January/February 2024

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US GULF OF MEXICO
Deepwater discoveries update

EASTERN MEDITERRANEAN
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New hydrogen platform

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SPECIAL REPORT
Remote inspections & operations

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JANUARY/FEBRUARY 2024

2024 REMOTE INSPECTIONS & OPERATIONS SPECIAL REPORT

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Offshore

VOL. 84, NO. 1

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Offshore® (USPS Permit 403-760, ISSN 0030-0608 print, ISSN 2688-3295 online) is published bi-monthly in Jan/Feb, Mar/Apr, May/Jun, Jul/Aug, Sep/Oct, Nov/Dec by Endeavor Business Media, LLC. 201 N Main St, 5th Floor, Fort Atkinson, WI 53538. Periodicals postage paid at Fort Atkinson, WI, and additional mailing offices. **POSTMASTER:** Send address changes to Offshore, PO Box 3257, Northbrook, IL 60065-3257. **SUBSCRIPTIONS:** Publisher reserves the right to reject non-qualified subscriptions. Subscription prices: U.S. ($158.75 per year); Canada/Mexico ($206.25 per year); All other countries ($260.00 per year). All subscriptions are payable in U.S. funds. Send subscription inquiries to Offshore, PO Box 3257, Northbrook, IL 60065-3257. Customer service can be reached toll-free at 877-382-9187 or at OFF@omeda.com for magazine subscription assistance or questions.

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Offshore construction market forecast

The offshore construction market is revving up as the demand for energy resources continues to drive demand for new oil and gas supplies. Engineering and construction activities are underway on new floating production platforms, subsea production systems and renewable energy facilities. Join industry experts David Boggs, managing director of Energy Maritime Energy Associates Pte Ltd., and David Sheret, director with Archer Knight, on Feb. 13 for a live discussion on recent industry trends, updates on projects under construction and a forecast for new orders.
WWW.OFFSHORE-MAG.COM/14303369

A new year's update from the FPSO Coalition

In May 2023, SLB, Rockwell Automation Inc., Sensia LLC and Cognite announced a collaboration that will accelerate the evolution of the offshore industry's FPSO facilities through digital solutions to improve the reliability, availability, safety and efficiency of these critical facilities—all while lowering the carbon footprint of their offshore operations. In this webchat, now available for on-demand viewing, Matt Mohajer from SLB and Greg Trostel from Rockwell Automation provided an update on the achievements and lessons learned of the coalition so far and discussed the unique challenges in this effort. The discussion also looks forward into 2024, both from an FPSO market standpoint and with respect to the goals and top priorities for the coalition, as it continues to evolve performance in this market.
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2023 US Gulf of Mexico Map

2022 Worldwide Survey of Floating Production Storage and Offloading (FPSO) Units Poster

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Maximizing subsea controls equipment with innovative IR recovery technology

With a presence across six continents and headquarters in the UK and US, Viper Innovations provides cutting-edge subsea technology to the global oil and gas industry. Their award-winning Insulation Resistance (IR) recovery technology, **V-LIFE**, has been helping operators to maximize their subsea controls equipment around the world for over a decade.

The risks of unmonitored subsea cables

Underwater electrical cables are critical to the operation of subsea equipment, and loss of cable integrity can ultimately lead to field shutdown and lost production revenue. The ability of a cable to protect its conductor is called its Insulation Resistance (IR). Monitoring, predicting, and preserving the IR of a cable over the life of a subsea field is a science in itself.

Damaged and faulty cables will eventually allow seawater to ingress onto the conductors, causing low IR and leakage currents, which can be hazardous to personnel and will eventually lead to system shutdown. The saltwater also acts as an electrolyte, promoting a chemical reaction that can erode and weaken the copper conductors, which may accelerate the time taken for a fault condition to occur.

Insulation Resistance (IR) recovery with V-LIFE technology

A **V-LIFE** application involves the installation of a **V-LIM** line insulation monitor (the hardware) and enabling its **V-LIFE** passivation signal by uploading a software config file. **V-LIM** and **V-LIFE** can typically be installed and commissioned within 2 to 3 shifts offshore. The installation work is all topside; no subsea intervention is required. Additional support is provided as part of the **V-LIFE** service in the form of condition reports, trend analysis, and engineering recommendations.

Before Viper's **V-LIFE** technology became available, expensive subsea fault-finding interventions and the replacement of cables, equipment, and umbilicals were the only solutions to this problem. For over a decade, **V-LIFE** has been helping operators around the world avoid costly umbilical replacement, mitigate loss of production, and maximize asset yield by extending the life of subsea control systems. Widely used by operators across the globe, **V-LIFE** is the leading alternative to subsea interventions.

In a recent installation in the Gulf of Mexico, **V-LIFE** was used to avoid a threat to continued production of a subsea production control system. The operator saw results of a 100 times increase in IR within hours, which increased to a 200 times within a week. The operator commented: "**V-LIFE** was activated seamlessly and has delivered outstanding results, providing protection against subsea controls failures."

The common causes of IR failure are well known. Without monitoring and prompt action, its effects can be catastrophic to the operation of a subsea field, so take advantage of Viper's innovative subsea control system solutions today.

Visit **www.viperinnovations.com/us or contact us.enquiries@viperinnovations.com** to find out more.

New year brings wide range of opportunities

David Paganie
CHIEF EDITOR

The offshore industry continues to benefit from strong demand for all sources of energy, driven by policy direction on energy security and energy transformation. Some international operators are responding by adjusting capex allocations in favor of oil and gas developments, while others are doubling down on renewable power from offshore wind. Either way, the low-breakeven cost/barrel of offshore oil and gas developments, favorable carbon intensity versus onshore projects, and strong wind resources are making offshore energy targets increasingly attractive to investors. Regionally, Asia, led by China, will take the largest share of global capex this year for offshore wind; and offshore upstream oil and gas activity will be led by projects in the US Gulf of Mexico and offshore Brazil, Guyana, Saudi Arabia, and Norway. A new area, offshore Cyprus, could be the anchor point of that nation's first natural gas development. The project operator and Cypriot government are working toward agreement on the field development plan.

The area of greatest opportunity this year for offshore contractors and suppliers is related to floating oil and gas platform construction. A recent survey by Energy Maritime Associates assessed industry sentiment in the market, opportunities, and challenges. Survey respondents expect busy times this year, particularly in the areas of tendering and project execution. Regarding platform type, FPSOs have the largest growth potential, and floating wind technology could have the greatest impact on the industry. But, despite a promising outlook, the market will be challenged by capacity constraints and access to finance. See page 13 for the complete survey results and market analysis.

Meanwhile, decarbonization approaches are providing additional opportunities for the traditional offshore contractors. One approach is carbon, capture, and storage (CCS). The need for well construction, maintenance and P&A work from offshore CCS is presenting new opportunities for drilling rig contractors and downhole service firms, according to Bruce Beaubouef, *Offshore* managing editor. In Northwest Europe, CCS projects and related P&A work are prompting new jackup rig demand in the region. See page 26 for Bruce's full report on the growth in CCS projects and related drilling contractor work.

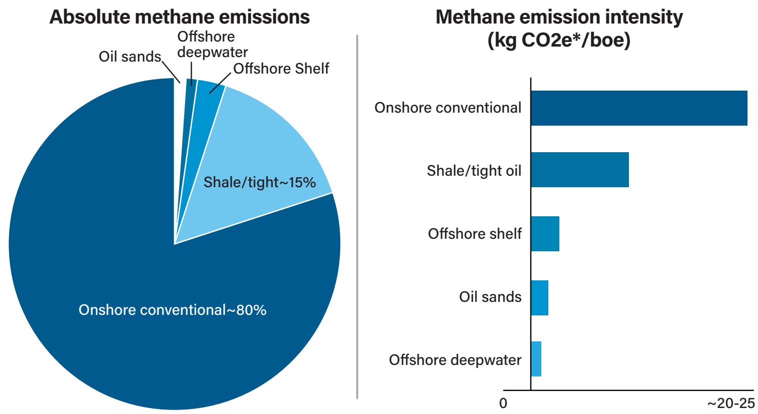
All this growth in offshore infrastructure elevates the importance of ongoing innovation in above water and subsea robotics and vehicles for inspections and maintenance. And improvements in these technologies are adding impetus to increase the level of remote and autonomous operations. This month's special report, beginning on page 36, reviews the state of technology for offshore remote inspections and operations. ●

To respond to articles in *Offshore*, or to offer articles for publication, contact the editor at dpaganie@endeavorb2b.com.

Offshore proves a lower methane footprint

About 80% of methane emissions from upstream activities come from conventional onshore fields, with the rest from offshore and oil sands. Offshore production has a lower methane footprint than the global average, especially deepwater developments. Lower emissions from deepwater operations can be attributed to technology, scale and subsurface conditions. Modern offshore platforms often feature improved methane monitoring and equipment systems, and deepwater fields tend to have relatively low flaring.—*Rystad Energy*

Upstream oil and gas methane emissions and intensities, 2022

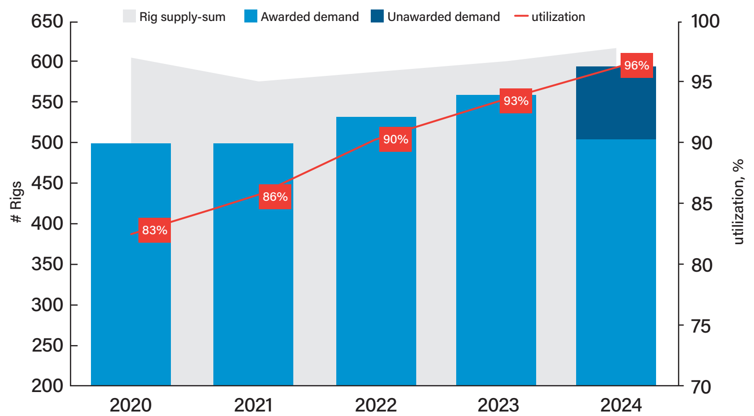


**GWP100 of 28 used for CO2e estimates*
Source: Rystad Energy's Service Market SOlution: December 2023
A Rystad Energy graphic

Some white space in 1H but further overall utilization growth

The overall outlook for the offshore rig market remains highly optimistic, albeit with the potential for more availability during first-half 2024. In addition to current warm-stacked supply with no future work in place, including 27 jackups, three drillships and eight semisubs, there are another 18 jackups, four drillships and five semisubs that are working and set to roll off hire in the first quarter of this year alone (these figures do not include rigs that have contract options available).—*Westwood Global Energy Group*

Offshore rig marketed supply, demand & utilization (2020-2024f)



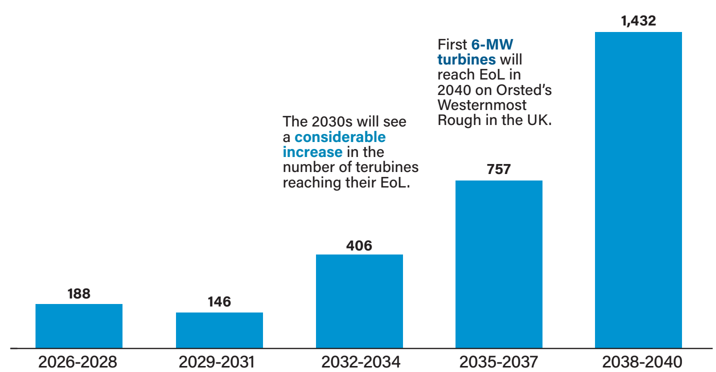
Source: Westwood Riglogix

Decommissioning wind farm projects will impact global capacity targets

Sif Group and Ballast Nedam have signed an MoU to continue developing the BNS Decom JV to provide turn-key decommissioning for offshore wind farms. Decommissioning of offshore wind farms represents a very tiny market. By the end of this decade, however, almost 200 offshore wind turbines will reach their projected end-of-life (EoL) annually. In the following decade, the number is set to increase 700% by 2040. Many North Sea offshore wind farms, being some of the earliest projects in the industry, are going through their EoL now.—*Spinergie*

Turbine EoL projections: will the fleet be enough?

Number of turbines reaching EoL per year (25-year lifetime scenario)



Courtesy Spinergie

Jeremy Beckman LONDON

NORTH AMERICA

Shell and Equinor are moving ahead with the deepwater Sparta development in the Garden Banks area of the US Gulf of Mexico. Seatrium in Singapore will construct the semi-submersible floating production unit: this will largely replicate Shell's Whale FPU which is due to start operating in the Perdido corridor later in the year. Sparta's platform, located 275 km (171 m) offshore Louisiana in over 1,400 m (4,700 ft) of water, will be Shell's first in the GOM to produce from reservoirs with pressures of up to 20,000 lb/sq in. The two-level topside will also feature all-electric compression equipment to reduce emissions, and will have capacity to produce 90,000 boe/d.

Elsewhere in the sector, Shell and partners Chevron and bp have sanctioned three new production wells through the Perdido spar platform, 200 mi (322 km) south of Galveston in 8,000 ft (2,438 m) water depth. These will be drilled in the Great White unit area, delivering an additional 22,000 boe/d at peak.

Talos Energy has produced first oil and gas from its Lime Rock and Venice subsea tiebacks to the Ram Powell platform, at an initial combined rate of over 18,500 boe/d. And the company has moved to boost its GoM production further by acquiring privately-owned QuarterNorth Energy, which operates the deepwater Katmai discovery in the Green Canyon region and has interests in other fields such as Gunflint and Galapagos, for $1.29 billion.

SOUTH AMERICA

Four companies have signed PSCs with state-owned Staatsolie under Suriname's Demerara bid round in the offshore Guyana-Suriname basin. Petronas gained 100% of Block 63, 200 km offshore in water depths of around 1,700 m, and participation in Block 64, 250 km (124 mi) from the shore in 1,300 m (4,265 ft) of water. TotalEnergies operates, QatarEnergy is the other partner: both concessions carry a commitment to drill a well in the initial three-year exploration phase. Shell subsidiary BG International operates the shallower-water Block 65 alongside QatarEnergy, and will drill a well in the second exploration period. Staatsolie also expects TotalEnergies and partner APA Corp to take FID on their first deepwater development in Block 58 by the end of this year.

Brazil too has made awards under the ANP's 4th Permanent Concession Offer Cycle. Petrobras will operate 29 blocks in the frontier offshore Pelotas basin shared with Uruguay, all in partnership with Shell and CNOOC, with Chevron named operator for 15 further blocks. Other operatorships in the Santos basin to the north went to CNOOC, Equinor and Karoon Energy.

Petrobras has produced first oil from the second full-scale FPSO development on the Mero field in the Libra block in the Santos basin pre-salt. The *Sepetiba*, supplied by and on charter from SBM Offshore, is stationed over 180 km (112 mi) from the coast of Rio de Janeiro, with capacity to produce 180,000 b/d of oil and compress 12 MMcf/d of gas for re-injection of the associated CO_2-rich gas. Mero-2 will lift overall production from the field above 400,000 b/d, with two more FPSOs under construction and set to add 180,000 b/d each by 2025.

Yinson expected the converted FPSO *Atlanta* to depart Drydocks World in Dubai in the current quarter for Enauta's Atlanta field in the Santos basin. The vessel includes a carbon management plant that employs fuel gas for cargo tank inertization, and a closed flare system.

The four-legged jacket, topsides, piles and pre-installed risers for the Fenix wellhead platform offshore southern Argentina sailed from eastern Italy early last month onboard the transport vessel *Interocean II*. Rosetti Marino built the structures for operator TotalEnergies, which is developing the Fenix field via three horizontal wells. Gas production, due to start early 2025, will head through a new 35-km pipeline to the company's Véga Pleyade platform off Tierra del Fuego.

WEST AFRICA

Energean has agreed to farm in as operator to two licenses offshore Morocco, Lixus and Rissana. The company will carry current incumbent Chariot for its share of pre-FID costs of up to $85 million for the Anchois gas field in the Lixus permit, including a planned appraisal well this year on the field's east flank, targeting up to 11 bcm from two undrilled prospects. Chariot and state-owned ONHYM will remain partners.

COURTESY MODEC

The FPSO Léopold Sédar Senghor on its way to the Sangomar field offshore Senegal.

Late last year the FPSO *Léopold Sédar Senghor* departed the Seatrium shipyard in Singapore for Woodside's Phase 1 deepwater Sangomar oilfield development, 100 km (62 mi) offshore Senegal. The vessel, converted from a VLCC, will process 100,000 b/d and store at least 1.3 MMbbl of oil, and should start operations in mid-year.

Akrake Petroleum, a subsidiary of Porto Novo Resources, plans a redevelopment of the shallow-water Sèmè oilfield offshore Benin after signing a PSC for the surrounding Block 1. Norway's Saga Petroleum developed the field, producing around 22 MMbbl between 1982 and 1982, before shutting down operations due to a heavy fall in the oil price. Initially, production should resume through a jackup MOPU, horizontal wells and modern completions for water control, to maximize recovery, with the oil stored on an FSO.

Tower Resources has contracted Borr Drilling's jackup *Norve* to drill the NJOM-3 appraisal well on the Thali license offshore Cameroon, after the rig completes programs for other clients. Tower also aims to bring in partners to the Thali license to co-fund drilling and a subsequent development.

Eni expected to produce the first LNG cargo this quarter from the *FLNG Tango*, moored offshore Congo. The vessel, with a liquefaction capacity of almost 1 bcm/yr, is the first phase of the Congo LNG project which harnesses gas produced from the Marine XII offshore permit. It is moored alongside the *Excalibur* FSU. A second FLNG, with a 3.5-bcm capacity, is under construction and should begin operating in 2025.

Galp Energia has added to the growing inventory of deepwater oil discoveries in the Orange basin. The Mapane-1X well in Petroleum Exploration License 83 was due to undergo a DST to determine commercial viability of the light oil find before drilling continued into deeper targets. The license is north of three Shell-operated discoveries in PEL39 and west of Venus-1 in the TotalEnergies-led PEL 56.

NORTHWEST EUROPE

Equinor aimed to close a transaction this quarter with Norske Shell for the latter's 30% operated interest in the Linnorm gas field in the Norwegian Sea. Linnorm, discovered in 2005, is said to be Norway's largest undeveloped gas resource with up to 30 bcm thought recoverable. As the new operator, Equinor and partners Petoro and TotalEnergies will consider a subsea tieback to either the Kristin or Åsgard B semisubmersible platforms.

Malaysian independent Ping Petroleum has conditionally agreed to take an 81.25% operated interest from Orcadian Energy in the heavy-oil Pilot field development in UK license P2444. The two companies will work to deliver a field development plan involving a polymer flood.

RockRose UKCS, a subsidiary of Viaro Energy, has agreed to farm into 15% of Bressay, another heavy oil field located in the UK's East Shetland basin, paying operator EnQuest $56.4 million. Bressay is one of the UK's largest undeveloped fields and could potentially produce around 200 MMboe, according to Viaro. It estimates capex for an early production system at $762 million.

ASIA-PACIFIC

Shapoorji Pallonji Energy's FPSO *Armada Sterling V* has produced first oil for ONGC at the deepwater KG-DWN-98/2 block offshore Kakinada, eastern India. The vessel has a liquids processing capacity of around 60,000 b/d and gas capacity of 3 MMcm/d. It is co-owned by SP Energy's 70:30 joint venture with Malaysia's Bumi Armada group, and is the company's third FPSO to operate in Indian waters.

PTTEP KH Offshore has discovered three oil and gas fields offshore Sarawak via the Chenda-1 well in block SK405B, and the Bangsawan-1 and Babadon-1 wells in SK438. All are close to previous finds made by the company, with Babadon-1 containing sweet gas sandstone reservoirs up to 200 m (656 ft) thick, the largest PTTEP has proven to date in the region following its Lang Lebah breakthrough discovery.

In addition, the company has signed development agreements with Petronas Carigali. One is an MoU concerning exports of production from SK405B through existing facilities to the Petronas-operated Bintulu onshore crude oil terminal and a technical study of design requirements for connecting the block's discoveries to the facilities. The other agreement covers engineering design support for taking gas and condensate from Lang Lebah in block SK410B to Bintulu.

Malaysia Marine and Heavy Engineering (MMHE) has contracted McDermott to perform transport and installation of facilities for Petronas Carigali's Kasawari carbon capture and storage project offshore Sarawak. The scope of work covers a 138-km (85-mi) section of pipeline, the 15,000-metric ton CCS platform jacket, and the bridge connection to the existing central processing platform.

CNOOC has started production from the Lufeng Oilfields Phase II development in the eastern South China Sea, in a water depth of 136 m (446 ft). The company installed a new drilling platform and plans to eventually have 13 producer wells and one water injector in service, supporting peak production of around 22,600 b/d by 2025.

Mubadala Energy has made a potentially giant gas discovery - over 6 tcf - with Layaran-1, its first deepwater exploration well in the Andaman Sea, 100 km (62 mi) offshore North Sumatra, Indonesia. The well was drilled in 1,207 m (3,960 ft) of water in the South Andaman Gross Split PSC and to a depth of 4,208 m (13,806 ft), encountering a gas column over 230 m thick in an Oligocene sandstone reservoir. ●

 Ariana Hurtado HOUSTON

ALL IMAGES COURTESY SUBC IMAGING

Subsea imaging technology created to help with inspection challenges

Single-channel inspection system integrates real-time topside media and data transfer

Offshore oil and gas projects routinely call for inspection and survey needs. To help with this, everything from cameras, LEDs and lasers to ROVs and AUVs are utilized, and cloud-based software and comprehensive hardware technologies provide remote operation capabilities.

