbf	500 psi pressure drop at bit	1800	60 lb/bbl med nut plug	Lithium Batteries	Application Specific	No
	5.17, 6.42, NA, NA	Y	Rotary	3 Minutes	0	400 RPM/55 klbf	500 psi pressure drop at bit	800	60 lb/bbl med nut plug	Lithium Batteries	Application Specific	No
/ Azm 12.01 9.01	Y	Flow rate and/or RPM change	While drilling ahead	0	350 RPM As per Smith PDC bit guidelines	220	650	50 lb/bbl med. nut plug	Turbine generator	Application specific	Modular	
/ Azm / 10.51 7.51	Y	Flow rate and/or RPM change	While drilling ahead	0	350 RPM As per Smith PDC bit guidelines	130	355	35 lb/bbl med. nut plug	Turbine generator	Application specific	Modular	
/ Azm / 11.19 8.19	Y	Flow rate and/or RPM change	While drilling ahead	0	350 RPM 225 klbf	280	2000	50 lb/bbl med. nut plug	Turbine generator	Application specific	Modular	
	Inc / Azm 7.71 / 9.91 GR 6.92	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 370 klbf	280	2,000	50 lb/bbl med. nut plug	Turbine generator	Application specific	Modular
	Inc / Azm 7.94 / 10.14 GR 7.14	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 270 klbf	280	2000	50 lb/bbl med. nut plug	Turbine generator	Application specific	Modular
	Inc / Azm 7.10 / 9.30 GR 6.31	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 180 klbf	210	970	50 lb/bbl med. nut plug	Turbine generator	Application specific	Modular
	Inc / Azm 6.85/ 8.95 GR 5.96	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 31 klbf	120	355	35 lb/bbl med. nut plug	Turbine generator	Application specific	Modular
	Inc / Azm 8.99 / 11.19 GR 8.19	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 225 klbf	280	2000	50 lb/bbl med. nut plug	Turbine generator	Application specific	Modular
	Inc / Azm 7.71 / 9.91 GR 6.92	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 370 klbf	280	2,000	50 lb/bbl med. nut plug	Turbine generator	Application specific	Modular
	Inc / Azm 7.94 / 10.14 GR 7.14	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 270 klbf	280	2000	50 lb/bbl med. nut plug	Turbine generator	Application specific	Modular
	Inc / Azm 7.10 / 9.30 GR 6.31	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 180 klbf	210	970	50 lb/bbl med. nut plug	Turbine generator	Application specific	Modular
	Inc / Azm 6.85/ 8.95 GR 5.96	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 31 klbf	120	355	35 lb/bbl med. nut plug	Turbine generator	Application specific	Modular
	Inc / Azm 14.5 / 12.9 GR 15.83	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 55 klbf	260	805	50 lb/bbl med. nut plug	Turbine generator	Application specific - bi-center compatible	Modular

2020 ROTARY STEERABLE DRILLING SYSTEMS DIRECTORY

Product trade name	Point-the-bit or Push-the-bit	Length (ft)	O.D. & I.D. (in.)	Hole size (in.)	Max DLS capability (°/100')	Automated closed loop deviation control (yes/no) (+/-degrees)	Build rate increment	Is deviation force continuous?	Max temp (°C/°F)	Max internal pressure (psi)	Other special pressure limitations	Does tool require configuration based on anticipated flow rate?
PowerDrive Xcel 900	Point-the-bit	27.89	OD: 9.00 ID: N/A	12-17.5	6.5	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	150/302	20,000	None	Optimized for Drilling conditions
PowerDrive ICE	Hybrid Push-the-bit	34.26	OD: 6.75 ID: N/A	8.5	8	Yes, Azimuth and Inclination +/- 0.1°	1% and 1° TF resolution	Adjustable on Fully Rotating Tool	200/392	30,000	Optimized for Drilling conditions	Optimized for Drilling conditions
Scientific Drilling International												
HALO 650	Push-the-bit / proportional control	35.5 ft	OD: 6.50" ID: N/A	7.875" - 9.875"	15	Yes, azimuth to 0.5 deg, inclination to 0.125 deg	Controllable in 12.5% Force or 0.125 deg increments	Yes, in Autopilot modes deviation force will auto adjust.	150/302	20k psi	None	Steering Unit - No. MWD - Yes.
HALO 500	Push-the-bit / proportional control	35.1 ft	OD: 5.00" ID: N/A	5.875"-6.75"	13	Yes, azimuth to 0.5 deg, inclination to 0.125 deg	Controllable in 12.5% Force or 0.125 deg increments	Yes, in Autopilot modes deviation force will auto adjust.	150/302	20k psi	None	Steering Unit - No. MWD - Yes.
TerraVici Drilling Solutions	**Kevin McMillin**	**kevin.mcmillin@terravici.com**										
TerraVici 4.75" RSS	Point-the-bit	20	4.75	6.00 - 6.75	15	Yes	0-100% and 1° TF resolution	Yes	150 / 302	20,000	None	Yes
TerraVici 6.5" RSS	Point-the-bit	22	6.5	7.875 - 9.875	12	Yes	0-100% and 1° TF resolution	Yes	150 / 302	20,000	None	Yes
TerraVici 8" RSS	Point-the-bit	23	8	9.875 - 12.25	4	Yes	0-100% and 1° TF resolution	Yes	150 / 302	20,000	None	Yes
Weatherford	**John Rice, Global Service Line Manager - RSS**	**John.Rice@weatherford.com**										
Revolution 825 rotary steerable system (Core, Heat)	Point	17.8	OD: 8.25 ID: 2.75	10.625 -18.25	7.5	Yes	Variable	Yes	149/300 Core 175/347 Heat	25,000 Core 30,000 Heat	None	No
Revolution 675 rotary steerable system (Core, Heat)	Point	14.8	OD: 6.75 ID: 2.0	7.875 - 9.875	10	Yes	Variable	Yes	149/300 Core 175/347 Heat	25,000 Core 30,000 Heat	None	No
Revolution 475 rotary steerable system (Core, Heat)	Point	12.9	OD: 4.75 ID: 1.75	5.875 - 6.75	10	Yes	Variable	Yes	149/300 Core 175/347 Heat	25,000 Core 30,000 Heat	None	No
Magnus 1100 Rotary Steerable System	Push	22.7	OD: 11.00 ID: 2.75	14.75 - 18.50	5	Yes	Variable	Yes	150/302	25,000	None	Yes
Magnus 950 Rotary Steerable System	Push	22.7	OD: 9.50 ID: 2.75	12.00 - 14.50 -	6	Yes	Variable	Yes	150/302	25,000	None	Yes
Magnus 675 Rotary Steerable System	Push	21.5	OD: 6.75 ID: 2.0	8.375 - 9.875	10	Yes	Variable	Yes	150/302	30,000	None	Yes

	Sensor distance (ft) Inc/Azm/GR/ Res	Control from surface (Downlink) (Y/ N)	If yes, tool control method	Rig time req'd to communicate change in target (minutes)	Minimum kickoff inclination (degrees)	Max RPM / WOB	Min flow rate (gpm)	Max flow rate (gpm)	LCM limits	Power source	Bit requirements	Integrated LWD?
	Inc / Azm 16.2 / 14.6 GR 10.89	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 75 klbf	260	1,800	50 lb/bbl med. nut plug	Turbine generator	Application specific - bi-center compatible	Modular
	Inc / Azm 13.30/13.30	Y	Flow rate and/ or RPM change	While drilling ahead	0	350 RPM 105.6 klbf	275	800	50 lb/bbl med. nut plug	Turbine generator	Application specific	Modular
	PWD - 2.3' NBI/NBA - 5.9' AZ GR - 15.4' Survey - 21.0'	Y	Rig pumps - variable flow rate.	3-6 mins with confirmation. Downlinks can be performed while drilling ahead. Full MWD decoding possible during downlink.	Vertical	350 RPM / 60 klbs WOB	350 gpm	600 gpm	50 ppb medium fibrous	System powered by downhole generator. Lithium battery used for flow off surveys.	Application Specific	Single collar loadout, with steering unit and integrated MWD system.
	PWD - 2.1' NBI/NBA - 5.5' AZ GR - 14.4' Survey - 21.0'	Y	Rig pumps - variable flow rate.	3-6 mins with confirmation. Downlinks can be performed while drilling ahead. Full MWD decoding possible during downlink.	Vertical	350 RPM / 30 klbs WOB	130 gpm	360 gpm	50 ppb medium fibrous	System powered by downhole generator. Lithium battery used for flow off surveys.	Application Specific	Single collar loadout, with steering unit and integrated MWD system.
	Inc / Azm 10 / 10	Y	Flow rate change, MWD direct-connect, or short hop	While drilling ahead	0	250 RPM / 25 klbf	180	400	40 lb/bbl med. nut plug	Turbine generator	Application Specific	No - Will function below any MWD/ LWD
	Inc / Azm 10 / 10	Y	Flow rate change, MWD direct-connect, or short hop	While drilling ahead	0	250 RPM / 50 klbf	320	750	40 lb/bbl med. nut plug	Turbine generator	Application Specific	No - Will function below any MWD/ LWD
	Inc / Azm 10 / 10	Y	Flow rate change, MWD direct-connect, or short hop	While drilling ahead	0	250 RPM / 50 klbf	320	750	40 lb/bbl med. nut plug	Turbine generator	Application Specific	No - Will function below any MWD/ LWD
	Brad Zukiwsky, Product Champion - Magnus RSS			**bradley.zukiwsky@weatherford.com**		**www.weatherford.com**						
	14/14/16/42	Y	Drillstring rotation or negative pulse from surface	Typically < 3	0	180 RPM 90 klb	No minimum requirement	1,500	Steering system: None MWD system: 80 lb/bbl fine/ med (higher conc. on request)	Lithium batteries	Long passive gauge PDC	Yes
	12/ 12/14/40	Y	Drillstring rotation or negative pulse from surface	Typically < 3	0	200 RPM 50 klb	No minimum requirement	750	Steering system: None MWD system: 80 lb/bbl fine/ med (higher conc. on request)	Lithium batteries	Long passive gauge PDC	Yes
	9/ 9/16/39	Y	Drillstring rotation or negative pulse from surface	Typically < 3	0	200 RPM 25 klb	No minimum requirement	350	Steering system: None MWD system: 80 lb/bbl fine/ med (higher conc. on request)	Lithium batteries	Long passive gauge PDC	Yes
	7/7/7/47	Y	Negative pulse from surface	Typically < 3	0	300 RPM / 90 klb	No minimum requirement	1,400	80 lb/bbl fine/ med (higher conc. on request)	Turbine Generator or Lithium batteries	None	Yes
	7/7/7/47	Y	Negative pulse from surface	Typically < 3	0	300 RPM / 90 klb	No minimum requirement	1,200	80 lb/bbl fine/ med (higher conc. on request)	Turbine Generator or Lithium batteries	None	Yes
	6/6/6/444	Y	Negative pulse from surface	Typically < 3	0	300 RPM / 50 klb	No minimum requirement	700	80 lb/bbl fine/ med (higher conc. on request)	Turbine Generator or Lithium batteries	None	Yes

The *Alvheim* FPSO is located in the central part of the North Sea, and produces about 100,000 b/d of oil. *(Images courtesy Aker BP ASA except as noted)*

Thermal flare gas flow meter solves measurement challenges on FPSO vessel

Innovative metering system deployed on Alvheim FPSO in the North Sea

BØRGE OLAFSEN, *AKER BP ASA*
SIMON OBARO, *FLOW-TEKNIKK AS*
RICHARD KOEKEN, *FCI*

THE ACCURATE MEASUREMENT and disposal of flare gases aboard floating production storage and offloading (FPSO) vessels is essential to manage these potentially hazardous combustible, flammable and toxic gases. Accurate measurement of these waste gases allows them to be processed efficiently and effectively to protect people and equipment aboard the vessel. Measuring of flare gas is also most often a strict regulatory requirement, as it can form the basis for payment of environmental taxes, climate quotas, etc.

