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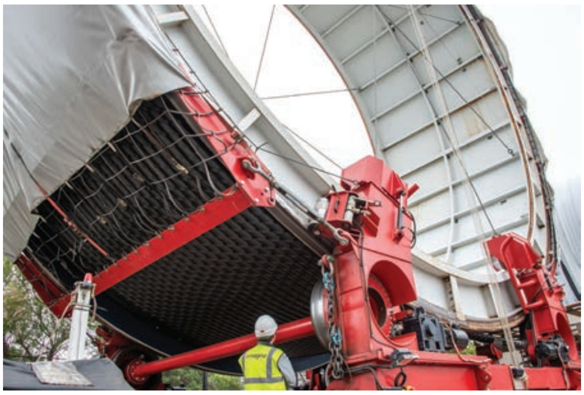
Woodside Targets Pipeline Cost Reduction

Woodside has set a goal to halve the manufacturing and installation cost of its future pipeline portfolio as it eyes longer subsea tiebacks to tap remote and deep offshore oil and gas fields.

The Australian oil and gas producer has good reason to target pipeline costs. Woodside has some 1,600 km (994 miles) of pipeline to lay as part of potential future projects over the next eight to 12 years. Some 80% of that new pipeline will be for gas projects and will need to be more than 24 in. in diameter and longer than 50 km (31 miles), Martin Davies, subsea pipeline technology lead at Woodside Energy told the Underwater Technology Conference attendees in Bergen, Norway, earlier this year.



Magma Global's 6-in. m-pipe spooled and read to ship. Could larger diameter composite pipe be used for export pipeline? (Source: Magma Global)

Woodside is not alone. Long-distance subsea tiebacks are increasingly under focus as an economical way to unlock remote, deepwater offshore oil and gas fields, because it means existing surface infrastructure can be used.

Woodside is no stranger to subsea tiebacks. It's due to bring the Greater Enfield development online next year. Greater Enfield is a 12-well, 31-km (19-mile) oil field tieback to the Ngujima-Yin floating production vessel, which is moored, 43 km (26 miles) offshore Australia. While it's not the world's longest tieback, it's currently Woodside's longest. That's not likely to last very long, however, as the firm has its sight on more and longer tiebacks—up to 150 km (93 miles) for oil and up to 300 km (186 miles) for gas, in fact, Davies said.

"We see similar needs in other regions," he said. "So how do we make this work? While there's been much focus on introducing all-electric systems to reduce the burden of umbilicals; subsea processing technologies, such as compression and boosting, and flow assurance challenges, more attention should be paid to reducing the cost of the pipelines that transport oil and gas to process facilities."

Pipeline manufacturing and installation amounts to about a quarter of a typical tieback cost, Davies said. "And for a typical offshore pipeline, 20% to 30% of the cost is materials, 40% to 50% is installation," he said. But he added: "A lot of what we have done [in pipelines] hasn't changed much. In the past 30 years, the automotive industry has changed a lot, for example, but nothing has changed greatly on a pipelay barge. We believe there are significant cost savings to be had. We have set a target to half the cost of our future pipeline portfolio."

Woodside has launched its pipeline cost reduction mission through a series of internal workshops and by looking at disruptive technologies, such as composite pipeline for medium-size pipelines, a digital pipeline design concept, and one-shot welding techniques, for long pipelines.

WHAT'S INSIDE

For medium-sized pipelines, using composite pipeline could reduce installed costs by 30%, according to vendors, Davies said.

"Products like this are already being supplied for jumpers and small flowlines, so why not larger pipelines?" he asked. "There is no need for welding or a firing line, and there is much less weight in the catenary. Fewer people are needed offshore, and you could use a smaller installation vessel."

Alternative design processes also have scope to reduce costs. Digital pipeline design "has the ability to bring a step change in design," Davies said. The idea is to use Big Data and then compute different scenarios—more than a human can do—to aid efficiency and optimization.

"We are working with suppliers to create a digital design basis database, centralizing all the input data we need in the cloud, and which can be accessed by a range of design modules," Davies said. "We have found in test cases that we can run hundreds and thousands of scenarios, which in traditional methods would be limited to a few dozen. This frees up engineers to use their intelligence to get more out of these scenarios. We believe this will give them the opportunity to focus on optimization that they couldn't find time to do before."

In a trial run of this concept, a gas trunk line routing and design project took two and a quarter engineers just seven weeks, significantly reducing the length of the process and its cost compared to the traditional approach. The design created also shaved 30 km (18 miles) off the length of pipeline that was thought would be needed. Taken over an entire pipeline project duration, Woodside believes that design costs could be reduced by as much as 80% and design duration by 20%.

Automating the pipelay process could also reduce costs significantly. Multipass welding is currently used, which typically takes 10 minutes a joint for carbon steel and 20 to 30 minutes for corrosion-resistant alloy, Davies said.

"This puts it on the critical path. What if we could do it in 1 to 2 minutes?" he said. "One-pass welding using electron beams or laser welding is already being used in other industries. It could reduce pipelay times by 80%. That's interesting."

He added that there is already work in progress that could see this technique available offshore in two to three years.

Davies thinks there are other areas that could be addressed, for example, eliminating offshore hydrotesting, which adds to cost and increases schedules, for low cost pipelines. Connectors could also be used instead of welding, in conjunction with modular pipelay.

"The way we do our pipelines has scope for massive change," he concluded. "The way we do it now is ripe for disruption. We need to make some changes."