SubC Imaging, a company that offers remote operations technologies for offshore energy industries, aims to solve remote challenges such as real-time low latency video; securing shared viewing and presentations; redundancy and back-ups; communications between teams and locations; remote piloting and vehicle control; and data capture, recording, logging and eventing.

Adam Rowe, vice president of software with SubC, recently shared with *Offshore* an exclusive sneak peek of the company's new Rayfin Single-Channel Inspection System (SCI). Available later this spring, this live inspection system combines software and hardware for efficient and organized inspections and surveys. The system combines camera, LED, laser and DVR software technology into one complete tool. It also integrates real-time topside media and data transfer. Unlike traditional systems, Rayfin SCI eliminates the need for downloads, allowing immediate access to crucial data. Looking ahead, a multi-channel version of this Rayfin SCI system is on the company's development roadmap.

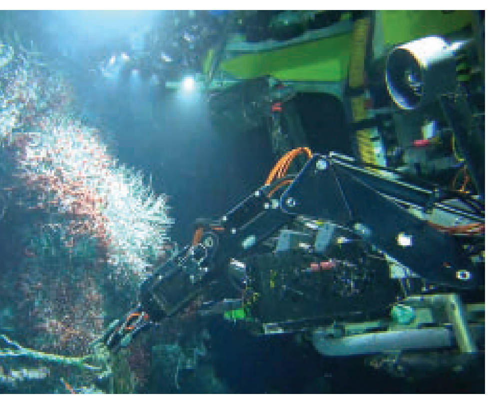
"Rayfin SCI addresses key pain points and challenges the oil and gas industry has when it comes to underwater inspections," Rowe said. "These include the need to streamline workflows by eliminating the use of separate software applications, reduce redundancy, enhance user-friendliness, and have better visibility and images."

The technology was designed to provide real-time data transfer, automated organization, and improved live image enhancement and visibility capabilities in challenging underwater conditions. Rowe said these features, paired with Rayfin Rapid Digital Imaging (RDI), can optimize the growing trend of rapid stills inspections within the offshore energy sector.

According to SubC, this is the first technology that offers a complete package for subsea imaging. "The oil and gas sector is looking for complete solutions," Rowe continued. "You don't need to cobble together piecemeal parts that are hard to integrate with your ROVs. From the camera, lights, lasers and software, Rayfin SCI delivers a system with everything you need for efficient inspections with the highest quality data."

The imaging power of the Rayfin camera is designed to capture the sharpest images, with a scratch-resistant sapphire lens paired with water-corrected LiquidOptics. In addition, the company's RDI technology comes standard with any system. "Instead of video frame grabs, fast digital stills give you exceptional resolution and zoom capabilities," Rowe added.

SubC has been evolving this imaging technology since 2017. In an effort to solve inspection challenges, SubC designed a new, optimized workflow and created this complete end-to-end single-channel live inspection suite. The specifications include a single interface for controlling cameras, lights and lasers, real-time topside media and data transfer, automatic organization of data, and features like Rayfin RDI with adjustable capture rates up to 2 Hz for improved inspection speed and accuracy. The technology offers overlays and annotations on the live and recorded video as well as voice-over capabilities.



SubC delivered low-latency video, audio and data transmission crucial for the remote piloting of the Fugro USV and eROV in 2023.

"At the end of the day, this system enables more efficient inspections with the highest quality outputs," Rowe said. "You get immediate access to images, video and data topside without extended ROV power-on periods. Because the system automates the logging of date, time, GPS, sensor data, etc., you can redirect resources, saving you time and costs. Data is automatically transferred and saved in an organized folder structure that you can customize."

In late 2023, SubC integrated its real-time streaming and audio rooms technology with Fugro systems to successfully conduct what it says is the world's first fully remote inspection of offshore wind farm assets. The inspection took place in the North Sea.

SubC delivered low-latency video, audio and data transmission crucial for the remote piloting of the Fugro USV and eROV. The technology ensured operators experienced real-time control, fostering an immediate connection with the site. Additionally, SubC's technology offered a reliable online connection, virtually eliminating dropouts for uninterrupted data streaming during inspections. The distributed accessibility of the technology enabled multiple teams in different locations to monitor the live data stream simultaneously, contributing to the collaborative success of the project by ensuring all stakeholders had access to critical information. ●

FLNG market may be regaining momentum

Confidence may be returning to the FLNG market, with several units expected to be contracted this year according to Westwood Global Energy Group (see page 17). The FLNG market has an expected EPC award value of approximately $15 billion, says Westwood.

One project that looks to be moving forward is the Cedar FLNG project offshore Canada. Samsung Heavy Industries (SHI) recently announced the award for a newbuild FLNG unit valued at $1.5 billion, believed to be for the Cedar FLNG vessel. That announcement had been preceded by another one in December by Black & Veatch, which said that it had signed a heads of agreement (HOA) with Cedar LNG Partners LP and Samsung Heavy Industries (SHI) to secure capacity in SHI's shipyard to support Cedar LNG's targeted commercial startup in Kitimat, British Columbia. The HOA also calls for the stakeholders to work together to exclusively advance the EPC agreement for the proposed FLNG facility. According to Black & Veatch, this export facility will employ a nearshore FLNG vessel utilizing its PRICO liquefaction technology integrated with the hull and LNG storage tanks. Black & Veatch also says that it will be responsible for complete topside design and equipment supply. An FID on the Cedar FLNG project is expected soon.

COURTESY WISON NEW ENERGIES

Wison New Energies has launched pre-FEED studies for two new FLNG vessels under a "design one and build two" strategy.

Meanwhile, Wison New Energies says that it has started the design validation and early engineering studies for two FLNG projects owned by Nigerian companies Ace Gas and FLNG and Transoceanic Gas & Power. In January, Wison reported that it had launched the pre-FEED phase for two 3 million tons per annum (mtpa) FLNG vessels under a "design one and build two" strategy. Transoceanic's FLNG project is located offshore Pennington and proximal to OML 289, a block operated by the company on behalf of Cleanwaters consortium. It is designed to supply 3 mtpa of LNG to the international market, and 150,000 metric tons per year (MT/yr) of LPG to the domestic market. As part of the phased development plan, the project will deploy a floating power barge concept, starting with a Phase 1 Power capacity of 250MW. The Ace Gas and FLNG project is located offshore Escravos and is also designed to supply 3 mtpa of LNG to the international market, and 150,000 MT/yr of LPG to the domestic market.

Other FLNG units that may be contracted this year include Delfin Midstream's FLNG project off the coast of Louisiana, Nisga'a Nation's Ksi Lisims FLNG project (Canada), Genting Oil and Gas' AKM FLNG unit (Indonesia), Eni's Coral Norte unit (Mozambique) and UTM Offshore's Yoho FLNG project (Nigeria).

While industry observers will wait to see if these contract awards materialize this year, other FLNG projects are moving forward.

The FLNG Gimi vessel has reached the Greater Tortue Ahmeyim (GTA) field location offshore Mauritania and Senegal following a voyage from the Seatrium conversion yard in Singapore. Supplier Golar LNG has notified GTA operator bp of the arrival.

Upon completion of preparatory activities, the vessel will be directed to its berth at the projects' hub for subsequent connection to the offshore gas pipeline.

In the meantime, Golar LNG and bp have agreed that FLNG Gimi will proceed to moor offshore Tenerife in the Canary Islands while awaiting completion of the preparatory program. The vessel is due to operate on the GTA Field for the next 20 years.

Elsewhere, Eni has introduced first gas to the Tango FLNG vessel moored offshore Congo, 12 months after taking FID on the Congo LNG project. On completion of the commissioning phase, the vessel will produce its first LNG cargo sometime within 1Q 2024.

Tango FLNG has a liquefaction capacity of close to 1 bcm/yr and is moored alongside the Excalibur Floating Storage Unit (FSU) via a split mooring configuration. This is the first implementation at a floating LNG terminal, the company added.

Congo LNG will monetize gas resources from the Marine XII permit and reach around 4.5 bcm/yr of plateau gas liquefaction capacity under a phased development, with a target of zero routine gas flaring. A second FLNG facility (3.5 bcm/r capacity) is under construction and should start production for Eni in 2025. ●

Bruce Beaubouef HOUSTON

Energy Islands projects advancing in North Sea, Baltic Sea


COURTESY ELIA

Developers of the Princess Elisabeth Island describe it as the "the world's first artificial energy island."

Developers are moving forward with plans to build two "energy islands" in the North Sea and Baltic Sea that will serve as large-scale offshore energy hubs for nearby offshore wind farms. As planned, these islands will connect surrounding wind farms with onshore power markets and will – developers hope – serve as the building blocks of an integrated European offshore electricity grid.

Last November, tendering started for the offshore Bornholm Energy Island project that will supply 3 GW of power to Germany and Denmark. The project is being developed by Energinet and 50Hertz, who have plans to create a power hub on the island of Bornholm that can provide electricity to consumers in Germany or Denmark, and possibly more widely. The partners aim to start awarding contracts in the second half of 2024, and they also plan on splitting the tender into multiple contracts.

50Hertz has already signed a contract for procurement of HVDC cables for Bornholm Energy Island, while Energinet has initiated the tender of one contract for production of cables and for offshore installation. Onshore installation and horizontal directional drilling will form a separate contract as will the surveying and removal of unexploded ordnance.

Construction on the Danish part of the project can begin once an environmental permit has come through and archaeological excavations have been completed, anticipated in 2025. In Germany installation and construction can start after the authorities have granted permits.

Meanwhile, work should get underway soon on Princess Elisabeth Island, described as the "the world's first artificial energy island," located some 45 km off the Belgian coast. The Belgian consortium TM EDISON, including DEME and Jan De Nul, has won the tender for the construction of Princess Elisabeth Island.

The construction of the foundations of the island were expected to begin in early 2024 and will last 2.5 years. After that, the installation of the high-voltage infrastructure can be started. The latter will be necessary for bringing the electricity from Belgium's future offshore wind zone to shore.

The island could also be the first building block of an integrated European offshore electricity grid that will connect various hubs and countries together. For instance, Belgium wants to build additional joint interconnections with Great Britain and Denmark.

DEME says Princess Elisabeth Island will be the world's first artificial energy island that combines both direct current (HVDC) and alternating current (HVAC). The island's high-voltage infrastructure will bundle the wind farm export cables of the Princess Elisabeth zone together, while also serving as a hub for future interconnectors with Great Britain (Nautilus) and Denmark (TritonLink). These are so-called "hybrid interconnectors" that have a dual function and are therefore said to be more efficient.

Now that the construction contract has been awarded, the design of the island can be finalized. The caissons will be built and installed in 2024 and 2025. These will form the contours of the island. After that, the base of the island will be raised and prepared for the construction of the electrical infrastructure. It will be connected with the new offshore wind farms and with the Elia onshore grid.

And just recently, Copenhagen Infrastructure Partners (CIP) announced that it is working on about 10 energy island projects in the North Sea area, the Baltic Sea and in Southeast Asia. According to the company, they combine existing, proven technologies in an innovative way and at a much larger scale, allowing for a cost-efficient build-out and integration of offshore wind. To advance these projects, CIP says it is launching Copenhagen Energy Islands, a new development company dedicated to developing energy islands globally with backing from Nordic, European and North American investors. ●

COVER STORY

Floating platform construction market maintains momentum from high oil, gas prices

Access to finance deemed as greatest obstacle, according to FPS market survey

David Boggs, ENERGY MARITIME ASSOCIATES

The floating production facility construction market remains one of the brightest spots in the offshore industry today. Offshore development costs remain low, with break-evens under $35/bbl for the most robust projects. Activity levels are expected to remain high from 2024-2026 but will be challenged by capacity constraints and access to finance.

The Global Floating Production Industry Survey, now in its eleventh year, gauges the current market sentiment as well as where the industry is heading in the future. Respondents come from all areas of the industry and from all parts of the globe.

This year the sentiment is overwhelmingly positive, with 93% of respondents confident in achieving their revenue and production targets. This is a record high in the survey's 11 years. There has been a continuing trend over the past four years. In 2021, 19% were somewhat or highly pessimistic, which declined to 8% in 2022, 5% in 2023 to 0% this year. On the other end, the number of highly optimistic responses increased dramatically from 29% to 50%. The number of slightly optimistic responses decreased slightly from 48% to 43%. Also decreasing was the percentage of those in the middle, with 7% having a neutral outlook (down from 19% last year). This overwhelmingly shows great confidence in the outlook for the offshore energy sector, with little to no expectations of a negative future.

Cost inflation

Higher prices are a certainty for 2024 according to all respondents. Increased activity, reduced competition, and general inflation continue to drive this escalation. Over two-thirds expect a 5-10% increase in capex costs, while 20% believe inflation will be more than 10%. This is a significant change from last year, when 40% of respondents believed that costs would increase by more than 10%. The number who expected prices to rise less than 5% remains essentially unchanged (13%). So there seems to be consensus that costs will continue to increase in 2024, but at a slower rate than last year.

Activity levels

Each year we ask respondents their views on future activity levels. Comparing last year's expectations for 2023 with actual activity, we see that predictions were broadly in-line, with tendering and project execution even busier than predicted.

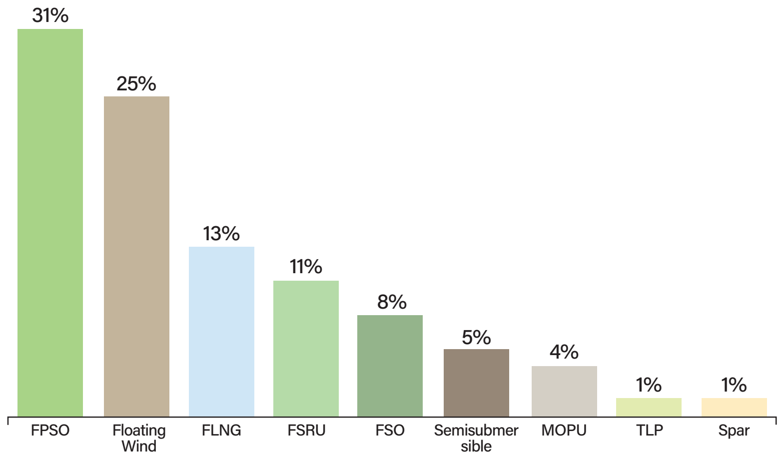
Busy times are expected for the next two years, particularly in tendering and project execution. For 2024, levels for these two areas were the highest ever recorded in the survey's history, with 61% and 70% expecting high levels of activity for tendering and project management respectively. Activity may ease slightly in 2025, with 52% and 58% of respondents expecting high levels of activity for tendering and project management respectively.

Obstacles to growth

Access to finance was named as the greatest obstacle to offshore project growth, moving up from second place in 2023 and fourth place in 2022. Financing has been a growing concern, as an increasing number of banks have ceased or restricted funding for hydrocarbon developments. As a result of this and higher financing costs, more field operators have shifted their contracting approach, and contractors throughout the industry are seeking alternative sources of capital, including bonds and private equity.

PHOTO 96208820 © SEDI78 | DREAMSTIME.COM

Which of the following FPS types present the largest growth opportunities? (Select up to three)



COURTESY ENERGY MARITIME ASSOCIATES

Tied for second place were political issues and industry capacity. Industry capacity has been a growing concern, increasing to 16% of respondents, up from 10% last year, 7% in 2022 and 5% in 2021. Political issues had been the top issue for the past two years, but moved to second place this year. Concerns remain about global conflicts, particularly Russia-Ukraine and in the Middle East.

ESG issues/investor sentiment remained in third place this year, unchanged from 2023. Some respondents believe these are an existential threat to the industry and companies certainly factor in these issues when making investments, as seen by Shell's exit from the UK's Cambo development. This is another factor contributing to the difficulty in finding finance for these developments.

Environmental regulations and more attractive investment opportunities tied for fourth place. Environmental regulations slipped one place from third last year, perhaps as energy security issues and political winds have shifted.

FPS growth markets

FPSOs remained the clear leader as the floating production system with the most promising growth potential, according to 31% of respondents. Floating wind held second position again, reflecting continued enthusiasm for renewables, despite recent setbacks due to cost overruns and supply chain constraints. FLNG remained in third place, although with less support than last year (13% of responses, down from 19% last year). Perhaps last year there was more optimism driven by the surge in LNG prices and need for energy security.

Technology game changers

This year, when we asked which type of technology will have the largest impact on the offshore industry, floating wind was again the winner by far, accounting for almost one third of the votes. While still in its infancy, there is a great deal of enthusiasm and hope for floating wind. Time will tell if it can live up to the expectations. FLNG was the top ranked technology in this survey from 2013- 2019, before dropping off the list.

This year there was a three-way tie for second place among unmanned production facilities (UPFs), subsea production, and long-distance tiebacks. Several reasons account for UPF's popularity – the high cost of personnel as a portion of operating costs, application of digital solutions, and increasing comfort with working remotely. While unmanned fixed facilities are common, the technology is just beginning to be transferred to floaters. Even if a completely unmanned facility is not realized, reductions in personnel offshore would result in lower operating costs. In 2022, Chevron placed a $554-million order with Daewoo for the Jansz-Io production semi, which would be the first normally unmanned floating facility.

Subsea production moved up one spot with 20% of the vote. Use of this technology can reduce the topside requirements on floating facilities and keep them within existing designs. The Jansz-Io project features a $795-million subsea gas compression station, which is connected to the previously mentioned production semi.

Long-distance subsea tiebacks moved up two places this year. This technology could increase the utilization of existing facilities and follows the trend of infrastructure-led investment. Tiebacks certainly will extend the life of currently installed production units, while the impact of future requirements is yet to be seen. Some stand-alone FPS developments could be replaced by tiebacks, while an FPS hub with tieback of multiple fields could also become economic. ●

Editor's note: Read the extended version of this article at offshore-mag.com/14304068.

David Boggs is the Managing Director of Energy Maritime Associates, which publishes market-leading reports on the floating production industry and advisory services for developments requiring FPSOs, FLNGs, FSRUs, Semis, Spars, TLPs, MOPUs, and FSOs.

Oil and gas capex to remain elevated, even grow marginally

With wind included, total offshore investments to increase by 17%

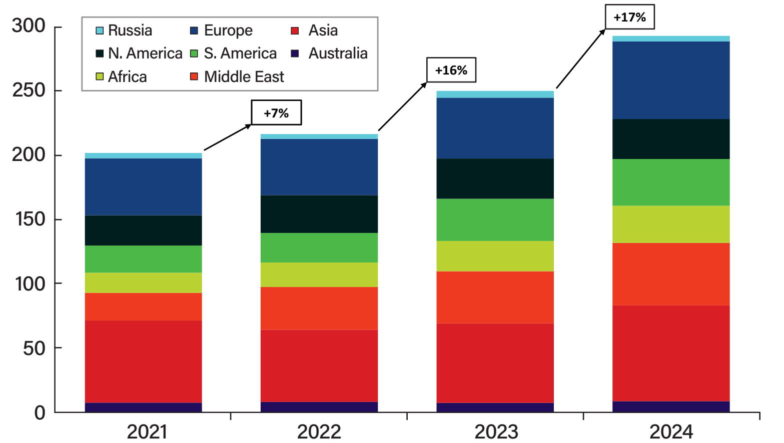
Matthew Hale, RYSTAD ENERGY

As suppliers to the offshore industry enter a new year, energy developers are poised to grow capital expenditures (capex) beyond last year's recent high water mark of $250 billion, spanning oil and gas and power markets. After expanding project spending by 7% in 2022 and 16% in 2023, Rystad Energy projects the same metric to reach 17% in 2024. This is still below the record set in 2014 when offshore upstream capex reached an all-time high, and offshore wind expenditures contributed less than 3% of the total. In 2024, offshore wind and floating solar will contribute almost 19% of this sum as solar and wind installation continue to take a larger share of the power generation mix. Regionally, Asia will continue to be the largest market for offshore investments led by China, while Norway and the UK will push the European continent higher.