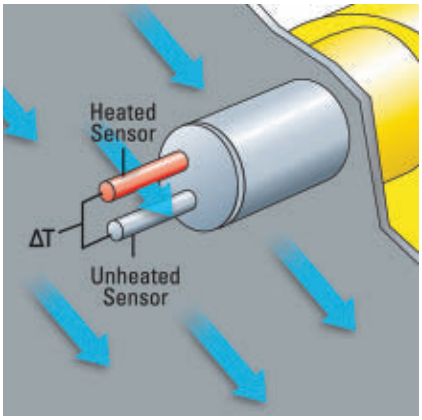
The dangers of improper hydrocarbon gas handling are well known and are regulated strictly by international safety organizations. The combustible and flammable properties of hydrocarbons make their handling a highly regulated process, requiring flow meter design certifications from multiple international approval agencies including FM, FMc, ATEX and IECEx to name a few.

Measuring flare gas is challenging for several reasons. These issues include mixed gas compositions, highly variable flow rates, large line sizes, lack of available pipe straight-run, limited access for installation or maintenance, and the effects of corrosive sea salt water and air. Only a few flow meter sensing technologies are robust enough to meet these many demanding requirements while providing accurate and consistent gas flow measurement.

THE PROBLEM

Aker BP ASA, one of the largest independent offshore oil companies in Europe, began to experience flare gas measurement accuracy and consistency issues aboard its *Alvheim* FPSO vessel. This FPSO vessel is located in the central part of the North Sea, close to the UK sector, and produces about 100,000 b/d of oil, including gas passing through its production pipelines and various metering stations (including those for flare gas).

The vessel's engineers reported that the ultrasonic flow meters on the flare gas vent lines had stopped working at higher flow rates.



Thermal flow meters rely on the thermal dispersion principle of operation to measure gas. *(Courtesy FCI)*

They identified liquid condensation on the ultrasonic meter transducers and other challenging installation conditions as possible causes of the meter failures for which there was no immediate and/or permanent fix available to them.

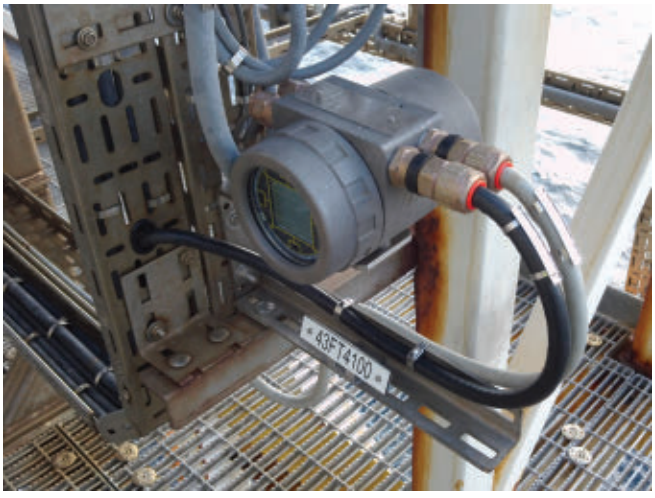
The vessel's engineers then researched alternative flow sensor technologies from several meter manufacturers for a new solution to measuring vent line flare gas. After contacting Fluid Components International (FCI), its applications team recommended the thermal dispersion ST100 Series Flare Gas Meter.

An innovative solution was chosen: The two existing thermowells used for dual temperature measurement as input to the ultrasonic flow meter were removed and standard 18-in. isolation ball valves were installed. By doing so during a process shutdown, it meant that the ST100 probes could be installed at any time at a later stage. The built-in temperature measurement of the ST100 thermal meter was then re-routed to the existing ultrasonic flow meter, thus keeping the original measurement intact.

The selected thermal flow meter configuration included an in-situ calibration verification system and stainless steel local and remote enclosures, which are designed for offshore flare gas systems. With no moving parts or orifices to plug or foul, thermal mass flow meters are virtually immune to clogging by dirty gas, require almost no maintenance for continuous operation, and offer a lower lifecycle cost.

Thermal flow meters rely on the thermal dispersion principle of operation to measure gas. This technology places two thermowell protected platinum RTD temperature sensors in the process stream. One RTD is heated while the other senses the actual process temperature. The temperature difference between these sensors generates a voltage output, which is proportional to the media cooling effect and can be used to measure the gas mass flow rate without the need for additional pressure or temperature transmitters.

To comply with local regulations, which are intended to protect the environment through the monitoring of greenhouse gases (GHG), the reporting of (vent) flare gases should be done accurately over the entire flow range. The calibration of the chosen thermal meters was based on the actual gas composition as close as possible to the flare gas composition and



The thermal flow meter selected for the Alvheim FPSO featured a rugged remote enclosure that was rated for hazardous environment operation.

the vessel engineers' desired flow range, with calibration performed at FCI's unique actual gas calibration laboratory.

The thermal meter selected can store up to five unique calibration curves to accommodate differing gas mixtures, multiple flare gas compositions, and it obtains up to 1000:1 turndown ratio. Measurement accuracy is 0.75% of reading + 0.50% of full scale with a maximum of 5% of reading over the entire 1000:1 turndown. The thermal flow sensing element measures flow from 0.07 to 305 Nm/s (0.25 to 1000 SFPS).

The selected thermal flow meter is agency approved for hazardous environments, including the entire instrument, the transmitter and the rugged, NEMA 4X/IP67 rated remote enclosure (Fig 3). Instrument approvals in addition to SIL-1 include ATEX, IECEx, FM and FMc.

When it comes to outputs, this meter offers all the most popular solutions: 4-20 mA analog, frequency/pulse, alarm relays or digital bus communications such as HART, Fieldbus, Profibus or Modbus. Also standard is an on-board data logger with an easily accessible, removable micro-SD memory card capable of storing 40 million readings.

FLOW METER TESTING

The FPSO vessel's engineers designed a test protocol to compare the thermal and the ultrasonic meter. Their objectives included:

- Find a dependable solution for accurate measurement at higher flare flow rates
- Investigate whether existing ultrasonic flare meters work as well as intended
- Be on the forefront of technology.

As mentioned, the thermal mass flow meter with its built-in temperature measurement was connected to the flow computer, and the temperature reading was shared with the existing ultrasonic flow meter for correct conversion from line to standard condition flow. The ultrasonic meter is located 1 meter upstream of the thermal meter.

The 18-in. [DN450] vent flare gas flowline on the FPSO vessel was monitored with a dual-averaging thermal dispersion sensor element configuration for better accuracy and to compensate for the larger line size and limited installation length. With the dual-averaging sensor design of the thermal flow element providing built-in temperature measurement, the vessel's engineers were also able to eliminate the cost and installation complexity of adding two additional thermowells/temperature sensors. Two existing thermowells were basically replaced with two ST100 probes with built-in temperature measurement.

The thermal dual-averaging flow meter installed included the following specifications:

- Calibration flow range: Extended with more than 26 flow points and max 5% accuracy of reading accuracy over entire flow range
  - Normal operating: 60 – 850 NCMH [0,11 to 1,50 Nm/s]
  - Upset conditions: 850 – 172500 NCMH [1,50 to 304,66 Nm/s]
- Calibration media: Actual flare gas (offshore, upstream, stable gas composition):
  - Methane 93%
  - Ethane 4.58%
  - Carbon Dioxide 1.16%
  - Nitrogen 0.91%
  - Propane 0.27%
  - n-Hexane 0.06%.

Both of the new dual-averaging thermal flow sensor probes were installed in existing flanged process connections, previously used for thermowells and temperature elements, through full-bore ball valves in series with the existing ultrasonic meter for a one-year trial. The reason for having these probes in the upper half of pipe ID was the suspected stress/high torque that might occur on the probes with long entry during full flow/upset flaring situation because the pipe ID is 18 inches. This was slightly different than the suggested 15% and 85% of pipe ID installation depth.

Installed thermal flow meter on flare gas vent.

TEST RESULTS

The metering system's July 2019 daily report for flare activity confirmed that the thermal meter correctly reported 54,000 Nm^3/hr, while the ultrasonic meter (blue) incorrectly reported only 7394 Nm^3/hr, due to the limitation of max flow capabilities of the ultrasonic meters. Based on the overall experience with the thermal meter, the FPSO vessel engineers concluded that for new flaring systems/production installations, the company would prepare piping for insertion type thermal mass flowmeters by adding flanges and valves for easy installation. Thermal meters were judged to be a cost effective and simple solution to measure flare gas across the entire flow range.

The July monthly summary report indicated a mismeasurement where the ultrasonic meter was not able to measure correctly; while the thermal meter was able to measure as expected. The export gas flow was redirected to the flare line due to a process upset. After the flow was redirected, almost instantly the thermal meter correctly measures the same flow rate in the flare gas line and follows the trend, while the ultrasonic meter is incorrectly measuring only 15% of the real flare gas flow. In these situations, it has been convenient to just use the thermal meter's daily figures for daily flare gas reporting.

During a trip condition, the complete gas export flow is redirected to the flare where the new thermal meter immediately measures the same maximum flow as expected (equals gas export flow), while the ultrasonic meter is measuring only 20% of this flow. The result is a huge difference in totalized flow and demonstrates that a large amount of flare gas is not measured by the ultrasonic meter.

Moreover, the vessel's engineers were aware that ultrasonic meter calibration checks had to be verified in the field by requesting the meter supplier to check the ultrasonic transducers in a "zero box." This process typically took a total of three days (including time to get on-site) at a cost of approximately €10,000.00 for every verification.

In comparison, the installed thermal mass flow meter is able to perform a complete self-verification of calibration using a simple nitrogen connection/bottle. With this optional accessory to the basic meter, there is no requirement to shut down the line, pull the meter, install a spare and paying a lab fee to help meet air quality management regulations.

THE AUTHORS

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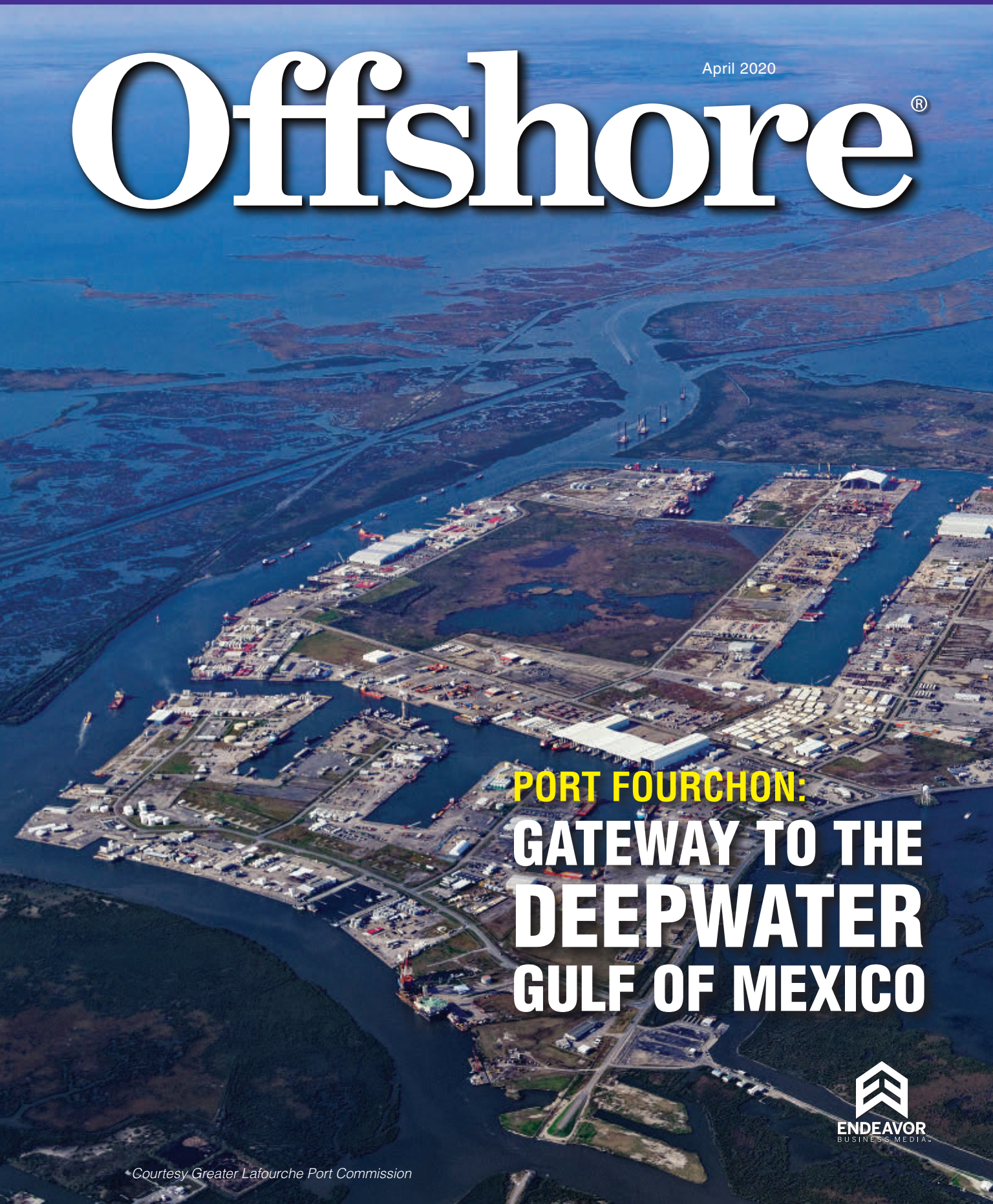
April 2020



