SEN
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McDermott Embraces Digital Technology With New Engineering Platform

Technology can be a blessing and a curse. Just ask any engineer that spends chunks of the work day navigating in and out of software programs while tackling engineering, procurement, construction and installation (EPCI) jobs.

There are Microsoft Word documents, Excel spreadsheets, email and PDF files plus other software programs used depending on the job at hand. Then, there is the seemingly endless task of tracking changes, making adjustments, searching for documents and communicating changes. Each discipline does its work and passes it on to the next stage. Although the work is necessary, the process can be a time-drain.

"Basically, engineering in today's industry is done by document transfer," Vaseem Khan, vice president of engineering for McDermott International Inc., told *SEN*. "What we're moving in those documents are data [and] it's information, and the technology exists today to move data, not documents."

McDermott, working with Dassault Systèmes' 3D Experience platform, is piloting Project Lifecycle Management (PLM) technology. McDermott aims to simplify work processes into one integrated, agnostic engineering platform with the software. Data from the PLM is combined with 3-D modeling software, creating a digital twin.

McDermott will digitize and standardize its processes, simplifying work processes into a single integrated, software-agnostic engineering platform. (Source: McDermott)

"What our PLM system is doing, the Gemini project, is engineering by means of data management, not document management," Khan said. "When I move data, that field knows exactly where the data are coming from. More importantly, when those data change the upstream and downstream parts know that a change has occurred."

Khan used, for example, changing from a 4-in. valve to 6-in. valve. The supply chain is notified of the need for a larger valve, but the change prompts adjustments in other areas. The piping and instrumentation diagram (P&ID) and structural support needs to change, he said, noting the procurement staff also needs to be told to purchase a 4-in. flange.

Today that information is communicated by email or a PDF file, he said.

"Once Gemini is up and running it will be communicated by transfer of data," Khan said. When the valve size is changed, the software will automatically trigger a P&ID flash that warns others of the change and the need for a fix. "It improves our quality. It reduces our waste. I don't buy incorrect material, and it brings certainty to the project.

"I am now certain that my engineering is going to be correct. I am now certain that I am going to buy the right

WHAT'S INSIDE

parts of fabricating. I am now certain that the parts I buy will fit together," Khan said. "The platform is going to be agnostic so it doesn't matter which software package we use."

The technology, which features a real-time dashboard, can be put to use from the early stages of a project to decommissioning. The EPCI specialist is embarking upon the project as the oil and gas industry increasingly turns to technology to become more efficient in terms of operations and reducing costs.

Part of what makes this data management PLM technology unique is its ability to marry with 3-D models. The "platform of the future," as McDermott calls it, is suitable for not only subsea assets and vessels but also operating platforms and onshore facilities.

"Every piece of information is in one place," Khan said. "All you have to do is go to the 3-D model, which has PLM behind it, and click on what you want from the menu. If you want to be sci-fi, you can put on your 3-D glasses, walk through it and touch the pump. Data come up. … It gives you information instantaneously. You don't have to go looking for it."

The technology has information such as engineering documents, supplier documents, test records, regulatory certificates and inspection information, among other data—all of which will be accessible by the client, he added.

McDermott seems hopeful that the digital platform will standardize and simplify processes, while driving down costs. Owners and operators that "continually experience delays and additional costs due to missing, incomplete or poorly organized information at handover," could benefit, according to the company, which noted the platform addresses handover and post-handover challenges such as:

- Knowing what information is required;
- File maintenance after operations have started; and
- Incomplete or outdated 3-D models of the facility, to name a few.

McDermott plans to start the pilot project in fourth-quarter 2017, integrating the platform into its business. Phase 1 is scheduled for completion next year.

But Khan is already thinking about the next step: predictive analytics.

Phase 2 will package predictive analytics with the PLM software to pull in data, perform analytics and send back information to the 3-D model.

It could prove useful, for instance, in relaying information such as how long a bearing has been running hot, when the bearing could statistically fail and how long the oil will be good.

If the bearing has been running hot for two weeks and predictive analytics shows that statistically it will fail in four weeks but the oil is good for another two years, "you don't have to shut down the machine for 30 days just to do an oil change," he said.

"Imagine the savings of that," Khan added. "If you don't have to do a turnaround for another year, I can stretch it out. If my turnaround is 30 days every three years, that's 10 days of additional production. Maybe I'm producing 20,000 barrels of oil per day. That's 10 days of 20,000 barrels of oil per day—significant numbers."

—Velda Addison

DEVELOPMENT

New Deals Buoy UK Offshore Sector

The U.K. North Sea oil and gas sector has enjoyed a week of high activity, with installation awards, a major development coming onstream, more funding for a new project West of Shetland, contracts being won and decommissioning work being handed out.

While it could not be described as an upturn, the rise in work levels is definitely encouraging for the industry.

Maersk Oil has given Semco Maritime a deal for the installation and preparation (hookup) of the Culzean gas field development in the U.K. North Sea.

Work will start when the production units arrive from Singapore in summer 2018. Culzean is located 240 km (149 miles) east of Aberdeen.

"The contract is the largest ever for Semco Maritime's Aberdeen office. Semco Maritime will be responsible for carrying out the electrical work, while the piping and painting work will be carried out by two other companies," Semco said.

The Culzean complex consists of a central processing platform, a wellhead platform and a living quarter platform, which are currently under construction at the Sembcorp Marine yard in Singapore. Production from the field is expected to start in 2019.

The *Glen Lyon* FPSO vessel leaves the Hyundai Heavy Industries yard in South Korea in October 2016. (Source: BP)

The offshore work will be carried out from Semco's base in Aberdeen, where the company expects to employ 75 to 150 people for the eight to nine months that it will take to prepare Culzean.

UK Schiehallion Area Onstream

BP and partners Shell and Siccar Point Energy have achieved first oil from the redeveloped Schiehallion Area, as part of the Quad 204 project west of Shetland.

The project is the third of seven new upstream major projects expected to come onstream for BP this year as the major pursues a production goal of 4 MMbbl/d by 2020.

Schiehallion and the adjacent Loyal fields were first developed in the mid-1990s and have produced nearly 400 MMbbl of oil since production started in 1998.

With the fields' redevelopment through the Quad 204 project, BP and co-venturers expect to unlock a further estimated 450 MMbbl of resources, extending the life of the fields out to 2035 and beyond. Production from the project is expected to ramp up through the remainder of 2017 to a plateau level of 130 Mbbl/d of oil, BP said in a statement.

The project included construction of the *Glen Lyon* FPSO vessel plus 20 new wells, BP said.

"BP is planning to double its U.K. North Sea production to 200,000 boe/d by 2020 and sustain a material business in the region for several decades," the company said. "Production from the new Clair Ridge major project is expected next year. Over the next 18 months, BP plans to participate in up to five exploration wells in the U.K., in addition to drilling approximately 50 development wells over the next three to four years."

Hurricane's Lancaster Funding

Hurricane Energy has entered an agreement to secure funds "to help preserve liquidity ahead of a future larger fundraising" for the Lancaster Field development West of Shetland.

The operator has signed a deal with investment bank Stifel Nicolaus Europe that allowed Stifel to subscribe 25 million ordinary shares of the capital of Hurricane. This raised about $16.55 million for Hurricane.

The company has already committed to certain pre-sanction long lead items in an effort to meet targeted first oil in 2019 from its Early Production System (EPS) development at Lancaster.

Hurricane said it will incur the long lead expenditures on a staged basis over the rest of second-quarter 2017.

"By committing to these expenditures the company reduces the risk that key equipment will not be available for installation during the benign weather window in Q2 and Q3 2018," Hurricane said.

Hurricane plans to sanction the EPS phase of the Lancaster development toward the end of first-half 2017 or early second-half 2017 in hopes of achieving first oil during first-half 2019. This, however, is subject to financing.

Contract Awards, Work Landed

Paragon Offshore has landed work for three of its jackup rigs.

The jack-up rig *MSS1* has been awarded a one-well contract in the U.K. sector of the North Sea with Centrica. The contract will start in early August and end in mid-October 2017. The day rate has not been disclosed.

In other news, Wood Group has won a deal to support Shell with the decommissioning of the Brent Bravo platform in the U.K. North Sea.

"Effective immediately, Wood Group will prepare the platform for removal via single-lift methodology. This includes conductor removal, structural strengthening and installation of under deck lift points, in addition to the modifications required to enable the platform to operate on minimum manning mode," Wood Group said.

—Steve Hamlen

Development Warms Up In Asia-Pacific Region

Field development projects have been thin on the ground in Asia since the industry has been going through its largest recession in years. However, there are some signs of recovery—like other parts of the world—with a tender for major projects offshore India being launched and a couple of developments in the Gulf of Thailand making good progress.