—Elaine Maslin

DEVELOPMENT

Pertamina Hulu Toils To Manage Mahakam

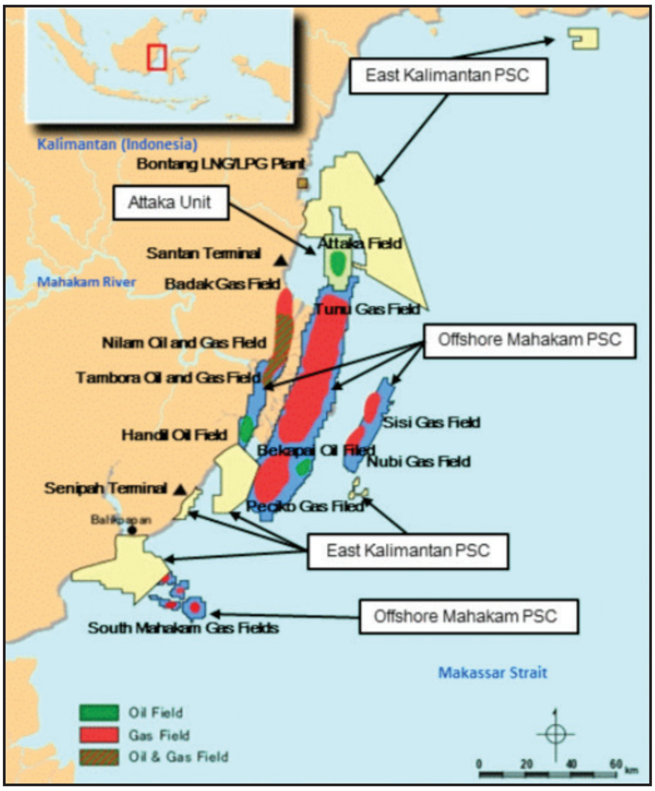
PT Pertamina Hulu Mahakam (PHM), a subsidiary of Indonesia's state-run Pertamina, is struggling to maintain production from aging oil and gas fields in the Mahakam Block, off Makassar Strait, just months after it acquired operatorship from Total.

The Indonesian company has drilled only 18 new development wells of this year's target of 69 by the end of July and shut down some of the new wells before reaching the targeted depth due to the technical problems.

Pertamina Upstream Director Syamsu Alam admitted that the PHM had faced obstacles in drilling the new development wells. "Some wells had to be turned off because of safety problems," the director said during a media briefing.

The official did not disclose the details of the obstacles but maintained the company is making efforts to address the problems.

Industry analysts, however, have raised doubts over the PHM's technical and financial ability to develop new wells and revive production from the aging Mahakam asset, which is known to be a complex geophysical zone for hydrocarbons.



The Mahakam Block is located offshore Indonesia in the Makassar Strait. (Source: Inpex)

Falling Production

The obstacles have affected oil and gas production from the Mahakam concession, the largest gas producer in Indonesia. Oil and gas fields in Mahakam, according to the upstream regulator SKK Migas, pumped an average of 46,376 bbl/d of oil and 916 MMscf/d of gas from January to June, down from the average production of 52,000 bbl/d and 1,360 MMscf/d during the same period in 2017.

After acquiring operatorship from Total in January, PHM launched a $1.7-billion plan to develop new wells and rework old wells to revive the production from the aging seven oil and gas fields—Handil, Bekapai, Tambora, Nubi, Tunu, Sisi and Peciko—in the Maharam Block.

The development plan involves drilling 69 development wells, reworking 132 wells and conducting maintenance on 5,601wells in the fields in 2018. The company targeted production of 1,100 MMscf/d of gas and 48,000 bbl/d of oil from Mahakam this year. The plan aimed to maintain the bulk of gas supplies to the Bontang LNG plant with a capacity of 22.5 million tonnes per annum in East Kalimantan.

Strategic Partner

The Indonesian company is looking to re-engage a strategic partner to revive production from the block, considering the geophysical complexities of the aging oil and gas fields in the concession.

Alam said four international companies have shown interest in managing the block. These companies include Inpex Corp. and United Arab Emirates-based Mubadala Petroleum.

Energy and Mineral Resources Minister Ignasius Jonan has advised Pertamina to enter a partnership with the former operator, Total, to gain development expertise used in the fields over the last 10 years.

During the operatorship, Total, along with partner Inpex Corp., drilled more than 2,000 wells in the concession with various type of wells based on function, architecture, completion type, lifting mechanism and wellhead-tree technology to maintain production levels since Bekapai Field was discovered in 1974.

Total adopted different methods—on a field basis—to tackle challenges encountered in the concession. Production from the Tunu Field, according to the operator, was revived through lowering network pressure, using lighter well architecture and lowering well spacing to reaccess disconnected reservoirs. The Handil and Bekapai fields were reactivated through measures like pressure maintenance and intensive drilling.

PHM President Director Bambang Manumayoso said that in the absence of any revival efforts, oil and gas production from the Mahakam fields could drop drastically in the coming months.

The Mahakam concession is estimated to contain proven reserves of 139 Bcm (4.9 Tcf) of gas, 57 MMbbl of oil and 45 MMbbl of condensate as Jan. 1, 2016.

—Ravi Prasad

Nexen: Buzzard Phase II In North Sea Moves Into Execution Mode

The second phase of the Buzzard development in the North Sea has been fully sanctioned by partners Suncor Energy UK Ltd., Chrysaor Ltd., Dyas EOG Ltd. and Oranje-Nassau Energie Resources Ltd., according to Nexen, a CNOOC. Ltd. Co.

Nexen, operator of the Buzzard platform, announced the news Aug. 6. With the investment, FEED work finished and field development plan approved by the UK Oil and Gas Authority, the project moves into execution mode.

Plans are for the subsea development to tie back to the existing Buzzard complex with a pipeline bundle assembly incorporating pipelines, manifolds, subsea controls and chemical injection, Nexen said in a news release. The development includes a 12-slot manifold comprised of eight production slots and four water injectors. A brownfield module will be installed on the production platform for processing and export via current export pipeline routes.

"The objective of this project is to safely develop additional reserves and bring new production on stream, supporting the goal of maximizing economic recovery in the North Sea," Nexen said in the release. Work is focused on developing the field's northern section.

First oil is scheduled for first-quarter 2021.

Several companies have already landed contracts for the project, working based on "an incentivized, outcome-based commercial model." Supply chain partners are AGR Well Management Ltd.; Baker Hughes, a GE company (BHGE); COSL Drilling Europe AS; Subsea 7 Ltd. and WorleyParsons Services UK Ltd.

In a separate statement, BHGE said it will supply oilfield equipment, which includes six medium-water horizontal subsea trees, wellheads and subsea and topside control systems along with integrated drilling, evaluation completions and intervention services.

Nexen selected Subsea 7 for project management, engineering, procurement, construction and installation of a 5-km (3-mile) pipeline bundle along with associated well and platform tie-ins, and provision of a heavy-lift vessel for transport and installation of a new topside module.

Project management and detailed engineering has commenced at Subsea 7's office in Aberdeen, Subsea 7 said. The pipeline bundle will be fabricated at Subsea 7's Wester site near Wick, with technical support from Subsea 7's specialist pipeline group in Glasgow. Project management and engineering for the heavy-lift work scope will be conducted from Seaway Heavy Lifting's office in Zoetermeer in the Netherlands. Offshore activities will mainly take place in 2020.