PORT FOURCHON:
GATEWAY TO THE DEEPWATER GULF OF MEXICO

ENDEAVOR BUSINESS MEDIA

Courtesy Greater Lafourche Port Commission

According to statistics from the LaDOTD, the South Lafourche Leonard Miller, Jr. Airport ranked fourth in the state in total economic benefits in 2019. *(Images courtesy Greater Lafourche Port Commission)*

Port Fourchon: Ready today, ready for tomorrow

GLPC celebrates 60 years in business

JUDY MURRAY, *CONTRIBUTING EDITOR*

ACCORDING TO CHETT CHIASSON, executive director of the Greater Lafourche Port Complex, it is an exciting time to be working in Port Fourchon.

"The Port is celebrating 60 years of serving the Gulf of Mexico (GoM), and we are working on plans that will position it well for the future," he said.

Expansion work continues on Slip C, which will add 2,500 ft (762 m) of waterfront. "We're also doing the final dredge of Slip D that will increase the water depth to 27 ft (8.2 m)," Chiasson said, noting the slip will be fully dredged this year and ready for development.

Chiasson also is pleased with the progress the port commission has been made with mitigation and restoration through the years. He pointed to the Maritime Forest Ridge, a now 6,000 linear foot ridge that has been in place for more than 12 years, as an example. Chenier ridges and maritime forests are physically and ecologically important to the coast. In addition to their function topographically in slowing storm surges, they are the critical habitat for more than 338 migrating bird species that travel along the Mississippi Flyway each spring and fall. Working together, the Barataria-Terrebonne National Estuary Program, Gulf of Mexico Program, Gulf of Mexico Foundation, National Oceanic and Atmospheric Administration, Louisiana Department of Natural Resources, USDA National Resources Conservation Service, Shell and the Port have restored the ridge that had eroded away over

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the years. Also, the port has restored more than 1,000 acres of wetlands with material beneficially used through the slip and channel hydraulic dredging process.

INVESTING IN AIRPORT EXPANSION

Restoration and refurbishment are going on in many areas around the Port, including projects at the South Lafourche Leonard Miller, Jr. Airport. Updates and upgrades are important, Chiasson said, because the number of people going through the airport continues to grow as does the facility's impact on the local economy.

Last year, more than 130,000 people transited the airport, and according to statistics from the Louisiana Department of Transportation and Development (LaDOTD), the airport ranked fourth in the state in total economic benefits in 2019, with a net output of $97,628,000. This constitutes an increase of more than $25 million since the last impact assessment was conducted in 2015. In 2019, the airport employed 500 people, compared to 380 in 2015, with an $18 million payroll.

While these numbers are impressive, Chiasson said there is still room for growth. "The Airport Corridor, as much as has been done, is a clean slate for attracting new business and economic development," he said, and improved access created by the new airport road will facilitate new investment.

A grant from the Federal Economic Development Administration, money from the Port Commission, and contributions by the parish government, amounting to $1.2 million have gone to rebuilding the sub-basin, raising and paving the airport road and completing the intersection at LA 308. Meanwhile, an airfield drainage project has been completed, and design work is being finalized for a new hangar.

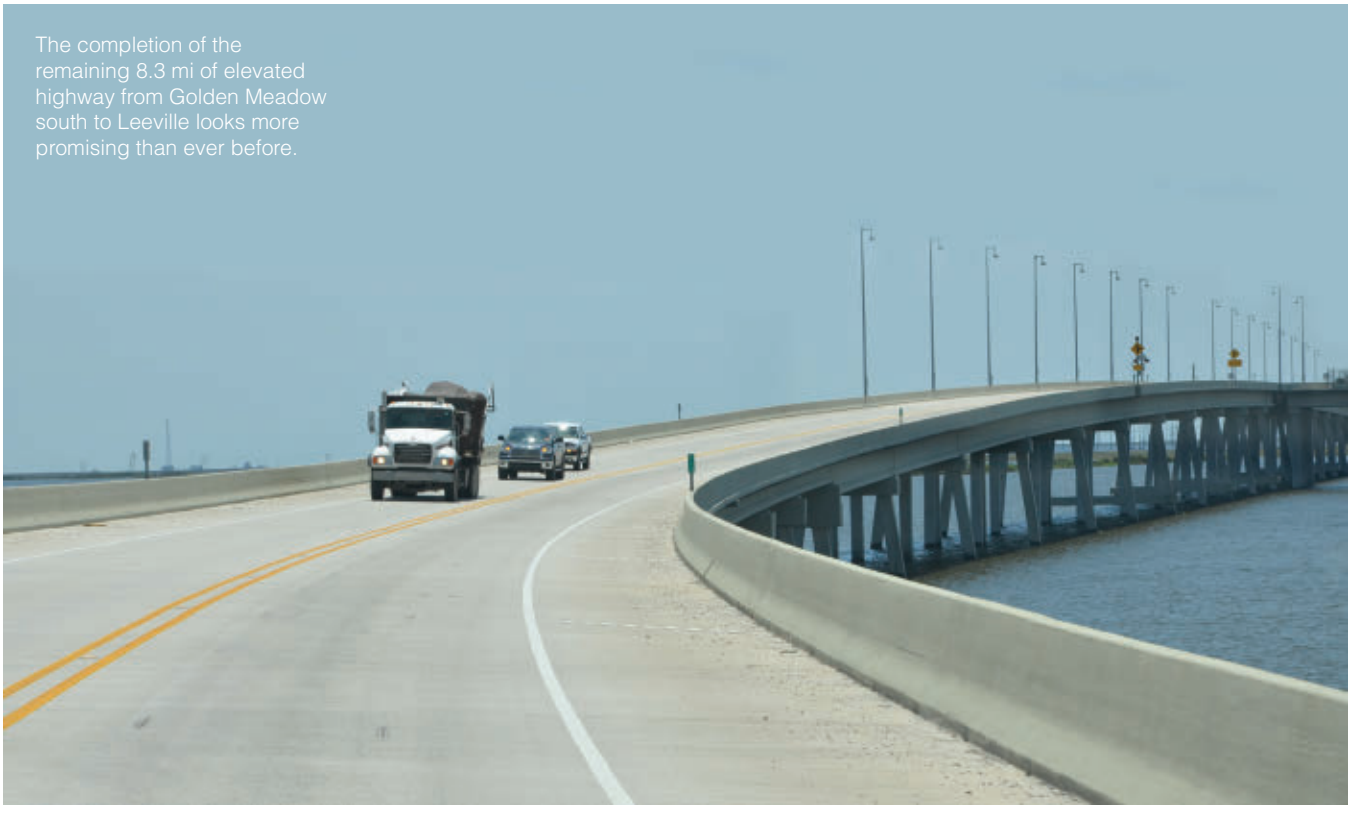
The next big thing will be a $35 million project for a three-lane bridge across Bayou Lafourche, connecting highway LA 308 with LA 1 and an access road that will provide a direct connection to the airport. This will be funded by a $16.4 million federal BUILD Grant, $9.3 million provided by the state and the balance coming from the Parish and the Port Commission.

The first two phases – repaving the road and constructing the intersection – are finished, according to Chiasson, and the next phase is being designed. "It is 60% complete and will be ready for bid by September," he said. Construction is expected to begin in the spring of 2021.

"This is only one of the construction projects going on here," Chiasson said. "We are also making progress on LA 1, the two-lane highway that supports Grand Isle, Port Fourchon and the Louisiana Offshore Oil Port (LOOP), the only deepwater oil port facility in the United States."

IMPROVING ACCESS WITH LA 1

Henri Boulet, executive director of the LA 1 Coalition, is excited about the progress being made on the highway LA 1 initiative. "The LA 1 project has great momentum going into 2020," he said, noting that the coalition made significant progress last year, in particular with the Louisiana state legislature approving $150 million of funding for Phase 2 of the



The completion of the remaining 8.3 mi of elevated highway from Golden Meadow south to Leeville looks more promising than ever before.

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TETRA

The proposed future Coastal Wetlands Park is a result of a mitigation effort where dredged sediment from the Slip D development was placed in an open water area.

project, which is the 8.3 mi (13.4 km) of elevated highway from Golden Meadow south to Leeville.

"The state's 1999 commitment makes up 33% of what we believe we need for Phase 2," Boulet said, "and we have a second major commitment from the Port for $25 million for the project over a five-year period. We also are asking industry operators that rely on Port Fourchon to support their Gulf of Mexico operations to provide a multi-million-dollar collective industry pledge."

With a significant portion of the funding secured, the LA 1 Coalition worked with the LaDOTD to file an application with the US DOT INFRA Grant Program for $185 million to match other commitments.

Boulet said there is strong agreement among local, state and federal stakeholders that this project is critically important. It not only will enable safe entry and exit from the Port, it will allow access to Grand Isle, the only inhabited barrier island offshore Louisiana.

"People have homes on Grand Isle," Boulet said. "It's our version of Martha's Vineyard, and it draws thousands of tourists each year to beautiful beaches, crabbing grounds and speckled trout fishing."

With the present state of LA 1, access is compromised any time tides are unusually high or inclement weather forms in the GoM. When the island has to be evacuated, the poor condition of the current low-lying road poses evacuation challenges.

"LA 1 also provides the only access to barrier island and marsh restoration projects like the Belle Pass-Golden Meadow Marsh Creation Project, which will create 23,200 acres of marsh along the LA 1 corridor to provide new wetland habitat and restore degraded marsh," Boulet said.

Coastal restoration is vital in south Louisiana, where the coastline is shrinking. Although work is ongoing to rebuild as much of the wetlands as possible to sustain and maintain the coast, limited access drives up the cost of these projects. "The lack of a reliable road impacts restoration costs because project delays from compromised or delayed road access affect cost," Boulet says.

The seafood industry also relies on LA 1 to get to the fishing grounds and to move their catch to market. "Approximately 7.8 million pounds of seafood, amounting to $17 million, moves on this road every year," he said, "but when the road is closed, seafood docks can't get their catch to processing facilities. It's a critical road for a lot of reasons."

In fact, there are far-reaching repercussions when LA 1 is impassable. Each day LA 1 is closed costs $46 million in oil and gas production and $528 million in GDP.

"The cost of improving this road pales in comparison to what is lost when the road is closed," Boulet said. "It is clear that the proposed improvements need to be done."

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EXPANDING DEEPWATER CAPABILITIES

Improving access is critical for multiple areas, including Fourchon Island, another significant project that is in progress. Investment in the Fourchon Island Project will provide Port Fourchon greater access to the GoM by increasing inner harbor depths to accommodate larger vessels, rigs, and platforms. When completed, the channel at Belle Pass will be 50 ft (15.2 m) deep, with the dredged material going to the Barataria-Terrebonne basin.