As in many other domains, operators for China-based projects are the largest investors in offshore energy by a healthy margin, with over half of those capital expenditures in wind generation capacity. Of the top 10 national markets, only the UK can claim more power projects in comparison to oil and gas. With a forecasted 2024 growth rate of 12%, Chinese capital expenditures will expand by the most in dollar terms, followed by the United Arab Emirates (UAE) and the UK. The UAE will post an exceptional growth rate of 42%, driven primarily by the sanctioning of the Hail and Gasha project, which will produce 1.5 billion cubic feet per day (Bcfd) of natural gas per day and capture and store 1.5 million tonnes per annum of carbon dioxide. In the US, despite a contraction in offshore wind in 2023 as developers attempted to negotiate higher offtake electricity prices, wind capital expenditures will grow in 2024, offsetting a slight decline in upstream oil and gas investments. All of the top 10 countries will expand, with the exception of Mexico, which

Figure 1: Offshore energy capital expenditures by continent

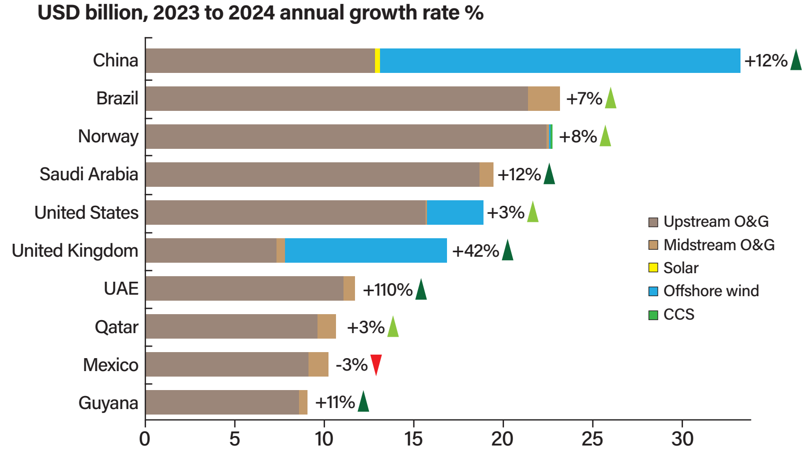
USD billion, 2023 to 2024 annual growth rate



Source: Rystad Energy ServiceCube

Figure 2: Top 10 countries for offshore energy investments by continent, 2024

USD billion, 2023 to 2024 annual growth rate %



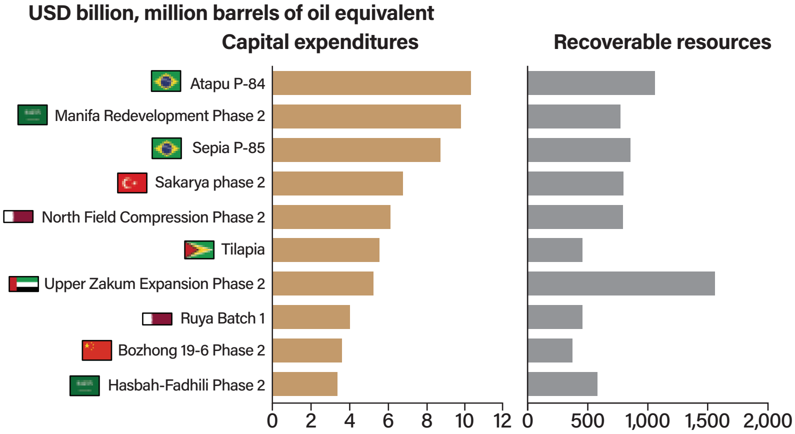
Source: Rystad Energy Service Cube

still faces foreign investment headwinds, despite the sanctioning of Woodside's Trion development and Pemex's plans to arrest several years of offshore production declines.

The bulk of expenditures are driven by the sanctioning of large upstream projects with Brazilian floating production storage and offloading (FPSO) vessels featuring prominently among the largest 2024 final investment decisions (FIDs). The P-84 and P-85 FPSOs are currently tendering for deployment on the Atapu and Sepia fields. The shallow waters of the Persian Gulf make up half of this top 10 list of FIDs with notable projects in Saudi Arabia, Qatar and the UAE. Most of this will feature large, fixed platforms, while the latest Upper Zakum expansion will rely on artificial islands based on extensive dredging services. ExxonMobil is expected to sanction its Tilapia project in Guyana this year with another jumbo FPSO development and associated subsea equipment orders. TPAO's Sakarya Phase II project has already awarded contracts to Saipem, SLB and Subsea7 with FID later this year. Finally, CNOOC will commit to the second phase of the Bozhong 19-6 gas and condensate project in the Bohai Bay after commencing production from the initial development in November 2023. These investment decisions will further stretch the offshore fabrication supply chain, which is still ramping up from a big 2023.

Reports of the demise of the offshore wind industry have been largely overblown, with more wind turbines slated for installation this year than in 2023. It is expected that 2024 will be the first year to see a material volume of turbines installed which exceed 12 megawatts (MW) in individual output capacity. Rystad Energy estimates that 280 12-14 MW turbines will be installed in 2024, up from a handful in 2023 and surpassing the installations

Figure 3: Top 10 E&P projects to be sanctioned in 2024 by expenditures and resources



Source: Rystad Energy UCube

of 10-12 MW turbines. Therefore, this year will be a milestone as well as a test in the emerging trend towards larger and larger wind turbines, which also come with increased installation and maintenance costs balanced by better efficiency and higher output. While the share of these larger models is set to grow, smaller 4-8 MW turbines are also expected to reach 543 units this year from 450 in 2023, with around half of these units in mainland China and Taiwan.

Shifting attention to the vessel and rig markets, the total demand for offshore units can be visualized by taking into account both the oil and gas and wind energy sectors. Asian countries will account for over a quarter of vessel demand at 878 years of work led by China, while the Middle East will be the second largest region for vessels with 591 years. When examining different types of vessels, we see that anchor handling tug supply (AHTS) vessels will require the largest fleet to supply over 1,000 years of demand, followed by platform supply vessels (PSVs), offshore construction vessels (OCVs), and jackup drilling rigs. Some vessels are able to work across both the upstream and wind sectors, while jackup and floating rigs are confined to oil and gas or carbon capture, utilization and storage (CCUS) work and wind installation vessels (WIVs) are limited to foundation and turbine installation. With limited new build rigs in the pipeline and a fast-growing wind sector, shipyards will be strained to meet the demand for these specialized vessels in the coming years.

With crude oil prices projected to remain above $80 in 2024, oil and gas capital expenditures will remain elevated and even grow marginally. Combined with the expansion of offshore wind installations, total offshore investments will increase by 17% over 2023. China will lead the way, with both the UAE and UK contributing materially to this expansion. Shallow water expansions in the Middle East will be supplemented by large FPSO-based greenfield developments in Brazil and Guyana. In 2024, a noteworthy milestone is on the horizon for 12-14 MW wind turbines, and the combined demand for offshore vessels and rigs will push utilization rates higher, leading to another banner year for service providers. ●

Matt Hale is Rystad Energy's Lead Analyst for Energy Services Americas. He has extensive experience in oilfield services, spending most of his career with Baker Hughes and NOV supporting product development.

Nearly 90 greenfield, brownfield project FIDs expected this year

Offshore EPC contracting opportunity valued at $68 billion

Mark Adeosun, WESTWOOD GLOBAL ENERGY GROUP

Global energy demand continues to ramp up as the world economy emerges from the constraints of the COVID-19 pandemic. According to the US EIA, liquids consumption has grown by 10% over the past three years, averaging 101 MMb/d in 2023.

The rebound in oil demand to above pre-pandemic levels continues to spur investments in oil and gas (O&G) projects, with upstream engineering, procurement and construction (EPC) contract award value in 2023 totalling approximately $39 billion (excluding letters of intent). This represents a 98% increase compared to the 2020 EPC award value but a 28% decline on 2022 as the inflationary cost environment and global supply chain crunch led to project delays.

Overall, Westwood recorded a total of 275 subsea tree unit awards in 2023 – a four percent increase compared to our January 2023 outlook. EPC-related activities for floating production systems (FPS) sanctioned in 2023 accounted for 1.2 MMboe/d of O&G throughput capacity and 2.7 MMtpa of LNG capacity, driven by 13 units (four newbuilds, three conversions and six upgrades/redeployment), with an EPC value of $11 billion. This represents a 45% decline in recorded EPC award value, compared to our January 2023 outlook, due to delays to bid submission deadlines for Petrobras' floating production, storage and offloading (FPSO) units such as the Albacora replacement FPSO, the P-84 and P-85 units. Given these delays, the Brazilian NOC did not sanction any FPSO construction project in 2023, compared to four units sanctioned in 2022.

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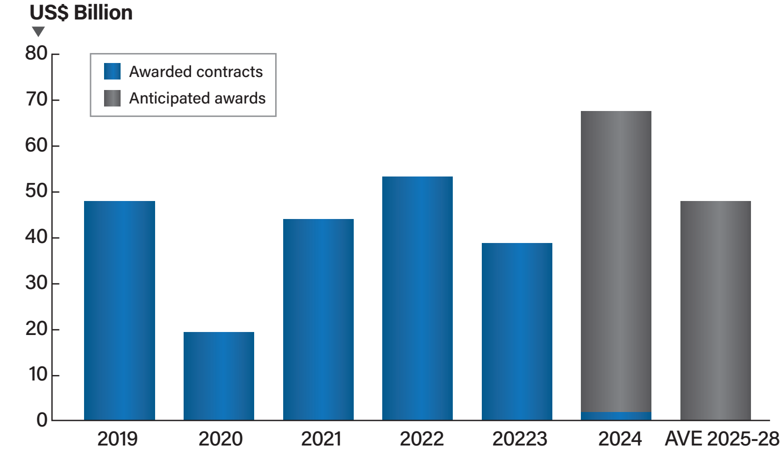
A total of 99 fixed platforms were sanctioned in 2023, with sanctioning activities in the Middle East accounting for 80%, driven by Saudi Aramco's contract release and purchase orders (CRPOs), including 87 and 102, 97, 117, 118, 121, 122 and 125. North Oil Company's Ruya (Gallaf phase 3) project and QatarEnergy's ISND Phase 5 project, both in Qatar, also contributed to fixed platform EPC-related investment in the region. Over 3,400 km of subsea umbilicals, risers and flowlines (SURF) and over 2,600 km of line pipe was sanctioned last year.

Outside of brownfield expansion projects in the Middle East, major projects sanctioned in 2023 include ExxonMobil's Uaru project (Guyana), Woodside's Trion (Mexico), Shell's Sparta (US GoM), TPOA's Sakarya Phase 2 (Turkey), Equinor's Rosebank (UK) and its Raia fields (Brazil), as well as Azule Energy's Agogo (Angola).

EPC activity outlook

Looking ahead to expectations for the offshore industry in 2024, Westwood forecasts global offshore O&G-related EPC contract award value to total approximately $68 billion, driven by 89 greenfield and brownfield project FIDs over the next 12 months. This represents a 74% increase on the EPC award value recorded in 2023. Contracting activities in 2024 will be driven by demand for over 320 subsea tree units, 22 floating production units (including seven FLNG units), over 130 fixed platforms, 4,500 km of SURF and approximately 3,900 km of line pipe. It is pertinent to state that while there has been historic optimism about the FLNG market, it has failed to live up to expectations in the past. This year, however, could be the time for the faltering FLNG industry to fully bloom, with an expected EPC award value of approximately $15 billion, of which Samsung Heavy Industries already announced the award for a newbuild FLNG unit valued at $1.5 billion, believed to be related to the Cedar FLNG project offshore Canada. FLNG EPC award value for 2024 will be driven mainly by projects that have historically experienced delays but are now prime to reach a final investment decision. This includes at least one unit for Delfin Midstream's FLNG project off the coast of Louisiana (US), Nisga'a Nation's Ksi Lisims FLNG project (Canada), Genting Oil and Gas' AKM FLNG unit (Indonesia), Eni's Coral Norte unit (Mozambique) and UTM Offshore's Yoho FLNG project (Nigeria). Should they all go ahead this year in their current stipulated capacity, these projects will account for 24.4 MMtpa of additional liquefaction capacity.

Offshore EPC contract award outlook



Source: Westood SubseaLogix & PlatformLogix

Regionally, offshore investment in 2024 will be concentrated in the Americas, accounting for 48% of forecast EPC spend. This will be driven by contract awards related to projects such as ExxonMobil's Whiptail development (Guyana), Pemex's Zama project (Mexico), TotalEnergies' Block 58 development (Suriname), as well as Petrobras' continued investment in the presalt basin, driven by the P-84 and P-85 FPSO units to be deployed on the Atapu and Sepia development. Westwood anticipates that the US GoM will continually thrive on subsea infill drilling and fast-track developments over the near term. Furthermore, there will be front-end engineering and design (FEED) contracting opportunities for projects such as Shell's Leopard and BP's Tiber and Kaskida projects, all in the US GoM, which are expected to be sanctioned within the next 18-36 months. Driven by planned and recently recorded investment, offshore production in the Americas is expected to grow 24% on 2023 by 2028, reaching 12.6 MMb/d.

In the Middle East, investment offshore from members of the Gulf Cooperation Council (GCC) will lead to a major production boost, with GCC offshore production forecast to reach 14.9 MMboe/d by 2028, up 30% on 2023. Saudi Aramco's Safaniya brownfield project driven by CRPOs 104 to 113 and CRPO 88, as well as QatarEnergy's delayed North Field South (NFS), North Field Compression project and ADNOC's Lower Zakum Long Term Development - Phase I development will represent key offshore EPC contracting opportunities in 2024. Energean's Katlan development offshore Israel, for which TechnipFMC was awarded an integrated FEED contract, will also represent a key award in the region.

Beyond 2024, continued investment in Petrobras' presalt basin, ExxonMobil's Starbroek block (Guyana), the East Mediterranean, deepwater Namibia, and the East African gas basin represent significant EPC contracting opportunities. Westwood anticipates strong levels of EPC contracting activities over the 2025-28 period sustained by oil prices (estimated to average over $65/bbl), favorable project economics and robust hydrocarbon demand. Given this, an annual O&G-related EPC award value is forecast to average $48 billion. Overall, potential upside remains, as Westwood has also identified EPC and modification contracting opportunities related to the offshore carbon storage (CS) industry, which remains vital for the energy transition. Identified CS projects requiring new infrastructure that have progressed to or beyond the concept phase will account for over $9 billion over the 2024-28 period, driven by approximately 65 subsea tree units, 3,200 km of subsea line pipe and 10 newbuilt fixed platforms.

The expected high levels of investment in 2024 will help increase global offshore production, even as most shallow water-focused areas outside of the Middle East continue a long-running decline trend. Overall, offshore production is expected to reach 56.4 MMboe/d by 2028, up from 48.3 MMboe/d in 2023. ●

Mark Adeosun is currently the Research Director for Westwood Global Energy Groups' SubseaLogix and PlatformLogix market analytic tools. Since joining Westwood in 2013, he has worked directly with as well as advised several clients within the oilfield services supply chain, as part of both analytic and commercial advisory projects.

Eastern Mediterranean remains key E&P focus area

Despite conflict, region's gas reserves still targeted by producers, exporters

Gina Cohen, GINA ENERGY *and*
Alexander Kislov, NATURAL GAS ANALYST & CONSULTANT

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The Yavuz drillship operates in the Mediterranean Sea.

There have been several shocks to the international energy market since 2020, including an oil price shock, pandemic-related restrictions, the Ukraine-Russia war, and the more recent and ongoing Israel-Gaza conflict. These tensions and uncertainties have brought even greater focus on the E&P potential of the Eastern Mediterranean region, which includes Israel, Egypt, Cyprus, Turkey, Jordan and Lebanon.

An interesting element of the region is the ebb and flow of inter-state relationships. These play a role on whether the Eastern Med can fully integrate into a regional player so that countries with surplus gas can feel secure in supplying most of their excess to regional markets. These relationships also play a key role in the mutual use of existing and/or new infrastructure that could be built to reach international markets. If these relationships fail to develop or progress, there are risks that some countries will remain short of gas, and that reserves that could benefit European markets could remain stranded.

Let us first have a look at the supply and demand equation of each country, and then delve into potential export projects.

Israel. With reserves of ~1,000 bcm, Israel currently produces ~25 bcm/a and consumes ~13 bcm. It exports ~3 bcm/a to Jordan and ~6 bcm/a to Egypt. Expansion plans include FIDs taken to increase the capacity at the Tamar field from 11 to 12 bcm, of the Leviathan field from 12 to 14 bcm/a, and Karish to 7.5 bcm/a. In October 2023, the Ministry of Energy awarded 12 new exploration licenses to six companies, including a group led by Italy's Eni and a group involving Azerbaijan's Socar along with BP. Both consortiums include Israeli partners.

Egypt. With reserves of 2,200 bcm, in 2022 Egypt produced ~67 bcm, consumed ~61 bcm, imported ~6 bcm/a of pipeline gas from Israel and exported ~10 bcm of LNG. Egypt has and continues to carry out exploration bidding rounds, but the only latest discovery was a modest 100 bcm by Chevron and Eni. Several of its legacy fields suffer from water infiltration problems and are depleting fast. The country has suffered hours a day of black-outs recently due to insufficient gas for its power generation.

Cyprus. With reserves of ~430 bcm, Cyprus has significant potential but currently has no gas production or development projects underway. Nor does it have much of an internal consumption market. In 2024, the country is expected to start consuming LNG via an FSRU, while it hopes to move ahead also on taking FID to develop its first discovery, the 105 bcm Aphrodite field.

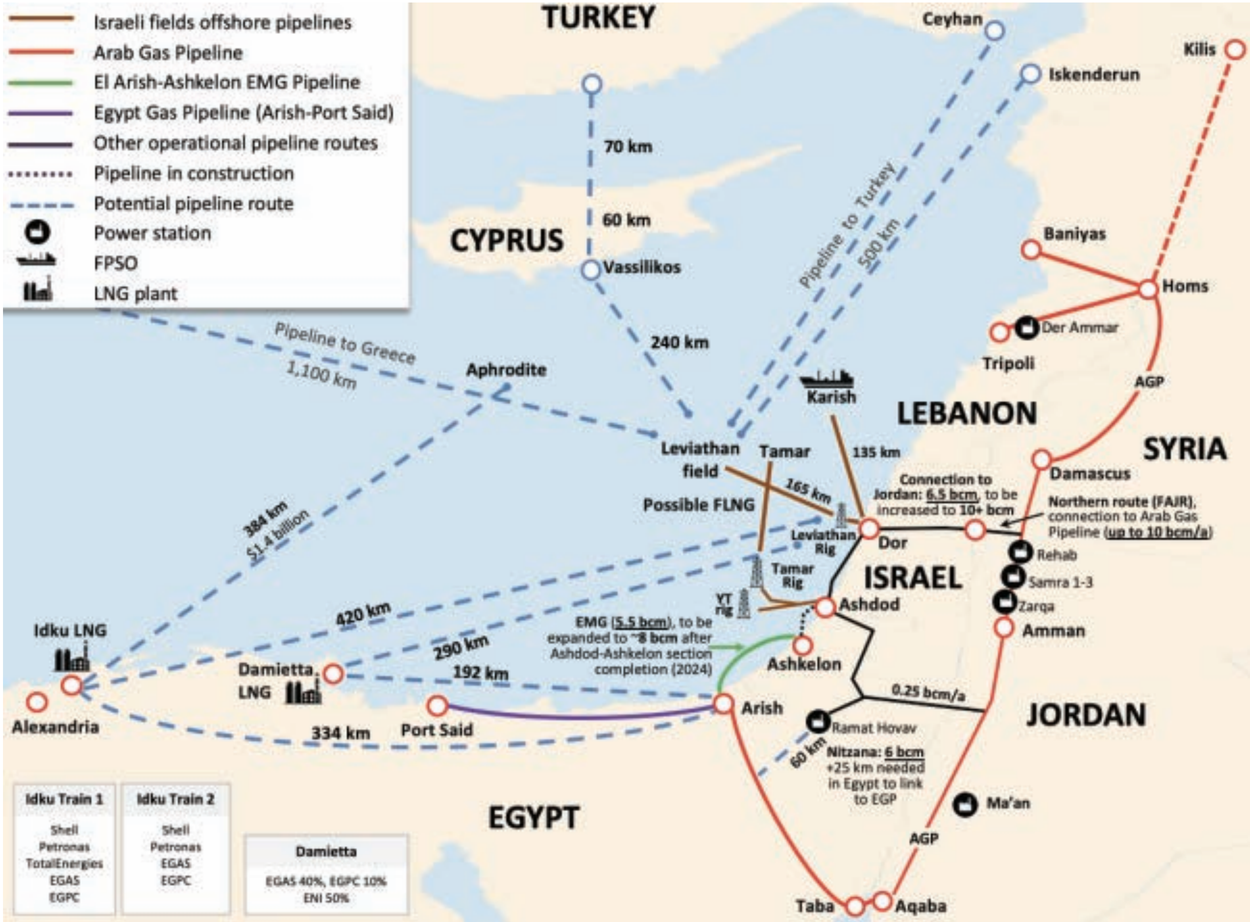
*Turkey.*With reserves of over 700 bcm, Turkey aims to reach ~3.5 bcm output from the first phase of its offshore Sakarya field. Turkey consumes 45-60 bcm/annum and is thus strongly dependent on imports from Russian, Iran, Azerbaijan and LNG.

*Lebanon.*Despite exploration carried out by TotalEnergies, Eni and QatarEnergy, Lebanon has not had discoveries to date and is not consuming any gas. Plans to import gas from Egypt, albeit from Israeli molecules via Jordan and Syria, are not moving ahead for now.

Export projects

Currently, as aforementioned, regional exporters include small to mid-size volumes from Israel (about 9 bcm a year to Jordan and Egypt) and from Egypt (about 10 bcm a year of LNG to the global market).

In order for the region to be able to export another 10-20 bcm of gas a year, the following projects are under consideration.



Map of the key EastMed natural gas infrastructure and Israeli fields (composed by the authors).

Cyprus. Hopes to reach FID to develop Aphrodite and export 6 bcm/a to Egypt. The partners in the field are due to conduct a one-year FEED to examine development options.

Egypt. Has long-standing ambitions to become a gas hub, but failing further discoveries and a recovery in its economic situation it may find itself rapidly becoming a net importer of gas. Indeed already in 2023, it is expected that its LNG exports will be close to half those in 2022.