In addition, a new supply base is planned to service Myanmar's offshore sector in a move that could give real impetus to the growth of the country's industry.

India's state-owned Oil and Natural Gas Corp. (ONGC) has kicked off the tender process for the offshore facilities it needs for the Ratna and R-Series oil field development offshore Western India.

ONGC is eager to bring the project offshore Mumbai onstream in 2019. The project has a budget of more than $600 million.

Production from the fields is scheduled to start at an initial rate of 10,000 bbl/d, ONGC's director of offshore Tapas Kumar Sengupta said.

The *Topaz Driller* jackup rig is being used for the 2017 infill drilling program at the Bualuang Field in the Gulf of Thailand. (Source: Vantage Drilling)

The Ratna and R-series oil fields hold an estimated 87 MMbbl of oil and 1.2 Bcm (42.36 Bcf) of gas reserves.

In March 2016 the Cabinet Committee on Economic Affairs, headed by Prime Minister Narendra Modi, decided to return the fields to their original licensee after the contract with Essar Oil and Premier Oil was canceled.

ONGC discovered the fields and installed the Ratna R-12 platform, which is part of the Ratna and R-series area. These facilities had been used by ONGC for production since 1983 before production stopped in September 1994 when the field was put up for sale.

The platform has since deteriorated due to "plundering and looting" of its utilities and equipment. Repairs would be too costly. "We have to build the infrastructure afresh," Sengupta said.

Gulf of Thailand FID

Meanwhile, in Southeast Asia Ophir Energy has made a final investment decision (FID) for Phase 4 of the Bualuang oil field development in the Gulf of Thailand. Total investment is expected to be $145 million from now until 2020. The project will consist of a 12-slot bridge-linked wellhead structure with additional power generation. It will include the drilling of up to 14 wells and an expansion of the water disposal capacity on the Bravo platform.

"ERC Equipoise, Ophir's reserves auditors, provided a letter of comfort to the board that forecasts that the development will convert 9.2 MMbbl of oil of contingent resources to reserves. First oil is expected in the second half of 2018," Ophir said. "Through a combination of additional debt leverage and the Thai fiscal terms, the project is expected to start delivering cumulative positive cash flows from the start of 2019."

Vantage Drilling's jackup rig *Topaz Driller* is on location at the Bualuang Field and has started operations on the 2017 infill drilling program. This program consists of two development wells and one well targeting untested prospective resources in a near-field step-out location.

"Abandoned well stock is to be recycled to target the three new locations with the goal of the development wells growing production by around 1,400 bbl/d of oil," Ophir added. "The cost of these development wells will be around $12 million. Production year to date from the field is averaging 8,100 bbl/d."

The Bualuang Field has been onstream since 2008 and is operated by Ophir with a 100% stake.

Hilong Block B-17-01 Contract

Hilong Marine Engineering has won a subcontract from CUEL Ltd. for the transportation and installation services for three wellhead platforms, subsea pipelines and host tie-ins in the Gulf of Thailand.

The contract is for the Phase 4 development project in Block B-17-01, which is located in the Malay Basin. The area is covered by the Thailand-Malaysia joint development area.

The maritime construction period of the contract will be from mid-December 2017 to March 2018.

"The total value of the contract is no less than US $25 million," Hilong said.

CUEL acts as the main contractor for Carigali-PTTEPI Operating Co. (CPOC), which is a 50:50 joint venture between Malaysia's state-owned Petronas Carigali and Thailand's state player PTTEP. CPOC is the operator of blocks B-17 and C-19.

"The board believes that the contract marks a significant breakthrough of Hilong's offshore installation, transportation and subsea pipeline laying contracting business in Southeast Asia," Hilong said. "The board considers that such an arrangement has laid the foundation for the group to further expand into international markets."

Myint's Myanmar Supply Base

Elsewhere in Southeast Asia, Myint & Associates has been given the green light by the Myanmar Investment Commission to build an offshore supply base for the country's oil and gas industry.

Myint plans to build and operate its offshore supply base in the Nga Yoke Kaung Bay area in the Ayeyarwady region.

In 2014 the Ministry of Electricity and Energy awarded 20 international consortia rights to explore and produce from offshore blocks via production-sharing contracts (PSCs). The terms of the PSCs require exploration

activity, including drilling a number of wells over a period of up to seven years.

"Myint believes that an offshore supply base located within Myanmar will be a critical requirement to support this activity. The company aims to capture this growing market as well as provide services to the already discovered offshore fields," Myint said.

The company has been working on its offshore supply base project for the past two years. Following the approval by the Myanmar Investment Commission, Myint plans to fast track the project and aims to have the base operational by year-end 2019.

—Steve Hamlen

DEVELOPMENT BRIEFS

Statoil Plans To Start Gina Krog Oil, Gas Field In June

Norwegian Petroleum Directorate (NPD) said on May 24 that it has given consent for Statoil to start the Gina Krog oil and gas field in the North Sea.

Operator Statoil, which holds a 58.7% stake, is planning to start production in June, the company said.

The field, named after Norwegian suffragist Gina Krog, was previously expected to start in April, information on the NPD's website stated.

Gina Krog is estimated to hold 106 MMbbl of oil, 11.8 Bcm (417 Bcf) of gas and 3.2 million tonnes of NGL, which will be produced by using a fixed production facility and a storage vessel. Oil will be exported via shuttle tankers, and gas will be sent to the Sleipner A platform for final processing.

The other partners in the field include Total, Kuwait's KUFPEC, Poland's PGNiG and Norway's Aker BP.

Norwegian oil startup Okea has agreed to buy Total's 15% stake in Gina Krog for $350 million, Norwegian financial daily *Finansavisen* reported on May 23.

Both Total and Okea have declined to comment.

Eni Launches OCTP Production Offshore Ghana

Eni has started production from the Integrated Oil and Gas Development Project in the Offshore Cape Three Points (OCTP) Block offshore Ghana, the company said May 20. The project was completed three months ahead of schedule in 2.5 years.

The project includes the Sankofa Main, Sankofa East and Gye-Nyame fields, which combined have 500 MMbbl of oil and about 40 Bcm (1.4 Tcf) of non-associated gas in place.

Production will be carried out via the *John Agyekum Kufuor* FPSO unit, which will produce up to 85 Mboe/d through 18 underwater wells. A 63-km (39-mile) submarine pipeline will transport gas to Sanzule's Onshore Receiving Facilities, where it will be processed and transmitted to Ghana's national grid, supplying about 180 MMscf/d, Eni said in the release.

With a 44.44% stake, Eni is the operator of the block with Vitol (35.56%) and Ghana National Petroleum Corp. (20%).

Oceaneering Lands Work For Shell's Appomattox In GoM

Shell Offshore Inc. has tapped Oceaneering International Inc. to provide services and products to support the design, fabrication and installation of ancillary flowline hardware for the Appomattox development in the U.S. Gulf of Mexico (GoM), a news release said.

As part of the contract, the work scope for ancillary flowline hardware will include the procurement and installation of pre-lay and post-lay crossing mattresses, flowline jumper fabrication and installation, and manifold installation. It also includes the design, procurement, fabrication and installation of subsea buoyancy for flowline thermal expansion, Oceaneering said.

The company plans to use its *Ocean Evolution* vessel, scheduled for delivery later this year, to perform offshore installation services in various phases. The work is slated to start in late 2017 and year-end 2019.

In addition, Oceaneering said it also is expected to provide project management, engineering, ROV services, survey services, subsea tooling and global data solution services to Shell as needed for this work.

The Appomattox development is located in the GoM's Mississippi Canyon area.

Tullow Will Boost TEN Field Output After Resolving Maritime Dispute

Tullow Oil plans to drill new wells and boost output at its TEN Field offshore Ghana to 80,000 bbl/d once a maritime dispute between Ghana and Ivory Coast is resolved, Tullow's managing director in Ghana Charles Darku said May 17.

The British company will also invest in exploring possible new Ghana reserves in addition to its Jubilee and TEN fields, Darku said. The International Tribunal for the Law of the Sea is set to rule on the maritime border dispute in the coming months.

"We are looking to the Ghana government to reach a resolution on that to enable us immediately to resume drilling new wells as planned in order to boost production to the plateau of 80,000 [bbl/d]," he told Ghanaian shareholders in Accra.

The offshore TEN Field, comprising the Tweneboa, Enyenra and Ntomme blocks, poured its first oil in August 2016, and the partners said they need to drill at least six more wells to reach its potential.

Production at Ghana's flagship offshore Jubilee Field stands at about 100,000 bbl/d, Darku said. Ghana, which also exports cocoa and gold, is hoping to use increased oil and gas output to boost its GDP and create jobs.