—Staff Reports

DEVELOPMENT BRIEFS

Shell Awards GoM Contract To McDermott

McDermott International Inc. said Aug. 7 it has been awarded a contract from Shell Exploration and Production Co. Inc., a subsidiary of Royal Dutch Shell Plc, for subsea umbilical and flowline installation at the Perdido development in the U.S. Gulf of Mexico (GoM).

The scope of work includes project management of engineering and installation of a flexible flowline from the well to a pipeline end termination; installation of an umbilical; installation of four electrical flying leads and pre-commissioning. Project management and engineering will be performed in Houston, Texas, with offshore installation by McDermott's North Ocean 102 targeted for completion in 2019.

The Perdido development is Shell's pioneering deepwater oil and gas project that unlocked a new frontier of energy development in the Lower Tertiary Paleogene. The Perdido production hub produces oil and gas from the Silvertip, Great White and Tobago fields. Shell is focused on safely and competitively growing production from Perdido by optimizing the performance of existing wells and through targeted of additional infield and near-field development opportunities.

The contract award is reflected in McDermott's second-quarter 2018 backlog.

BP, Kosmos Push Toward Tortue FID

BP and partner Kosmos Energy expect to reach a final investment decision (FID) on the Tortue Phase 1 development offshore Mauritania and Senegal in fourth-quarter 2018, the companies said.

The field is estimated to hold more than 425 Bcm (15 Tcf) of recoverable gas.

BP, the operator, has already awarded FEED contracts for the project and the gas marketing process has begun, Kosmos Energy CEO Andrew Inglis said Aug. 6. Bids have been received by several parties, including two supermajors and an international commodity trading house, he added.

"Importantly, the bids include financial offers for the NOCs, which means financing for partners should not impact timing of FID," Inglis told analysts on a call. "The remaining item ahead of FID is the harmonization of any non-PSA [production-sharing agreement] fiscal terms. With the ICA [Inter-Government Cooperation Agreement] signed earlier this year these discussions are taking place and progressing well."

Located on the border between Mauritania and Senegal, the Tortue/Ahmeyim gas field is located in the C-8 Block offshore Mauritania and the Saint-Louis Profond Block offshore Senegal. Development plans call for use of an FPSO.

Partners, which also include Société Mauritanienne Des Hydrocarbures et de Patrimoine Minier and Société des Pétroles du Senegal, are targeting late 2021 for first gas.

Eni To Invest $1.8 Billion In Offshore Mexican Oil Fields By 2040

Eni expects to invest $1.795 billion in three offshore Mexican oil fields by 2040, according to a development plan approved by Mexico's oil regulator July 31.

The plan covering the Amoca, Mizton and Tecoalli shallow-water fields is the second one approved by the regulator, known as the National Hydrocarbons Commission (CNH), following a landmark 2013 energy opening.

Eni sees initial crude oil production of 8,000 bbl/d in early 2019 from its Amoca and Mizton fields and will be ramping up to 90,000 bbl/d by 2022, according to the CNH. Initial production at the Tecoalli Field is seen beginning in 2024. The development plan forecasts 32 wells, four platforms, a gas pipeline connecting to the coast of southern Tabasco state as well as the acquisition of an FPSO. The FPSO will be based in the Mizton Field and will be used to separate and store oil and gas, and ultimately fill arriving tankers with crude.

A final investment decision is expected in fourth-quarter 2018.

Through fourth-quarter 2020, state-run oil company Pemex will market the project's crude oil output but after that Eni will have the option of selling its crude directly from the FPSO.

Through year-end 2018, Eni plans to invest $232 million as part of its work program for the project, while the total value of the project is estimated at about $7.3 billion. The total government take from the project, the sum of the project's applicable tax and royalty payments to the state, is estimated at $12.7 billion, or about 92% of the estimated value of the oil and gas produced over the lifetime of the 25-year contract.

Anadarko Continues Development Work In GoM

Anadarko Petroleum Corp. continues to move forward with several developments underway in the U.S. Gulf of Mexico (GoM).

Drilling operations for the Marlin facility, which is located in the Dorado Field in the Mississippi Canyon area, are finished and first production from the tieback well is set for third-quarter 2018, the company said in its latest operations report.

Marlin, which was among the assets Anadarko acquired from Freeport-McMoRan in 2016, is a subsea tieback development.

In the Green Canyon area, completion operations continue at the Holstein development and well operations are complete for the eighth well at the Caesar/Tonga development. First production for both projects is expected in the third quarter.

BP-led Clair Ridge Field Moves Closer To Production In North Sea

BP and partners are moving closer to marking first oil from the Clair Ridge development west of Shetland in the North Sea, where they are targeting some 640 MMbbl of recoverable resources.

Clair Ridge is the second development on the Clair Field, which was discovered more than 40 years ago and brought online in 2005. (Source: BP)

"We expect startup before the end of the year and we're about 97% complete on the Clair Ridge project," BP Group Chief Executive Bob Dudley told analysts July 31 following the release of the company's second-quarter 2018 earnings.

The development, which includes two new bridge-linked platforms, has been designed to produce until 2050 with a peak production capacity of 120,000 bbl/d. It is the second development on the Clair Field, which was discovered more than 40 years ago and brought online in 2005. BP has said a third phase of the development is possible as appraisal drilling in the field continues.

"Clair has more than 7 billion barrels of oil initially in place and has significant value associated with future development opportunities, including the Clair Ridge project currently under development," Dudley said.

In related news, accommodation vessel owner and operator Prosafe said Aug. 6 that BP exercised its one-month extension option for the *Safe Caledonia* vessel for $2.4 million. The operational period now runs through November.

BP serves as operator of the field and earlier this month increased its stake to 45.1% after an acreage swap with partner ConocoPhillips (7.5%). Royal Dutch Shell and Chevron are also partners.

Clair Ridge is among the six major projects BP has on tap this year as the company works toward adding 800,000 boe/d of new production by the end of the decade. Other major projects for 2018 include Constellation in the U.S. Gulf of Mexico's Green Canyon area, the West Nile Delta—Giza/Fayoum deepwater gas project offshore Egypt in the Mediterranean.

The company produced 3.6 MMboe/d in the second quarter, up 1.4% compared to a year ago.

McDermott Wins EPCI Subsea Tieback Contract For Ayatsil Offshore Mexico

Pemex has awarded McDermott International Inc. a contract for subsea pipeline flowline installation in support of its Ayatsil heavy crude oil field in the Bay of Campeche offshore Mexico, according to a news release.