"We will be able to create more than 4,700 acres of marsh over the years with this project," Chiasson said. "The port has constructed more than 1,000 acres of wetlands and developed another 1,000 acres of land since 2000." Those efforts will increase during the next phase of development.

The plans for Fourchon Island are ambitious. In late January, the Port filed a permit to develop a slip on the island and an application for a federal grant from MARAD to rebuild the Fourchon Bridge to provide road access to the island.

"The previous pedestal bridge wasn't safe," Chiasson said. "It had to be removed because it couldn't be closed. It is over a navigable waterway, so it needed to be opened, but it couldn't be left open because it presents a safety hazard in its open state."

Chiasson said the bridge cost is estimated at $24 million and is hoping for $14 million in federal funding, but even if the grant does not come through, he hopes the project will proceed. "We absolutely need access with or without the grant. The island is only accessible by boat today. Having a bridge is vital not only for future development but for safety reasons," Chiasson said, pointing out that there are pipelines running through the beach head on the island and a facility manned by workers.

Early in 2019, GLPC submitted an addendum to its original feasibility report for plans to increase the water depth around the island. The goal is to eventually dredge to 50 ft (15.2 m) in Belle Pass, then 30 ft (9.1 m) through Bayou Lafourche into Floatation Canal and into the northern expansion at the port. This water depth will permit future development on Fourchon Island, enabling GLPC to carry out its plans to build a deepwater rig, repair and refurbishment facility.

"Having a deepwater facility here would be enormously beneficial for operators," Chiasson said, "but the environmental benefits on the back end – creating habitat and repairing the coastline that has been lost over the years – are even more important to us as than the economic side."

GETTING LNG IN THE MIX

Adding to the capabilities at Port Fourchon is a priority, Chiasson said. "We need diversification, and we are excited about adding LNG facilities to our offering."

Fourchon LNG LLC is making progress on the LNG development, which is intended to supply clean fuel to the company's power generation assets being developed in the Caribbean and Asia. At the January GLPC Board Meeting, Energy World Group, the parent company of Fourchon LNG LLC, provided a status report on the new LNG facility, the first phase of which will require an estimated $888 million to build.

"The Port is celebrating 60 years of serving the Gulf of Mexico, and we are working on plans that will position it well for the future," — Chett Chiasson, Greater Lafourche Port Commission Executive Director

Construction is expected to begin in mid-2021 on Phase 1 – an LNG train with 2 million tons per year (MTPA) capacity, a storage tank, and associated marine facilities for loading and exporting LNG. The facility is expected to be ready for commercial operation by mid-2023. Phase 2 is expected to begin commercial operation in mid-2025, increasing capacity by 3 MTPA and providing a second LNG tank.

The project management team is in place, as are the environmental and legal advisors, and key equipment and technology suppliers have been selected. Plans and strategies have been completed, and work is beginning on the next steps, which include the final filing of resource reports, FERC approval, formalizing gas supply agreements and project funding.

"This is a great addition to the suite of vessel services that are offered by our tenants and greatly enhances our capability and versatility," Chiasson said.

CONTINUING THE JOURNEY

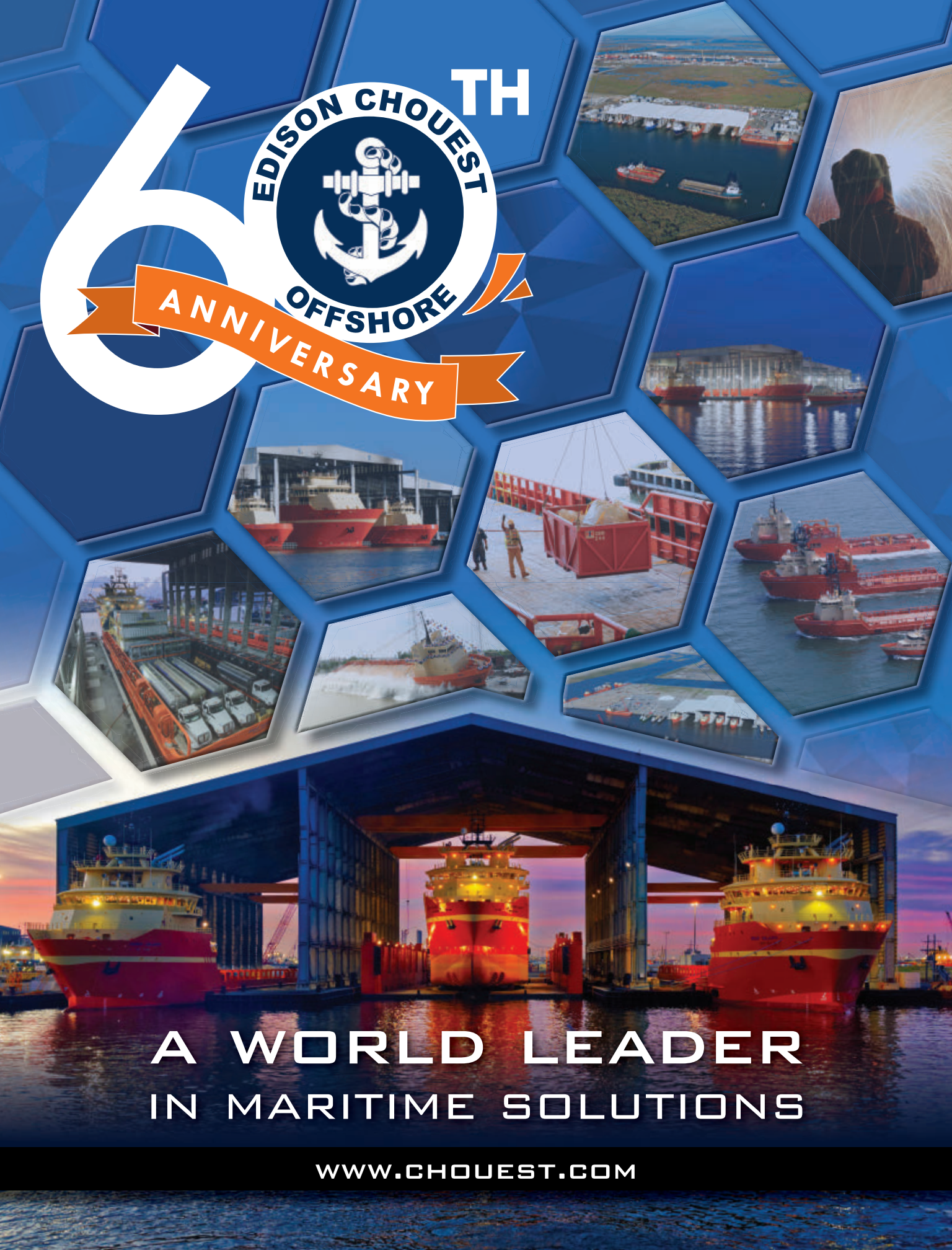
As the port celebrates 60 years in business, Chiasson and his team are working with the elected Board of Commissioners to chart the way forward. "We want to be a leader into the future," he said. "We are always looking for the next best value additions to our Port."

With lower barrel prices constituting the new normal, it is more important than ever to plan and invest wisely.

"Sixty years ago, the Port was just an idea," Chiasson said. "Today, it's critical to Gulf of Mexico oil and gas operations, and the environmental work we've done is contributing to the wellbeing of our community and industry. Without the oil and gas industry, the area Port Fourchon sits on would have been washed away. We take a lot of pride in what we have accomplished here."

Prudent investment at the Port will allow it to continue to serve the needs of the industry and the community, but its continued success really rests on the companies that call the Port home, Chiasson said.

"We're very thankful to our tenants. Without their loyalty and their commitment to providing world-class service to customers, we wouldn't have a port. They made the decision to invest in Port Fourchon, and we're grateful for that," he said.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From its facility in Port Fourchon, TETRA delivers CBFs, specialty fluid blends, and chemical additives, as well as a range of lube oils and drilling fluids. *(Images courtesy TETRA Technologies)*

Leveraging location to deliver leading technologies

Investment in products, processes improves service offerings

JUDY MURRAY, *CONTRIBUTING EDITOR*

THE MOVE INTO DEEPWATER necessitated the development of capabilities and technologies that would be effective in this new and demanding operating environment. As the number of deepwater discoveries grew, companies began to develop products specifically designed to deliver drilling and production efficiencies to maximize productivity for deepwater wells.

These changing demands led to the development of new completion design philosophies and technologies and created a market for advanced completion fluids. TETRA Technologies is one of the companies that responded to the deepwater challenge, delivering innovation and technological leadership to address evolving industry needs.

Since its inception in 1981, TETRA Technologies has designed and manufactured fluids for use in well drilling, completion, and workover operations and today serves a global market that includes customers in the US, Latin America, Africa, Europe, Asia, and the Middle East. One of the most active markets is the Gulf of Mexico (GoM), which the company serves in part from its facility in Port Fourchon, where TETRA has been a tenant for 36 years, expanding its presence six times since first setting up shop.

Today, the TETRA site covers 250,000 sq ft (23,226 sq m) with 3,750 sq ft (348.4 sq m) warehouse capacity and enjoys 850 ft (259 m) of waterfront bulkhead with a 22 ft (6.7 m) water depth. There is a 185 cu ft/min air compressor on site as well as a 150-ton crane and two forklifts rated for 4 tons and 18 tons. Fluids can be loaded or unloaded simultaneously on two boats using 6-in. (16.2-cm) load lines flowing at 31.25 bbl/min and 4-in. (10.2-cm) load lines flowing at 12.5 bbl/min.

The full-service facility houses two covered 250 bbl clear brine fluid (CBF) blending pits, three 500-bbl covered blending pits, 66,000 bbl of fixed asset storage capacity and 9,000 bbl CBF staging tanks for pre-blending orders.

From this facility in Port Fourchon, TETRA delivers CBFs, chemical additives, lube oils, drill water, potable water and diesel fuel and provides complete crane services as well as blending, filtration and fluid reclamation services to the GoM.

According to Joey Detiveaux, TETRA offshore completion services and fluids regional manager for the US, TETRA boasts the largest fixed blending facility for completion fluids at the Port. This location, with its easy access to the GoM, is one of the biggest selling points, he says.

Being located at the port is an advantage because the Greater Lafourche Port Commission advocates for Port tenants. "They are very helpful in understanding what we need," Detiveaux said. "Whatever they can do to help, they do."

Completion fluid blending taking place in one of three 500-bbl TETRA blending pits. Samples are taken to ensure fluids are blended to correct specifications prior to shipment.

COMPLETION FLUIDS

TETRA is leveraging its position near Port Fourchon to provide GoM operators with advanced completion fluid systems.

Unlike mud, "which you can get a feel for," Detiveaux said, "blending completion fluids is an art," explaining that special requirements demand precise blending because different downhole drilling environments dictate specific performance characteristics.

In simple terms, completions fluids ensure a smooth transition between the reservoir drilling and the completion phases of well development. They are designed to effectively complete a well and initiate economically viable production flow.

In the early days, completion "brines" were used to displace drilling fluid. As the nature of drilling changed, new methods for well completion were introduced, and the need arose for more specialized fluids. This spurred the creation of completion fluids that were more advanced than the traditional brines. As completion technology advanced, there was a greater need for customized completion fluids that delivered superior effectiveness.

"This is where TETRA made a name for itself," Detiveaux said, and continuing investment in R&D is producing more specialized fluids for the industry.

"Our TETRA CS Neptune completion fluids are a prime example," he said, explaining that this versatile product family can be blended for use as completion, drill-in, packer, and workover fluids and, because of their components, do not require zero-discharge equipment.

These fluids were developed by TETRA to be environmentally friendly alternatives to traditional zinc-based fluids and a cost-effective alternative to fluids containing cesium formate. This is significant, Detiveaux pointed out, because cesium formate is not only expensive, it is nearing depletion, and zinc is a priority pollutant, meaning it is on the list of specific pollutants defined in the US Clean Water Act that includes heavy metals and specific organic chemicals.