Centrica Targets Higher Production From Chestnut Oil Field

Centrica said it will drill a new production well at its Chestnut oil field in the North Sea, which was going to be shut later this year.

The Chestnut oil field is off the coast of Aberdeen in Scotland and has been producing oil since 2008 but was only expected to do so for three years.

The field produces 4,000 boe/d and the additional production well should bring a further 10,000 bbl/d onstream, bringing total production to nearly 14,000 bbl/d, Centrica said. The $45 million investment will extend the life of the field by at least three years.

"Chestnut has been an important part of Centrica's North Sea portfolio for nearly 10 years, so we're delighted to not only boost production from the field but also extend its life even further," Nigel MacLean, asset manager for the central North Sea at Centrica, said in a statement.

"Fields like Chestnut underline the importance of maximizing the potential of as many North Sea fields as possible, whether they are major finds or small pools," he added.

Eni Starts Production From Jangkrik Project Offshore Indonesia

Eni has begun producing natural gas from the deepwater Jangkrik Development Project offshore Indonesia, the company said in a news release.

The fast-tracked project was completed early, with production startup happening within 3.5 years of the project's sanctioning, Eni said.

"It provides the opportunity for the Jangkrik floating production unit [FPU] to become a hub for the development of our nearby gas discovery Merakes (Eni 85%, Pertamina 15%), which could start production within the next two years," Eni CEO Claudio Descalzi said in the release. "We will consolidate our near-field exploration strategy and operating model and maximize the integrated development of our projects also in Indonesia."

The Jangkrik project comprises the Jangkrik and Jangkrik Northeast gas fields in the Kutei Basin's Muara Bakau Block in deepwater Makassar Strait.

Production from 10 deepwater subsea wells, connected to the newbuild *Jangkrik* FPU, will gradually reach 450 MMscf/d, Eni said in the release. After being processed onboard the FPU, gas will travel via a 79-km (49-mile) pipeline to the Eni-built onshore receiving facility and then to the East Kalimantan Transportation System before reaching the Bontang gas liquefaction plant.

The gas will supply the Indonesian market and the LNG export market, according to Eni.

With a 55% stake of the Muara Bakau PSC through its subsidiary Eni Muara Bakau BV, Eni is the operator. Partners are ENGIE E&P, through its subsidiary GDF SUEZ Exploration Indonesia BV, with 33.334% and PT. Saka Energi Muara Bakau with 11.666%.

Heerema Scoops Up Peregrino II Jacket Contract

South Atlantic Holding has awarded the procurement and construction contract for the jacket for Statoil's Peregrino II project to the Heerema Fabrication Group, according to a news release.

"With the Valemon jacket, the Gina Krog jacket and the Oseberg Vestflanken 2 unmanned wellhead

platform—which we will deliver next month—we have a good track record with Statoil," Heerema Fabrication Group CEO Koos-Jan van Brouwershaven said in the release.

The Peregrino II project, located in the Campos Basin offshore Brazil, involves adding a third wellhead platform to the field. Heerema said the Peregrino jacket will be about 135 m (443 ft) tall with a 66 m-by-53 m (217 ft-by-174 ft) footprint. Excluding the piles, it will weigh 9,300 tonnes.

Construction is set to begin in November at the Heerema yard in Vlissingen, the Netherlands, to be ready for sailaway in October 2019.

Statoil aims to grow production from the field by increasing the number of production wells. Plans are for 15 oil producers and six water injectors to be drilled. Production is expected by year-end 2020. "The estimated recoverable resources from this development until the end of 2040, when the concession period will end, are 250 million barrels," the release said.

Wood Group Secures Engineering Contracts For Tigris, Anchor

Wood Group is lining up work for Chevron after signing a 10-year master services agreement.

The agreement allows Wood Group to deliver conceptual engineering, pre-FEED, FEED, detailed design and procurement services across Chevron's global onshore and offshore asset portfolio, according to Wood Group.

Under the new agreement, Wood Group will provide topsides conceptual and pre-FEED for two semisubmersible platforms on the Tigris and Anchor developments in the Gulf of Mexico.The Tigris and Anchor platforms will operate in 1,219 to 1,524 m (4,000 to 5,000 ft) of water about 225 km (140 miles) offshore Louisiana.

—Staff & Reuters Reports

TECHNOLOGY

Is Standardization The Key?

Subsea tree technology is a key element in today's multiwell subsea developments. Most production facilities have subsea trees clustered at drill centers producing through gathering manifolds with flowlines tied back to the host.

The downturn in oil prices since 2014 has led to a period of normalization and reset across the subsea business. The challenge in today's economic climate is the pursuit of drastic cost reductions needed for subsea developments to go forward in current market conditions.

Currently, subsea systems are too expensive, and deliveries are too long. Subsea trees are a large part of capex and therefore must be part of project cost adjustments. In addition, tree deliveries drive the drilling schedule, which is a huge part of project capex. The focus has to be on identifying how to reduce costs and delivery schedules that have resulted from too many unique one-off and highly customized end-user specific solutions. Standardization is a tool that can drive lower costs and shorter deliveries for combined project capex benefits. The International Association of Oil and Gas Producers (IOGP) has recognized the need for standardization with Joint Industry Project (JIP) 33, supported by the World Economic Forum Capital Project Complexity Initiative. The intent of the initiative is to cut costs in offshore projects.

"In our industry, we have been eroding value by developing bespoke components in each of our projects," according to IOGP. "Our vision is to achieve industry-level standardization to enable efficient cost-effective procurement and support improved delivery of safe, reliable and competitive projects and operations across the globe."

Cultural Shift Required

Subsea tree standardization requires a cultural shift in the industry's approach to the specification and procurement of subsea trees. Collaboration between end users and suppliers to adopt common fit-for-purpose solutions is one of the most important challenges the industry faces.

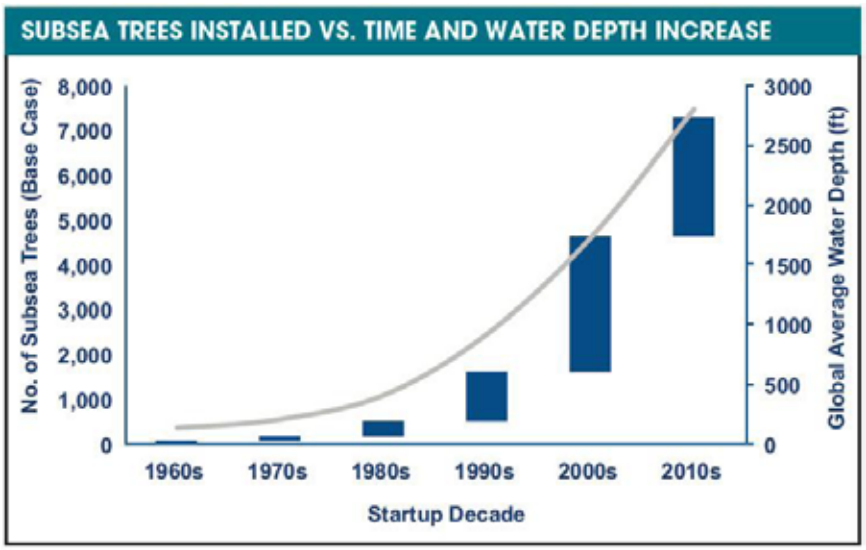


FIGURE 1. Over time, subsea trees have been installed in greater water depths and have been designed to last longer. (Source: Wood Mackenzie)

Although challenges with this cultural shift are unlike the focus on technology development, true diligence associated with standardization is where significant cost reductions will be achieved.

Hard Choices, Coming To Agreement

In subsea, no single tree design will ever provide the 100% solution to all project cases. However, by standardizing on the majority cases, the industry can align along functional and technical requirements such that it can realize the cost and schedule efficiencies of scale for a large percentage of new subsea projects. No new technology developments are needed for this next step.

Mature Technology

Subsea tree systems technology is already mature from lessons learned and continuous improvement over 50 years of development as new discoveries across the globe were made. The increasing number of subsea trees installed over the past 50 years with the progression into deeper waters confirms this conclusion (Figure 1).