McDermott said the scope of work includes design and detailed engineering, procurement, construction and installation (EPCI) of two subsea pipelines. The first line is a 24-in. diameter, 3.2-km (1.9-mile) long natural gas pipeline that will connect the PP-Ayatsil-C and PP-Ayatsil-A platforms. The second is an 8-in. diameter gas pipeline, which is about 1.5 km (.9 mile) in length, connecting to the PP-Ayatsil-C platform.

McDermott's operating center in Mexico City will perform project management and engineering. Offshore installation is scheduled to be completed in early 2019, McDermott said in the news release.

The contract, which is reflected in McDermott's second-quarter 2018 backlog, is valued at between US$1 million and $50 million.

Hurricane Installs Lancaster Field's Turret Mooring System

Hurricane Energy reached a milestone for the Lancaster Field development on the U.K. Continental Shelf when it completed installation of the turret mooring system.

The company said on Aug. 2 that the system along with the new buoy for the *Aoka Mizu* FPSO were installed successfully using the *Normand Installer* offshore construction vessel among other vessels.

Next up is installation of subsea umbilical, risers and flowlines (SURF) for the early production system, the development's first phase.

"SURF is the last phase of the offshore installation program in preparation for the arrival of the *Aoka Mizu* FPSO at the Lancaster Field," Hurricane said in a news release. "The buoy will now sit submerged below the surface, held in place by 12 mooring lines connected to piles, until the FPSO's arrival."

The field is being developed as a two-well tieback to the *Aoka Mizu* FPSO. First oil is planned for first-half 2019 with an IP rate of 17,000 bbl/d.

Shell To Make Final Investment Call On Nigeria Oil Field In 2019

Royal Dutch Shell and its partners will decide next year on whether to go ahead with the development of Nigeria's Bonga Southwest offshore oil field, a senior company official said July 31.

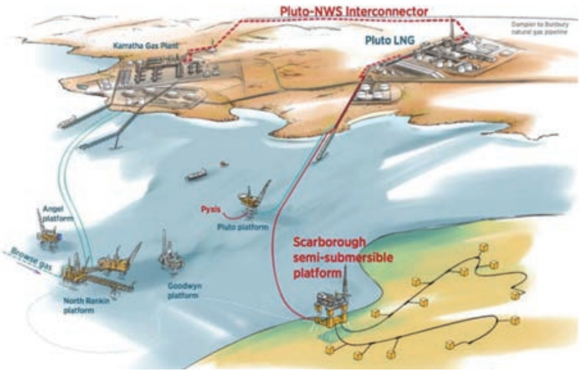
The project, one of the country's largest with an expected production of 180,000 bbl/d, will generate profit at below $50 per barrel, Bayo Ojuli, managing director of Shell Nigeria Exploration and Production Co., told reporters.

Shell is negotiating a production sharing contract with the Nigerian government, which will determine the viability of the project, he said. The negotiations are expected to finish this year.

Shell operates the project and ExxonMobil, Total, Eni and the Nigerian National Petroleum Co. are partners.

SEA Wins Contract For Scarborough Export Trunk Line

Woodside Energy Ltd. has awarded Subsea Engineering Associates Pty Ltd. (SEA) the contract for define phase engineering services for the Scarborough development export trunkline, SEA said in a news release.



Located in the Carnarvon Basin, Scarborough resources will be developed with 12 subsea gas wells tied back to a semisubmersible platform. (Source: SEA)

SEA said the award allows it to use the ICE platform, described as a cloud-based intelligent computation, engineering and data platform for subsea systems, for the "rapid delivery of engineering and a mature digital basis of design to be carried into FEED." The company added it has subcontracted INTECSEA to provide specialized deepwater experience

The project includes a 430-km (267-mile) diameter export trunk line that will run from the deepwater facility in field to the Woodside-operated infrastructure on the Burrup Peninsula, SEA said in the release. The Scarborough Field is located offshore Western Australia.

Inpex's Ichthys LNG Produces First Gas Offshore Australia

Inpex Corp. said on July 30 it has begun producing gas at its giant Ichthys Field offshore northern Australia, putting it a big step closer toward shipping its first LNG cargo from the long-delayed $40 billion project.

Startup of gas production is a major milestone for the project, Japan's biggest overseas investment and first major energy development to be operated by the country's top oil and gas producer.

Inpex said it now expects to start exporting products by the end of September, with condensate to be shipped first, then LNG and liquefied petroleum gas (LPG), nearly two years later than its initial target.

"The project expects to begin the shipment of products towards the end of the first half of the current fiscal year," Inpex said in a statement. The first half ends in September.

The project is expected to take two or three years to reach its full capacity of 8.9 million tonnes of LNG a year, along with about 1.7 million tonnes of LPG and about 100,000 bbl/d of condensate, an ultralight form of crude oil.

Inpex said it was reviewing expected revenue contributions from the Ichthys project for the year to March 2019, taking into account the oil price outlook and other factors, and would inform the market if its forecasts are revised.

Inpex owns just over 62% of Ichthys LNG, with France's Total SA holding 30%. The remainder is owned by Taiwan's CPC Corp. and Japanese utilities.

Total Starts Production At Kaombo Project Offshore Angola

French energy group Total said on July 27 that it had started production at the Kaombo project, which is currently the biggest, deep offshore development in Angola.

The *Kaombo Norte* FPSO was successfully brought onstream and will produce an estimated 115,000 barrels of oil per day, while the second one—*Kaombo Sul*— is set to start up next year, Total said.

The overall production will reach an estimated 230,000 barrels of oil per day at peak and the associated gas will be exported to the Angola LNG plant.

"The Kaombo startup is a great milestone for Total. Developing the estimated 650 million barrels of reserves will contribute to the group's growing production and cash flow in Africa," said Arnaud Breuillac, president of E&P for Total.

Alongside Total, other companies that have invested in Kaombo's Block 32 are Sonangol, Esso and Galp Energia.

Equinor Reaches Agreement For $8.3 Billion Bay du Nord Project

Newfoundland and Labrador's foray into deepwater production scene took a step forward July 26 when the government signed a framework agreement for the Equinor Canada-led US$8.3 billion Bay du Nord oil project.

A final investment decision for the Flemish Pass Basin development is expected in 2020. (Source: Hart Energy/Shutterstock.com)

Discovered in 2013, the basin-opening development is said to hold some 300 MMbbl of oil reserves in Flemish Pass offshore Newfoundland in the Atlantic Ocean. The volumes include the Bay de Verde and Baccalieu discoveries announced in 2016.