The TETRA CS Neptune completion fluids product line, which includes both divalent and monovalent high-density fluids, are formulated without the use of undissolved solids, zinc, priority pollutants, or formate ions and can achieve the densities normally only achieved by either zinc bromide or cesium formate.

These fluids can lower operating cost and simplify logistics because they require no special mixing, handling, or storage at the rig site. Also, the neutral-to-alkaline pH reduces HSE risk, so they can be reclaimed for reuse.

The original fluid system in the TETRA CS Neptune completion fluids product line was formulated by the TETRA R&D group specifically for a deepwater GoM project and was developed and deployed in less than 18 months, Detiveaux noted. Successful use offshore led the customer to use TETRA fluids in four subsequent wells. "We continued to develop this family of fluids for the last five years, and we now offer related fluid chemistries at densities up to 17.5 lb/gal (2.10 sg)."

According to Detiveaux, the same objectives that led engineers to develop completion fluids that mitigate or eliminate impact on the environment is a driver for other programs.

RECLAMATION

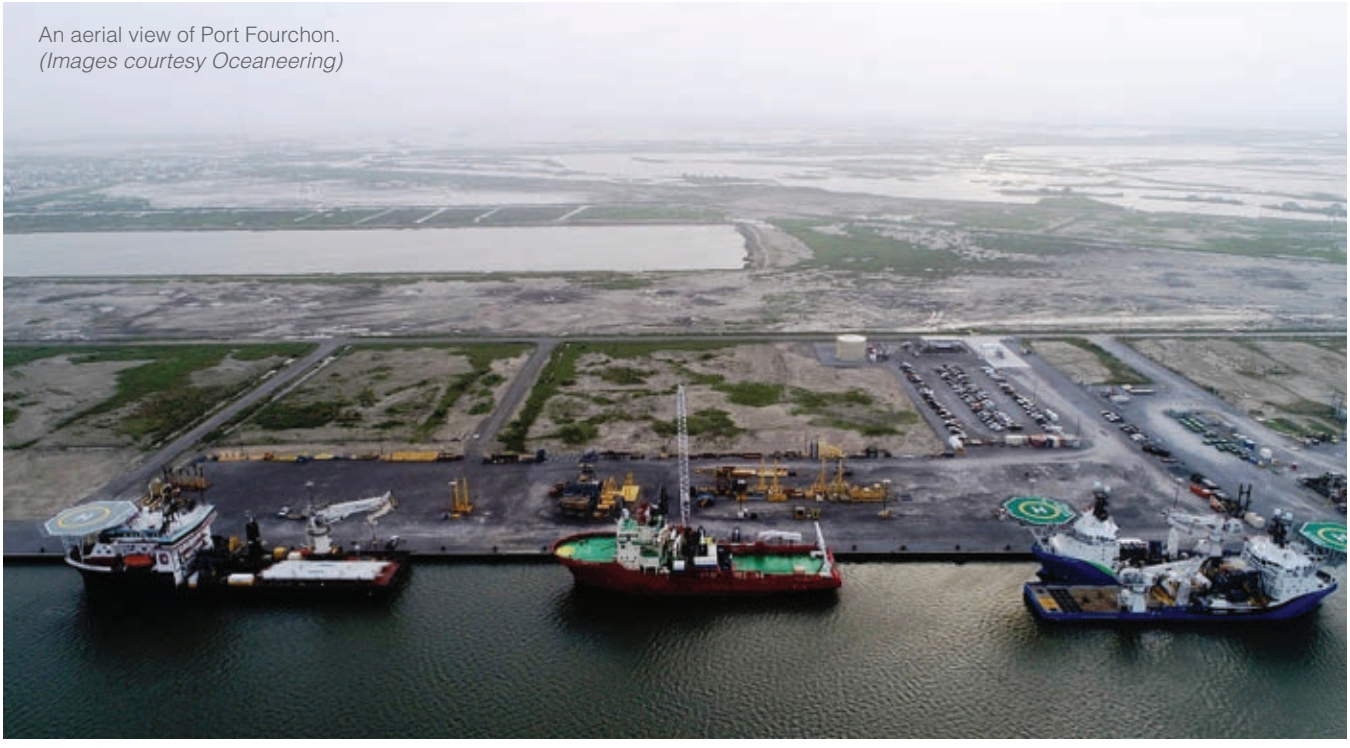
Reducing waste is a focus for a lot of operators in the GoM, and at the Port Fourchon site, TETRA reclaims used fluids. TETRA is helping companies manage increasing completion fluids requirements by recycling, treating, and delivering optimized fluid for well operations.

"We've gotten really good at completion fluid reclamation work. The process returns the fluid to a salable state with no solids, no oil, and no contaminants," he said. "It's the same quality as the original fluid."

According to Detiveaux, now that TETRA has achieved this objective, it is focusing on improvements, in particular, increasing productivity by finding ways to move fluid more efficiently.

Better products and better processes improve TETRA's ability to serve its GoM customers from Port Fourchon, Detiveaux noted, pointing out that continuous improvement is the best way for the company to differentiate itself in a competitive market.

"We are always trying to get better at what we do," he said.



An aerial view of Port Fourchon.
(Images courtesy Oceaneering)

Increased port facility enables greater range of service offerings

New technologies, specialized vessels deliver enhanced efficiencies

JUDY MURRAY, *CONTRIBUTING EDITOR*

AS WATER DEPTH CAPABILITIES have increased in the Gulf of Mexico (GoM), the companies that service offshore assets also have evolved. More capable rigs are working at greater depths than ever before, and new technologies are enabling safe and efficient operations in areas that a few years ago would have been considered unreachable.

When Oceaneering International began over 50 years ago – out of a merger between World Wide Divers and two other diving companies – rigs were working at water depths that could easily be managed by the divers, who carried out maintenance and repair activities. Over the years, Oceaneering has transformed from a small regional diving company into a global provider of ROVs and deepwater engineered products and services, umbilicals, subsea hardware, and tooling.

LEVERAGING LOCATION

Oceaneering has been working out of Port Fourchon to service GoM operators for 25 years. From its 22-acre facility, the company provides services to the entire region from shallow water to ultra-deepwater.

Tommy Lord, Subsea Projects Group operations manager, says working from the Port allows the company to reach its GoM customers easily, simplifying logistics and enabling the rapid delivery of services.

"From day one, we knew this was going to be the best location for us," he said.

That realization led the company to increase its footprint in 2018, when Oceaneering moved its facility to the port's Northern Expansion Slip B, which offers more storage space, parking, and a more expansive staging area. It also added more wharfage, which today totals 1,200 linear feet (366 m) of bulkhead.

According to Lord, the Greater Lafourche Port Commission (GLPC) has made it easy to expand and has invested in improving access to the Oceaneering facility, completing a paved roadway to accommodate increased traffic much more quickly than Lord and the other tenants in the area expected. "The Port is always moving forward to advance the collective interest of the tenants," he said.

GLPC efforts are influenced by input from the tenants, he explained. "We have regular meetings, and they are always asking, 'How can the Port help?' That attentiveness to tenant needs makes Port Fourchon a good place to set up shop."

In addition, security is exceptional. "The Port Police come by daily. They know all the tenants. They are always close by and always responsive," said Lord.

The combined services and advocacy from the GLPC support the tenants, allowing the companies working in Port Fourchon to focus on themselves and their customers. "We couldn't do it without them," Lord said.

ADVANCED SERVICES

Oceaneering has executed a broad range of projects in the GoM supported by its Port Fourchon facility.

The company was engaged by a GoM operator to design and manufacture two 23,000-ft (7,000-m) dynamic power umbilicals that meet the environmental and mechanical demands of operating at ultra-deepwater to 9,000 ft (2,743 m). Dozens of designs with varying component configurations, armoring options, conductor materials, component sizing, and helix angles were developed and tested before arriving at a technically feasible design that met the stringent requirements. The company also designed and manufactured a custom pulling head able to support up to 200 tons of installation load for the operator's development site.

Custom ROV tooling also was designed to accommodate pipeline end termination (PLET) operations. Oceaneering expedited manufacturing of the tooling and completed PLET lockout with ROVs that compensated for persistent currents encountered in deepwater.

The company also has helped GoM operators better manage rig move costs by applying its proprietary Remotely Operated Survey (ROS) solution.

Just one week after an initial rig survey, Oceaneering mobilized and installed equipment over a three-day period, enabling a rig move over the course of two days. A field report was delivered within two hours of spud-in, and the final report and certified well location plat were delivered in 48 hours, allowing the operator to identify the final well position, close out drilling permits, and continue planning the development of the field.

Using ROS allowed the move to be completed for a low-cost, single-day rate, including all equipment and deliverables, and reduced safety risks by eliminating the mobilization of personnel and equipment. The success of this operation led to the decision to keep the equipment used for the rig move in place for use on future moves.

The MSV *Ocean Evolution* heads out to sea.

VESSEL SUPPORT

Oceaneering is continuing to invest in increasing its technical offerings and at the same time is expanding its fleet. The most recent addition is the MSV *Ocean Evolution* advanced subsea construction support vessel, which delivers deepwater stimulation and intervention services.

Measuring 353 ft (108 m) long, 72 ft (22 m) wide, the *Ocean Evolution* is an ABS-classed DP-2 subsea multi-service vessel with accommodations for 110. The vessel's 12,595 sq ft (1,170 sq m) steel-constructed deck is rated to support 10 metric tons/sq m, with underdeck storage capacity of up to 109,000 gal (413 cu m) of special products. On-deck utilities include water, power and fuel, advanced communications technology for rapid loading, as well as welding tiedown and hookup for specialized deck equipment during project mobilization and demobilization.

The vessel's enhanced station keeping capabilities have earned it the highest possible ERN station keeping reliability rating of 99.99.99.99, validating the ability of the vessel to maintain position even during extreme weather conditions.

The *Ocean Evolution* is fitted with a 250-metric ton active heave compensated (AHC) crane, two work-class ROVs with AHC launch systems, survey systems and subsea tooling for work in depths to 13,000 ft (4,000 m). The AHC crane is designed with a special lifting mode that allows heavy lifts with alternate reeving of the boom eliminating the jib that provides increased hook heights of 118 ft (36 m) above the main deck. This provides the ability for crews to lift tall wellheads, large pin piles, and other oversized equipment off the deck using the maximum lifting capacity of the crane. A second auxiliary crane on deck adjacent to the working moonpool is rated for 40 metric tons for lifting and handling equipment on deck and to water depths of 600 ft (180 m).

Its unique bridge is configured with port and starboard redundant control stations located to provide a better view of crane operations, ROV deployment and simultaneous operations with other vessels and platforms on both sides of the vessel, making offshore operations safer and more productive. It carries two work class ROV systems, each with active heave compensated launch and recovery systems installed in a custom indoor hangar for port and starboard launch.

The *Ocean Evolution* already has completed a range of projects out of the Port facility, including well stimulation, hydrate remediation, control umbilical installation, subsea tree testing and installation, rigid and flexible jumper installation, and pipeline sleeper installation.

The vessel was recently mobilized for a well stimulation job in the deepwater Alaminos Canyon area of the GoM, where a well had experienced low production issues from the formation, and a decision had been made to use an acid stimulation technique to address falling production. Oceaneering proposed rigless stimulation, using a well stimulation tool to bullhead the planned chemical matrix down the wellbore and into the formation. The full acid well stimulation equipment spread was mobilized on the *Ocean Evolution*.

Despite several challenges, this well stimulation job was completed on schedule and without incident. The full matrix of chemicals was delivered to the well, increasing the production rate by 85-90%.

ECO's port facilities include three terminals that serve as the focal point of the company's Port operations, housing 24 covered slips. *(Images courtesy Edison Chouest Offshore)*

Extensive capabilities deliver value for asset owners

Focus on efficiencies delivers time and cost savings

JUDY MURRAY, *CONTRIBUTING EDITOR*

EDISON CHOUEST OFFSHORE (ECO) has come a long way since Edison Chouest Boat Rentals was established 60 years ago in Galliano, with the launch of the *Holiday* utility vessel. Today, six decades after its inception, ECO has expanded far beyond boat rentals, establishing itself as one of the most diverse and dynamic marine transportation solution providers in the world.