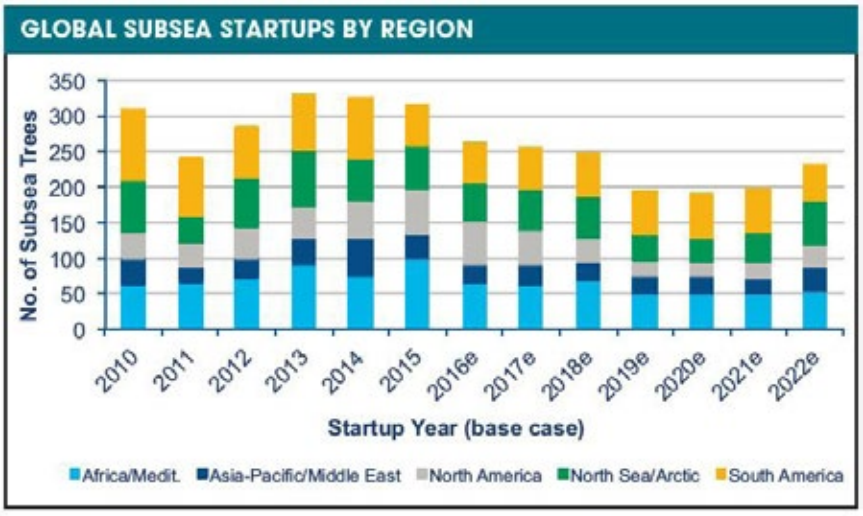


FIGURE 2. Subsea tree installation is not forecast to repeat the success it saw in 2012 to 2014, but it is expected to rise after 2020. (Source: Wood Mackenzie)

Figure 2 shows global subsea tree startups by region beginning with 2010 and extending with an estimated forecast through 2022. This provides more specific confirmation of subsea tree use in the future. With this many trees installed worldwide operators have had significant successful experience with subsea trees for field developments under a wide variety of operating circumstances. Consequently, subsea tree technology has evolved from the very basics into complex systems, having grown in both size and complexity.

A comparison of an early technology basic tree vs. an example of today's highly customized project-specific configuration follows the brief descriptions of each below.

Early Subsea Trees

Early subsea trees were only a conduit for bringing production to the surface for processing and an annulus for monitoring. They still are, essentially. By definition, all subsea trees include a simple tree-to-wellhead connector interfacing with the production tubing string below and a series of typically fail closed and/or manual (ROV) valves in both the production stream and the annulus access pathway.

This was the extent of the tree equipment in the beginning, which at the time was satisfactory for floating production systems that were considered a temporary means of achieving early production, often intended only as a transitionary extended well-test phase followed by expanded fixed platform development. At that time long-term life-of-field requirements were not considered in the tree design.

Step Change

As more subsea trees were installed in early production system projects, their viability for longer term use gained acceptance. However, additional capabilities were needed to address all key considerations for any field development, including the reservoir characteristics/fluid properties and flow assurance over the projected life of the field. The requirement to design the subsea tree for a field life of 20-plus years is considered the step change responsible for the technology evolution that followed.

Today's fully capable subsea trees can be equipped for downhole chemical injection, downhole gas lift, intelligent well completions, and downhole electrical and fiber-optic connectivity, among other functional options. All of these are associated with optimizing production over the field life.

Subsea Tree Standardization Is Key

As a consequence of abnormally high oil prices from 2009 to 2014, tree cost and delivery have been disregarded. Additionally, subsea tree technology, although mature enough to cover the majority of subsea technology needs, has resulted in increased cost and delivery when pushed beyond the 10,000-psi standard tree design.

Customization and the continuous pursuit of optionality has been eroding value by escalating cost and adding to the delivery time. Subsea trees should be as simple as possible functionally such that:

- They can be delivered in the shortest lead time possible;
- Operators can reduce schedule risk exposure to

the drilling rig completion schedule; and
- The unit cost capex can be minimized.

Alignment on the following is key:
- Core functional requirements;
- Material, welding and inspection specifications;
- Tree configurations that limit optionality; and
- The provision to the manufacturing community of the confidence to support the industry with stocking programs of long-lead schedule-critical components.

To see more details of progress at IOGP, visit iogp.org/JIP33.

—Dudley Gray, Craig Hume and Ron Ledbetter, INTECSEA

Silicone Rubber Insulation Available For Subsea Applications

As the quest to find new sources of oil and gas takes operators farther and deeper offshore into harsher environments, so does the need for technologies capable of withstanding higher temperatures and pressures.

When it comes to subsea operations and insulation technology, guarding against problems such as cracking and joint separation is a must. Developers of silicone rubber insulation technology believe the material is a good fit, particularly for HP/HT equipment used in deepwater production and for tiebacks.

Silicone rubber has been billed as a material capable of withstanding both high and low temperatures and being resistant to solvents, oil and other chemicals. It is known to have thermal conductivity that is better than other rubbers and to be highly adhesive.

Dow Oil & Gas Co. subsidiary Dow Corning developed a solid, non-syntactic silicone rubber system for subsea flow assurance applications. Called XTI-1003, the silicone rubber insulation is suitable for use on equipment such as wellheads, subsea trees, pipeline end manifolds and terminations, jumpers, flowline and rise ends, and flange connections—to name a few.

The technology came in response to industry needs, according to Brian Swanton, an industry specialist in silicone elastomer for Dow Corning. And it could help optimize flow assurance.

"The oil industry is looking for higher temperature insulation materials, alternatives in the market, which can go up to 200 C [392 F]," Swanton told *SEN* earlier this month. "Silicones are naturally very good at thermal insulation. They're very good hot, so it was a natural fit to have silicone in this type of application."

Swanton called XTI-1003 a relatively simple solution, considering it is cast similarly to polyurethane or glass syntactic polyurethane.

"The mix ratios are similar," Swanton said. "The processing equipment is similar. The way you apply it is similar. The chemistry is different."

The silicone rubber insulation system is not syntactic.

"This is a solid, so it really doesn't have a limit to it," when it comes to pressure, he added. "We've tested it up to 400 bar [5,802 psi] with no issues."

As described by Dow, performance advantages include:
- Thermal stability across a wide temperature range;
- Good insulating properties for longer cooldown times;
- Increased joint strength and high heat capacity; and
- Long-term flexibility and resistance to extreme pressures.

The Medusa manifold application is shown. (Source: PERMA-PIPE Oil)

The technology was cast as a core raw material for ExxonMobil affiliate Esso Exploration and Production Nigeria Ltd.'s Erha North subsea development offshore Nigeria.

"Subsea7 turned to Trelleborg Offshore's advanced silicone insulation system, Vikotherm S1, which uses XTI-1003 RTV Silicone Rubber Insulation," Dow said in article distributed during this year's Offshore Technology Conference. The Vikotherm S1 system can effectively operate in depths of 3,000 m (9,842.5 ft) and in temperatures in excess of 135 C (275 F).

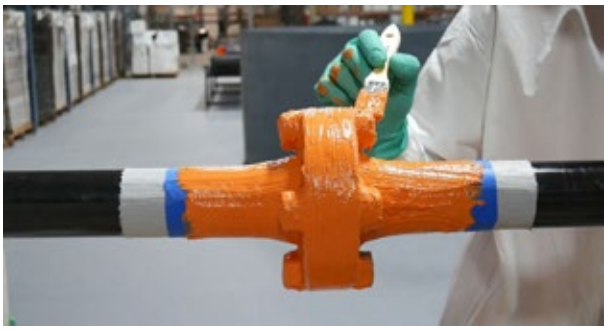
"On insulation projects that are completed or in progress, Vikotherm S1 is used on components such as tapered stress joints, manifolds, pipeline end terminations, pipeline end manifolds, vertical connection systems, and subsea pump stations," Dow said.

When asked about any other new technologies in this area, Swanton said, "We're always trying to get hotter. The temperature requirements are going hotter. They want easier to apply materials in general, [and] things that cost less. Those are all things that need to be worked on. Dow works on many different technologies, and we are working on new solutions."

—Velda Addison

TECHNOLOGY BRIEFS

Belzona Releases New Coating To Protect Against Corrosion



The Belzona 3412 material takes between one and four hours to become touch-dry, meaning minimal downtime for the coated equipment. (Source: Belzona)

Belzona has released the encapsulating membrane Belzona 3412. This coating can be brush or spray applied onto complex surfaces to protect them from corrosion.

When used in conjunction with Belzona 8411, a release agent/corrosion inhibitor, Belzona 3412 can be cut and peeled back during required maintenance or to check the status of the substrate, before being fully resealed with an extra layer.

Belzona 3412 provides protection to a range of machinery and equipment, from the smallest bearings to the risers of offshore platforms. Its elasticity and adhesion properties allow it to encapsulate and bond effectively to many types of metallic and painted surfaces. Belzona 3412 provides a durable layer of protection against many types of corrosion, such as galvanic and crevice.

Belzona 3412 has the additional advantage of protection against aggressive environmental factors, including UV resistance, which furthers its protection capabilities.

Petrobras Aims To Improve BOPs, Subsea Safety Valves

(Source: Petobras)

Petrobras recently released results of its collaboration with Embraer, a Brazilian aerospace company, aimed at improving BOP and subsea safety valves.