Israel. Hopes to reach FID on Tamar to increase capacity by another 4 bcm/a and to increase Leviathan capacity by another 4-9 bcm/a. Export projects being examined to sustain such development include:

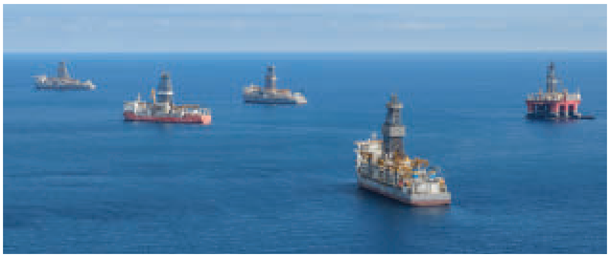
- Additional sales to Egypt – Tamar hopes to export an additional 38-43 bcm to Egypt from 2025 to 2034. Additional volumes to Egypt, also coming from Leviathan, would require both further upstream and midstream developments. Partners in Israel would want to see that Egypt's financial situation stabilizes, and that its gas supply and demand ratio ensures that additional Israeli gas to Egypt would be safeguarded to the higher paying global LNG market.
- A pipeline to export gas to Turkey – Although relations between Israel and Turkey had improved over much of last year, the Oct. 7 Israel-Gaza war saw Turkey President Erdogan supporting Hamas and pausing plans for energy cooperation. This effectively buries an option for exports via Turkey and from Turkey to eastern Europe for the medium term. The project could be revisited in the future.
- FLNG offshore Israel – The Leviathan partners are considering a 6.4 bcm/a FLNG project. The capex of such a project however is considerable and the security implications of a nearshore Israeli facility may require further analysis to see if and how to proceed with such an option.
- Poseidon project – This would involve an offshore pipeline from Israel which would gather supplies from Cyprus and move them onwards via Greece and Italy. FEED for this project was completed last year and it is part of the EU's project of Common Interest. Although this is a complex $6.4-billion project, its feasibility has potentially become more prominent considering some of the complexities involved in other regional projects.

Each project is feasible but requires further investigation and decisions to be taken. Despite a complex regional situation, energy security remains of paramount importance to local, regional and global gas consumers. ●

Gulf of Mexico deepwater discoveries survey shows notable increase

Eight new finds announced over past 12 months

Bruce Beaubouef, MANAGING EDITOR



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Operators announced eight new discoveries in the deepwater Gulf of Mexico over the past twelve months, representing a notable increase over the three deepwater discoveries reported the year before.

While this is a marked increase over some recent surveys, the overall number of deepwater discoveries is down significantly as compared to the amount seen 20 years ago. In 2004, for example, there were 12 discoveries recorded in the deepwater Gulf of Mexico. The lower level has been driven by two oil price shocks in recent years; and more recently, a suspension of lease sales and a focus on renewable energy that has in turn led to lower levels of investment and drilling.

As has often been the case in recent years, the drilling activity has been driven by the larger independents and medium-sized operators, with Talos Energy, Murphy Oil, Kosmos Energy and Hess Corp. (now part of Chevron) leading the way.

Last May, Murphy Oil reported that it had discovered oil in the Longclaw prospect in the Green Canyon block 433. The well delivered about 62 ft of net oil pay and reached a total measured depth of 25,106 ft. Further studies are underway, the company reported in its latest results statement. The company also started production from the Samurai #5 well in Green Canyon 432, with better-than-expected volumes, reflecting discovery of new pay zones in the field in 2022.

Another discovery last summer was Hess's oil find at its Pickerel-1 prospect in Mississippi Canyon block 727. The Pickerel-1 well encountered net pay of about 90 ft in an oil bearing, Miocene age reservoir. Plans are underway for a tieback of the well to the Tubular Bells production platform, 135 km southeast of New Orleans, with first oil expected in mid-2024.

Meanwhile, Kosmos Energy says that it is conducting rock and fluid analysis on its Tiberius oil discovery in Keathley Canyon block 964. The well, drilled in 7,500 ft (2,300 m) of water last October, delivered 250 ft (75 m) net oil pay in the main Wilcox target. Kosmos says that it is working with partners on subsea development options. Tiberius is six miles southeast of the Occidental-operated Lucius spar production platform.

Talos Energy reported six successful exploration wells in the US Gulf of Mexico last year, and four of these have moved close to production.

At the Pompano field, the Mount Hunter development well delivered commercial volumes of oil and gas, with estimated recoverable resources of 5-6 MMboe. Located in Viosca Knoll block 989, production is expected to ramp up to 4 MMboe/d.

The A-26 ST well drilled from the Lobster platform in Ewing Bank 873 encountered pay in multiple field horizons. Talos has a 67% interest in Lobster, which came with its acquisition of EnVen's portfolio.

The Gunflint #1-ST well in Mississippi Canyon block 948 also proved commercial quantities of oil and gas.

The Spruance West discovery, located in Ewing Bank block 877, was also part of the EnVen package, with initial flow rates of over 3 MMboe/d.

In Green Canyon block 821, the BP-operated Puma West appraisal well (PW #2) and subsequent downdip sidetrack were both reported to have encountered hydrocarbons in multiple sands. But more hydrocarbons from a subsequent well or sidetrack will likely be needed to proceed with a development.

Meanwhile, Talos says that its Lime Rock and Venice prospects were deemed to have commercial quantities of oil and natural gas last year. Talos expects combined gross production rates of approximately 15-20 MBoe/d from expected combined gross recoverable resources of 20-30 MMBoe. Both wells will be subsea tiebacks to the Talos owned and operated Ram Powell facility and are expected online sometime in 1Q 2024. ●

Status of US Gulf of Mexico deepwater discoveries since 2000

Field name	Location	Year of disc.	Water depth (ft)	Operator	Status	Onstream	Projected onstream	Prod. Type*
A-26 ST	Ewing Bank 873	2023	775	Talos Energy	Discovery			
Allegheny South	Green Canyon 298	2005	3,280	Eni	Producing	2005		SS
Amethyst	Mississippi Canyon 26	2014	1,122	Talos Energy	Producing	2016		SS
Anchor	Green Canyon 807	2015	5,183	Chevron	Development		2024	FPU
Anduin	Mississippi Canyon 755	2005	2,400	W&T	Producing	2007		SS
Appaloosa	Mississippi Canyon 459	2008	2,500	Eni	Producing	2011		SS
Appomattox	Mississippi Canyon 392	2010	7,290	Shell	Producing	2019		FPS
Aspen	Green Canyon 243	2001	3,063	Walter	Producing	2002		SS
Atlas	Lloyd Ridge 50	2003	9,000	Occidental Petroleum	Producing	2007		SS
Atlas NW	Lloyd Ridge 5	2004	8,810	Occidental Petroleum	Producing	2007		SS
Balboa	East Breaks 597	2001	3,373	Apache	Producing	2010		SS
Ballymore	Mississippi Canyon 607	2018	6,562	Chevron	Appraisal			
Barataria	Mississippi Canyon 521	2015	6,771	Kosmos Energy	Producing	2017		SS
Bass Lite	Atwater Valley 426	2001	6,623	Apache	Producing	2008		SS
Big Bend	Mississippi Canyon 698	2012	7,200	QuarterNorth	Producing	2015		SS
Big Foot	Walker Ridge 29	2006	5,000	Chevron	Producing	2018		TLP
Blacktip	Alaminos Canyon 380	2019	6,200	Shell	Appraisal			
Blacktip North	Alaminos Canyon 336	2021	4,487	Shell	Appraisal			
Blind Faith	Mississippi Canyon 696	2001	6,900	Chevron	Producing	2008		Semi
Blue Wing Olive	Mississippi Canyon 427	2016	5,800	Beacon Offshore Energy	Producing	2018		SS
Boomvang North	East Breaks 599	2001	3,153	Occidental Petroleum	Producing	2007		SS
Boris	Green Canyon 282	2001	2,393	BHP	Producing	2003		SS
Brutus Ru	Green Canyon 202	2002	3,160	EnVen Energy Ventures	Producing	2003		SS
Buckskin	Keathley Canyon 872	2009	6,920	LLOG	Producing	2019		SS
Bulleit	Green Canyon 21	2019	1,300	Talos Energy	Producing	2020		SS
Caesar/Tonga	Green Canyon 683	2006	4,500	Occidental Petroleum	Producing	2012		SS
Caicos	Green Canyon 564	2016	4,225	BHP	Appraisal			
Callisto	Mississippi Canyon 876	2001	7,800	Occidental Petroleum	Producing	2011		SS
Calpurnia	Green Canyon 727	2017	4,330	Occidental Petroleum	Appraisal			SS
Cardamom	Garden Banks 427	2010	2,720	Shell	Producing	2014		SS
Cardona	Mississippi Canyon 29	2014	2,135	Talos Energy	Producing	2014		SS
Cardona South	Mississippi Canyon 29	2014	2,135	Talos Energy	Producing	2014		SS
Cascade	Walker Ridge 206	2002	8,203	Murphy	Producing	2012		FPSO
Castile (Moccasin)	Keathley Canyon 736	2011	6,739	LLOG	Appraisal		2025	FPU
Cheyenne	Lloyd Ridge 399	2004	8,987	Occidental Petroleum	Producing	2007		SS
Chinook	Walker Ridge 469	2003	8,826	Murphy	Producing	2012		SS
Claiborne	Mississippi Canyon 794	2015	1,500	Beacon Offshore Energy	Producing	2018		SS
Clipper	Green Canyon 299	2005	3,452	Murphy	Producing	2013		SS
Coelacanth	Ewing Bank 834	2012	1,186	Walter	Producing	2016		FP
Constellation	Green Canyon 627	2014	4,385	Occidental Petroleum	Producing	2019		SS
Constitution	Green Canyon 680	2003	5,100	Occidental Petroleum	Producing	2006		Spar
Coronado	Walker Ridge 98	2013	6,127	Chevron	Appraisal			

Status of US Gulf of Mexico deepwater discoveries since 2000

Field name	Location	Year of disc.	Water depth (ft)	Operator	Status	Onstream	Projected onstream	Prod. Type*
Cottonwood	Garden Banks 244	2001	2,000	Murphy	Producing	2007		SS
Crown & Anchor	Viosca Knoll 959	2015	4,300	Beacon Offshore Energy	Producing	2018		SS
Dalmatian	DeSoto Canyon 48	2008	5,876	Murphy	Producing	2014		SS
Dalmatian South	DeSoto Canyon 134	2012	6,394	Murphy	Producing	2014		SS
Danny	Garden Banks 506	2007	2,700	Talos Energy	Producing	2010		SS
Daniel Boone	Green Canyon 646	2004	4,230	W&T	Producing	2009		SS
Dantzler	Mississippi Canyon 782	2013	6,580	Fieldwood Energy	Producing	2015		SS
Dawson	Garden Banks 669	2001	3,000	Occidental Petroleum	Producing	2004		SS
Dawson Deep	Garden Banks 625	2004	2,900	Occidental Petroleum	Producing	2006		SS
Deimos	Mississippi Canyon 806	2002	3,000	Shell	Producing	2005		SS
Delta House	Mississippi Canyon 254	2008	4,450	Murphy	Producing	2015		FPS
Delta House - Marmalard	Mississippi Canyon 300	2012	5,781	Murphy	Producing	2015		SS
Delta House - Marmalard East	Mississippi Canyon 301	2017	6,000	Murphy	Producing	2017		SS
Delta House - Son of Bluto II	Mississippi Canyon 431	2012	5,013	Murphy	Producing	2015		SS
Don Larsen	East Breaks 598	2001	3,416	Occidental Petroleum	Producing	2007		SS
Dorado	Viosca Knoll 915	2002	4,023	Occidental Petroleum	Producing	2009		SS
Dover	Mississippi Canyon 612	2018	7,500	Shell	Appraisal			
Droshky	Green Canyon 244	2007	2,900	Marathon	Producing	2010		SS
Durango	Garden Banks 667	2001	3,150	Occidental Petroleum	Producing	2004		SS
Esox	Mississippi Canyon 726	2019	4,609	Hess	Producing	2020		SS
Ewing Bank 1006	Ewing Bank 1006	2003	1,854	Walter	Producing	2005		SS
Ewing Bank 998	Ewing Bank 998	2009	1,000	Walter	Producing	2011		SS
Ewing Bank 878	Ewing Bank 878	2000	1,523	Walter	Producing	2001		SS
Falcon	East Breaks 579	2001	3,400	Marubeni	Producing	2003		SS
Fort Sumter	Mississippi Canyon 566	2016	7,062	Shell	Appraisal			
Friesian	Green Canyon 599	2006	3,830	Occidental Petroleum	Appraisal			
Front Runner	Green Canyon 338	2000	3,500	Murphy	Producing	2004		Spar
Front Runner South	Green Canyon 339	2001	3,500	Murphy	Producing	2005		SS
Geauxpher	Garden Banks 462	2008	2,820	Apache	Producing	2009		SS
Genghis Khan	Green Canyon 652	2005	4,300	BHP	Producing	2007		SS
Gila	Keathley Canyon 93	2013	4,900	bp	Appraisal			
Gladden	Mississippi Canyon 800	2008	3,116	W&T	Producing	2011		SS
Gladden Deep	Mississippi Canyon 800	2019	3,000	W&T	Producing	2019		SS
Goldfinger	Mississippi Canyon 771	2004	5,423	Eni	Producing	2005		SS
Great White	Alaminos Canyon 857	2002	8,009	Shell	Producing	2010		Spar
Guadalupe	Keathley Canyon 10	2014	3,992	Chevron	Appraisal			
Gunflint #1 ST	Mississippi Canyon 948	2023	6,100	Talos Energy	Discovery			
Gunnison	Garden Banks 668	2000	3,131	Occidental Petroleum	Producing	2003		Spar
Hadrian South	Keathley Canyon 919	2009	7,425	ExxonMobil	Producing	2015		SS
Harrier	East Breaks 759	2003	3,609	Marubeni	Producing	2004		SS
Hawkes	Mississippi Canyon 509	2001	4,174	ExxonMobil				FPS
Healey	Green Canyon 82	2007	2,420	W&T	Appraisal			
Heidelberg	Green Canyon 903	2009	5,300	Occidental Petroleum	Producing	2016		Spar
Holstein Deep	Green Canyon 643	2014	2,890	Occidental Petroleum	Development	TBD		SS

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Horn Mountain	Mississippi Canyon 126	1999	5,400	Occidental Petroleum	Producing	2002		Spar
Huron	Green Canyon 69	2022	2,000	Hess	Appraisal			
Isabela	Mississippi Canyon 562	2007	6,500	bp	Producing	2012		SS
Jack	Walker Ridge 759	2004	7,000	Chevron	Producing	2014		FPS
Jubilee	Atwater Valley 349	2003	8,800	Occidental Petroleum	Producing	2007		SS
Jubilee Extension	Lloyd Ridge 309	2005	8,774	Occidental Petroleum	Producing	2007		SS
Julia	Walker Ridge 627	2007	7,087	ExxonMobil	Producing	2016		SS
K2	Green Canyon 562	2002	3,956	Occidental Petroleum	Producing	2005		SS
K2 North	Green Canyon 518	2004	4,000	Occidental Petroleum	Producing	2006		SS
Kaikias	Mississippi Canyon	2014	4,575	Shell	Producing	2018		SS
Kaskida	Keathley Canyon 292	2006	5,860	bp	Appraisal			
Katmai	Green Canyon 40	2014	2,100	QuarterNorth	Producing	2020		
Khaleesi	Green Canyon 389	2017	3,552	Murphy	Producing	2022		SS
King West	Mississippi Canyon 84	2002	5,430	Occidental Petroleum	Producing	2003		SS
Kodiak	Mississippi Canyon 771	2008	4,829	Kosmos Energy	Producing	2016		SS
LaFemme	Mississippi Canyon 427	2016	5,800	Beacon Offshore Energy	Producing	2018		SS
Leon	Keathley Canyon 642	2014	6,119	Repsol	Appraisal			
Leopard	Alaminos Canyon 691	2021	6,800	Shell	Appraisal			
Lime Rock	Viosca Knoll 956	2022	3,200	Talos Energy	Appraisal			
Logan	Walker Ridge 969	2011	7,750	Equinor	Appraisal			
Longclaw	Green Canyon 433	2023	3,900	Murphy	Discovery			
Longhorn	Mississippi Canyon 502, 546	2006	2,461	Eni	Producing	2009		SS
Lucius	Keathley Canyon 875	2009	7,100	Occidental Petroleum	Producing	2015		Spar
Magellan	East Breaks 424	2007	2,800	Apache	Appraisal			SS
Mandy	Mississippi Canyon 199	2010	2,465	LLOG	Producing	2012		SS
Manuel	Mississippi Canyon 520	2018	6,234	bp	Producing	2021		SS
Marco Polo	Green Canyon 608	2000	4,300	Occidental Petroleum	Producing	2004		TLP
Mars B - West Boreas	Mississippi Canyon 762	2004	3,112	Shell	Producing	2014		SS
Mars B - South Deimos	Mississippi Canyon 762	2010	3,122	Shell	Producing	2014		SS
Medusa North	Mississippi Canyon 538	2003	2,185	Murphy	Producing	2005		SS
Merganser	Atwater Valley 37	2002	7,900	Occidental Petroleum	Producing	2007		SS
Monument	Walker Ridge 316	2020	6,234	Equinor	Appraisal			
Mormont	Green Canyon 478	2017	3,774	Murphy	Producing	2022		SS
Mount Hunter	Viosca Knoll 989	2023	1,300	Talos Energy	Discovery			
Navajo	East Breaks 690	2001	4,114	Occidental Petroleum	Producing	2002		SS
Nearly Headless Nick	Mississippi Canyon 387	2018	6,500	Murphy	Producing	2019		SS
Niedermeyer	Mississippi Canyon 208	2013	5,100	Murphy	Producing	2015		SS
Northwest Navajo	East Breaks 646	2002	3,937	Occidental Petroleum	Producing	2003		SS
North Platte	Garden Banks 959	2012	4,871	Shell	Appraisal			
Ochre	Mississippi Canyon 66	2002	1,144	Apache	Producing	2003		SS
Odd Job	Mississippi Canyon 215	2014	5,996	Kosmos Energy	Producing	2016		SS
Otis	Mississippi Canyon 79	2014	3,800	Murphy	Producing	2016		SS
Ozona Deep	Garden Banks 515	2001	3,280	Marathon	Producing	2011		SS
Pardner	Mississippi Canyon 400	2001	1,200	Occidental Petroleum	Producing	2002		SS
Pegasus	Green Canyon 385	2005	3,491	Eni	Producing	2008		SS

Status of US Gulf of Mexico deepwater discoveries since 2000

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Perseus	Viosca Knoll 830	2003	3,376	Chevron	Producing	2005		DT
Phobos	Sigsbee Escarpment 39	2013	8,500	Occidental Petroleum	Appraisal			
Pickerel-1	Mississippi Canyon 727	2023	5,000	Hess	Discovery			
PowerNap	Mississippi Canyon 943	2014	4,200	Shell	Producing	2022		SS
Power Play	Garden Banks 258/302	2006	2,310	Occidental Petroleum	Producing	2008		SS
Praline	Mississippi Canyon 74	2020	2,600	LLOG	Producing	2021		SS
Princess	Mississippi Canyon 765	2000	3,650	Shell	Producing	2002		SS
Puma	Green Canyon 821	2004	4,130	bp	Appraisal			
Puma West	Green Canyon 821	2021	4,108	bp	Appraisal			
Puma West #2	Green Canyon 821	2023		bp	Discovery			
Pyrenees	Garden Banks 293	2009	2,100	W&T	Producing	2012		SS
Q	Mississippi Canyon 961	2005	7,925	Equinor	Producing	2007		SS
Quatrain	Green Canyon 382	2002	3,500	Murphy	Producing	2005		SS
Raptor	East Breaks 668	2003	3,600	Marubeni	Producing	2004		SS
Red Zinger	Mississippi Canyon 257	2016	6,000	Beacon Offshore Energy	Producing	2018		SS
Rydberg	Mississippi Canyon 525	2014	7,479	Shell	Appraisal			
Sargent	Garden Banks 339	2008	2,240	Kosmos Energy	Producing	2010		SS
Samurai	Green Canyon 432	2009	3,400	Murphy	Producing	2022		SS
San Jacinto	DeSoto Canyon 618	2004	7,850	Eni	Producing	2007		SS
Seventeen Hands	Mississippi Canyon 299	2000	5,400	Eni	Producing	2006		SS
Shenandoah	Walker Ridge 52	2009	5,750	LLOG	Appraisal		2024	
Shaft	Green Canyon 141	2008	1,016	LLOG	Producing	2010		SS
Shenzi	Green Canyon 654	2002	4,400	BHP	Producing	2009		TLP
Shiloh	DeSoto Canyon 269	2003	7,509	Shell	Appraisal			
Silvertip	Alaminos Canyon 815	2004	9,226	Shell	Producing	2010		SS
South Dachshund/Mondo NW Extension	Lloyd Ridge 001	2005	8,340	Occidental Petroleum	Producing	2007		SS
South Dorado	Viosca Knoll 915	2003	3,494	Occidental Petroleum	Producing	2004		SS
South Raton	Mississippi Canyon 292	2007	3,400	QuarterNorth	Producing	2012		SS
South Santa Cruz	Mississippi Canyon 563	2015	6,500	Kosmos Energy	Producing	2017		SS
Spiderman	DeSoto Canyon 621	2003	8,100	Occidental Petroleum	Producing	2007		SS
Spruance	Ewing Bank 877	2019	1,600	LLOG	Producing	2022		SS
Spruance West	Ewing Bank 877	2023	1,600	Talos Energy	Discovery			
St. Malo	Walker Ridge 678	2003	6,900	Chevron	Producing	2014		FPS
Stampede - Knotty Head	Green Canyon 512	2005	3,557	Hess	Producing	2018		TLP
Stampede - Pony	Green Canyon 468	2005	3,440	Hess	Producing	2018		TLP
Stones	Walker Ridge 508	2005	9,576	Shell	Producing	2016		FPSO
Stonefly	Viosca Knoll 999	2016	4,119	Beacon Offshore Energy	Producing	2019		SS
Sturgis	Atwater Valley 183	2003	3,700	Chevron	Appraisal			
SW Horseshoe	East Breaks 430	2000	2,285	Walter	Producing	2005		SS
Swordfish	Viosca Knoll 961	2001	4,677	QuarterNorth	Producing	2005		SS
Tahiti	Green Canyon 640	2002	4,017	Chevron	Producing	2009		Spar
Taggart	Mississippi Canyon 816	2013	5,650	LLOG	Producing	2022		SS
Telemark	Atwater Valley 63	2000	4,385	Bennu Oil & Gas	Producing	2010		SS
Thunder Hawk	Mississippi Canyon 734	2004	5,724	DAA	Producing	2009		Semi