The company's current leadership position is due in part to its ability to design and build technologically advanced, high-capacity vessels that it also owns and operates. Being able to manage the fleet from conception through operations allows ECO to identify areas for improvement and determine where a new design or capability could introduce competitive advantages. The result is a diverse fleet that delivers value and efficiencies around the world.

The ECO fleet numbers more than 200 vessels ranging in length from 87 ft (26.5 m) to more than 525 ft (160 m). The operating fleet includes light construction vessels, anchor handlers, platform supply vessels, multi-purpose supply and fast supply vessels, oil spill response vessels, tractor tugs, and a range of specialty vessels. ECO has multiple shipbuilding and repair yards in Louisiana, Mississippi, Florida, and Brazil.

SETTING UP CAPABILITIES

Having in-depth knowledge of vessels and the experience of many years working in the Gulf of Mexico (GoM) provided the insight needed for ECO to develop a multi-service complex in Port Fourchon.

Management at ECO recognized the challenge of servicing assets in the GoM as an opportunity to develop a solution. The

first step was in 1997 with the creation of what is known as C-Port, a facility that enables ECO to offer cutting-edge vessel support technology and marine material movement. Over the next few years, ECO added C-Port 2 and C-Port 3 to expand its presence in Port Fourchon.

The C-Port complex includes three terminals that serve as the focal point of the company's Port operations. These terminals include 24 covered slips configured to optimize cargo transfer along with more than 25,000 sq ft (2,322 sq m) of covered staging area and 33,000 sq ft (3,066 sq m) of outdoor storage. There are facilities for pipe storage, testing and repair, and bucking services for pipe up to 12 in. in diameter. Certified professionals are on hand to load and offload risers or perform riser inspections and repairs. C-Port has 25-ft (7.6-m) drafts to accommodate large offshore vessels and 47 overhead cranes ready for complete dockside services 24 hours a day. The facility can manage as many as eighty-eight 300-ft (91.4-m) vessels at a time with a throughput of 450-500 vessels a day.

According to Reggie Ledet, general manager of ECO's C-Port 3, having multiple facilities in one location with a range of functions delivers significant value for customers. "Chouest offers a package of services that makes it easy for companies to efficiently get into and out of the Port with everything they need," he says. "Our facilities are very well thought out and planned for effectiveness."

The covered slips in the Chouest port facilities deliver unique benefits and efficiencies, according to C-Logistics General Manager Dane Vizier, Sr.

"Bad weather doesn't shut them down," he says, explaining that safety measures dictate shutdowns for outdoor operations in inclement conditions. "All workers move indoors when there is lightning within 10 mi of the Port, and shutdowns are required for conditional cranes working outdoors when winds reach 35 mph."

In the covered slips where the cranes are protected, however, there is no need to stop because operations are not affected by weather, Vizier says. Even when there is a power outage, there are backup generators to keep crews working 24/7, 365 days a year.

The cranes used in the Chouest port facilities are electric — meaning there are no emissions — and because they are positioned for optimal efficiency, they simplify the loading and unloading process. "The cranes can easily load the deck from stem to stern, and they are much easier to operate because the operator is in a basket with a bird's eye view of the deck, where he has a clear line of sight," Vizier explains. "This makes operations much safer. It also makes us a lot more efficient than everyone else."

The arrangement of the slips delivers additional advantages. Because the slips are designed so intakes are at back of slip, a vessel can take on mud and bulk products while a crane is loading the vessel. "This is the only place in the world that you can load a vessel at the same time that it is taking on mud," he says.

"Time is money," says Ledet. "It's our job to get the vessel in here and back offshore in a safe and timely manner."

EXPANDED SERVICES

ECO has a range of businesses in Port Fourchon in addition to the three C-Port facilities. The company's offshore support services has 2,486 ft (758 m) of bulkhead with dockside mobile crane services as well as warehousing with gantry crane support. It offers full-service fuel and lube services and houses five diesel fuel transfer stations as well as storage for 400,000 gallons of freshwater and six associated transfer stations.

Two yards make up the company's Martin Terminal. The smaller

The ECO fleet numbers more than 200 vessels and includes light construction vessels, platform supply vessels, and a range of specialty vessels.

North Yard has 1,914 linear feet of bulkhead with dockside mobile cranes and forklift services, warehousing, and outdoor storage for 210,000 gallons of fresh water and six transfer stations. The South Yard has 2,130 linear feet of bulkhead and houses 3,200,000 gallons of diesel fuel with seven transfer stations and 1,680,000 gallons of freshwater with 14 transfer stations. The Martin South Yard also has storage and transfer stations for methanol, xylene, and glycol.

ECO established Clean Tank in 1998 to provide tank cleaning and fluid recovery services to oil and gas companies operating out of Port Fourchon. Clean Tank has since evolved into one of the largest tank cleaning companies serving the US Gulf Coast with services that include cleaning of liquid mud, dry bulk, fuel, methanol and chemical tanks; fuel and chemical recovery and filtering; and cleaning of bilges, frac tanks, MPTs, cutting boxes, valves, baskets and other miscellaneous oil and gas containment devices and equipment.

The C-Logistics facility, opened in 1999, offers material movement and containerization, fleet management and reporting as well as file and document storage. ECO's C-Logistics team captures such useful information as engine vibration, fuel efficiency, and fuel consumption data in real time. Approximately 4,000 data points are being monitored on each vessel, allowing the company to determine when service and maintenance should be done and where design or equipment performance could be enhanced.

The Northern Expansion also is part of the ECO offering in the Port. It features two wet slips, each equipped with two 25-ton gantry cranes and a 15-story covered drydock with two 50-ton gantry cranes. This facility has 3,500 ft of linear bulkhead with a dockside mobile crane and forklift service as well as shoreside electrical services.

Fourchon Heavy Lift, added in 2006, is home to a 475-ton derrick crane and offers outdoor storage on a site with 1,320 linear ft of bulkhead. This facility provides dockside mobile crane and forklift services in addition to heavy-lift capabilities, subsea construction support, long-term heavy-lift storage, and warehousing.

ECO's C-Terminal, which opened in 2013, has three dockside pedestal cranes in addition to dockside mobile crane and forklift services and warehousing. The facility houses a bulk/cement/barite plant and provides fuel, water, mud and drilling fluids for purchase on site.

The company's expansive presence in Port Fourchon allows ECO to offer services for all types of exploration and development work in the GoM.

"We have a huge range of resources for companies working in the Gulf of Mexico," Ledet says. "We offer so many more services here that it makes perfect business sense for customers to come to us."

GAO

SOUTH LAFOURCHE LEONARD MILLER JR AIRPORT

HOW THE GULF GETS TO WORK

SOUTH LAFOURCHE AIRPORT

- The South Lafourche Airport (GAO), located along Bayou Lafourche in close proximity to Port Fourchon and the Gulf of Mexico, is the ideal jumping off point for aviation logistics to service and support the Deepwater oil industry.
- GAO has become the fastest-growing airport in Louisiana by offering round-the-clock service for both tenants and visitors. We pride ourselves on offering fuel at competitive prices as well as providing self-serve fueling capabilities 24/7. Our 6,500 ft. runway and full instrument landing system (ILS), located inside the protection of two levee systems, allow us to handle nearly any aircraft.
- Whether for work or for play, GAO is perfect for your travel needs throughout South Louisiana and right across the Oil Patch.

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Thermoplastic composite pipe provides alternative to steel

Eliminates corrosion, lowers CO_2 footprint

MARTIN VAN ONNA, *AIRBORNE OIL & GAS*

THE GLOBAL ANNUAL EXPENDITURE to mitigate corrosion is in the range of $2.5 trillion, roughly equal to 3.4% of the world's GDP, according to NACE International. The corrosion problem is further magnified by enhanced oil recovery rates from mature fields. The use of water injection methods, for example, is leading hydrocarbons to become sourer, thereby over time, the production fluid that flows through the pipeline gradually becomes more corrosive. This is an increasingly complex challenge for operators as they are looking to raise production and profits while countering the potentially catastrophic consequences of corrosion with relatively ineffective and expensive inhibitors.

Until a decade ago, steel material for pipelines and pipe structures was the main option for the oil and gas industry. Now, the rapid development and deployment of thermoplastic composite pipe (TCP) is growing to counter the inherent drawbacks of steel: corrosion, fatigue, and weight.

There is now a growing variety of applications offshore which include flowlines, risers, jumpers, expansion spools, and lines for uses such as chemical injection, methanol injection, gas lift, wellbore access, choke and kill, decommissioning, and intervention.

Often, systems used to mitigate corrosion through pumping corrosion inhibitors need to have an uptime above 90% to be effective. Depending on the region, that is rarely achieved. For instance, in Asia operators are sometimes at only 50% uptime on their corrosion inhibitor system. To increase this uptime requires a constant supply of chemicals to the various platforms, working pumps and available power supply, all of which are working in a harsh offshore environment. Typically, for every month they lose on corrosion inhibitors, they lose a whole year of design life of the pipeline.

The past decade has seen a rapid advance in the qualification and application of thermoplastic composite pipe. *(Images courtesy Airborne Oil & Gas)*

Anasuria Operating Company ordered a gas lift jumper for the Guillemot field in the UK central North Sea.

THE COMPOSITE PIPE DREAM COMES TRUE

TCP features a solid pipe wall constructed from glass or carbon reinforcement fibers and thermoplastic polymeric materials. The proprietary melt-fusing manufacturing process results in a true composite structure, with the fibers fully embedded within the polymer matrix and ensuring the strongest interface possible between the different pipe layers. The fibers are linear in behavior and typically do not show plastic deformation or yielding. This creates a robust spoolable pipe, 80% lighter than metallic equivalents, and adapted to customer-specific requirements.

Based on the application, the company selects the right thermoplastic matrix and fiber to ensure it has the best fit-for-purpose solution for highly loaded, critical applications in the challenging offshore and subsea environments.

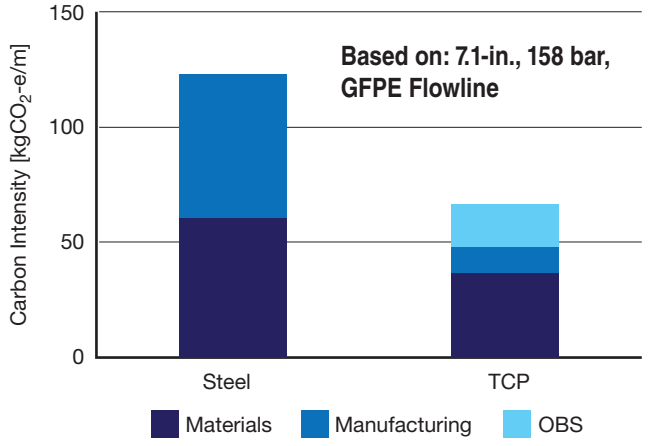
TCP can be installed with smaller vessels than traditional steel-based pipes. Where required, a weight coating can be applied, again based on the same polymer with additional heavy compounds.

Airborne Oil & Gas is fully qualified to DNV GL standards and was instrumental in the creation of the first standard for the requirements for flexible TCP for offshore applications, DNVGL-ST-F119. The document supports operators in their choice of TCP instead of steel or traditional flexibles for pipelines or risers.

THE CORROSIVE CONUNDRUM

Over the past 10 years there has been a relatively slow uptake in this new material. Residual reticence to adapt and change coupled with general ignorance on the benefits TCP can bring

TCP REDUCES CO_2 FOOTPRINT, INCLUDING ON BOTTOM STABILITY



is now dissipating. In today's cost-conscious climate, eliminating the corrosion problem and the issues it brings, while drastically slashing the cost for subsea infrastructure, are the two primary reasons for operators now assertively switching from steel to composite.