Among the innovations developed is an improved valve design made by a BOP manufacture, Petrobras said in a news release. "The new valve leads to increased reliability, ensuring fewer BOP failures, increasing operating safety and reducing the likelihood of project delays."

The two also worked on improving safety index calculations, such as the likelihood of completing the well phase without a BOP failure; system reliability in drilling and completion activities; identifying the most critical component to increase BOP system reliability; and pinpointing opportunities and conceptual design developments for a new regulating valve with a focus on reliability.

Petrobras also presented initiatives in progress related to subsurface safety valves (SSSV). The initiatives draw on knowledge gained from the Embraer partnership and aim to increase critical system reliability and safety in the construction and operation of subsea wells.

Improving the reliability of SSSV will not only boost well safety and integrity, Petrobras said, it also will lower costs associated with interventions to correct faults.

The update was shared during meetings in May with offshore operators and representatives of the International Association of Drilling Companies in Houston.

ABB Lands Subsea Research Grant From Research Council Of Norway

The Research Council of Norway has awarded ABB a three-year $1.2 million research grant to develop subsea technology for use on the Norwegian Continental Shelf and the Barents Sea, according to a news release.

The award marks the third for ABB under the council's DEMO2000 initiative.

"ABB is currently engaged in a five-year joint industry program [JIP], which commenced in 2013, to develop pressure-compensated electrical and control equipment as part of a drive to move oil production systems from surface platforms to the sea bed," the release said.

Per-Erik Holsten, managing director of ABB's oil, gas and chemicals business, said the award recognizes ABB's innovation in subsea technologies.

"The research result will contribute to the creation of a complete subsea factory—turning the vision of leading oil and gas companies into reality," Holsten said in the release.

ABB entered the JIP, along with other oil companies, in 2013 with a goal to advance Statoil's vision for an autonomous subsea factory that can be powered and controlled from shore.

"The program aims to develop equipment that can transmit electrical power up to 100 MW, delivered over a distance of 600 km [373 miles], and which can operate at

a water depth of 3 km [2 miles] for 30 years with little or no maintenance," the release said. "ABB has moved from laboratory testing of physical principles to manufacturing sub-assemblies and prototypes. The first installation of the subsea power products in the real offshore production site is expected to begin in 2020."

Cloud-based Technology To Digitize Offshore Field Development

Xvision Software has release FieldAP, the first 100% cloud-based technology for the energy industry providing offshore project managers with an online tool for visual field development, digital planning and cost containment, a press release stated.

The online tool is capable of accelerating project timelines by up to 80%, especially during the early concept and FEED phases. These time savings can drive cost savings as high as 70% across the life of the project.

FieldAP brings all offshore field development project data—assets and activities, both subsea and topside—into plain sight through easy-to-understand online 2-D/3-D visualizations. The tool's digital working environment also provides the power of real-time multilocation collaboration, allowing users a lower risk of communications errors, reduced costs in the design process for the whole value chain by quickly finding the best solution and accelerated timelines across the life of a project.

—Staff Reports

EXPLORATION

China, Japan Make Progress With Methane Hydrates

China has produced gas hydrates in the northern part of the South China Sea, according to a government department.

The China Geographical Survey (CGS) said it managed to collect samples from the Shenhu area in the South China Sea in a test that started last week. Production of 16 Mcm/d (564.8 Mcf/d) of gas, nearly all of which was methane, was achieved from the test.

Gas hydrate, methane hydrate in particular, is a cage-like structure of crystallized ice that contain trapped molecules of methane, the main constituent of natural gas, the CGS said. If methane hydrate is either warmed or depressurized, it reverts back to water and natural gas.

According to the U.S. Department of Energy, global estimates vary but the energy content of methane in hydrates is "immense, possibly exceeding the combined energy content of all other known fossil fuels." But no methane production other than small-scale field experiments has been documented so far such as the recent study offshore Japan.

Japan's trade ministry on May 8 reported success in producing gas last week by extracting methane gas from methane hydrate deposits offshore Japan's central coast.

The tests being run at two different wells are the first since 2013, when Japan achieved the world's first-ever extraction of gas from offshore deposits of methane hydrate, a frozen gas known as "flammable ice."

Japan's Ministry of Economy, Trade and Industry (METI) said the methane hydrate production tests will continue for a combined four to five weeks. Japan's first methane hydrate tests in 2013 ended abruptly after less than a week due to problems with sand flowing into the well.

Japan, which imports nearly all of its energy sources, has been aiming to launch private sector commercial production of methane hydrates by between 2023 and 2027, but METI officials have said the goal will still be a challenge as many obstacles remain to be solved.

Japan is the world's top importer of LNG, and its need for domestic gas resources has become greater since the Fukushima nuclear crisis in 2011 shut down most of its nuclear power plants and sharply raised fossil fuel imports such as LNG and coal.

Methane hydrate is formed from a mixture of methane and water under certain pressures and conditions. India, Canada, the U.S. and China are among the countries also looking at exploiting hydrate deposits as an alternative source of energy, the trade ministry said.

A Japanese study has estimated that at least 1.1 Tcm (40 Tcf) of methane hydrates lie in the eastern Nankai Trough off the country's Pacific coast, equal to about 11 years of Japanese gas consumption.

—Staff & Reuters Report

US Will Resume Review Of Atlantic Seismic Permit Applications

There is hope for six companies wanting to conduct geological and geophysical (G&G) activities in the Atlantic Ocean.

The U.S. Department of the Interior said on May 10 that Walter Cruickshank, acting director for the Bureau of Ocean Energy Management (BOEM), asked the Interior Board of Land Appeals (IBLA) to remand six application denials under appeal. The move follows Secretarial Order 3350, which implements President Trump's America-First Offshore Energy Strategy, the Interior Department said in a news release. Upon the grant of the remand by the IBLA, the previous adminis-

tration's decision that ordered BOEM to deny the permit applications reverses.

TGS, GX Technology Corp., WesternGeco LLC, CGG Services (US) Inc., Spectrum Geo Inc. and PGS filed appeals with the IBLA after the permit requests were denied.

The latest move allows BOEM to resume its evaluation to determine whether to approve or deny each application.

The Interior Department said the previous administration's decision underestimated the benefits of obtaining updated G&G information and ignored the conclusions of BOEM's Atlantic G&G Programmatic Environmental Impact Statement and Record of Decision. The agency said no significant impacts are expected as a result of these seismic surveys.

"Seismic surveying helps a variety of federal and state partners better understand our nation's offshore areas, including locating offshore hazards, siting of wind turbines as well as offshore energy development," said Secretary of the Interior Ryan Zinke. "Allowing this scientific pursuit enables us to safely identify and evaluate resources that belong to the American people. This will play an important role in the President's strategy to create jobs and reduce our dependence on foreign energy resources."

More than 30 years have passed since the last G&G seismic data for the Mid- and South-Atlantic Outer Continental Shelf (OCS) were collected. During that time, technological advances also have been made in exploration.

The Atlantic region is not included in the current five-year OCS Oil and Gas Leasing Program; however, President Trump has directed the Interior Department and BOEM to begin developing a new national program. Information gained from possible seismic surveys in the Atlantic will help with future decision-making, the release said.

—Staff Reports

EXPLORATION BRIEFS

Mexico's Oil Regulator Approves New GoM Area For Pemex

Mexico's oil regulator on May 24 approved a promising new deepwater block for state oil company Pemex, but conditioned the allotment on the firm developing the area with a partner that would eventually operate it.

The new Chachiquin area, adjacent to Pemex's Nobilis-Maximino Block, could produce 80,000 bbl/d of oil once it reaches peak output, according to the regulator's estimates. Development of the area is not expected to begin until 2024 at the earliest.

"It's incredibly important for the country to move forward with deepwater projects," said Hector Moriera, a commissioner with the regulator, known as the CNH, adding that 53% of Mexico's prospective oil resources are in deepwater deposits. "That's where much of our country's oil future lies."

An auction to pick a partner for Pemex in the Nobilis-Maximino Block, which would only be Mexico's second deepwater joint venture (JV), was approved last month by the company's board and is set for year-end 2017.

Nobilis-Maximino is estimated to hold reserves of some 500 MMbbl based on data gathered from five wells drilled in the past and is located just south of Mexico's maritime border with the U.S. in the Perdido Fold Belt, where dozens of successful projects have been developed on the U.S. side of the same basin in recent decades.

The JV partnerships are fruit of a sweeping sector overhaul finalized in 2014 that ended Pemex's decades-long monopoly and for the first times allowed JVs in E&P of oil and gas with equity partners.

PGS, TGS Ramp Up Newfoundland-Labrador 3-D Seismic Projects

Petroleum Geo-Services ASA and TGS will ramp up its 3-D seismic acquisition in Newfoundland-Labrador with two new multiclient 3-D seismic projects, according to a news release.