Status of US Gulf of Mexico deepwater discoveries since 2000

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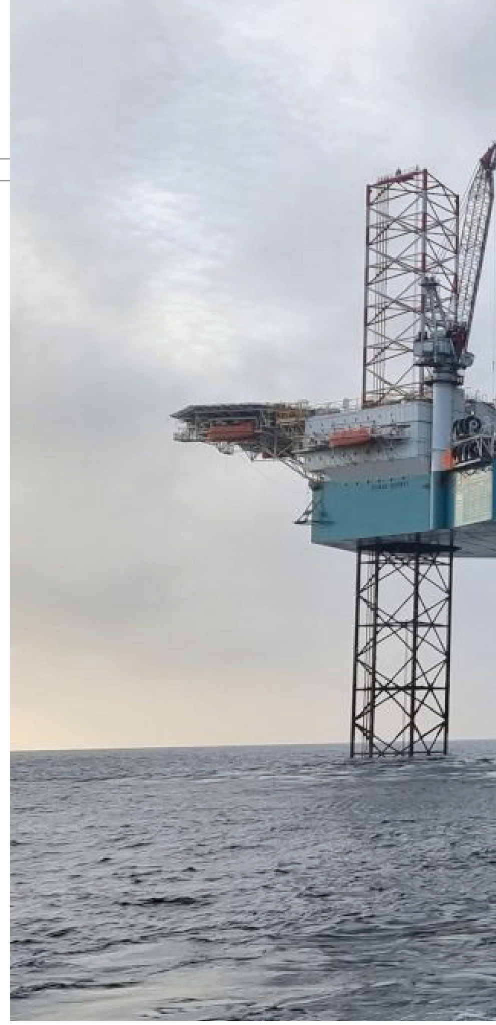
Thunder Horse North	Mississippi Canyon 776	2000	5,640	bp	Producing	2009		SS
Tiber	Keathley Canyon 102	2009	4,132	bp	Appraisal			
Tiberius	Keathley Canyon 964	2023	7,500	Kosmos Energy	Discovery			
Ticonderoga	Green Canyon 768	2004	5,250	Occidental Petroleum	Producing	2006		SS
Tiger	Alaminos Canyon 818	2004	9,004	Chevron	Appraisal			
Tobago	Alaminos Canyon 859	2004	9,627	Shell	Producing	2010		SS
Tomahawk	East Breaks 623	2003	3,514	Marubeni	Producing	2004		SS
Tornado	Green Canyon 280	2016	2,760	Talos Energy	Producing	2016		SS
Tortuga	Mississippi Canyon 561/605	2008	6,500	QuarterNorth	Appraisal			
Trident	Alaminos Canyon 903	2002	9,687	Chevron	Producing	2010		SS
Trion	AE-0092/93	2002	8,202	BHP	Appraisal			
Triton	Mississippi Canyon 772	2002	5,610	Eni	Producing	2005		SS
Troubadour	Mississippi Canyon 699	2013	7,273	QuarterNorth	Appraisal			
Tubular Bells	Mississippi Canyon 683	2003	4,300	Hess	Producing	2014		FPS
Tucker	Walker Ridge 543	2006	6,778	Equinor	Appraisal			
Tulane	Garden Banks 158	2001	1,100	Hess	Producing	2001		SS
Venice	Viosca Knoll 956	2022	3,200	Talos Energy	Appraisal			
Vicksburg	DeSoto Canyon 353	2007	7,457	Shell	Producing	2019		SS
Vito	Mississippi Canyon 984	2009	4,038	Shell	Development		2023	FPU
Vortex	Atwater Valley 261	2002	8,340	Occidental Petroleum	Producing	2007		SS
Warrior	Green Canyon 518	2016	4,122	Occidental Petroleum	Appraisal			SS
West Navajo	East Breaks 689	2002	3,905	Occidental Petroleum	Producing	2003		SS
West Tonga	Green Canyon 726	2007	4,700	Occidental Petroleum	Producing	2012		SS
Whale	Alaminos Canyon 772	2018	8,000	Shell	Development		2024	FPU
Who Dat	Mississippi Canyon 503	2007	3,099	LLOG	Producing	2011		FPS
Wide Berth	Green Canyon 490	2009	3,700	Apache	Producing	2012		SS
Wildling-2	Green Canyon 520	2017	4,157	BHP	Appraisal			
Winter	Garden Banks 605	2009	3,400	W&T	Appraisal			
Winterfell	Green Canyon 944	2021	5,300	Beacon Offshore Energy	Appraisal			
Wrigley	Mississippi Canyon 506	2005	3,700	W&T	Producing	2007		SS
Yeti	Walker Ridge 160	2015	5,900	Equinor	Appraisal			
Yosemite	Green Canyon 516	2001	4,452	Eni	Producing	2002		SS
Yucatan	Walker Ridge 95	2013	5,881	Shell	Appraisal			
West Tonga	Green Canyon 726	2007	4,700	Occidental Petroleum	Producing	2012	SS	
Whale	Alaminos Canyon 772	2018	8,000	Shell	Development	2024	FPU	
Who Dat	Mississippi Canyon 503	2007	3,099	LLOG	Producing	2011	FPS	
Wide Berth	Green Canyon 490	2009	3,700	Apache	Producing	2012	SS	
Wildling-2	Green Canyon 520	2017	4,157	BHP	Appraisal			
Winter	Garden Banks 605	2009	3,400	W&T	Appraisal			
Winterfell	Green Canyon 944	2021	5,300	Beacon Offshore Energy	Appraisal			
Wrigley	Mississippi Canyon 506	2005	3,700	W&T	Producing	2007	SS	
Yeti	Walker Ridge 160	2015	5,900	Equinor	Appraisal			
Yosemite	Green Canyon 516	2001	4,452	Eni	Producing	2002	SS	
Yucatan	Walker Ridge 95	2013	5,881	Shell	Appraisal			

** CT is compliant tower. FP is fixed platform. FPS is floating production system. FPU is floating production unit. SS is subsea. DT is dry tree. TLP is tension leg platform.*
Editor's Note: First production year and development type are estimated for fields not yet onstream.

Drillers see opportunity in CCS market

Carbon capture and storage projects requiring new wells, P&A work

Bruce Beaubouef, MANAGING EDITOR



While the traditional oil and gas drilling market continues to remain hot, the need for well construction, maintenance and P&A work from offshore carbon capture and storage projects is presenting new opportunities for drilling rig contractors and downhole service firms.

In some cases, CCS projects will call for new wells to be drilled. In other cases, decommissioned oil and gas fields will be re-used specifically for CCS with gas injected using both old and new wellheads. While it is unclear how much drilling will be required for these projects, some sources have indicated that retrofitting could be more expensive than drilling new wells, making it likely that further drilling will be required at most projects.

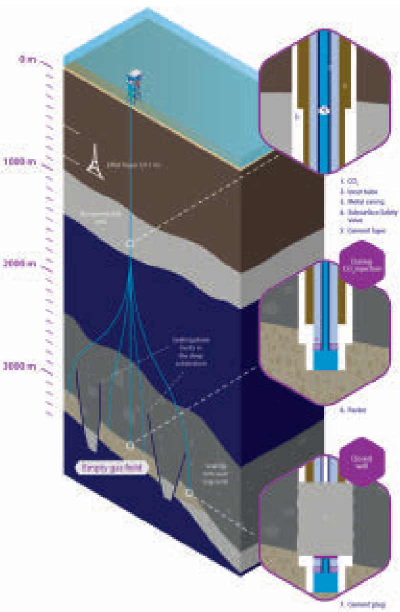
Besides drilling services and technologies, CCS projects will require completions, liners, and monitoring products and services. CCS projects may also drive new demand for P&A technologies and services. Many of the world's most promising geological targets for large scale CO_2 storage exist within and above late-life and depleted hydrocarbon plays. Late-life fields often have many existing wells that penetrate the target storage geology and can pose seal integrity risks. Here, advanced plug and abandonment solutions may be needed to ensure that the integrity of the aging well structure is not compromised for the life of the sequestration project.

In Northwest Europe, CCS projects and related P&A work is prompting new jackup rig demand in the region. Two recent contracts provide examples of the CCS trend. The first, involving TAQA and the jackup *Valaris 123*, entails a program for wells on the Porthos CCS project in the Dutch sector, expected to commence in late 2024. The contract for the *Valaris 123* involves six wells plus up to ten optional wells and has a minimum duration of 170 days plus a total optional duration of 300 days.

Additionally, the Hynet CCS project in the East Irish Sea awarded contracts to the jackup *Valaris 72* and the jackup *Valaris 292*, with the *Valaris 72* scheduled to begin a P&A campaign in late 2023.

These developments represent a meaningful shift in the offshore rig market, says consulting firm Evercore ISI, indicating nearly four rig-years out of 13.8 rig-years awarded to jackups in the UK, Dutch, and Danish sectors supporting CCS projects this year. Certain projects will require the drilling of new wells to enable CO_2 injection, while others might require extensive P&A work, similar to Eni's Hynet project (a 55-well P&A contract), Evercore said.

Norway in particular is leading the way on offshore CCS projects. At least five operating companies have submitted applications to the Norwegian government to store CO_2 in the Norwegian waters of the North



COURTESY PORTHOS CO2 TRANSPORT AND STORAGE C.V.

Well concepts for the Port of Rotterdam CO_2 Transport Hub and Offshore Storage (Porthos) project in the North Sea.

COURTESY VALARIS

The Valaris 292 and Valaris 123 jackups will be undertaking work related to CCS projects.

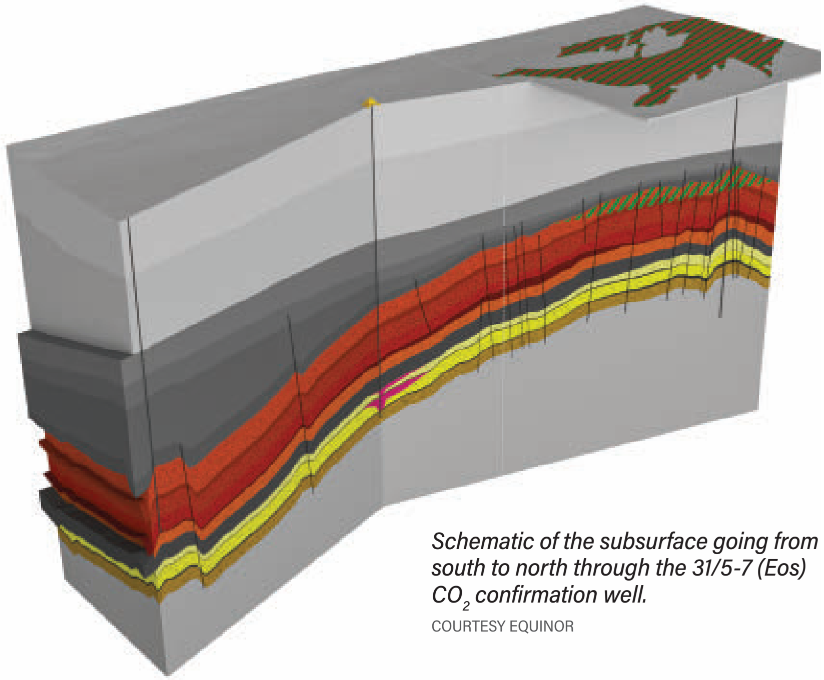
Sea. They include Equinor, Neptune Energy, Storegga, Sval Energi, and Wintershall Dea. Two years ago, the semisubmersible *Transocean Enabler* won a contract to drill one carbon injection well and a side track for another carbon injection well for the Northern Lights CCS project in the northern Norwegian North Sea. Work is expected to wrap up on this project, awarded by Equinor, sometime this year.

The growing number of CCS projects is also offering opportunities for downhole service firms. Halliburton says that it recently completed two subsea wells in the first phase of a cross border offshore CCS project. Phase I of this project includes the capacity to transport, inject, and permanently store up to 1.5 million metric tons of CO_2 per year. Carbon dioxide storage will be possible through one injection well, which was sidetracked and completed from the original exploration well and a new contingency well. With these two wells in place, Halliburton says that the customer has plans to drill and complete three additional injection wells to expand capacity by an additional 3.5 million metric tons to a total of 5 million metric tons annually.

To help ensure the safe and permanent storage of CO_2 during well construction, several factors were considered, including injection CO_2 composition, anticipated reservoir pressure evolution, well temperature variations during injection and shut-in, formation fluids composition, and previous knowledge gained from other CO_2 injector wells. Laboratory corrosion testing determined that tubulars and completion equipment installed at the bottom of the well should be 25% chrome alloy or superior materials to allow a 25-year well lifetime.

Halliburton said that during construction of the primary injection well, a 14-in. XtremeGrip low equivalent circulating density (ECD) and 9 5/8-in. XtremeGrip Quick Lock liner hanger were installed and sand control was achieved using standalone sand screens in the openhole section. For the lower completion of the well, the Halliburton Versa-Trieve retrievable sand control packer and FS2 fluid loss control valve were used. The upper completion was finalized using the Halliburton hydrostatic-set Perma-Series HNT packer, 4 1/2- and 7-in. Opsis gauges and the SP tubing-retrievable safety valve (TRSV) to ensure safety.

The contingency injector was completed in a similar manner. A 14-in. low ECD liner hanger was installed during well construction and sand control was achieved by gravel packing the openhole section. A Versa-Trieve retrievable sand control packer and FS2 fluid loss control valve were used for the lower completion, and the upper completion consisted of the X-Trieve XHHC retrievable production packer, two seven-inch Opsis gauges and the SP TRSV. Once Phase I of the project is completed, the operator will have the capacity to capture and store 1.5 million metric tons of liquid CO_2 annually. Based on customer demand, the operator may opt to drill and complete additional wells to increase the storage volume annually.



Schematic of the subsurface going from south to north through the 31/5-7 (Eos) CO_2 confirmation well.
COURTESY EQUINOR

CCS well design

The safe and successful design and operation of CCS wells requires careful consideration of a range of technical challenges. The primary objective is to ensure the permanent sequestration of CO_2 underground, which is dependent on the integrity of the well. One challenge is to prevent leakage of CO_2 to the atmosphere, which could occur if materials used during well construction are not selected carefully. For example, the formation of carbonic acid CO_2 due to the mixing of dry CO_2 and saline formation water can lead to corrosion of carbon steel, potentially having a negative impact on well integrity. To help prevent such issues, operators must select materials suitable for the well environment and compatible with the operator's objectives.

There are key differences between CCS wells and conventional oil and gas wells. CCS wells are different in that they are expected to have much longer regulatory lifetimes; increasing pressure over well lifetimes; inherently corrosive environments; intermittent operation; and large variation of CO_2 injection stream properties depending on its impurities. These differences require a different approach to well design for CCS projects. As noted by consulting company Blade Energy Partners in a 2022 paper (SPE-208738-MS), if CCS wells were to be designed using conventional methods, the wells might fail to maintain their integrity, thus resulting in the failure to contain injected CO_2 in the sequestration zone.

Blade Energy Partners contends that for CCS wells, the design should start with the completion size required to achieve the desired CO_2 injection rate, and progress outwards. Dual containment is essential; the second barrier must not only be designed for the corrosive environment, but the second barrier and its associated equipment must be periodically inspected or tested. All CCS wells, including injection, monitoring and utility wells, must be designed for potential CO_2 exposure. Highest loads may be imposed during transient or upset operations, and may originate from changing thermal conditions. Cement integrity is essential to prevent undetected migration of stored CO_2 >out of the storage zones. It is also necessary to have pre-prepared contingency plans to detect, shut-in, kill, repair and/or P&A failed wells.

Pipeline opportunities

The growth of CCS projects has also led to opportunities in the pipeline infrastructure market. Last year, Baker Hughes won a contract from Malaysia Marine and Heavy Engineering (MMHE) to supply CO_2 compression equipment to the Kasawari offshore CCS project being developed by Petronas Carigali Sdn. Bhd. offshore Sarawak, Malaysia. The project is expected to be the world's largest offshore CCS facility, with capacity to reduce CO_2 emissions by 3.3 mtpa.

Baker Hughes says it will deliver a "compression solution with minimized footprint and weight as well as a power density allowing for larger flows per unit and best-in-class efficiency." The compressors will be used to enable the transportation and reinjection of the CO_2 separated from natural gas into a depleted offshore field via a subsea pipeline.

The CCS project is expected to significantly reduce CO_2 volume currently emitted via flaring of the overall Kasawari gas development, supporting Petronas' ambitions to unlock Malaysia's potential to be a global carbon capture, utilization and storage (CCUS) hub and enable the company to progress toward achieving its own net-zero carbon emission targets by 2050.

Baker Hughes will deliver two trains of low-pressure booster compressors to enable CO_2 removal through membrane separation technology as well as two trains for reinjecting the separated CO_2 into a dedicated storage site. ●

Models describe BSEE deepwater decommissioning cost estimates

Methods provide simple means to estimate cost

Mark J. Kaiser, LOUISIANA STATE UNIVERSITY

BSEE estimates platform decommissioning cost in the US Gulf of Mexico in water depth 122-250 meters at $4.8 million, about twice as expensive as removals in the 61-122 m water depth range. For platforms residing in 250-500 m water depth, cost estimates range from $10-80 million.

For pipeline decommissioning, a unit cost of approximately $1.6 million per pipeline segment is applied for bulk oil, bulk gas, lift, umbilical and water product classes, and $1.35 million per segment for oil and gas product classes. In part 3 of this article series, we examine BSEE decommissioning cost estimates for fixed platforms and deepwater pipelines in the US Gulf of Mexico.

Decommissioning options

Shallow-water fixed platform decommissioning typically follows a complete removal procedure, removing the platform and scrapping the deck and jacket in a shipyard, or removing the deck and reefing the jacket in a designated reefing location.

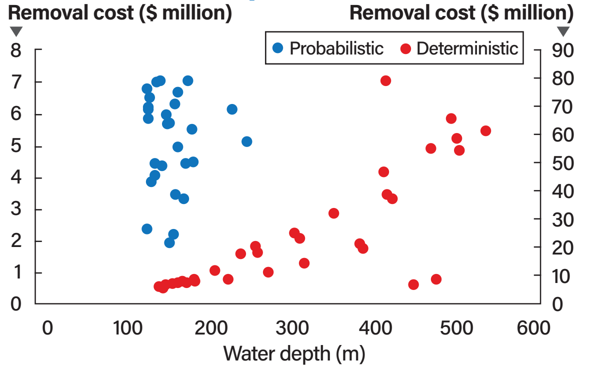
In deepwater, fixed platforms and compliant towers are large heavy structures and all decommissioning options are evaluated for engineering and economic feasibility, including toppling-in-place. Most floaters will require complete removal but opportunities for reefing may be available.

A pipeline may be abandoned in place if it does not constitute a hazard to navigation, commercial fishing operations, or unduly interferes with other users.

Pipelines abandoned in place need to be flushed, filled with seawater, and plugged with the ends buried at least three feet below the mudline, typically under sand bags or concrete type mats.

Umbilical lines and flowlines are flushed and different vessel spreads are utilized depending on water depth, length and market conditions at the time of the operation, and unlike export pipelines, umbilicals and flowlines are expected to be completely removed from the seabed.

Deepwater fixed platform probabilistic and deterministic removal cost estimates as a function of water depth circa 2022.



Source: Data from BSEE, May 2022.

Fixed platforms: probabilistic cost estimates

From 2016-2021, eight fixed platforms, one compliant tower, two floaters, and several pipeline segments were decommissioned in the US Gulf of Mexico in water depth greater than 400 ft (122 m).

For fixed platforms in the 'shallow' deepwater (122-200 m water depth), BSEE estimated the decommissioning cost for 29 fixed platforms (FPs) using probabilistic methods. Total removal cost was reported at $149 million, or $5.1 million/FP.

All the structures reside within water depth <200 m and have estimated removal cost less than $8 million per structure. About half the structures are classified as major and manned.

Correlating FP removal cost with water depth yields a robust correspondence for these probabilistic estimates:

- FP Cost (Probabilistic) = 32,402 WD

where FP removal cost is reported in dollars and water depth WD is in meters. The probabilistic estimates represent median (P50) values.

TABLE 1. Fixed Platform Removal Cost Functions in the Deepwater Gulf of Mexico circa 2022

	PROBABILISTIC COST		DETERMINISTIC COST	
VARIABLE	MODEL I	MODEL II	MODEL I	MODEL II
WD	28,184 (9.6)	20,932 (6.7)	66,479 (5.2)	48,591 (2.8)
BEDS	49,882 (2.0)	20,994 (1.0)	161,945 (1.4)	189,063 (1.7)
SLOTS		90,003 (3.7)		264,671 (1.5)
R^2	0.87	0.89	0.78	0.79

Note: 1) Cost ($) = α WD (m) + β BEDS (#) + γ SLOTS (#)
2) t-statistics described in parenthesis.