The value proposition that TCP has is two-fold. One is completely doing away with corrosion and the other is the reduction in total installation costs. This cost element is all around the ability to use small vessels to transport and install pipes in a cost-effective manner. This is not possible with steel pipes because the pipelay barge often must mobilize from other regions before pipeline installation can start.

As TCP Flowline is supplied in long, spoolable lengths, it is particularly cost-effective for horizontal lay methods, using rental reel drive and overboarding systems that can be placed on smaller vessels, resulting in around 40% saving on as-installed cost. In addition, the lack of corrosion reduces associated corrosion-related costs such as pumping of corrosion inhibitors, related pigging, and inspection and maintenance requirements.

In 2012, Petronas Carigali was the first operator to contract the company to supply a non-metallic, TCP subsea flowline pipe to eliminate all corrosion issues on its infield pipelines in Malaysia.

At the time, the operator had a large stock of corroding subsea flowlines suffering from sulphur reducing bacteria, or microbacteria induced corrosion. This led to an extensive five-year qualification program which included lab and prototype testing as well as full-scale offshore installation trials. In 2017, Petronas installed the world's first pilot TCP Flowline in Malaysia for hydrocarbon service. A year later it was awarded Technology Readiness Level (TRL) 6 following comprehensive monitoring of the flowline.

TCP solutions, manufactured up to 7.5-in. ID, 121°C (250°F) and 10,000 psi (689 bar) working pressure, for hydrocarbon production, water, gas lift, and chemicals injection have since been installed in West Africa, the North Sea. Later this year more will be installed in Australia and West Africa.

A third added value is TCP operations offer a lower CO_2 footprint. From a manufacturing point of view, studies have shown that TCP has a much smaller carbon footprint compared to steel pipelines, and its installation provides even bigger savings on CO_2.

LIFE EXTENSION AND PRODUCTION OPTIMIZATION

The company uses a specific 'staircase approach' for each of its clients, whereby operators can execute collaborative studies and pilots to optimize the disruptive potential and performance of TCP in their operations as well as build acceptance within the organization. Brownfield applications such as water injection and gas lift are ideal first applications for TCP, where the business case is strong and return on investment high.

Some of the latest contract awards include:

- Anasuria Operating Company ordered a gas lift jumper to support operations in the Guillemot field, about 175 km (109 mi) east of Aberdeen
- A supermajor ordered a 10-km (6-mi) flowline for water injection in West Africa
- A large operator in Asia ordered two off methanol injection jumpers.

The world's first crude oil TCP Flowline was for Petronas Carigali in Malaysia.

The company allows the operator to use small vessels that are already in-country. Especially in West Africa, this makes a huge, very powerful case. Small vessels that are already in Angola, or in Ghana or in Nigeria, can be used to install these pipes. So, the mobilization cost is almost avoided.

For mature sectors such as the North Sea, TCP is proving its credibility to help enhance production particularly in brownfields for the replacement of old pipelines and/or the installation of gas lift.

At some point production hits a low level of a couple of thousand barrels. Many of the bigger companies will abandon this field and stop production. However, the firms that specialize in lengthening the field life through the company's gas lift products, for example, are able to add an extra 10, 20 years or more of continuous production.

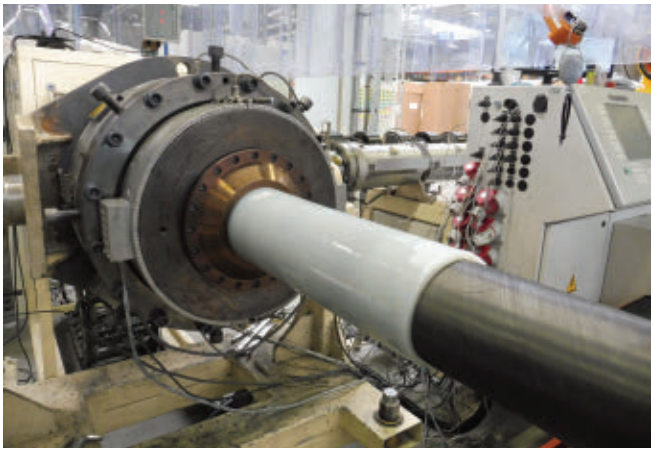
PIPELINE INNOVATION

In line with DNVGL-ST-F119, the Ijmuiden-headquartered business has carried out several qualification programs to certify its design methodology, production, and materials for all its products.

Compared to steel pipe, TCP is competitive on up to 10 to 20 km (6.2 to 12 mi) of pipe. For corrosion resistant alloy, TCP is competitive altogether.

The company is continuing to develop, qualify, and deploy new and more advanced TCP products. This includes:

- Carbon fiber with polyamide 12 (PA12), qualified to 10,000 psi (689 bar) and 80°C (180°F) in use for water injection in the Gulf of Mexico
- Carbon fiber with polyvinylidene difluoride (PVDF) is now being qualified for up to 10,000 psi and 121°C (250°F). The combination of fiber and polymer offers the best alliance of submerged weight, chemical resistance, and minimum bend radius and will enable the commercial deployment of TCP dynamic risers
- Weight coating to give pipes greater stability on the seabed, without having to work with ballast elements or concrete, ropes or chains
- Development of 'smart pipe', such as the integration of optical fibers and sensing
- Enhanced insulation for higher temperature applications.



The world's first fully bonded 4-in. carbon fiber PVDF pipe.

CONCLUSION

Carbon steel structures exposed to natural waters and corrosive environments generally corrode at an unacceptably high rate unless preventive actions are taken. An estimated one-sixth of all steel production worldwide is used to replace corroded metal, much of it at cooling water piping systems, and yet the rate of corrosion in pipelines is increasing and becoming more difficult to overcome.

Aker Solutions, Shell, Chevron, Evonik, Saudi Aramco, Subsea 7, and Sumitomo Corp. have all demonstrated belief in the future of disruptive composites for oil and gas applications with major investments in the company.

The corrosion challenge is a major issue in the industry. Next to fire, pipeline corrosion represents the most serious threat and monetary loss to any operation.

Artificial intelligence emerging as useful tool for assessing marine coating conditions

Machine learning teamed with AI increasingly comparable to human judgement

GU HAI, *ABS*

ASSESSING THE CONDITION of marine and offshore coatings continues to be one of the major tasks to be addressed during class survey and one that has benefitted from the increased use of remote inspection technologies (RITs). The development of more effective RITs – including unmanned and remotely operated vehicles – has enabled safer and more efficient visual inspections of the condition of protective coatings in historically hard to access and hazardous locations.

Visual inspections by properly trained and highly experienced surveyors continue to make up the majority of maintenance surveys, but the growing use of RITs provides an opportunity to augment human skills with computing power.

The accuracy of these assessments is commonly dependent upon the inspector's previous experience as well as their familiarity with the different types of structures being inspected. While class inspections demand a high level of experience from surveyors, these factors may cause inconsistency during coating inspections.

To overcome the challenges in conventional inspection of coating condition and advance the use of new technology, ABS is leading a project to apply Artificial Intelligence (AI) and Machine Learning (ML) in an image recognition tool designed to aid inspectors in reviewing data and making coating condition assessments.

POSITIVE INITIAL RESULTS

Phase one of this work was completed in 2019 and has been followed by a second phase to expand the scope of the data used to train the AI tool. Where the pilot phase delivered a reasonably positive result using only a few hundred images, the need for improved accuracy saw the use of about 10,000 images for enhanced accuracy.

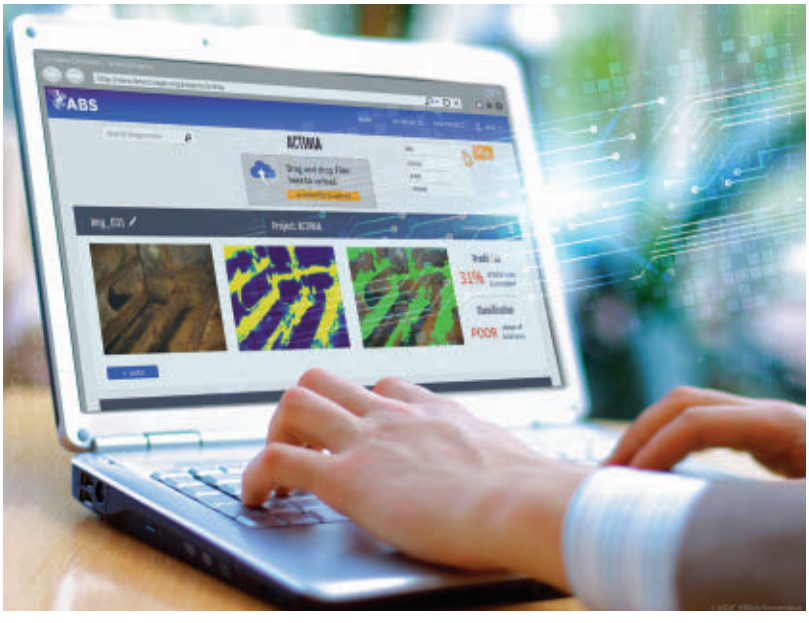
The ML-based image recognition tool developed by ABS can automatically analyze input data, identify coating failure areas and grade the coating condition of the structure. Inspectors can use these results as references, just like the assessment scales from coating guidance, to improve the consistency of coating assessments. The tool can also be utilized during screening inspection processes, where it can be used as a filter to identify the critical areas for review purposes.

The ML algorithm/model program utilizes images taken from different types of maritime and offshore assets and it can deal with various kinds of structural components, coating failures, lighting conditions and rust.

To achieve the best possible results, the study employed ML algorithms known as Convolutional Neural Networks (CNN) also used in autonomy and facial recognition in analyzing images and videos.

REPRESENTATIVE DATASETS

Besides model selection, another key action to help improve the performance of the CNN model was to prepare a large dataset with high quality data which also need to be properly labeled/annotated by subject matter experts. The CNN models then used these data in the algorithm training process, applying the judgement of subject matter experts to learn based on the labeled patterns and features known as a Supervised Learning Approach.



ABS says that its image recognition tool can automatically analyze input data and identify coating failure areas.

The total database used in this study consists of approximately 32,000 images, taken from different types of marine and offshore structures, most of which are internal tank structures such as water ballast tanks, cargo tanks and oil tanks. As different models may need different formats of labels for training, different labeling processes must be employed.

To conduct the training process, first the model was trained and validated using the labeled training dataset, then was tested by the test dataset (also labeled, but different data from the training set) to judge the performance of the data. If the test results were unsatisfactory, either the model or the training data was improved until an acceptable performance of the model was achieved.

The project has proven the value of using AI technology in the marine and offshore industry as a means of supporting trained inspectors with a fast and reliable means to aid their decision-making processes during coating assessment tasks, especially when remote inspection technologies are applied.

A RELIABLE REFERENCE

Through data tests and case studies, it has been concluded that the tool can provide reliable reference data and information to surveyors in the field. Test results of the best performing model show its ability to identify coating failures from field images that have not been previously processed.

These factors support the value of the tool to act as a scanning process for inspection with remote inspection technologies and as an electronic coating evaluation standard/guideline to aid inspectors.

These tools and capabilities will continue to improve. With the iterative labeling process integrated, new data will be fed continuously into the training process to improve the capability of the tool, make it more accurate, reliable and general.

While currently focused on coating assessment of internal tank structures, the scope of the AI tool can be expanded to coating assessment of other types of structures or evaluating of other defects such as cracks, fractures or large structural deformations.

MATCHING HUMAN JUDGEMENT

A common question from ABS clients is whether the algorithm is of sufficient quality to accurately assess the problem of coating failure. Comparison studies show the tool can match the human judgment in general for the purpose it is developed for.

The AI tool will mark areas of coating failures/corrosion with colour to give a rating of the coating's condition based on which the client can make decisions. The accuracy of the AI algorithm for the grading task is above 90% for test data used at the development stage. Field test results have also shown similar accuracy level to human inspectors.

In addition to images with which to train the AI, the process needs labels placed by experienced surveyors to indicate to the computer the location of the coating failures/corrosion. Improved labelling of the coating failures/corrosion provided by the surveyors will lead to better accuracy of the AI output.