These projects are supported by industry funding.

East Flemish Pass 3-D Phase II is a 1,950-sq km (753-sq mile) extension of a survey acquired by the joint venture in 2016 in eastern Newfoundland. The survey will extend eastward into Block EL1150, which will likely be drilled in the future, the press release said.

Harbour Deep 3-D will comprise a minimum of 2,700 sq km (1,042 sq miles) of 3-D GeoStreamer data in eastern Newfoundland, over held and open acreage to be included in the November 2018 licensing round under Newfoundland-Labrador's scheduled land tenure system.

Following completion of these surveys, the jointly owned library will have more than 175,000 line km of 2-D GeoStreamer data and 19,400 sq km (7,490 sq miles) of 3-D GeoStreamer data.

Cairn Deems SNE-6 Appraisal Well Results 'Successful'

Results from Cairn's SNE-6 appraisal well offshore Senegal have confirmed connectivity with its SNE-5 well, proving oil of similar quality, the company said.

"This is our ninth successful well in Senegal in three years," Cairn CEO Simon Thomson said in the release. "The results from this latest well, together with SNE-5 and VR-1, provide essential data as we move toward submitting a development plan for the SNE Field to the government of Senegal in 2018."

Two drillstem tests were conducted in the upper reservoir units, the company said. During the first test oil flowed from an 11-m (36-ft) interval at a maximum rate of about 4,600 bbl/d. For the second test, an additional 12-m (39-ft) zone was added and the well flowed at a max-

imum of about 5,400 bbl/d. Pressure data from SNE-6 confirmed the upper reservoir is connected with SNE-5.

"Further analysis will be performed once interference test data have been collected from the observation wells, to determine the impact on modeled reservoir architecture, recoverable resource base and forward development plan," Cairn said. "We expect to provide further information at our half-year results in August."

SNE-6 was drilled by the *Stena DrillMAX* drillship, which is moving to the site of the FAN South exploration well. Located about 20 km (12 miles) southwest of the SNE-3 well at a water depth of about 2,175 m (7,136 ft), Cairn said "FAN South is targeting a mean prospective resource of more than 110 MMbbl with dual prospects: an Upper Cretaceous stacked multilayer channelized turbidite fan prospect and a Lower Cretaceous base of slope turbidite fan prospect, which is equivalent to the FAN-1 2014 oil discovery."

—Staff & Reuters Reports

FLOATER BRIEFS

Petrobras Cranks Up *P-66* At Lula Field Offshore Brazil

Petrobras and its partners in the BM-S-11 Consortium have started oil and gas production in the Santos Basin's Lula Sul area through platform *P-66*, the first FPSO vessel owned by the consortium, the company said.

With a daily capacity to process 150,00 bbl of oil and to compress 6 MMcm (211 MMcf) of gas, the *P-66* is located at a water depth of 2,150 m (7,054 ft) about 290 km (180 miles) offshore Rio de Janeiro. The vessel is connected to the Lula Field through well 7-LL-60D, Petrobras said.

Lula Field is located at concession BM-S-11. Petrobras is the operator with 65% interest. Partners are Royal Dutch Shell subsidiary BG E&P Brasil with 25% and Petrogal Brasil with 10%.

Catcher Project Stays On Track For 2017 First Oil

Progress is being made at the Catcher project in the U.K. North Sea with costs falling by nearly 30% to $1.6 billion, according to Premier Oil.

"Good progress is being made on the FPSO [unit] with the construction work for the installation and integration of the topsides complete while the construction scope in the hull is nearing completion," the operator said in a May 15 operations update. "Commissioning is underway, and this will continue up until sail away."

First oil is targeted for later this year.

The company also reported that seven producers and three injectors have been drilled. A subsea campaign is set to begin in June to tie in four Varadero wells.

"As a result of the positive drilling results, Premier is optimistic that a higher plateau production rate can be achieved and a review is underway to understand the potential additional production capacity available from the FPSO [unit]," Premier said.

—Staff Reports

VESSELS

With *Amazon*, McDermott Sees Potential For Raftload Of Projects

To grasp the size of McDermott International Inc.'s new pipelayer *Amazon*, imagine lifting the 27,449-ton ship and dropping it through the open roof onto the playing field of NRG Stadium in Houston, where the recent Offshore Technology Conference was held.

Now imagine something else because that idea—not to mention the boat—won't fly. The 200-m (654-ft) vessel is just too big to fit through the roof of a stadium that needed to be massive enough to contain an all-out Lady Gaga performance.

Now try to imagine the role *Amazon* will play in the long-term strategy of McDermott. Hint: it's big.

"When we bought the vessel, we had already a plan in mind for what we wanted to do with the ship," Alan Marriott, McDermott's vice president for fabrication and marine asset operations, told *SEN*. "We'll now continue to execute that plan before we go back to the board for the next phase of that, probably Q3 or Q4 of this year."

McDermott completed the purchase of *Amazon*, built in 2014, in February for a reported $80 million from financially ailing London-based Ceona. The price was about 77% less than the estimated $350 million cost of the vessel.

Since then, the company has made minor upgrades to the ship in the Keppel fabrication yard in Singapore before its first assignment offshore Australia on INPEX's Ichthys LNG project. That work will likely last the rest of 2017, Marriott said, before *Amazon* heads to the Middle East, McDermott's busiest region.

The company continues to reposition ships to support its work in the Middle East.

"I don't think [the Middle East has] missed a beat at all," Marriott said. "If anything it's running faster than it normally does. The Middle East is our core business at the moment."

McDermott's advantage in the region is that it's had a presence there, in some form or another, for the past 50 years, he said.

"We were encouraged in the '80s to move to Jebel Ali," Marriott said. "It's been massively successful, I think."

The Jebel Ali fabrication yard in Dubai, United Arab Emirates, has an annual output of 8 million man-hours in a region where temperatures reach as high as 113 degrees. The yard takes care of multiple repeat customers in the Middle East and India.

Marriott attributed the company's success in the region to the trust built over time with Saudi Aramco.

"I'm not saying there haven't been difficult times but the respect that both Saudi Aramco and McDermott have for each other is pretty strong," he said. "With their new programs they're trying to build more domestic content. We've got an engineering office now in Saudi Arabia and a fabrication yard [in Dammam] already. We've signed an MOU [memorandum of understanding] to build a future yard in Saudi Arabia."

Saudi Arabia has also provided a rich supply of engineering talent. McDermott maintains a staff of between 250 and 300 engineers in its Saudi office with plans to grow.

To keep up with the pace of work in the region, the company recently moved its versatile derrick lay vessel *DLV 2000* to support two derrick barges, DB 27 and DB 32. *DLV 2000* joined the fleet in 2016 and was immediately deployed to the Ichthys project.

"*[DLV 2000]* for us was a good strategic investment for the right type of asset," Marriott said. "It brings a different type of asset for the Middle East market. It complements what we do and allows us to afford even more capacity into the market."

But newbuilds are a luxury in a lower-for-longer oil price environment. And while McDermott is looking at options for some of the older ships in its fleet, its replacement strategy is necessarily flexible.

"Is that newbuild? Is that one of the vessels of opportunities that are circulating in the market?" Marriott asked. "Could be either. It all depends on where we see the best value for McDermott in terms of investment. There are opportunities in the marketplace. We're not sitting on oodles of cash that you can just go and spend."

Buying and building are not the company's only options. It charters some 50 third-party ships in the Middle East at the moment and that is fine with Marriott, who doesn't see the company's 13-vessel fleet ever increasing past 20.

"I think the market's already got enough assets in it," he said. "It's a case of looking at them and finding the right price point that you can make them do what you want them to do."

Not every vessel will be made available as a virtual newbuild at 80% off, like *Amazon*. The quiet offshore climate at the moment is advantageous, giving the company time to retrofit her with an advanced pipelay system and be ready for an upswing in late 2019 or early 2020.

"Long term, I see the *Amazon* as being another enabler," Marriott said. "We see that ship getting us more and more vertically integrated. That's our delivery model."

—Joseph Markman

VESSEL BRIEFS

ELA Delivers Control Room For Semisubmersible Crane Vessel

ELA's office container will be used as a control room to operate anchor winches aboard *Thialf*, a semisubmersible crane vessel operated by Heerema Marine Contractors. (Source: ELA Container Offshore GmbH)

The crew of Heerema Marine Contractors' (HMC) *Thialf* semisubmersible crane vessel (SSCV) has a new 6-m (20-ft) office container to house its control room for operation of anchor winches.