"This framework agreement provides important clarity and stability as Equinor and our partner Husky Energy work to move this project toward a sanction decision in the coming years," Unni Fjaer, vice president, offshore Newfoundland, Equinor Canada, said in a statement announcing the agreement. "We also welcome our new equity partner, the province's energy company, to the project."

The province's energy company would get a 10% equity stake. Equinor currently holds a 65% stake with partner Husky holding 35%.

Equinor has described the geology of the Flemish Pass Basin as "very encouraging," pointing out its Jurassic reservoirs with high porosity, high permeability and mature source rocks. The company, formerly known as Statoil, said the basin's geology is similar to that of the Norwegian Continental Shelf.

A final investment decision on the development is expected in 2020. If sanctioned, first oil would flow in 2025.

At 1,170 m (3,839 ft) deep, Bay du Nord's resources would be produced via an FPSO. The development also calls for offshore construction, installation, hook-up and commission, drilling, production operations, maintenance and decommissioning activities plus surveys, field work, supply and servicing activities; however, no land-based activities are included, according to Equinor.

TechnipFMC Bags Subsea Contract In Australia

TechnipFMC has been awarded a subsea installation contract by Chevron Australia, for the Gorgon Stage Two development, located offshore Western Australia in water depths ranging from 250 m (820 ft) to 1,340 m (4,396 ft), the company said on July 26.

The contract covers the project management and engineering, transportation, installation and pre-commissioning of umbilicals and flying leads as well as manifolds. The award also includes fabrication, transportation, installation and testing of rigid spools.

TechnipFMC will leverage local capabilities as well as its global state-of-the-art pipelay fleet for the offshore campaign.

The Gorgon project is operated by Chevron Australia and is a joint venture of the Australian subsidiaries of Chevron (46.3%), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and JERA (0.417%). The Phase 2 development aims to upgrade the project's existing subsea facilities to ensure production is maintained for future gas supply.

—Staff & Reuters Reports

EXPLORATION

Exploration Steps Up Offshore Suriname

The Guyana-Suriname Basin has an estimated resource potential of more than 13 Bbbl of oil, according to the U.S. Geological Survey. (Source: Shutterstock.com)

Oil and gas companies hoping to create their own exploration success stories, following Exxon Mobil Corp. and partners' impressive string of discoveries offshore Guyana, are progressing drilling plans offshore neighboring Suriname.

Working with partners Chevron Corp. and Hess Corp., Kosmos Energy Ltd. on Aug. 6 said it plans to begin drilling operations for the Pontoenoe-1 well offshore Suriname in mid-August. Drilling is expected to last about 60 days.

"Pontoenoe is the first of up to three independent prospects in Block 42 and is a similar play type to the Turbot and Longtail discoveries located about 70 km (43 miles) to the west in Guyana," Kosmos Energy CEO Andy Inglis said on a call with analysts.

Both Turbot and Longtail were discovered by Exxon Mobil southeast of the Liza Field. Combined, the fields—located in the Stabroek Block offshore Guyana—have estimated recoverable resources of more than 500 MMboe.

The Guyana-Suriname Basin has an estimated resource potential of more than 13 Bbbl of oil, according to the U.S. Geological Survey, and is considered one of the world's top unexplored basins. The mainly offshore basin partially lies onshore, where state-run Staatsolie's E&P efforts have been concentrated. But Exxon Mobil's eight discoveries in Guyanese waters have piqued the interest of many oil players eager to get in on the action.

The Pontoenoe prospect is located in Block 42 offshore Suriname, which is believed to be an extension of the petroleum system offshore Guyana. Pontoenoe is a late Cretaceous Liza-type stratigraphic play, Kosmos said. When combined with two other prospects on the block—Aurora and Apetina—the three are prospective for more than 500 MMbbl of resources.

The company has said it plans to test "multibillion barrel prospectivity" spanning five independent Cretaceous plays. Exploration drilling is expected to continue from 2019 to 2021 in the area.

But Kosmos struck out with the Anapai-1A exploration well, which was drilled to test a Cretaceous structural/stratigraphic trap in Block 45. The well failed to hit hydrocarbons, Kosmos said in late June. About a month earlier the company experienced shallow borehole stability issues before reaching its target interval, which prompted it to re-spud the well.

In Block 45, Kosmos (50%) is working with Chevron (50%). In Block 42, Kosmos (33.33%) is also partnered with Chevron (33.33%) along with Hess Corp. (33.33%), which is among Exxon Mobil's partners in the Stabroek Block offshore Guyana.

These companies aren't the only ones gearing up for exploration drilling offshore Suriname. Apache Corp. is chasing the potential oil prize as well. The company has interest in two blocks—Block 58 (100%) and Block 53 (45%). Together, the blocks span about 1.4 million acres.

During Apache's latest earnings call, CEO John Christmann said the company has ordered long lead items in preparation for beginning a drilling program at Block 58, which is also on trend with recent discoveries offshore Guyana.

"We will definitely commence a program in 2019. … We got the 3-D back and we're very excited about the potential," Christmann said. "We're on trend with the success that's happened across the water boundary in Guyana."

The exploration efforts could have a big impact for Apache, he added.

In July, Tullow Oil Plc also named Suriname as one of the areas including in its 2019 exploration drilling program. The company has identified the Goliathberg prospect in Block 47 as a candidate for drilling. Tullow failed to hit oil with the Araku-1 wildcat well offshore Suriname in 2017 but was encouraged by the recovery of gas condensate.

—Velda Addison

TECHNOLOGY

Specialized Seals For Subsea Systems

The petroleum industry's continuous move to greater offshore depths has put an increased emphasis on EOR processes to extend global oil reserves. It is a high priority for operators of these offshore wells to achieve the greatest yield.

Meeting HP/HT, safety demands

Unconventional wells—onshore or offshore—are essentially any reservoir that requires special recovery operations outside the traditional operating practices. In the past these types of offshore wells were thought to be too deep for existing technology. However, development of these wells is more frequently undertaken and the associated subsea intervention needs to be even more sophisticated than previous attempts.

Processing technology must be able to withstand high fluid pressures while subjected to HP/HT conditions. Typical subsea operating temperatures of up to 120 C-plus (248 F-plus) often increase in unconventional wells to more than 200 C-plus (392 F-plus) in deep reservoirs, while typical pressures have on occasion trebled from a previous standard of 10,000 psi to 30,000 psi.

Seals are critical elements within oil and gas systems, as they ensure that oilfield equipment is working to its optimum capacity. Sealing systems are the primary barrier to preventing any system fluid loss or system fluid contamination from external sources. This is especially true for valves and downhole drilling, completion and intervention tools.