The cost function for the probabilistic one-variable estimate is robust and significant. Regression models that employ bed count and/or well slots as a proxy for structure complexity and size splits out the cost between factors but does not otherwise improve the model fit.

Note that as new attributes are added to the model, the water depth coefficient decreases [from 32,402/m to 28,184/m (one attribute) to 20,932/m (two attributes)] since the elements enter as positive variables.

TABLE 2. Pipeline Decommissioning Cost by Product Group circa 2022

	TOTAL COST ($ MILLION)	NUMBER #	UNIT COST ($MILLION/SEG)	LENGTH (1000 FT)	UNIT COST ($MILLION/FT)	COST RANGE ($MILLION/SEG)
OIL	25.7	19	1.35	102	252	0.34-1.59
BLKO	1287	805	1.60	2245	573	1.48-1.90
BLKG	111	70	1.59	293	380	0.91-1.75
GAS	20.7	15	1.38	153	135	0.34-1.59
LIFT	158	99	1.60	609	259	1.59-1.75
UMB	117	72	1.63	845	139	1.59-1.89
H2O	74.7	46	1.62	210	356	1.59-1.89
All	2255	1412	1.60	7556	298	0.34-1.90

The cost functions depicted are the cost data reported by operators with a reasonable degree of accuracy; the cost functions are also expected to reflect the cost estimation algorithms employed by BSEE.

Fixed platforms: deterministic cost estimates)

There are 34 FPs and 2 compliant towers (CTs) in the deepwater Gulf of Mexico where deterministic estimates were performed at a total reported cost of $843 million, or $21.4 million/FP and $59 million/CT.

Most of the platforms reside in water depth between 200-500 m and have decommissioning cost that range from $10 million up to $80 million (Figure 1).

Deterministic cost estimates are performed when operator-reported cost data does not allow for a reliable statistical assessment. In such cases, work decomposition methods or a simple average/median cost estimate are applied.

Work decomposition methods are a formal hypothetical approach performed by breaking down operations into several tasks and then estimating the time and cost of each task to arrive at an estimate.

Work decomposition methods are similar to AFE (authorization for expenditure) estimates made by engineers for well drilling and related project development cost, and are a standard and accepted approach in industry, but when performed over a large and diverse collection of assets special care needs to be made in providing reliable assessments.

Excluding three data points from the sample because of their exceptional nature (for reasons described below), a water depth correspondence yields a robust relation with a slope coefficient about two-and-a-half times larger than the probabilistic:

- FP Cost (Deterministic) = 85,141 WD

where FP removal cost is reported in dollars and water depth WD in meters.

Again, since bed count and well slots are positive variables, if these attributes are used in the model the water depth unit cost will necessarily decrease with each new attribute [from $85,141/m to $66,479/m (one attribute) to $48,591/m (two attributes)].

Three platforms with individual removal cost >$100 million each were excluded from the evaluation: Bullwinkle (23552) in GC65 in 429 m, Taylor Energy's MC20 platform (23051) in 169 m, and McMoRan's EW947 platform (23925) in 253 m water depth.

Operators for these structures probably acquired third-party decommissioning cost estimates or performed their own detailed engineering study because of unique circumstances. Bullwinkle is the largest fixed platform in the world and is estimated to cost $434 million for structure removal, while the MC20 platform and EW947 platform were both toppled by hurricanes (and currently lie on the seabed) with expected decommissioning cost of $125 million each.

The two compliant towers in the Gulf of Mexico, Baldpate (33039, 503 m) and Petronius (70012, 535 m), have an estimated decommissioning cost of $55 million and $62 million, respectively.

Pipeline decommissioning

All BSEE pipeline decommissioning cost estimates are reported in deterministic terms, probably an indication of the wide variation in reported data. This is not surprising considering the sparsity of pipeline decommissioning cost data, nature of operations, and the diversity of pipeline types.

Apparently, a unit cost approximately $1.6 million per pipeline segment is applied across bulk oil, bulk gas, lift, umbilical and water product classes, and about $1.35 million per segment is applied for oil and gas product classes.

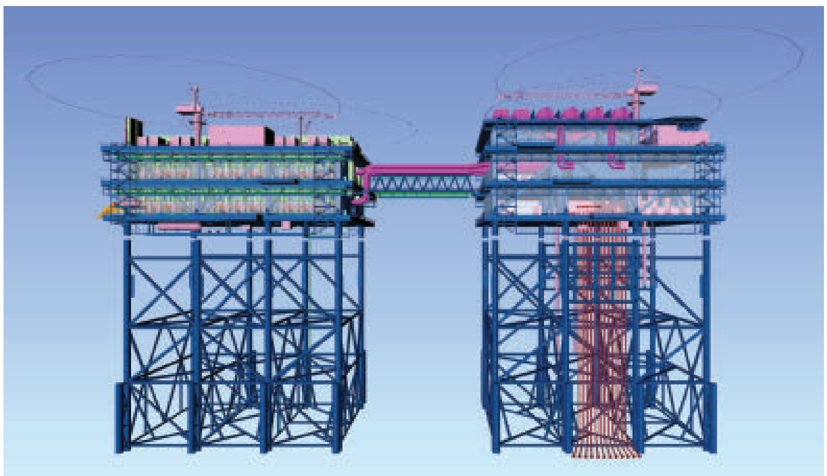
The unit cost applied is likely determined by a simple aggregate average (or median) of operator cost data.

Pipeline segments are of various diameter and length, and on a footage basis, the values vary widely. The vast majority of pipeline decommissioning cost is reported as either $1.59, $1.75, or $1.90 million per segment, a variation of about 20%, and this is applied with somewhat lower values for oil and gas lines, and somewhat higher values for other classes. ●

Mark J. Kaiser is a professor at the Center for Energy Studies, Louisiana State University, Baton Rouge, Louisiana.

Bridge-linked platform design can support high-volume green hydrogen production

Ron Vis, Vincent van Duijvenbode, MCDERMOTT



ALL IMAGES COURTESY MCDERMOTT

Bridge-linked hydrogen production platform complex.

Rising demand for hydrogen as a new clean source of power will drive the emergence of gigawatt-scale green hydrogen production installations close to offshore wind farms.

Various pilot projects are under development and early-phase small-scale hydrogen production facilities are being installed in the Dutch North Sea. There are no large-scale green hydrogen installations operating offshore anywhere at present although again, several schemes are under development or planned. These include the recently announced 100-MW Demo1 and 500-MW Demo2 green hydrogen project in Europe that will be powered by wind and which is due to start operating after 2031.

To address the challenge of scaling up production while at the same time minimizing environmental impact, McDermott is investigating the potential for green hydrogen production on a large offshore installation, drawing on the company's experience in offshore high-voltage direct-current (HVDC) transmission and onshore electrolysers. There is market interest in electrolyser facilities in the range 300 to 500 MW for this purpose with the offshore solutions in a centralized or decentralized arrangement.

After evaluating different concepts, the study team opted to focus on a centralized configuration with an electrolyser capacity in the order of 500 MW. Further considerations included the use of a 10-MW PEM electrolyser and the possibility of connecting the hydrogen production plant to an offshore wind farm as well as serving as an intermittent facility between a wind farm and a 2-GW HVDC installation. This functionality allows the developer to select the most profitable operating mode between the production of electrons and hydrogen molecules.

The team went through several iterations and brainstorming sessions before determining the optimal design basis. Issues considered included the type of electrolyser, proton exchange member (PEM) or alkaline; installation of electrolyser modules versus the split of stack and arrays and electrical equipment; integration of a single platform vs the split in a hydrogen production facility; and use of a power transformer and utility platform.

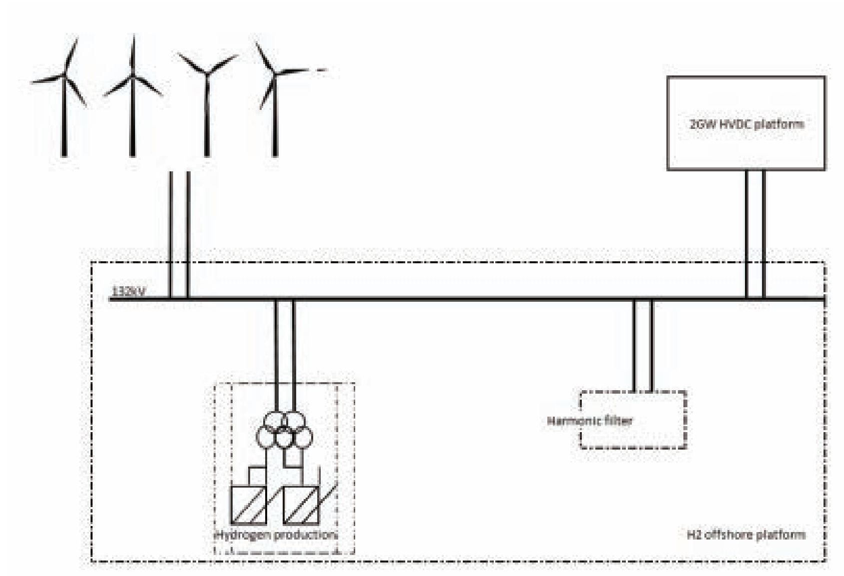
The concept settled on was a fully independent hydrogen facility that could be connected to a set of Wind Turbine Generators (WTGs) providing power input of 132 kV, seen as potentially the next standard voltage level offshore. The facility contains all electrical power transforming and harmonic filtering equipment to receive and transform the power to a DC voltage level feeding the electrolysers. Associated modules include sea water lift, filtration and desalination, treatment, and purification; nitrogen and air systems; drain and vent, hydrogen dryer and de-oxygen systems; and finally, compression to suit the export pipeline pressure.

One of the main areas of focus was on safe design and operation of the facility and ensuring compliance with ATEX requirements. McDermott's philosophy is based on segregation and sectionalization, dividing the installation into several smaller inventories in which each zone can be isolated. The team worked on several alternative layouts, re-arranging electrolysers, electrical equipment, utilities and the incoming power cables, J tubes and other interfaces.

The current centralized design features split platforms, with the process platform presenting a higher level of risk due to the large inventories of hydrogen (H<cpStyle:Subscript>2<cpStyle:>). The utility platform houses general supporting services, power transformation and living quarters: separation by distance is seen as the safest method of ensuring personnel safety, hence the bridge link between the two topsides.

In general, the safety principles are driven by separation to minimize the potential for hazardous releases, keeping the electrical installations away from locations with high volumes of hydrogen and oxygen, and forced ventilation to prevent explosive atmospheres. The electrical design is based on multiple 132-kV feeders from a nearby wind farm with the size of the wind turbine clusters determining the number of incoming feeders. In future, the maximum electrical capacity of a single offshore wind turbine will likely be 20 MW.

The selected distribution voltage of 132 kV for the wind farm enables installation of a single double busbar HV GIS. Due to the current limitation of 3,150A (4,000A in exceptional cases), a distribution voltage of 66kV would lead to duplication of the double busbar HV gas-insulated switchgear (GIS) and a complicated downstream distribution. The likelihood is that in the near future, grid operators will accept 132 kV as offshore distribution voltage.

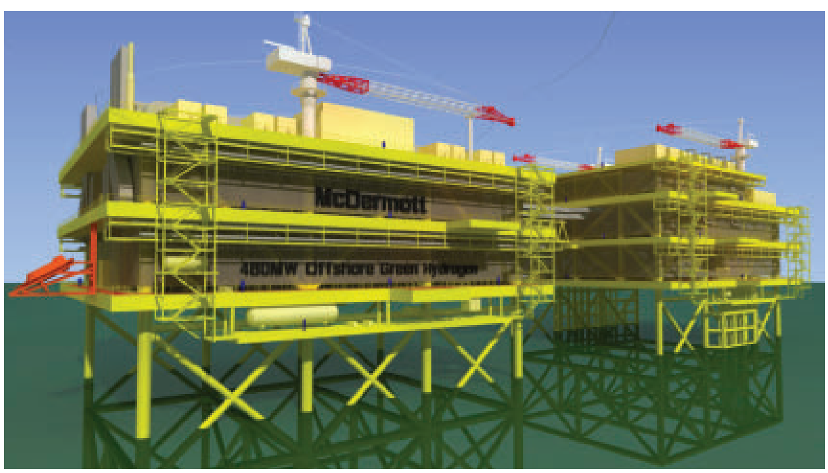


Electrical system concept for the hydrogen production platform complex.

Based on this, a 20-MW wind turbine capacity and a submarine cable of 1 x 3 x 800 sq mm (considered the maximum size for handling the purpose intended), seven wind turbines can be connected to a cluster. For a required power generation capacity of around 630 MW, 32 x 20-MW wind turbines would be the minimum, resulting in at least five clusters of seven wind turbines.

To suit offshore operations flexibility, the 132-kV GIS can also be connected to a nearby 2-GW HVDC platform with the same number of cables from the wind farm, with the generated power used either for production of hydrogen, exported to the HVDC platform, or for a hybrid operation case.

The purpose of the Information Communication Technology (ICT) system in this study is to provide a concept that fully supports unmanned/remote control of the offshore platform. The design assumes that a remote location is available onshore and that a connection is provided through a redundant fiber optic network. The platform will be



The platform structure is designed to accommodate the electrolyser facilities needed to produce 300 to 500 MW.

equipped with a control room providing localized control, as back-up to the remote operation.

Future studies will involve a further investigation into autonomous operation. The ICT design basis is prepared to meet a level between 2 and 3 of the autonomous level scale. To achieve a higher level of autonomy, both the scope and client expectations must be addressed as early as possible in the development phase.

The production platform topside has 24 arrays on each deck level with the top deck accommodating the compression system and all ventilation and air handling systems. The utility topside supports all electrical and utility systems and includes rooms for system controls and safeguarding, space reserved for living quarters, and technical rooms for maintenance activities. At present the facility includes lifeboat escape, a helideck and pedestal cranes for maintenance and heavy lifting.

McDermott has designed identical jackets for both facilities with respect to legs, cross bracings, and pile configuration. Details such as J-tubes and supports for SW intake conducts are specific to the utility platform jacket, in addition to the export pipeline J-tube for the hydrogen production platform.

The weight report and cost estimating work are complete and data can be made available to interested parties. Furthermore, the building blocks developed for this approximately 500-MW facility can be scaled up or down, depending on the project's needs.

Global targets for increased use of renewable energy will not be met solely via the production and transport of power from wind farms via HVDC facilities to shore. The concept of transferring electrons into hydrogen via an offshore hydrogen production facility is a technically feasible alternative. McDermott's offshore knowledge and hydrogen production, combined with its fabrication capability, can support this development. ●

Vincent van Duijvenbode is a Principal Piping Engineer at McDermott. He has more than 25 years of experience in piping layout/plant design of offshore and onshore facilities throughout various project stages from concept, FEED to full EPC detailed design.

Ron Vis is Project Director at McDermott based at the office in The Hague. He has led the McDermott Floating LNG program from its conception and provides leadership and support to the modularization execution model. He has over 35 years of experience with projects in the oil and gas and petrochemical industries.

Offshore
SPECIAL REPORT

2024
REMOTE INSPECTIONS & OPERATIONS

PHOTO COURTESY AKER BP

Offshore's 2nd annual overview of the latest trends in drones, robotics, ROVs/AUVs and remote-controlled operations

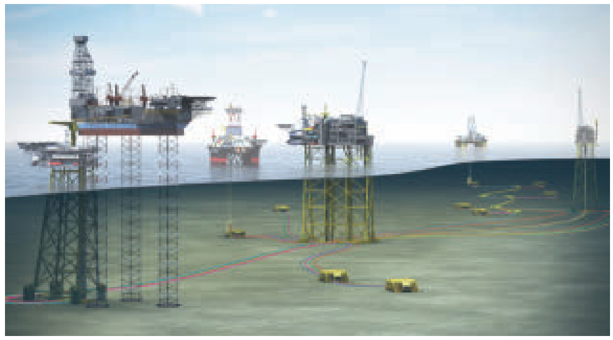
Yggdrasil project sets standard for remote, digital field management

Nine fields coordinated from operations complex in Stavanger

JEREMY BECKMAN, *Editor, Europe*

Yggdrasil in the Central North Sea is one of Norway's most extensive and ambitious development projects to date, encompassing multiple fields across three license groups and with an estimated cost of NOK11.5 billion. Prior to the final investment decision in late 2022, Aker BP and Equinor operated the licenses, but the two Norwegian majors had been collaborating for some time on a coordinated, area-wide development. On submission of the plan for development and operation, Aker BP took over as operator of the entire area for both the development and operations phase to ensure efficient and streamlined execution of the project.

Construction started late last year at various fabrication yards in Norway and across the world. A notable feature of the platforms, wells and subsea facilities will be the emphasis on remote operations to a level not previously attempted on the Norwegian Continental Shelf. *Offshore* spoke to Lars Hoier, Aker BP's senior vice president of Yggdrasil, about how the company and its partners plan to implement this philosophy and the associated technological solutions.



The development will feature three platforms connected to 55 wells. The Munin production platform will operate fully unmanned while the Hugin A process/living quarters installation and the unmanned wellhead facility Hugin B are designed for low manning or fully unmanned operations. All will be controlled from a new operations center in Stavanger.

COURTESY OF AKER BP

Offshore: Was the decision to go for a fully remote controlled/digitalized development from the outset governed by the complexity of tying in production from fields in different areas through the three platforms/pipeline system?

Høier: Aker BP's ambition is to be the oil and gas company of the future. A key strategic priority is to lead the transformation of oil and gas through alliances, digitalization and future operations. Yggdrasil is a locomotive, with project delivery through strategic partnerships, smarter ways of working and through setting a new standard in both project execution and operations.

Yggdrasil is a complex development. It stretches approximately 60 km [37 miles] from north to south and has nine fields, all with different characteristics. The operating strategy is based on remote operations, periodically unmanned and unmanned installations, and digital design. This is to drive efficiency, lower operating cost, lower GHG emissions and ensure maximum value creation from the area.

Aker BP, Equinor and PGNiG Upstream Norway (formerly LOTOS) agreed to a coordinated development of the licenses in the Yggdrasil area in June 2020. The license partners already then shared the ambition to develop the area with a minimal carbon footprint and state-of-the-art technological solutions. When the concept was selected the year after, remote operations were part of the design for both Aker BP and Equinor.

In December 2022, Aker BP took over as the operator for the full area. The companies agreed that one operator gave a good basis for efficient project execution and for safe and efficient operation, creating stronger synergies between the two developments and fewer interfaces. Aker BP is now delivering on the Munin concept developed by Equinor. One of the key synergies from transferring the operatorship to Aker BP is one central control room onshore instead of two. The Yggdrasil control room will be part of Aker BP's new Integrated Operations Center in Stavanger, currently under construction.

Offshore: As partners, do Aker BP and Equinor bring different capabilities in remote operations?

Høier: Aker BP has several normally unmanned installations in the Ula and Valhall area in the southern Norwegian North Sea. The company has also gained experience with operating a manned installation from shore, with the central control room from Ivar Aasen farther north located in Trondheim. Equinor has extensive experience in remote operation as well. Equinor has worked closely with Aker BP over many years to maximize the value creation from the Yggdrasil area, and experience transfer is a natural part of the license cooperation.

Offshore: Can you explain what Aker BP is looking to achieve via its partnership with various solutions providers for the Yggdrasil digital twin 'ecosystem'?

Høier: The partnership with Aker BP, Aker Solutions, Cognite and Aize has two purposes. The first is to develop work processes, applications and software, increasing efficiency in project execution and reducing the number of engineering hours. Aker Solutions provides data to the Cognite Data Fusion platform. Aize builds applications to make the data available to end users.

A digital twin for the Aker Solutions' EPC phase has been developed. Several applications have also been rolled out in Yggdrasil. One application, Project Execution Control, gives real-time status of the engineering and construction progress of structures and sections of Hugin A. Another tool, Visual Construction Planning, visualizes the construction method and sequence of Hugin A for users involved in the construction of the topsides. The partnership also has an application for smarter collaboration with other vendors contributing to the project.

Secondly, the partnership provides important data to the Yggdrasil digital platform. The Yggdrasil data platform is the foundation for the digital version of Yggdrasil. This will be central in fulfilling the operating strategy of the area. Both Aize and Cognite offer SaaS services for their technology deliveries, and Microsoft Azure Data Factory plays an important role in transferring data between the digital platform and the applications through data pipelines, connected through standardized APIs, built by standard Microsoft cloud components.

Offshore: Can you provide more detail on the functions of the integrated operations center?

Høier: Yggdrasil's Integrated Operations Center (IOC) in Stavanger is part of Aker BP's new office facilities under construction in the city. The IOC will consist of the central control room to operate the Yggdrasil area and a center to support the operation. Hugin A, Hugin B, Munin, subsea and power-from-shore stations will be operated from Stavanger. The IOC will facilitate efficient cooperation and enable seamless collaboration between the offshore and onshore organization. The control room technicians will work closely with the production and process engineers. From the IOC, Aker BP will perform extensive monitoring of all equipment and conduct analysis to ensure safe, reliable and efficient operation. Other Aker BP operated assets will also have dedicated spaces in the IOC.