Thialf is the largest SSCV in Heerema's fleet and capable of a tandem lift of 14,200 tons (15,600 short tons). Its two cranes have both depth reach lowering capability and heavy-lift capacity to install topsides. The SSCV can be used to install foundations, moorings, SPARs, tension-leg platforms and integrated topsides, as well as pipelines and flowlines.

"Originally HMC was looking for a 10-ft [3-m] office container to monitor the work," Frank ter Haak, business development manager Netherlands at ELA Container Offshore GmbH, said in a statement. "However we managed to convince them in using our standard 20-ft [6-m] offshore office container to serve as a control room. The container was needed on short notice, and we managed to adjust the interior for installing their monitors and further inventory."

Heerema said the addition helped in its operations.

"The container was placed on top of our winch container and a stairway and platform was built from scaffolding, providing us a perfect view on the hoses over the stern of the *Thialf*," said Water de Winter, Heerema's equipment management NFE. "We were very pleased with the way things were handled by ELA Container Offshore."

Cosco Guangdong Delivers Mariner Sentinel

Scotland's Sentinel Marine has taken delivery of a new emergency response and rescue vessel (ERRV) that will operate offshore the U.K.

The 65-m (213-ft) long, 16.6-m (54.5-ft) wide ERRV was delivered by China's Cosco Guangdong Shipyard.

The *Mariner Sentinel* was custom built for Statoil, which will deploy it to support operations at the Mariner Field in the North Sea. The field lies about 150 km (93 miles) east of the Shetland Isles and is due onstream in 2018.

The ERRV will provide emergency cover, oil spill response preparedness and tanker assist capabilities.

The five-year ERRV contract Sentinel Marine has with Statoil started in July 2016.

—Staff Reports

BUSINESS

Kashagan: An Oil Market Game-Changer In The Making?

HOUSTON—There is a wild-card among the world's oil market players that some believe could be a game-changer, throwing a production curveball.

"It's such a fascinating project. From the technical point of view it's rich," Daniel Johnston, president of upstream oil and gas consultancy Daniel Johnston & Company Inc., said during the recently held Association of International Petroleum Negotiator's (AIPN) International Petroleum Summit.

The Kashagan oil field in the Caspian Sea features artificial islands. (Source: Eni)

Located in the northern Caspian Sea offshore Kazakhstan, the shallow-water Kashagan Field has some of the highest pressures in the world along with high sour gas content—which is mostly reinjected—and what Johnston described as one of the world's most sensitive ecological environments.

The Kashagan reservoir is about 4,200 m (13,780 ft) below the seabed and has a high pressure of about 11,168 psi, according to operator North Caspian Operating Co. (NCOC). The field's offshore facilities are located on artificial islands, considering logistical challenges posed by thick ice during parts of the year. NCOC and partners—Eni, KazMunayGas, Royal Dutch Shell, Total, ExxonMobil, CNPC and Inpex—restarted production in late 2016 after overcoming a myriad of challenges that included leaks and ballooning costs that rose to about $50 billion.

However, "Kashagan is on the verge of finally, potentially meeting some of its promises of the past," Johnston said. "In the next couple of years it could easily be producing over a million barrels per day or more than it's producing now."

By year-end 2017, Kashagan production is set to increase to about 370,000.

The multiphase development is part of an effort to develop between 7 billion barrels (Bbbl) and 9 Bbbl of reserves from the Kashagan, Kashagan Southwest, Kalamkas, Aktote and Kairan fields.

With transportation infrastructure in place, Johnston said Kashagan could reach up to about 1.8 MMbbl/d without much trouble.

But he questioned what impact an extra million or so barrels of oil per day could have on the market within the next three years.

"Kashagan on its own could be a global game-changer," Fereidun Fesharaki, founder and chairman of the London-based FGE oil and gas consultancy, said in response. An increase of 1 MMbbl/d to 1.5 MMbbl/d in the next year or two could create global crash, he added.

Oil prices increased this week on hopes that OPEC members will agree to extend output cuts in an effort to improve market conditions. West Texas Intermediate crude oil was trading for nearly $51 per barrel, with Brent at $53.80/bbl, on Monday morning.

"The decision (to extend cuts) seems to be almost a done deal," Bjarne Schieldrop, chief commodities analyst at SEB Markets, said in a Reuters article. "There seems to be a very high harmony in the group."

OPEC Secretary-General Mohammad Barkindo said on May 22 that he saw a growing consensus among the group's members as well as non-OPEC producers on the duration of an extension. Saudi Arabia and Russia support extended the cuts until March 2018.

Last week, the news agency reported that Kazakhstan, which is not an OPEC member country, supported extending the oil output cut. However, the government wants to renegotiate its production ceiling, considering it plans to increase production at Kashagan.

"We must support efforts to limit output, because the balance on the market has not been restored yet," Kazakhstan Energy Minister Kanat Bozumbayev said in the article.

"(But) we will not be able to join this (extended cut) agreement automatically on the same terms, but we will discuss to what degree we can participate in it."

Kazakhstan joined the current OPEC and non-OPEC pact in November, pledging to cut its output by 20,000 barrels per day to about 1.7 million barrels per day (MMbbl/d). However, a report released by the International Energy Agency in March showed Kazakhstan's output increased to more than 1.8 MMbbl/d in February. Kazakhstan's production continued to rise in March, according to the IEA.

The country's production, however, is below that of some other non-OPEC countries that agreed to the existing pact. Russia produces just over 11 MMbbl/d.

—Velda Addison

Statoil Builds Operational Efficiency Through Investment In Technology Suppliers

OSLO, Norway—Operational efficiency is the watchword for E&P within the current low oil price scenario, and at the heart of this is innovation. That's why Statoil established Statoil Technology Invest (STI) to support small and medium enterprises with new technologies.

As a company, Statoil's annual research budget is $300 million, and half of that is managed by STI. Managing Director Kristin Aamodt manages that budget. She sat down with EPmag.com at the company's Oslo office to discuss the strategy of fostering operation efficiency and its use of suppliers.

"The industry is changing, as we all know," said Aamodt, a 14-year veteran of the oil, energy, biotech and venture industries. "It's in transformation and we need to adapt to that. Within Statoil, we've already done a very good job in cutting costs. We've saved $3.2 billion annually compared to 2014. But we need new technology and innovation to fuel the radical changes.

"This fits very well with Statoil because we have always been a technology-driven company. It's in our backbone to use technology," she continued. "In 2017, our budget for research and technology is $300 million, and our ambition is to use half of that externally in collaboration with external companies, with universities, with research institutions, to get new technology brought forward."

This is where STI come into play. As Aamodt explains, it focuses on the small- and medium-size companies because the best ideas don't always come from the big, established suppliers.

"Very often, we see great ideas coming from small startup companies, and it's hard for these small companies to become a supplier to Statoil, or to any other huge oil company," she said. "That's why you need people like us believing in the technology, believing in the entrepreneurs, and seeing the potential and helping these companies grow so they can really establish supply to Statoil."

Statoil Technology Invest Managing Director Kristin Aamodt manages to support small and medium enterprises with new technology. (Source: Statoil)

Aamodt explains that STI has three main activities. The first one is to find, invest in and build the startups.

"We find the entrepreneurs in the small companies with the really good ideas," she said. "We go in with capital and competence, and take an active part in the board. Then we spend a lot of time on implementing the technology in Statoil. And it's here we see the greatest value in what we do for Statoil as a company, getting these technologies in use for Statoil. That's where we can save a lot of money in our operations."

STI provides equity or project-based funding with varying levels of maturity divided into three phases. The LOOP program provides project funding and access to technical expertise and pilots without taking ownership,

while seed funding and venture capital both involve STI paying for an ownership stake in a company.

When the company has matured and becomes an established supplier, STI typically seeks to sell out and maintain the position as a technology user. It will continue using the technology, but the supplier will be treated like any other supplier Statoil uses in its operations.

The targets are innovative, high-impact, upstream technology companies. A recent success was Sekal, an advanced software tool for monitoring and trend analysis during drilling operations. It creates a dynamic, real-time picture of the entire wellbore with changes between the model and reality visualized as trends graphs. This helps drilling analysts and engineers to optimize operational performance and to proactively avoid problems in the borehole.

Another recent partner was Raptor Oil, which used proven proprietary signal processing technology to deliver an intelligent bidirectional wireless communication system with low latency and high data rate transmission capabilities to deliver high-value data into and out of the wellbore.

Fishbones is another example. "This is a unique stimulation technology for low-producing wells," Aamodt said. "The technology is hundreds of needles that go out from the main wellbore and stimulate production. By using this technology, you can stimulate low-producing or non-producing wells to produce better. This has been proven in various sites around the world. We see some wells that were not producing that started producing with this technology.