When working in the subsea environment, the seal function becomes more significant still. Subsea seals are the principal components that prevent hydrocarbon leakage from oilfield completion or production equipment into the world's delicate oceans and as such perform a vital role in meeting environmental concerns while also ensuring workforce safety compliance. This is in addition to enhancing the performance of the tools themselves.

Controlling rapid gas decompression

Not all standard sealing solutions and materials can withstand the extreme operating temperatures and pressures of drilling in greater water depths to reach deeper into the reserves. Specialized solutions in both material and seal profile technology are required for the industry to start exploring unconventional wells.

New material and product solutions have come onto the market that focus on specific oil and gas issues such as rapid gas decompression (RGD). This phenomenon occurs when an elastomer has been subjected to high pressures for a sustained period, driving gas deep into the structure of the polymer. If the system pressure is then released relatively quickly, this trapped gas can expand significantly before it has a chance to escape from the material matrix, potentially damaging elastomer seals by ripping them apart from the inside.

Sealing systems are the primary barrier to preventing system fluid loss or contamination. (Source: Trelleborg Sealing Solutions)

Special compounds from hydrogenated nitrile butadiene rubber (HNBR) to fluoroelastomer (FKM) to tetrafluoroethylene/propylene copolymer and perfluoroelastomer are available for RGD resistance.

These newly produced elastomer materials feature low compression set characteristics. This material property is particularly relevant to EOR applications, where seals may be required to function for much longer durations than in traditional interventions, while at the same time managing HP/HT conditions. The ability of the elastomer to resist compression set and hence maintain a large degree of the latent internal sealing forces is critical in ensuring that the seal continues to function correctly across the range of energizing pressures for extended tool operating lifetimes. Specifically engineered for the offshore and subsea industry, the materials match up to the most demanding of upstream requirements and are ideally suited for challenging EOR systems.

Going beyond the requirements

While recognizing the traditional standards used in the industry, such as American Petroleum Institute 6A, International Organization for Standardization 23936 and NORSOK M710, and having a portfolio of materials that satisfy these, specific applications sometimes require materials that go beyond the standards. These are particularly prevalent when dealing with unconventional subsea wells and often require tailored materials. Applications may have, for example, exceptionally high methane content in the well or a focus on compression set properties at high temperatures for long endurance capability.

Some specialist HNBR materials, for example, exhibit exceptional low-temperature sealing performance making them suitable for use within HP/HT conditions. These materials can be ideal where equipment is stored topside in cold climates and then sent downhole, where pressures rise quickly, but the equipment temperature increase lags behind. The influence of pressure on the glass transition/cold temperature flexibility of an elastomer can have serious consequences on the performance of seals in such applications.

Furthermore, HNBR materials exhibit superior low compression set performance and high temperature sealing capability, making them eminently suitable for operating for extended lifetimes in aggressive well environments. Additionally, high mechanical strength HNBR grades provide outstanding wear and abrasion capabilities, giving excellent results for use in dynamic applications while under higher pressure and temperature conditions.

Specialist FKM materials that exhibit superior methanol resistance and optimal chemical resistance for EOR applications also have been developed. Industry standards, such as NORSOK M710, require testing to certain levels of methanol concentration and temperature for example. However, in high-methanol applications, the actual well conditions present very differently from the industry standard. For such wells, it means the materials, even though they meet standards, would not necessarily achieve performance criteria.

Meeting the most extreme conditions

Although oil and gas applications face increasingly critical challenges, the upside is that equipment manufacturers serving them are thinking out of the box—from the use of seismic imaging systems to see below the seabed to the development of subsea robots working underwater to 3,048 m (10,000 ft) depths. Sealing material developers are following suit by pushing the envelope with advanced sealing materials and profiles to handle the most extreme of temperatures, the highest of pressures and prolonged exposure to the most aggressive of fluids.

—Andrew Longdon, Trelleborg Sealing Solutions

TECHNOLOGY BRIEFS

OGTC Kicks Off 'Facility Of The Future' Project

Crondall Energy, together with the Oil & Gas Technology Centre, has joined forces with international oil and gas firms to explore whether a new reusable production buoy concept could help extend North Sea production by unlocking smaller oil and gas reservoirs.

The study will explore the feasibility of a floating normally unattended installation (NUI) as a standalone oil production facility for marginal fields in a North Sea environment and kicks off the Technology Centre's recently announced "Facility of the Future" initiative.

The multipartner study has been initiated by Crondall Energy, which developed the technology, and will be led and managed by Crondall's subsidiary, Buoyant Production Technologies Ltd.

Industry sponsors for the project include Premier Oil, Total E&P UK, Lloyd's Register, Siemens, Wärtsilä, Ampelmann and BW Offshore.

Enpro's FAM modules await subsea deployment in the in the GoM. (Source: Enpro Subsea)

LLOG Deploys Enpro Subsea FAM Technology In GoM

In June 2018, LLOG Exploration delivered first production from its Crown and Anchor Field in the Gulf of Mexico (GoM).

The milestone also represents an achievement for Aberdeen-based Enpro Subsea, as it is the first of multiple deployments by LLOG of its patented Flow Access Module (FAM) technology.

The FAM technology creates an enhanced production USB port within the jumper envelope. This enables the operator to use standard subsea christmas trees and manifolds, with the FAM providing life of field flexibility within the system design. It also delivers smart standardization and the capability to maximize the ultimate recovery from their subsea wells, according to a press release.

Enpro Subsea was awarded an engineering and procurement contract in August last year by LLOG Exploration for the delivery and installation of 12 FAMs in total, the remainder of which will be installed across multiple LLOG fields in the GoM throughout 2018.

The LLOG Flow Access Modules are initially being used to enable independently retrievable multiphase metering located within the jumper envelope between the XT and the manifold. Additionally, FAM enables a range of enhanced production options including water cut metering, flow assurance, hydraulic intervention and fluid sampling, allowing the operator to adapt the technology within the FAM to suit the needs of the reservoir.

The success with LLOG follows the adoption of the same FAM technology by an operator in West Africa earlier this year for full field development. It takes the number of wells benefiting from FAM technology globally to 38, since first introduced in 2016.

—Staff Reports

FLOATERS

Shell Lines Up Drillship As It Prepares To Begin Presalt Activities In Brazil

Royal Dutch Shell took an important step toward beginning its E&P activities in two of the presalt fields—Gato do Mato Sul and Alto Cabo Frio Oeste in the Santos Basin—the company acquired in 2017.