Work continues to make the tool more accurate for assessment of coatings and conversations with clients are ongoing to customise the tool for their particular applications using images specific to their assets and structures.

DEEPWATER OPERATIONS AND TOPSIDES, PLATFORMS & HULLS

DEEPWATER OPERATIONS and Topsides, Platforms & Hulls Conference and Exhibition was held Feb. 4-6, 2020 at Moody Gardens Hotel in Galveston, Texas. Two conference awards were given by each conference advisory board. The Best Presentation award was based on content and Best Presenter for delivery.

Deepwater Operations Best Presentation award winner Karel Schnebele

For Deepwater Operations, Karel Schnebele of Chevron won the Best Presentation award for "Application of Human Performance Concepts to Deepwater Projects and Operations"; and David Decuir of iCAN Technologies won the Best Presenter award for "Enhancing and Measuring Workforce Competency through Technology."

Deepwater Operations Best Presenter award winner David Decuir

For Topsides, Platforms & Hulls, Ben (Sun-Ngen) Chong of Murphy Oil Corp. won the Best Presentation award for "Medusa Platform Life Extension"; and Rocky Robbins of Fieldwood Energy won the Best Presenter award for "Swordfish: Using System Redundancies to Extend Field Life."

Topsides, Platforms & Hulls Best Presentation award winner Ben Chong

Topsides, Platforms & Hulls Best Presenter award winner Rocky Robbins

The annual event will return to Galveston on Feb. 2-4, 2021.

DEEPWATER OPERATIONS ADVISORY BOARD
From left to right: Reed Pere', Danos; Dave Hernandez, Shell; Mike Lynch, KBR; Conference Director David Paganie, Offshore; Richard Loveland, BP; Tom Keating, Wood; Pete Stracke, Equinor; Advisory Board Chairman Chuck Blevins, Chevron North America; Michiel Heuven, SBM Offshore; Will Hernandez, Willworks Consulting; David Murphy, Hess Corp.; Rusty Desormeaux, Murphy E&P Co.; Chris Landry, Anadarko Petroleum Corp.; Kevin Hurst, EnVen **Not pictured:** Karelis Anato, BHP; Wes Johnson, Noble Energy; Raffaello Rapacioli, Eni Petroleum; Gerhard Visser, Williams

TOPSIDES, PLATFORMS & HULLS ADVISORY BOARD
From left to right: David Brubaker, Keystone Engineering; Eric Wensel, Wood; Stafford Menard, Audubon Engineering Solutions; Marc Paquette, Shell; Matt Sellers, Kiewit Offshore Services; Scott Smith, KBR Inc; Conference Director David Paganie, Offshore; Rocky Robbins, Fieldwood Energy; Lars Ronning, Equinor; Jon Husby, Aker Solutions; Advisory Board Chairman Renard Falcon, Chevron; Curtis Lohr, Shell Alumni; Mike Clarke, Murphy; Fraser Senciall, Hess Corp.; Boyd Howell, MODEC; Kevin Raatz, SBM Offshore; Shree Akhave, TechnipFMC/Genesis Oil & Gas; Arun Antony, Houston Offshore Engineering; Robbie Primeaux, Worley **Not pictured:** Jonathan Brewer, Stress Engineering Services; Nathan Davidson, Williams

PEOPLE

Wintershall Dea has appointed **Dawn Summers** as COO, effective June 1, 2020. She will be responsible for the Germany, Norway, the Netherlands, UK, Denmark, Egypt, Libya, Algeria, and UAE business units.


Summers


Helweg

P&O Maritime Logistics has appointed **Martin Helweg** as CEO.

DNV GL has appointed **Kjetil M. Ebbesberg** as Group CFO. He will succeed **Thomas Vogth-Eriksen**, who will become director, Certification Division in DNV GL - Business Assurance.


Ebbesberg


Vogth-Eriksen

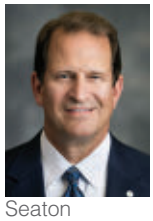
Alexandra Thomas has joined Neptune Energy as UK managing director.

David T. Seaton and **Al Walker** have joined the ConocoPhillips board of directors.


Thomas

Apache Corp. has named **Clay Bretches** executive vice president of Operations, and **David Pursell** executive vice president of Development.

Birgit Aagaard-Svendsen and **Herman R. Flinder** have joined the Seadrill Ltd. board of directors. They succeed **Eugene I. Davis** and **Scott D. Vogel**, who have stepped down.


Seaton

Geoquip Marine has appointed **Peter Østergaard Nielsen** as chairman of the board of directors.

WFS has appointed **Peter Sharpe** as interim CEO.

Archer Ltd. has appointed **Dag Skindlo** as CEO and **Espen Joranger** as CFO.


Walker

Noble Corp. plc has appointed **Richard Barker** as executive vice president and CFO. He succeeds **Stephen M. Butz**.

Clockspring|NRI has named **Frank Firsching** as CEO. He succeeds **Matt Boucher**.


Firsching

Sonardyne International Ltd. has appointed **Graham Brown** as managing director. He succeeds **John Ramsden**, who is taking the role of CEO of Sonardyne Group.

Julie Thomson has joined Proserv as Group CFO. She replaces **Andy Cooksey**, who served as interim Group CFO since last June.


Nunnally


Blount

Quality Companies has promoted **John Clay Nunnally** to CEO.

BCCK Inc. has appointed **Kevin Blount** as CEO.


Lindstrom

Hempel has appointed **Katarina Lindström** as executive vice president and COO, effective Aug. 1, 2020.

Lynn A. Dugle has joined the KBR board of directors. She will serve on the Audit and the Nominating and Corporate Governance Committees.


Papageorgiou

Lloyd's Register has appointed **Elina Papageorgiou** as Marine and Offshore President for UK and Ireland.

Ambyint has appointed **Blake McLean** as CFO.

Wayne Allen Cook Jr. has joined Stratagraph as director of business development.

David Newbigging has joined Survivex as business development manager.

Amarinth has appointed **Itai Choto** as sales manager for the Africa territory.

Dale Smith has joined Mayer Brown as a partner in the Corporate & Securities practice in Houston.

COMPANY NEWS

TechnipFMC has put on hold its planned separation into two new businesses. Market conditions brought on by the COVID-19 virus pandemic have deteriorated, the company explained, with a sharp decline in commodity prices and heightened volatility in global equity markets. The present environment therefore does not justify the separation into **TechnipFMC** and **Technip Energies**, the company said, although it stressed that the strategic rationale for the separation is unchanged. It remains committed to the transaction and will continue preparations to ensure that the two companies are ready for separation once conditions have improved.

Diamond Offshore has awarded **Logan Industries** a 10-year condition-based monitoring contract for its wireline tensioners. In this contract, Logan will provide fast turn-around upgrade and repairs to a fleet of wireline tensioners onboard five active drilling and completion vessels which have been in use for more than five years.

CNOOC Petroleum Europe Ltd. has awarded **ASCO** a five-year extension, with options for six more years, to support all its North Sea assets. The contract, worth more than £100 million ($129 million), will see the company continue to provide a fully managed and integrated, logistics, materials management, waste and marine gas oil supply services. The services will be predominantly delivered from its Peterhead supply base but also from Aberdeen and Scrabster.

KenzFigee has launched **KenzFigee (UK) Ltd.**

The **Petroleum Equipment & Services Association** (PESA) has launched its ESG Center of Excellence, a web-based clearinghouse of ESG information and resources, along with a new ESG knowledge sharing and individual certification program.

Sulzer has opened a service center in Riyadh, Saudi Arabia.

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The energy transition: adapting to a changing market landscape

THE GROWING CONCERN about carbon dioxide emissions is spurring change in the oil and gas industry. While fossil fuel demand is expected to continue growing for years to come, that growth will likely slow as alternatives to oil and gas with potential to reduce carbon increase. There are a wide range of peak-demand projections with some forecasting combined oil, gas, and coal consumption to plateau as early as 2030, while others do not see a peak until well after 2050.

Uncertainty is not new to the industry. But unlike the uncertainty that oil and gas companies have traditionally faced – in commodity prices, technologies, and geopolitics – the energy transition may require changes to longstanding market structures, value chains, and the economic drivers for the oil and gas business.

Many oil and gas companies are responding to this uncertainty by rebalancing their portfolios and shifting investments into greener projects. In the long term, companies may need to grapple with the financial and operational risk posed by stranded assets as declining oil and gas demand could translate into early asset retirement. That risk could be higher for long-lived conventional assets like offshore oil and gas platforms as many deepwater discoveries made in the last few years, if sanctioned, will likely still be producing in the 2040s and 2050s.

As a way of offsetting these risks and addressing stakeholder concerns about sustainability, more companies are investing in different assets today. Oil and gas companies, many of which aspire to be the broad-based energy companies of the future, are figuring out how to produce more oil and gas (and increasingly power) year after year while also being carbon-conscious. These companies have acquired assets outside their core oil and gas production businesses and will likely need to operate a range of assets, develop novel technologies, and enter new markets.

There are at least four concrete steps companies are taking in the near term.

First, companies can identify low-hanging fruit for reducing greenhouse gas emissions, such as eliminating methane leaks from existing infrastructure, reducing economic flaring, and boosting field, plant, and pipeline energy efficiency. For example, US flaring and venting has almost quadrupled in the last decade as oil and gas production has nearly doubled, exceeding two billion cubic feet a day. Reducing flaring to 2010 levels could eliminate more than 30 million tonnes of carbon dioxide emissions per year, equivalent to almost seven million less cars on the road.

Second, while a few have deployed renewables like wind and solar to power pumps and compressors in the field, more companies could follow suit as that could reduce both direct and indirect operational emissions. That could save money in the long run and increase revenue in the short run as oil and gas not consumed on site could be sold. For example, several oil companies are looking to tap into Norway's low-carbon electric grid to power offshore fields. There are opportunities to electrify more projects both onshore and off, sourcing power from low- and zero-carbon generation.

Third, companies could consider investing in increasing carbon capture, use, and storage technologies to tackle emissions from use of the oil and gas they produce. For example, carbon dioxide enhanced oil recovery could be an avenue to boost production while sequestering carbon, but it remains a niche industry today—though more companies are likely to evaluate such opportunities in future.

Lastly, fresh water use and waste water disposal continue to challenge shale producers. While the energy transition focus has mostly been on carbon emissions, more oil companies are evaluating the economics of water recycling to make their operations more sustainable. Fracking a typical shale well requires more than four million barrels of water, potentially straining local water sources. Recycling and reusing flowback and produced water, rather than injecting it in disposal wells, could mitigate the hydrological impact of oil and gas development. Moreover, investment in water recycling technology could be offset by reducing the costs of freshwater sourcing and the need for disposal, potentially proving cost effective in parched areas and those with limited disposal well capacity.

The energy transition is a long-term trend, but some of the industry has already started taking steps to prepare for this change. Part of that preparation has been the opening of a dialogue between energy producers, their consumers, and their broader stakeholders.

DUANE DICKSON, *VICE CHAIRMAN AND U.S. OIL, GAS & CHEMICALS LEADER, DELOITTE LLP*

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This page reflects viewpoints on the political, economic, cultural, technological, and environmental issues that shape the future of the petroleum industry. *Offshore* Magazine invites you to share your thoughts. Email your Beyond the Horizon manuscript to David Paganie at dpaganie@endeavorb2b.com.

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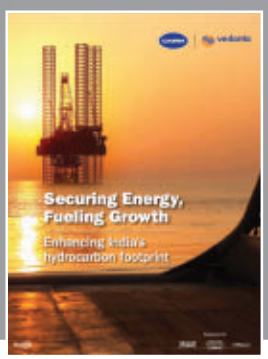

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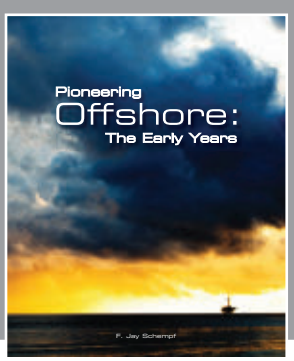

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