Offshore: Aker BP claims its Ivar Aasen platform in the North Sea was the first manned offshore installation in Norway to be operated remotely from a control room, in this case at Trondheim. What lessons has the company learned to build on this capability for Yggdrasil?

Høier: The Ivar Aasen control room has given us confidence that we can operate facilities from onshore in a safe and efficient manner. The company is transferring that experience to Yggdrasil to exploit synergies via the co-location of the central control room and the IOC. At Yggdrasil, the operations team will strengthen the cooperation between the production simulation and optimization community with the control room to gain a more proactive production optimization focus.

Siemens Energy will deliver the electrical, instrumentation, controls and telecommunications (EICT) systems for Hugin A, Hugin B and Munin. The Yggdrasil control system is an important enabler for achieving our operation strategy. The control system is conventional, but we will utilize application embedded in the solution. Yggdrasil will have additional surveillance compared to traditional setup and a higher degree of actuated and remotely controlled solutions to enable management of the facilities without personnel in field.

Offshore: OneSubsea is supplying its Vectus 6.0 subsea control modules for the subsea production system. What are the benefits in terms of the remote operations capabilities?

Høier: Yggdrasil is the largest subsea project development ever on the Norwegian Continental Shelf, featuring nine identical six-slot templates, 38 xmas trees, over 400 km of in-field pipelines and almost 100 km of umbilicals. We have designed the area with state-of-the-art instruments placed to let us know and control process conditions at all times. We will combine feedback from pressure sensors, temperature sensors, multiphase flowmeters and acoustic devices to maintain equipment within a safe operating envelope, and to optimize production from the different reservoirs.

The latest generation of subsea control modules will allow us to process a huge amount of information both quickly and reliably. The equipment will be operated from the onshore control center using automated sequences for operations like startup and shutdown. By combining information from downhole and subsea systems into the digital twin ecosystem, Aker BP aims to make sure that Yggdrasil is not only the largest, but also the most advanced subsea development to date.

Offshore: Are there any other innovations in this project in terms of remote inspection technology for the overall subsea network?

Høier: Yggdrasil's subsea facilities have been designed with a focus on inherent safety, minimizing the need for maintenance and inspection. Inspections and interventions will still be needed occasionally. We have designed equipment so that it is easy to inspect and with recoverable modules that can be changed out without undermining production efficiency. Aker BP and its partners regard themselves as at the forefront of developing energy and cost-efficient inspection, survey and intervention solutions.

Aker BP has entered into a strategic partnership with Palfinger Marine and Optilift for the development of remotely controlled and autonomous cranes for both Yggdrasil and the Valhall PWP-Fenris development project. Through the cooperation, Aker BP is changing the way equipment is transported to or offshore installations. The ability to remotely control cranes from shore is a first step, followed by innovations to load and offload equipment without manual intervention. Under the umbrella of this strategic partnership, Palfinger and Optilift will collaborate to co-develop and integrate Optilift's advanced technology into the control systems of offshore cranes. ●

Editor's note: Read the extended version of this interview at offshore-mag.com/14303858.

COURTESY NORDIC UNMANNED

Drone advances keeping up with offshore industry needs

Offshore projects are ramping up for drone companies with unmanned systems that offer increased efficiency in aerial operations.

ARIANA HURTADO, Editor and Director of Special Reports

Drone developers have released several innovative advancements over the past few years, as challenges and needs evolve to meet inspection, maintenance, repair and operations demands. The solutions that drones can provide for the offshore energy industries range from vessel inspections, logistics services and methane detection to cargo and equipment transfers.

Offshore aeriel operations projects over just the last quarter of 2023 included:

- MODEC and Terra Drone performing drone-based hull thickness measurement of a crude oil storage tank in two FPSOs offshore Brazil;
- TotalEnergies signing agreements with Petrobras, SOCAR and Sonangol to jointly conduct methane detection and measurement campaigns on oil and gas facilities, which involves deployment on drones of the AUSEA gas analyzer; and
- Ørsted deploying autonomous drones to transport cargo to offshore wind turbines, starting with the Hornsea 1 wind farm in the North Sea.

Drones must be able to exhibit agility, acceleration and maneuverability in high winds and harsh offshore conditions. They must also be able to resist the effects of salt buildup and corrosion for continuous operations in challenging ocean environments. In addition, for inspection purposes, drones need to be equipped with imaging systems and sensors to capture high-resolution images and gather data to assess the structural integrity of offshore assets.

Ship tank inspections

Another drones project that occured late last year was for G.S Marine Services, a company that needed a comprehensive visual inspection of the entire inner surface of a tank exceeding 10 m and faced time consumption and costs challenges as well as safety concerns. A Flybotix drone, equipped with a 4K camera and LED lighting, conducted thorough inspections of the cargo tanks (eliminating the need for costly scaffolding). Plus, the immediate streaming of high-quality images to the remote control center allowed real-time collaboration with surveyors.

Using Flybotix's ASIO drone, G.S Marine Services completed a visual inspection of the tank within 24 minutes, achieving a thorough assessment of the tank walls' condition and identifying potential issues. Flybotix said this inspection was significantly faster and cost-effective compared to traditional methods, reducing inspection time from several days. In addition, using the drone for visual inspection resulted in potential savings ranging from several thousand to more than $100,000, according to Flybotix. Staging costs, which could reach up to $195,000 for large ships, were reduced to $10,000 to $30,000 with the drone. Additionally, the company said elimination of drydock time and the ability to maintain the ship's productivity during inspections added further value.

Flybotix drones also can be used to avoid risks for personnel during the inspection of offshore rigs. They also can be utilized to ensure a ship's integrity by inspecting ballast tanks while keeping track of any corrosion spots as well as to inspect storage and fuel tanks of ships to ensure their integrity and the safety of merchandise and crew.

Offshore logistics testing

Last year Equinor and drone operator Nordic Unmanned tested the incorporation of logistics drones into offshore operations, and the partners say they successfully completed the world's first in-field drone logistics operation test at an offshore field. The drone operations took place at Equinor's Gullfaks C offshore installation in the North Sea from Aug. 15-29, 2023. The companies said they have proven the maturity of the technology and the readiness to include fully automatic drones in offshore logistics operations.

COURTESY FLYBOTIX

More than $190,000 was saved per ship tank inspection, according to a recent Flybotix case study.

COURTESY SKYPORTS DRONE SERVICES

The offshore crew performed 51 fully automated beyond visual line of sight (BVLOS) flights at the Gullfaks Field, consisting of flights delivering cargo between the three installations and an emergency response vessel. The team also developed the procedural framework allowing for quick implementation of offshore drone operations for Equinor and other offshore operators. Nordic Unmanned aims to obtain full autonomy for its system, allowing operations to be performed from an onshore operational center without crew present offshore.

Offshore cargo drone deliveries

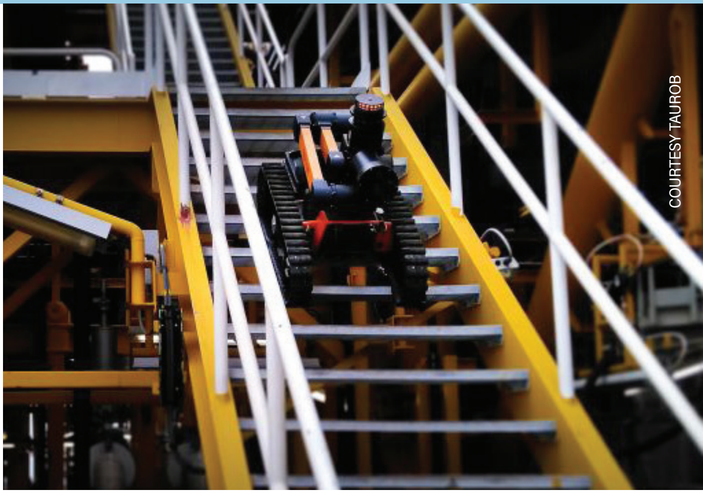
Equinor also has been collaborating with Skyports Drone Services, which offers drone logistics, survey and monitoring operations. The companies have partnered to trial electric drone deliveries to North Sea oil rigs and installations, with the goal of demonstrating how on-demand cargo drone services can solve logistical challenges and improve safety and sustainability offshore.

Launched in September 2023, Skyports said the two-month flight program marks the first time that daily, on-demand drone services offshore have been piloted from shore. The highly automated cargo drone, from Swoop Aero, flies distances of up to 114 km, operating cargo deliveries between Equinor's processing center site in Mongstad on the west coast of Norway and three installations in the Gullfaks oil field in the North Sea, as well as intra-installation. The North Sea operations with Equinor are Skyports' longest flights to date.

Skyports has operated dozens of flights for the project and is scheduled to operate hundreds more throughout the trial carrying spare parts, equipment and care packages.

The partners said a key focus of the trial is to explore how the service can be scaled with minimal human intervention. The aircrafts are remotely piloted by a small Skyports team from the Equinor remote operations center in Bergen. The drones fly automatically with Skyports remote pilots overseeing the duration of the operations. Equinor staff on the installations have been trained by Skyports to load and unload cargo, switch and charge batteries, safely interact with the drones, and have completed installation side activities for all flights conducted to date. Skyports said it has had positive project results, and deliveries could be extended to include additional offshore installations. ●

Evolution of robotics for use offshore has come a long way


COURTESY TAUROB

Offshore robotics providing more than inspection, data collection and repair tasks

ARIANA HURTADO, *Editor and Director of Special Reports*

Operators have been implementing robotics on offshore platforms for years now to allow for safer and more efficient remote inspections and maintenance work.

Back in 2002, French robotics specialist Cybernetix developed an underwater version of its automated ship's hull cleaning system, Octopus, which allows FPSO hulls to be stripped of marine growth at sea. Cybernetix developed its first prototype for the system for shipyards in 1999. The Octopus vehicle's wheels allow it to travel over vertical, horizontal or inclined steel surfaces by means of powerful magnets. The system can be pre-programmed to follow a pre-determined path or controlled remotely in real time using a joystick.

In 2018 an autonomous ground robot was deployed for the first time for inspection purposes offshore on the Alwyn platform in the North Sea. The technology at the time was capable of performing visual inspections; reading dials, level gauges and valve positions; navigating through narrow pathways and up/down stairs; measuring temperature and gas concentration; and detecting and navigating around obstacles and humans.

Fast forward through the years and technology developers continue to discover new ways of advancing robotics for use in offshore environments. For instance, Taurob, a developer of autonomous robots for routine operations and inspection, deploys its robots in remote offshore locations with the aim to improve safety and operational efficiency. Its Taurob Inspector was designed to provide advanced data collection capabilities and has been recently utilized by offshore operators. The robots continued routine inspection work on a platform offshore Angola throughout 2023. In addition, the company's engineers set up and ran FPSO deployment routines for two inspector robots, Poseidon and D'Artagnan, for their long autonomous data gathering missions offshore West Africa.

Among Taurob Inspector's capabilities are being able to climb and descend stairs with inclinations of up to 45 degrees, navigating different levels during daily operations. In addition to performing tasks on multiple floors, its mechanic braking system only disengages when the motors are on, allowing it to safely stop at any point on the stairs without sliding, falling or consuming energy. Taurob says this is a key differentiator from other robots. Inspection data insights are then sent to the customer's cloud to review and analyze. The company also notes that its robots help the energy sector reach its emissions reduction goals.

The next generation of the Inspector robot is manufactured and tested at Taurob's production center in Vienna and are fully operational. The first batch was delivered in March 2023.

Another highlight for the company's technology took place at last year's SPRINT Robotics Summit in Singapore when the company demonstrated the capability to remotely control the robot from 9,700 km away in real time.

Robot flies and drives

Another robotic innovation becoming available to the offshore sector is the recently introduced Hybrid Mobility Robot (HMR) by Arizona-based tech startup Revolute Robotics. This technology comprises a drone mounted inside a spherical exoskeleton with a mechanism that allows the drone to roll on the ground when flying isn't required. The company said the technology combines aerial mobility with the durability and long operating time of rovers.

"Drone and rover advancements have made remote inspection a reality, but the complexity of each inspection requires teams to deploy multiple robotic solutions (drones, rovers, crawlers, PIGs) depending on the need," CEO and Founder Collin Taylor told *Offshore* last summer. "Our hybrid aerial and terrestrial capability allows for a single solution to cover multiple uses, like the Swiss army knife of robotic inspections. One system instead of several is not only cheaper but easier to understand and implement."

As an example, the HMR offers operators of normally unmanned offshore facilities a robotic technology that can travel anywhere on the rig at any time. While the technology had not started field trials as of August 2023, the company said it was in testing at the time with alpha users, with an international patent pending. Plus, Revolute Robotics said it has received interest in inspecting Shell's deepwater Gulf of Mexico assets. ●

ROVs advancing capabilities of compact ocean robotics

Robots aim to enable more efficient and effective offshore operations while prioritizing safety for operators.

CURTIS LEE, QYSEA

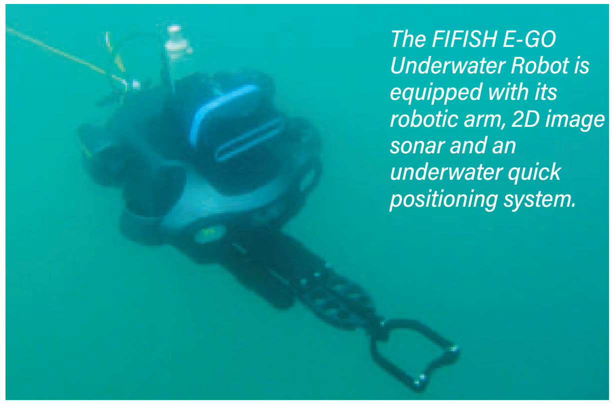
Advancements in subsea robotics and technologies, particularly within the realm of ROV/underwater robotics, have seen a significant surge. The development of increasingly compact, capable and autonomous systems has not only enhanced operational efficiencies but has also revolutionized data-collecting methods and improved working safety standards across the offshore industry.

QYSEA Technology has developed advanced compact ROVs for non-destructive inspections. Its FIFISH AI Underwater Robots, a series of compact professional ROV solutions, are designed for advanced small-scale operations and inspections. FIFISH's self-developed vector thruster system achieves 360-degree freedom in underwater mobility for the operator, allowing small robotics to be implemented for marine inspections, operations and explorations.

The robots range from small to medium-sized ROVs, all easily manageable by a single operator for offshore field work. QYSEA's autonomous technology aims to reduce human risks associated with traditional scuba diving in complex hydrological conditions around offshore platforms. The system enhances performance by providing a seamless operating experience with real-time feedback, addressing the dynamic demands of the industry.

AI-driven underwater inspections & operations

QYSEA's self-developed AI functions empower FIFISH Underwater Robots to adaptively lock onto target objects underwater with a touch control screen. The system enhances imaging clarity by mitigating underwater plankton and interferences, while also enabling precise measurements through augmented reality (AR) methods.FIFISH automatically eliminates the snowflake effect caused by underwater particles, enhancing image clarity for efficient decision-making in underwater operations. This real-time vision enhancement provides operators with advantages such as improved visual data for assessments, optimized inspection efficiency, and enhanced diver safety during maintenance operations. Algorithms, including dehazing and contrast enhancement, optimize images for realistic and high-quality visuals in underwater inspections.



The FIFISH E-GO Underwater Robot is equipped with its robotic arm, 2D image sonar and an underwater quick positioning system.

COURTESY QYSEA

QYSEA's Vision Lock function facilitates adaptive stabilization and precise targeting of underwater objects with a touch control screen. Operators can concentrate on points of interest, ensuring stability during collaborative efforts with divers for tasks like inspection or damage assessment. The system integrates AI-powered diver and subject tracking, which is designed to enhance diver monitoring safety and facilitate prompt communication between divers and surface teams in offshore operations.

FIFISH also combines built-in or add-on traditional laser scaling equipment with AI automation to accurately and efficiently measure underwater dimensions of objects. This enables the identification of damaged areas in underwater structures, such as ship hulls, bridge pillars and wind farm structures, with precision.

Small-scale offshore operations

As wind energy leads the way of renewable energy resources, offshore wind farms across the worlds' coastal regions are seeing increased importance, requiring high operating efficiency and frequent maintenance. In collaboration with an offshore energy company in Asia, operators deploy the FIFISH E-GO within the wind turbine's working platform. The high-precision robotic claw retrieves the tow rope from the monopile foundation's compact spaces, pulling it back to the platform. The restrictors and cables are then inserted and installed through the tow rope, while FIFISH ROVs monitor the operation inside and outside the wind turbine. This accelerates the typically weeklong installation process to one day, ensuring diver safety and utilizing non-destructive testing and evaluation methods, including add-on tools for ultrasonic thickness measurement and cathodic protection, for a smooth and successful long-term structural maintenance. ●

AUV transforms underwater capabilities at scale with adaptive autonomy

Hovering AUV launched in Europe utilized adaptive autonomy to halve costs and risks.

GRACE CHIA, BeeX

The method of underwater work, conducted primarily using ROVs to overcome the risks and physical limits of humans underwater, has changed little since the 1960s. ROVs now come in all shapes and sizes with varying capabilities, but the fundamental requirements of supporting vessels and highly trained human operators (remote or on site) remain constant.

If the world only had oil and gas infrastructure to maintain, using these field-proven methods will be the best way to go. However, the battle with climate change and geopolitical threats has resulted in a sudden large increase in volume of offshore infrastructure to protect.

BeeX defines adaptive autonomy as the intelligence to react in real time. Unlike the more generic versions of automation (i.e., staying at one point or moving from Point A to Point B), adaptive autonomy must be built robustly for full independence without constant operator oversight. This means that even if the user did not have real-time communications, they can and will trust the vehicle to make the correct decisions. It combines multiple human functions (e.g., process navigation sensor data, plan missions, control propulsion, process functional data, flag anomalies, re-plan) into one capability. Just like human intelligence, it is constantly improving.

Why has it taken so long?

Despite its disruptive nature, there was one fundamental operational issue with AUVs preventing widespread adoption—productivity has not matched up to that of ROVs supported by vessels. To date, the market has not seen solutions that can consistently match the productivity at an economic cost. The new technology is underperforming and has limited capabilities (e.g., cannot clean, turn valves, etc).

BeeX saw this under-performance as an opportunity to invest ahead. The company believes cost of subsea hardware will drop, and the more important aspect to scale is the robustness of the vehicles' brain. How can we build operator confidence in completing inspections in diverse conditions?

To build trust and robustness of the brain, BeeX launched the A.IKANBILIS Hovering AUV in Europe in 2022, alongside partner Subsea Europe Services. The HAUV was deployed on three wind farms and multiple nearshore infrastructure projects.

Technicians from other industries were trained on how to operate in less than three months, demonstrating the simplicity of the operator experience. BeeX focused on how the job can be done more efficiently with adaptive autonomy, and autonomy has been helping the company complete jobs two times faster than established means. Beyond that, the fully integrated cloud reporting portal cuts the data transfer requirements by 10X, allowing BeeX to transfer the most important packets of information to shore.

Performance and productivity gains

Every centimeter added to the A.IKANBILIS creates additional drag surfaces, which will result in lower physical performance (i.e., current fighting). The fully integrated design ensures high-quality data, even near splash zones with the additional forces from waves. Today, even with fully integrated positioning and MBES 3D capabilities adding some height, BeeX achieves all-round hovering stability in 1.5 knots coming from any lateral direction. By removing the tether, the company aims to achieve another breakthrough in productivity.

The original Hovering AUV will be joined by a larger model later in the year.
COURTESY BEEX

The use of real-time edge processing computing caters for both command and control of vehicle, as well as data deliverables. The surveying of surrounding seabed for debris and four piles for anomalous objects only took about 15 minutes during demsonstration. This was a task that previously took hours and that requires almost double the number of expert operators to pilot the vehicles and process the data. These metrics validate the productivity and efficiency gains of the system.

A larger HAUV from BeeX called BETTA will be launched in third-quarter 2024. Leveraging the same intelligence in A.IKANBILIS, BETTA features a physical body designed to match the productivity of WROVs. This is achieved through iterative hydrodynamic and electronics design calculations that balance capabilities and cost. ●

Grace Chia is co-founder and CEO of BeeX.

USV proves multi-sensor capability in shallow-water UXO survey

ANDY DOGGETT, *Sulmara*

When it comes to shallow-water surveys using uncrewed and remote technologies, the modern remote survey industry is making significant waves.

The work is inherently challenging for any vessel, and uncrewed and remote operations have faced additional challenges in the past, with towing multiple sensors being problematic. However, a recent project by subsea inspection specialist Sulmara is challenging conventional industry practices and encouraging new ways of thinking in remote inspections and operations.

The company completed a successful unexploded ordnance (UXO) and multibeam survey (MBES) of Ardersier Port, on the shores of the Inner Moray Firth, Scotland, for Haventus Ltd. To help service future wind farm projects under the UK's ScotWind program, the port is undergoing significant regeneration, including construction and dredging. The survey was required to identify potential UXO targets and collect detailed bathymetry in water depths ranging from 1 to 10 m.

The system was extensively and successfully trialed and de-risked in nearby Loch Ness before being commissioned for the Ardersier survey. The survey was executed using an advanced uncrewed surface vessel (USV), WAMV-16, which was equipped with a high-resolution NORBIT Subsea MBES system to acquire the bathymetric data, ensure safe towing operations and generate accurate seafloor mapping and charting. The USV is specifically designed for use in the near-shore environment. The Norbit MBES system had a wide coverage angle, enabling efficient data acquisition in shallow water.