The British major signed a contract for the *Brava Star* drillship owned by the Brazilian company Queiroz Galvão Oil & Gas (QGOG).

The agreement, signed on July 25, established the start of operations for first-half 2019. The rig will drill four wells in the Gato do Mato Sul and Alto de Cabo Frio Oeste presalt fields. Drilling is expected to last between 260 days and 810 days. The schedule will depend on progress of the environmental licensing process conducted by Brazil's Environment Ministry (IBAMA). The license is expected to be issued by year-end.

"We were looking for a modern drilling rig ready for this great challenge. *Brava Star* can meet all technical and commercial requirements. The rig is also owned by a Brazilian company, which further increases our satisfaction," said Rodolfo Vieira, general manager of contracts and procurement for Shell Brazil. "So we are very confident as we are working with a cutting-edge drilling rig, capable of operations in depth of 3,600 m [11,811 ft] of water."

Plans are for the first well to be run in the Gato do Mato Sul presalt field. With that move, Shell would become the second oil company to lead presalt fields operations in Brazil after state-run Petrobras.

According to QGOG, which provides drilling services for onshore and offshore oil wells, *Brava Star* is a sixth-generation drillship built in Samsung Heavy Industries' shipyard in South Korea. The rig follows the Samsung 96K design and is equipped with high-tech devices that aim for maximum uptime, safer operations and minimal emissions, discharge and human interface.

Besides the *Brava Star* drillship, QGOG has several other offshore rigs. These include two semisubmersibles moored to operate in a water depth up to 1,100 m (3,609 ft), three dynamic positioning for operation in a water depth up to 2,700 m (8,858 ft) and three drillships for operation in a water depth up to 3,000 m (9,843 ft).

Brava Star is the second drillship contracted by Shell from a Brazilian company this year. In February, Shell signed a contract for wells maintenance services to be carried out by the *Santa Catarina* drilling rig owned by Petroserv. The rig will be operated in Parque das Conchas in the Campos Basin.

Important Oil Fields

Vieira told SEN that Gato do Mato and Alto de Cabo Frio Oeste are very important oilfield areas for the company's Brazilian operations. According to Brazil's oil regulator ANP these two presalt fields are located in an area that could hold up to an estimated 9 Bbbl of oil *in situ*. "They [Gato do Mato and Alto de Cabo Frio Oeste] represent a new moment with Shell returning to work in projects in such a disputed area, which is the Brazilian presalt."

Shell holds 55% of Alto de Cabo Frio Oeste presalt field in partnership with China's CNOOC (20%) and Qatar Petroleum International (25%). The consortium paid a signing bonus of $100 million for the area during the third presalt auction. The area acquired covers 1,383 million sq km. The goodwill of profit oil offered by the consortium for the area was 11.53%

As for the Gato do Mato Sul presalt field, Shell holds 80% in partnership with French oil major Total (20%). The consortium spent $33 million. The block covers 128,832 sq km. The goodwill of profit oil offered by the consortium was 22.87%.

Both presalt fields were acquired under production-sharing agreements. Under the production-sharing regime, winning companies are those that offer the state the highest profit oil, starting from a minimum percentage established in the tender protocol. Signature bonuses, also established in the tender protocol, are fixed.

—Brunno Braga

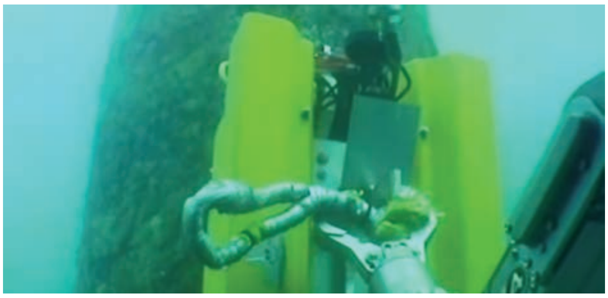
VESSEL BRIEFS

Three Partners Pursue Robotic For Inspecting FPSO Tanks

Three companies have joined to develop a robot system to inspect the cargo oil tanks of FPSOs.

Aberdeen, Scotland-based Innospection, along with Shell Brasil and Salvador, Brazil-based research institute SENAI CIMATEC have signed a partnership agreement to develop the $9 million MEC Combi Crawler Robot (MCCR) system that will be deployed externally to Shell's global fleet of FPSOs.

The robot system called MCCR (Magnetic Eddy Current [MEC] Combi Crawler Robot) will be deployed externally to the hull of Shell-operated and non-operated FPSOs worldwide. The partners believe that MCCR, in combination with other robotic inspection tools like aerial drones, can provide tank inspection cost savings of 20% to 30%.



Innospection's current version of its MEC Combi Crawler at work. (Source: Innospection)

"We are very excited with this promising partnership, which will lead to an optimized inspection process for our FPSOs, further contributing to streamlining the structural integrity management of our assets," said Jose Ferrari, Shell Brasil's Technology Manager. "We also look forward to having two important partners, Innospection and SENAI CIMATEC, who have previously worked for Shell in Brazil and abroad."

Shell Brasil will fund half of the project.

The robot will be able to clean marine fouling on ship hull, and detect defect size and depth, along with other features. The result would be a potential increase in tank inspection efficiency, which improves integrity and increases safety for FPSOs.

"In several aspects this project has already achieved great milestones, from R&D collaboration between an operator an Institute and a commercial technology company, to the high-end robotic integration of various inspection technologies and surface cleaning into an almost autonomous subsea operating system, to a major cost-saving aspect of the asset deployment and operation," said Innospection CEO Andreas Boenisch. "We are excited to work with a great team on a great industry solution."

Reach Subsea's Houston Office Off To A Fast Start

Reach Subsea's new Houston office has landed contracts constituting 100 days of work, moving forward with its objective of expansion in the subsea sector.

The Haugesund, Norway-based offshore services provider said it is moving faster than expected with two projects already executed in the region. Two frame agreements have been signed with oil majors, leading to other contract awards.

The company's recent three-year charter agreement with Havila Shipping for the subsea vessel *Havila Harmony* is the eighth subsea spread that Reach markets, either itself or with Gothenburg, Sweden-based partner MMT. The *Havila Harmony* deal includes an extension option for one plus one years.

"We are pleased with how quickly we have been able to gain traction with our new Houston office, and to already be able to offer another quality subsea spread to our clients," said Jostein Alendal, CEO of Reach Subsea. "*Havila Harmony* is a vessel that is very well suited for the kind of projects we currently have, as well as the nature of the project opportunities we see in the market.