"Then we have Eelume, a disruptive technology for subsea inspection and light interventions. A snake robot, as we call it. Instead of going down to a subsea well with a costly ROV, you can do an inspection and light repairs with the snake. In our operations, half the vessel bases we use are typically easy, light jobs so that you can respond quicker, reduce downtime, do it more cost efficiently. It gives much more flexibility when you look at building new subsea solutions that you have this flexible snake."

Aamodt explained that not all investments go this well. "Overall, that's kind of our ambition--to provide solid implementation value and, at the same time, provide solid financial return. We have a very good financial return history on our portfolio. We're pretty happy for this troubling time that we're in right now. Over the years, we have proven to provide some really good financial returns on the capital employed, as well."

—Mark Venables

BUSINESS BRIEFS

Halliburton CEO Dave Lesar To Retire, Be Replaced By Jeff Miller

Dave Lesar

Halliburton Co. said May 17 that CEO Dave Lesar will retire on June 1 and be replaced by Jeff Miller, Lesar's longtime deputy and fellow board member.

Lesar will stay on as executive chairman until December 2018 when he reaches the company's mandatory retirement age of 65. The transition, which was expected, comes as Halliburton tries to recover from a two-year oil price downturn that has eroded profit margins and forced the company to lay off thousands of workers.

Lesar, who became CEO after predecessor Dick Cheney was nominated to be U.S. vice president in 2000, will step back from day-to-day company management but still be involved in talks with customers and shareholders. He signed a new employment contract with the company through the end of 2018 that will prohibit him from working for peers for another four-year period.

Miller joined Halliburton in 1997. Like Lesar, he is an accountant by training. He assumes the top role after Halliburton lost its long-time CFO, Mark McCollum, who left in March to become CEO at Weatherford International Plc.

Anadarko Makes Leadership Changes

Anadarko Petroleum Corp.'s board of directors has named Daniel E. Brown executive vice president of international and deepwater operations and Bradley J. Holly executive vice president of U.S. onshore E&P, the company said in a news release.

Darrell E. Hollek, formerly executive vice president of operations, will serve as a senior adviser until his retirement later this year.

Brown, who began his career with Anadarko in 1998, most recently served as senior vice president of international and deepwater operations—a position he's held since August 2016. Holly, who most recently served as Anadarko's senior vice president of U.S. onshore E&P, began his career in 1994 with Amoco and joined Anadarko in 1997, according to the release.

US Names Scott Angelle New BSEE Director

Former Louisiana state official Scott A. Angelle has been tapped to lead the U.S. Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE), according to a news release.

Angelle, who most recently served as vice chairman of the Louisiana Public Service Commission, has held

numerous positions in Louisiana and parish governments, including interim lieutenant governor, secretary of the Louisiana Department of Natural Resources and St. Martin Parish president.

In the aftermath of the BP oil spill, Angelle served at the request of then Louisiana Gov. Bobby Jindal as liaison to the federal government and negotiated an early end of the previous administration's drilling moratorium.

Under his leadership as Louisiana's secretary of the Department of Natural Resources, a position he held for eight years, the state's coastal permitting system was reformed. BSEE said the reform provided for efficient permitting while increasing drilling rig counts in Louisiana by more than 150% during his tenure.

Wild Well Purchases Equipment, Expands Subsea Presence

Wild Well Control has purchased subsea capping equipment from Shell EP Wells Equipment Services B.V., a move that expands the company's global presence, according to a news release.

"The addition of this inventory enhances Wild Well's current global equipment and response capabilities for the WellCONTAINED subsea containment systems and provides added capabilities for its 7Series Subsea Well Intervention group," Wild Well Control said. "The newly purchased equipment will be staged strategically in Houston, Aberdeen, Singapore and elsewhere, as needed, for global deployment."

The company's current WellCONTAINED inventory is located in Aberdeen and Singapore. The equipment includes subsea well intervention systems, including subsea capping stacks, debris removal shears, hardware kits for the subsea application of dispersant and inhibition fluids, and other ancillary equipment, the release said.

DONG Plans To Sell Oil, Gas Business To Ineos For $1.3 Billion

Danish utility and offshore wind farm developer DONG Energy has agreed to sell its oil and gas business to petrochemicals firm Ineos for $1.3 billion, it said on May 24, the latest in a string of North Sea deals.

The sale is a blow to shipping group A.P. Moller-Maersk, which had sought to merge its oil and gas business with DONG into a company worth more than $10 billion as part of a major restructuring.

Talks between the two stalled late last year over price, sources told Reuters in December, and Maersk CEO Soren Skou said in January he saw a listing of the energy unit as the more likely option.

For DONG Energy, the world's biggest operator of offshore wind power, the sale marks a step away from fossil fuels as it seeks to focus solely on offshore wind.

Cobalt Files For Arbitration Against Angola For $2 Billion

Cobalt International Energy Inc. said it had filed requests for arbitration seeking more than $2 billion from Angola's state-run Sonangol after the two failed to reach an agreement on license deadline extensions on two deepwater blocks, company filings showed.

Cobalt said it was requesting an award against Sonangol in excess of $2 billion, plus applicable interest and costs. It filed a separate request for arbitration against Sonangol seeking more than $174 million, plus applicable interest and costs, for the joint interest receivable for operations on Block 21 offshore Angola.

Sonangol did not return a request for comment.

Cobalt said its yearslong efforts to find a buyer for its 40% stakes in blocks 20 and 21 offshore Angola were "negatively impacted by the uncertainty surrounding the extension."

A deal to sell the licenses to Sonangol in a $1.75 billion deal collapsed in 2016 because required approvals from the Angolan government did not come in time.

While Cobalt owns 40% of the blocks and Sonangol has 30%, the Angolan state company holds the rights to extend exploration deadlines for production sharing agreements.

Israeli Energy Firms Delek Drilling, Avner Oil Complete Merger

Israel's Delek Drilling LP and Avner Oil Exploration LP, both units of conglomerate Delek Group Ltd., said they have completed a long-awaited merger and will begin trading next week as one company.

The new entity will keep the name Delek Drilling and will have a market value in Tel Aviv of about $4.4 billion.

It is through Delek Drilling and Avner Oil that Delek Group owns major stakes in the large Israeli offshore natural gas fields Tamar, which began production in 2013, and Leviathan, which is due to come online in late 2019.

Delek Drilling also said in a statement that exports from Tamar to Jordan's Arab Potash Co. and Jordan Bromine plants began in January.

CEO Yossi Abu said he expects production at Tamar this year, "to cross the 10 billion cubic meter mark."

The companies' combined net profit in the first quarter was $78.9 million, up 23% from a year earlier.

Seadrill Names Anton Dibowitz CEO

Anton Dibowitz has been appointed to succeed Per Wullf as CEO of Seadrill Ltd., effective July 1, the company said in a news release.

The change is part of a succession planning process that was implemented during 2016.

Currently, Dibowitz serves as chief commercial officer and executive vice president for Seadrill.

"Anton has a strong industry track record and has taken roles of increasing responsibility during his 10 years at Seadrill, including the day to day business administration at Seadrill since 2016," John Fredriksen, chairman of Seadrill's board, said in the release. "We are confident that this succession plan provides Seadrill with the right combination of continuity and stability as the

company works to complete its financial restructuring aimed at building a bridge to a recovery and achieving a sustainable capital structure."

Wullf will remain a director for Seadrill, which Fredriksen said will allow the company to continue benefiting from his "in-depth industry experience, fleet knowledge and strong relationships."

Petrobras Sees Higher Oil Exports As Presalt Fields Develop

Petrobras expects higher oil exports this year than initial projections, Guilherme França, executive manager of trade and marketing, said May 24.

Petrobras expects oil exports to reach 742,000 bbl/d by 2021 as the company advances development of its presalt oil reserves, which are capable of producing lighter varieties which are demanded internationally, França said.

In March, França told Reuters in an interview that the company's oil exports would reach 450,000 bbl/d this year. That estimate has now been revised to 503,000 bbl/d, according to the executive.

China is the company's main client, accounting for 56% of Petrobras's exports in the first quarter.

ACE Winches, Scantrol Provide Subsea Deployment System For Saipem

ACE Winches has engineered and delivered a back deck system to Saipem.

ACE Winches and Scantrol provided a combined active heave compensation solution for Saipem. (Source: ACE Winches)

Within a 3½-week deadline, ACE Winches worked with Scantrol to supply an active heave compensation winch and A-frame solution that will be used as an auxiliary deepwater deployment system for subsea equipment, a news release said.

The deck machinery equipment was engineered and manufactured at ACE Winches facilities in Aberdeenshire, Scotland.

—Staff & Reuters Reports

UPCOMING

The next issue of *Subsea Engineering News* will be distributed June 8. Until then, visit *epmag.com*.

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