COURTESY SULMARA

The photo of the OPT Wave Adaptive Modular Vehicle (WAM-V -16) was taken at the end of April 2023 at Loch Ness, Scotland, during trials on the loch to scan it using the UXO detecting technology.

In partnership with SafeLane Global, an expert on UXO clearance and risk management, the WAMV-16 towed two SafeLane G882 magnetometers. These instruments detected magnetic anomalies associated with submerged UXOs, aiding in target identification and classification.

The USV surveyed the port's challenging waters with 4-m line spacing for optimum coverage (about 450,000 sq m), employing precise waypoint navigation to ensure a complete survey of the area. The UXO detection systems measured and recorded magnetic field variations, which were co-recorded with the multibeam to match potential UXO signatures with corresponding seafloor features. The data were monitored remotely in near-real time.

Continuous monitoring of the USV's onboard control system ensured safe navigation through constrained areas, including jetties, docks, submerged hazards, dredging equipment and other infrastructure.

Data collection, analysis

Utilizing an uncrewed asset enabled the field operational team to navigate a towed body through a challenging environment. It also gave the field ops team a better and safer vantage to assess hazards with a more manoeuvrable vehicle compared to a conventional vessel. Further to the navigational safety gains and the electronically and acoustically quiet nature of the operations, the USV's more stable platform yielded much higher data quality than could be expected from a crewed vessel. The WAMV's small size and high operability allowed the team to pre-empt and respond quickly to obstacles. Furthermore, it provided a low-carbon solution, generating zero CO_2 emissions.

Data obtained from the survey underwent post-processing and analysis. The multibeam bathymetric data generated digital terrain models and seafloor contours. This information helped identify shallow areas, potential navigational hazards and areas requiring further investigation. Advanced algorithms and pattern recognition techniques were applied to differentiate between natural seabed features and potential UXO targets, ensuring accurate identification.

The magnetic field data collected by the UXO detection systems were processed and analyzed, enabling the identification of magnetic anomalies associated with potential UXOs. The data analysis integrated all available information, including bathymetric data and magnetic signatures, to generate a comprehensive report highlighting the location and classification of potential UXOs within Ardersier Port.

The WAMV survey outcomes include accurate bathymetric charts, high-resolution seafloor imagery, identification of multiple ferrous objects and potential UXOs, that will contribute to the port's safety and aid in future decision-making regarding UXO clearance, risk strategy and management.

Furthermore, it proved the successful capabilities and benefits of USVs in towing multiple sensors in shallow water areas. ●

Andy Doggett is CTO of Sulmara.

Advantages of ROV and UAV technologies to the energy sector

Remote operations are continuously evolving to address challenges in the offshore energy industry.

STEVEN HENDERSON, *Interocean Marine Services Ltd.*

The adoption of advanced tools and systems has seen remotely operated vehicles (ROVs) and unmanned aerial vehicles (UAVs) become the technologies of choice in providing a safety-first approach for inspection and maintenance to the offshore energy industry, improving safety, performance and operating costs.

Interocean Marine Services' fleet of ROVs ranging from micro to observation class ROVs and its UAVs include advanced aerial drones and collision-tolerant confined spaces drones.

A recent project saw the utilization of both ROVs and UAVs, equipped with mission-specific inspection tools and sensors, to perform the DNV class internal and external structural assessment of six spud cans on a jackup barge vessel at a UK port. Spud cans play a pivotal role in anchoring vessels securely to the seabed. Regular assessment of the structures, welds and coatings conditions are vital to determine the extent of any deformation, damage, buckling or impact damage, which had been incurred during service.

Traditionally, external inspections of spud cans required human divers. Internal inspections required specially trained personnel to access the hazardous confined spaces, and the establishment of protocols for access, entry and rescue. These methods presented numerous limitations that have been resolved with advancements in technology. The quality of data typically gathered was limited due to visibility and restrictions around divers' permissible time underwater, while the conventional approach posed significant safety risks to the personnel executing these tasks.

Interocean offers an integrated approach deploying both ROVs and UAVs for the inspection process of client equipment and vessels. Eliminating human involvement in hazardous environments, Interocean's fleet significantly reduces project and safety risks, enhancing the well-being of inspection personnel as skilled ROV pilots can safely and effectively execute tasks, ranging from traditional inspections to equipment installation and challenging deepwater repairs, from afar. The combination of these advanced technologies also enhances the efficiency of inspections, reducing the overall time required for data acquisition, processing and management.

The UAV pilot prepares to fly the collision tolerant drone into a confined space area. The systems 4K camera provides high-quality images that allows the inspector to efficiently assess and confirm the structures condition in real time, while footage is recorded to allow post-inspection data analysis to be performed. COURTESY INTEROCEAN MARINE SERVICES

Case study

After coordination with the client and DNV class surveyors, considerable planning was undertaken to develop an inspection plan. This was augmented with comprehensive, task specific, risk assessments and method statements, ensuring safety of the projects' execution.

Interocean's fleet of ROVs and UAVs equipped with high-resolution cameras and an array of sensors, allowed a detailed analysis of the spud cans' conditions, showing precise identification of corrosion, structural defects or any signs of wear and tear, enabling proactive maintenance and, where necessary, repairs to be planned and undertaken to uphold the vessels' operational integrity.

The vehicles were maneuvered precisely around the areas of interest by the pilots, while inspection personnel observed and commented on the high-definition live video stream. Data was reviewed and detailed reports prepared for each area, ensuring a comprehensive inspection of the entire tank.

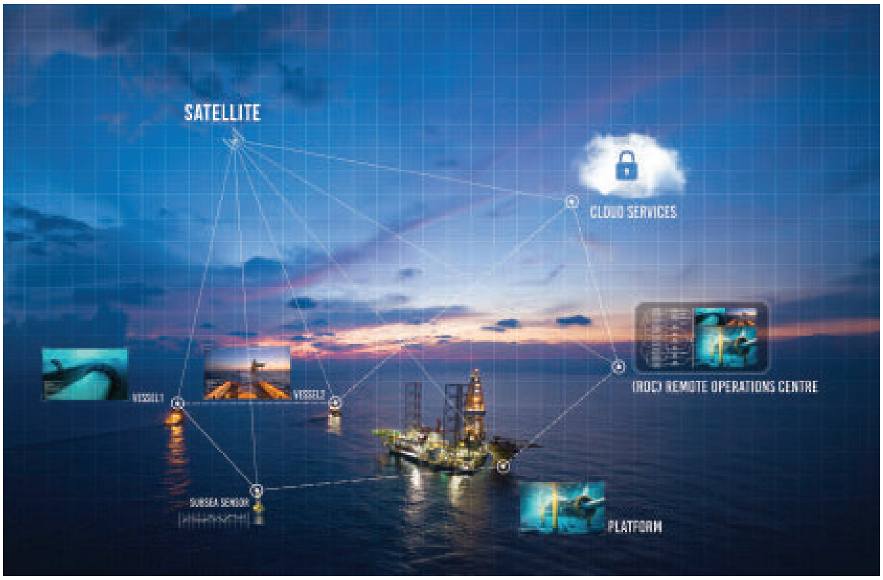
The ROV used for the underwater structural inspections was equipped with a high-pressure water jetting system, which removed surface contaminants prior to the capture of high-resolution images. Using this fleet for inspection, the data collected in real time provided an accurate assessment of each structure's integrity, resulting in the performance of an effective, class compliant inspection, ensuring the project's success. ●

Steven Henderson is the manager of remote inspections with Interocean Marine Services Ltd.

Navigating bandwidth challenges in offshore energy environments

Optimizing network capabilities is key.

PAUL GUILFOYLE, *Harvest Technology Group*



COURTESY HARVEST TECHNOLOGY GROUP

The offshore and energy industries are on the cusp of a paradigm shift as they look to remote technologies to bolster safety measures and augment operational efficiency. Ground-breaking innovations in remote inspection and surveillance are transforming the landscape of asset integrity management, resulting in decreased downtime and improved worker safety in the challenging and dynamic offshore environments.

A pivotal challenge facing remote offshore operations and uncrewed technology lies in the need for real-time communications for accurate, timely decision-making. Offshore operators need connectivity to be available, reliable and able to instantly transmit large packets of data between onshore and offshore. Isolated locations, harsh weather and powerful seas, however, are challenges to connectivity. Despite some solutions showcasing good download speeds, they often miss the mark due to insufficient upload speeds, unreliable connections, high costs, packet loss, patchy security and latency, which hinder operational efficiency and data integrity.

Effectively addressing these challenges is crucial for transmitting information that increasingly includes video, audio and data from remote offshore sites over ultra-low bandwidth or unreliable connections. Optimizing network capabilities is key. By integrating the right software and hardware into the operators own technology, they can navigate the bandwidth challenges of offshore environments to have situational awareness for real-time decision-making.

Geodata specialist Fugro exemplifies the growing trend toward remote inspections and operations. Their shift to an uncrewed fleet for offshore operations necessitated continuous 24/7 visibility and remote inspections of assets. Fugro integrated Harvest Technology Group's Nodestream and RiS (Remote Inspection Systems) technologies into its network and asset environments.

This integration allowed Fugro to perform remote subsea inspections of offshore assets through live-streamed high-quality 4K video, audio and data in real time, eliminating the need for large project teams and crew, while also enabling smaller vessel support. Additionally, it mitigated the necessity to send personnel into unsafe environments or require them to travel to and from remote locations.

Through the remote management of unmanned surface vehicles (USVs) and the use of smaller vessels, Fugro achieved a reduction of more than 90% in CO_2 emissions compared to traditional vessel operations. The USVs could operate over extended distances with minimal latency, allowing for up to 90% packet loss without loss of control. This reliability over low-bandwidth connections translated into significantly improved operational efficiency.

By utilizing Harvest's technology for remote inspection projects, Fugro's customers collectively realized cost savings exceeding $200 million and a reduction of more than 5 million HSE exposure hours in the field.

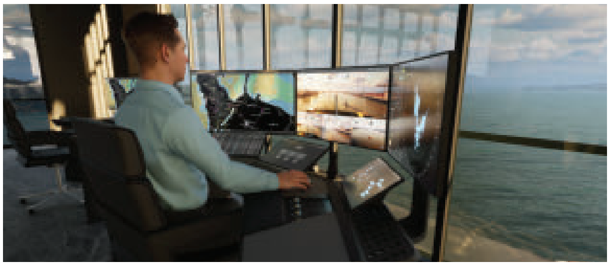
As the shift toward optimizing networks for offshore remote inspections and operations continues, it is not a culmination but rather the inception of a transformative era. Forward-thinking offshore and energy operators are extending their gaze beyond the seas and into the cloud. The power of AI and on-demand unified communications will redefine the boundaries of offshore operations. ●

Paul Guilfoyle is Group CEO of Harvest Technology Group.

Embracing open innovation in ROC workplace design

New developments in workplace design are applying open-source user interface design systems to achieve safe and efficient ROC workplaces.

KJETIL NORDBY, *Ocean Industries Concept Lab*



COURTESY JON FAUSKE, OICL

A concept sketch illustrates a generic ROC workstation from the OpenRemote project.

Recent advancements are significantly transforming remote operations centers (ROCs), particularly in the context of unmanned missions. These missions increasingly integrate subsea ROVs (Remotely Operated Vehicles) with other remotely controlled assets, such as surface vessels. This evolution not only complicates the operational aspects of ROCs but also necessitates the integration of innovative systems.

A critical aspect of these emerging systems is ensuring user-friendliness and operational efficiency. However, achieving efficient workplace design in ROCs presents a formidable challenge due to the complexity of integrating diverse systems. The next-generation ROCs often represent advanced, multi-vendor environments where various companies contribute partial solutions. Integrating these into a cohesive user experience is a significant challenge. This is due to the individual user interfaces of different systems, which may not align with the overarching design philosophies of the entire workplace.

Establishing a consistent design language in the workplace involves harmonizing various user interface elements across systems. Consistency is achieved through standardizing aspects such as UI components, layout structures, and visual styles. Such consistency not only facilitates knowledge transfer among different systems but also enhances overall usability. In the context of ROCs, the advantages of consistent design are particularly notable, as it simplifies the transition for operators moving between different ROCs, and between different assets within the same ROC. Conversely, a lack of consistent design can pose significant risks to operational efficiency and safety. It complicates the learning curve for operators and increases the probability of human errors during operations.

This challenge parallels issues identified and addressed in ship bridge design in the maritime sector. There, recent industry-led open innovation processes have produced the OpenBridge Design System, an open-source design framework offering shared design guidelines and tools.

Such neutral design guidelines are particularly important in advanced multi-vendor workplaces, as they allow multiple independent vendors to deliver consistent design across all systems. It represents a new approach to user-centered design in the ocean industries, delivering safe and efficient workplaces through cross-industry design collaboration. Since its launch in March 2020, a large number of maritime companies have accessed the OpenBridge tools and used them to design innovative products already available in the market.

As ROC workplaces increase in versatility and complexity, there is a risk that lack of design consistency also will emerge as a growing challenge. The newly established OpenRemote research project, with 22 industry-leading partners, is currently addressing this issue by extending and adapting the OpenBridge design system from ship bridges to ROCs. The existing OpenBridge system supports the design of most on-ship user interfaces as well as graphic libraries supporting digital information overlays over video streams. Initial design processes have already applied OpenBridge to underwater and surface vehicles with promising results. Future work will extend the current libraries to better adapt the system to land-based workplace form factors, communication systems, and support for human-automation interaction.

OpenRemote's objective is to develop an open-source design guideline that enables cost-effective and modern, consistently designed multi-vendor ROC workplaces supporting multiple types remotely controlled and autonomous assets, and that can deliver consistent design across workplaces on ships and in ROCs. The latter point is important since it is likely that there are multiple scenarios where maritime operations will be supported by both crewed ships and remotely operated drones.

Open, cross-industry collaborative design is a new phenomenon in the ocean industries. Yet, in this domain with rapid technology innovation and tight collaboration between specialized vendors, such collaboration seems especially important. After all, for people to keep up with the innovation, it is necessary that the workplaces are well designed and integrated. ●

Professor Kjetil Nordby is a research manager for Ocean Industries Concept Lab Institute of Design with the Oslo School of Architecture and Design.

Company News

Harbour Energy reached an agreement in late December for the acquisition of substantially all of **Wintershall Dea's** upstream assets for $11.2 billion. Completion of the acquisition is expected to occur in fourth-quarter 2024.

Cadeler and **Eneti** combined operations Dec. 23 to form an enlarged offshore wind installation contractor. The combined group is to be named Cadeler.

DeepOcean has acquired digitalization specialist **Btwn AS**.

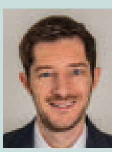
Velocity Partners, a private equity firm focused on the energy and industrials sector, has acquired **Moreld Apply**, **Moreld Ross Offshore** and **Moreld Global Maritime**.

HydroWing has opened a new office in Wales to support the development of its tidal stream energy project at Morlais on Anglesey.

People


Murray Auchincloss

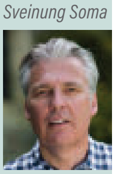
bp interim CEO **Murray Auchincloss** has been named permanent CEO, four months after the resignation of **Bernard Looney**.


Alan Bruce

Ithaca Energy CEO **Alan Bruce** will step down from his role to pursue new opportunities. Until a new CEO is appointed, **Iain Lewis** will fulfil a dual role of interim CEO and continue as CFO.


Sveinung Soma

Remote operations company Remota has named **Sveinung Soma** its new CEO.


Andrew Pearson

Shoreline Wind, developer of intelligent SaaS solutions for powering wind energy, has appointed **Andrew Pearson** its new CEO.


Stephen J. Riney

APA Corp. has promoted **Stephen J. Riney** to president and CFO.

Brett Woods has been named Beach Energy's managing director and CEO, effective Jan. 29.

Oceaneering International Inc. has appointed **Hilary Frisbie** to succeed **Mark Peterson** as senior director, investor relations.

Holiday Island Holdings Inc. has added **Glenn Klinker** to the executive staff as COO, responsible for the oil and gas operations.

IFS, a cloud enterprise software company, has promoted **Mark Moffat** to CEO. Moffat takes over from **Darren Roos** who has been appointed as the company's chair of the board.


Teresa Thomas

Teresa Thomas has been appointed vice chair, Deloitte LLP, and national sector leader for energy and chemicals. Thomas also serves as an advisory partner and leader in Deloitte & Touche LLP's Risk & Financial Advisory energy and chemicals practice. Thomas succeeds **Amy Chronis**, partner, Deloitte LLP, who will continue to serve within the energy and chemicals practice until her retirement in June 2024.

Westwood Global Energy Group's **Terry Childs** is retiring. He has more than 40 years of experience analyzing the offshore rig market.

The Acorn co-venturers have appointed **Nic Braley** to lead the Acorn Transport and Storage joint venture.

Valeura Energy Inc. has appointed **Anna Green** an independent director.

Simen Flaaten has notified Prosafe that he wants to resign as director due to other commitments. Flaaten has been a member of the board of directors since June 2023. He will remain on the board until a director to replace him has been elected.


Rebecca Dufour

C-Innovation has promoted **Rebecca Dufour** to commercial manager.

NDT Global has appointed **Ranbir Saini** senior vice president of products.

The G+ Global Offshore Wind Health and Safety Organisation has named **David Griffiths** its new chair.

Consumer Energy Alliance has welcomed two energy experts to its board of directors: **Michelle Michot Foss, Ph.D.**, a fellow in energy, minerals and materials at Rice University's Baker Institute; and **Chett Chiasson**, executive director of the Greater Lafourche Port Commission.


John Bomba

Deepwater marine pipeline design expert **John G. Bomba, P.E.** passed away in August 2023 at 91 years old. Over the years, he worked for R. J. Brown and Associates, Kvaerner, Aker, Coeflexip, Stena, Genesis Oil, and Technip. He received the OTC Distinguished Achievement Award for Individuals in May 2017.

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Energy transition faces challenges, will need greater investment

In recent years, energy majors have outlined strategic plans to diversify their businesses to include decarbonization technologies and renewable resources. Now we are seeing some of these companies moderate their previous net zero commitments. This is not true for all; in March of last year TotalEnergies reaffirmed a commitment to its transformation strategy. But a month earlier, BP revised its previous commitment to a 35% to 40% reduction in carbon emissions by 2030 to a 20% to 30% cut. Shell announced job cuts in its Low Carbon Solutions business to "strengthen its delivery on our core low-carbon business areas such as transport and industry," and CEO Wael Sawan recently stated that the company is "trying to provide energy security [which is] critical today and continues to be very much foundational on oil and gas production." ExxonMobil said in May that Net Zero by 2050 is highly unlikely. More recently, Saudi Aramco's CEO suggested that more investment in oil and gas is required just to meet the demand scenario outlined in the International Energy Agency (IEA)'s Net Zero by 2050 roadmap.

In November 2023, Womble Bond Dickinson conducted its third Energy Transition Outlook Survey Report. Respondents included companies and investors with interests in renewable energy (76%), oil and gas (64%), utilities (39%), mining (33%), EVs (30%) and nuclear (18%). The survey incorporated 456 responses from CEOs, chief financial officers, chief operating officers, legal counsel, and business, operations, and project managers.

The survey found that companies operating in the renewable energy space remain committed to Net Zero. Setbacks and challenges are expected, given the volatility of the industry and the complexity and enormity of the energy transition. But it is concerning that major renewable technologies are failing to clear cost hurdles in both the U.S. and Europe—due in part to escalating capital costs and inflation at levels not seen in decades. Wind and solar energy deployment risks reaching a bottleneck due to grid interconnectivity issues. Permitting is a challenge across the board. Multiyear delays are hampering the delivery of key grid equipment such as transformers. Meanwhile, in the face of insufficient supply and public opposition to mining practices, there is a rush to meet future demand for metals such as copper, nickel and lithium, as well as for the rare earths required for electric vehicles (EVs) and offshore wind turbines. Our research shows that industry leaders are maintaining or increasing their commitment to energy transition strategies. But this commitment is accompanied by a sobering understanding of economic realities and growing concerns about global conflict. The need to ensure energy security is real, and global consumption is increasing.

The survey results indicate that despite economic, political and regulatory challenges, energy industry executives and investors continue to pursue more sustainable power sources while facing persistent hurdles tied to cost, grid and infrastructure issues.

We asked energy industry executives and investors to rank, beyond their own businesses, what they believe to be the most relevant energy transition investment areas today. Key areas of opportunity, according to our respondents, include decarbonization-focused solutions such as biofuels and biomass (more broadly characterized as energy from waste); energy efficiency improvements; carbon capture technologies; utility-scale energy storage; and EVs. After biofuels and biomass (energy from waste), both constituencies clearly view energy efficiency—which has been described as the low-hanging fruit of the energy transition—as a priority. It tied with carbon capture as the second-ranked opportunity, selected by one-third (33%) of all respondents. Energy storage ranked fourth among all respondents (27%), and was fourth among executives (29%) and fifth for investors (24%), tied with green hydrogen.

Overall, it appears that business leaders continue to increase their commitment to the energy transition. However, with that intention to move forward also comes a clear-eyed perspective that the global energy transition is fraught with risks and will require a greater-than anticipated level of capital investment. Moving the energy industry forward will require sustained will, ingenuity and multifaceted solutions to seemingly infinite complex challenges. ●

Jeffrey Whittle, Partner, and **Lisa Rushton**, Partner, Womble Bond Dickinson