"As we have repeatedly said, an important part of our operational strategy is to cooperate with shipowners renowned for high-quality performance, which we have experienced firsthand in our first year of operation with the Havila Subsea spread. We look forward to continue the good cooperation with Havila Shipping in the years to come."

Reach Subsea's three-year charter for *Havila Harmony* was landed by the company's new Houston office. (Source: Reach Subsea)

FPSO *La Noumbi* On Track For Q3 Delivery

The newly named FPSO *La Noumbi* is on schedule for delivery to Dixstone Holdings in the third quarter.

The vessel, named July 26 and under construction by Keppel Offshore & Marine, will have a production capacity of 12,000 bbl/d of oil when it is deployed to the Yombo Field offshore Republic of the Congo. The field is operated by Dixstone affiliate Perenco Group.

La Noumbi will also be able to process 120,000 bbl/d of water and store 762,062 bbl/d of oil.

The conversion of the vessel from crude oil tanker to FPSO included installation and integration of topside process skids, fabrication of a new accommodation module as well as life extension works.

Transocean Lands Contract Extension For *Henry Goodrich*

Transocean Ltd. said July 31 that it had landed a one-year contract extension offshore Eastern Canada for its harsh environment semisubmersible *Henry Goodrich*.

The deal with Husky Oil Operations Ltd. is valued at about $100 million and expected to begin in the fourth quarter.

—Staff Reports

BUSINESS

Kosmos To Enter US GoM With Deep Gulf Energy Acquisition

Kosmos CEO Andrew Inglis said he believes a huge opportunity has opened in the U.S. GoM as many competitors leave the region for onshore shale. (Source: Shutterstock.com)

Kosmos Energy Ltd. said Aug. 6 it will acquire Deep Gulf Energy Cos., a portfolio company of First Reserve with deepwater assets in the U.S. Gulf of Mexico (GoM), for about $1.23 billion in cash and stock.

The purchase of Deep Gulf is Kosmos' largest acquisition and gives the company an entryway into the U.S. GoM. Currently, Kosmos' assets are focused offshore West Africa and South America.

Kosmos Chairman and CEO Andrew G. Inglis said the company's entry into the U.S. GoM is perfectly timed.

"With many competitors leaving the Gulf of Mexico to chase onshore shale plays, a huge opportunity has opened in the basin," Inglis said in a statement. "The best deepwater assets can compete with the best of shale, and now is a good time to enter the Gulf of Mexico."

Based in Dallas, Kosmos is a pure-play deepwater oil and gas company with assets focused on frontier and emerging areas along the Atlantic Margin, including offshore Ghana and Equatorial Guinea as well as Cote d'Ivoire, Mauritania, Morocco, Sao Tome and Principe, Senegal and Suriname.

On Aug. 6, the company also reported a net loss of $103.3 million, or $0.26 per diluted share, for the second quarter as higher costs and expenses offset increased revenues.

Still, Inglis said the Deep Gulf acquisition will create a platform for Kosmos to double production in the next four years.

"With this acquisition, Kosmos continues to grow into a larger, more balanced exploration and production company, with increasingly diversified production, a pipeline of world-class development projects, and a portfolio of short- and longer-cycle exploration opportunities," he said.

Inglis is no stranger to the U.S. GoM, having spent 30 years of his career with BP Plc (NYSE: BP). He left BP in 2010 as head of its E&P business. He later joined Kosmos in March 2014 from Petrofac, after leading the firm's integrated energy services division.

The acquisition of Deep Gulf will add roughly 25,000 boe/d of production (about 85% oil), with an estimated reserves-to-production ratio of 8.8, growing 2018 pro forma production by 50% to 70,000 boe/d from about 45,000 boe/d.

Under the terms of the transaction, Kosmos agreed to acquire Deep Gulf from First Reserve for $925 million cash and $300 million in Kosmos common shares.

First Reserve first backed the Deep Gulf Energy team in 2005 as part of its focus on supporting experience management teams. During that time, the private equity firm has backed the Deep Gulf team in three separate vehicles.

Deep Gulf Energy's management team is made up of a core group of mostly ex-Mariner Energy founders and personnel with a total of more than 300 years of E&P experience including over 175 years in the deepwater Gulf of Mexico (GoM), according to a First Reserve press release.

Richard Clark, president of Deep Gulf, said in a statement, "We look forward to becoming a part of the Kosmos team which, we believe, will not only enhance our exploration focus in the deepwater Gulf of Mexico but will add overall value and skills to the Kosmos group."

Kosmos intends to fund the cash portion of the purchase price with borrowings under its existing credit facilities. In connection with the transaction, the company has also received $200 million of additional firm commitments to increase its reserves-based loan facility capacity.

Kosmos is focusing on conjugate plays in the Atlantic Margin. (Source: Kosmos Energy Ltd.)

The transaction is expected to close around the end of third-quarter 2018.

Law firm Gibson, Dunn & Crutcher LLP represented First Reserve in its sale of Deep Gulf Energy to Kosmos. Vinson & Elkins represented Deep Gulf and Kosmos was represented by Davis Polk.

Evercore Inc. and Goldman Sachs & Co. LLC were financial advisers to Kosmos. Barclays was an adviser for First Reserve and Deep Gulf Energy. Lazard Freres & Co. LLC and Moelis & Co. provided fairness opinions to the special committees of the Deep Gulf Energy vehicles in the transaction.

—Emily Patsy

BUSINESS BRIEF

Thierry Hochoa Named CFO Of Bourbon Corp.

Thierry Hochoa has been named CFO at Bourbon Corp. effective Aug. 6. He reports directly to Gaël Bodénès, CEO.

A graduate of IAE Paris, ESCP Business School and also CPA, Hochoa began his career in 1994 as an external auditor at Arthur Andersen, then Ernst & Young (EY). In 2004, he joined Technip, first as director of internal audit, then held various finance positions at group level before becoming, in 2011, corporate financial control director.

In 2013, he was appointed CFO of operations in Southeast Asia on the key Yamal project in Shanghai. In February 2016, he became vice president, finance and group controller in Paris and actively worked on the merger and integration project of Technip with the American FMC Technologies.

In April 2018, Hochoa joined Bourbon Corp. as director of the financial structuring project for the three stand-alone companies created in the context of the company's strategic action plan.

—Reuters

UPCOMING

The next issue of *Subsea Engineering News* will be distributed August 23. Until then, visit *epmag.com*.

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