Brazil Embraces Change and Gets ‘Back on Track’

The country has made several regulatory changes as it prepares for upcoming licensing rounds, but there are still challenges to overcome.

BY VELDA ADDISON

As the oil and gas industry claws its way back from the downturn, Brazil is positioning itself to become more attractive not only for potential investors but for the country as a whole. This involves listening and being willing to make regulatory changes—qualities seen by Brazil's Minister of Mines and Energy Fernando Coelho Filho as being important to attracting investors to the country.

"I think we are far away from doing everything we want, but we have started moving in that direction," Filho told a full house gathered for a luncheon on May 1, opening day of OTC 2017. "We now have a clear calendar of dates of when the auctions will take place. ... What is in our reach and what we are trying to do to give the stability [that] the industry needs."

The Brazilian government's latest efforts include offering additional licensing rounds such as for covered presalt acreage in the prolific Campos and Santos basins—something many in the industry have been awaiting. Following OTC Brazil in October, Brazil will have its second and third presalt bid rounds—the country's first since the 2013 presalt licensing round for the Libra Field. The Libra Field alone is estimated to hold between 8 billion and 12 billion barrels of recoverable reserves. It is one of several massive discoveries made offshore Brazil in recent years, commanding the attention of oil and gas companies worldwide. But the country and its industry still face challenges—labor concerns that have sparked protests, economic issues and environmental licensing delays that have slowed exploration activity in parts of the country.

Another Jewel Added to Total’s Offshore Crown

With its Moho Nord development, Total delivers an impressive feat of human and industrial innovation.

BY JENNIFER PRESLEY

It's been a very busy decade-plus for Total in West Africa. The Paris-based operator's success in the region started with Girassol offshore Angola in 2001. Success attracts more success as additional Angola projects at Dalia and Pazflor witnessed first oil in 2006 and 2011, respectively. Success also came to Akpo offshore Nigeria in 2006.

The focus of an OTC luncheon on May 1 was the company's impressive feat of human and industrial innovation off the coast of Pointe-Noire in the Republic of Congo—Moho Nord. André Gofart, senior vice president of development and support for operations at Total, showcased for attendees the innovations responsible for the success at Moho Nord. Released in March 2013, Moho Nord is the second project on the Moho Bilondo license 75 km (46.6 miles) offshore Pointe-Noire in the Republic of the Congo. Gofart was onsite at OTC May 1 to sign two energy-related secretarial orders that will put the President's order into action and intended to further offshore exploration.

Speaking at the Consumer Energy Alliance policy session on May 1, Zinke, flanked by men and women who work on offshore oil and gas rigs, signed the first secretarial order implementing Trump's executive order to direct the Bureau of Ocean Energy Management (BOEM) to develop a new five-year plan for oil and gas exploration in offshore waters and to reconsider a number of regulations governing those activities.

"We're going to look at everything. We have to look at infrastructure. How is it that we extract wealth from our public lands in a meaningful, responsible way?" Zinke said. "How do we incentivize American energy dominance? There's a difference between energy independence and dominance. We're in a position to dominate."

He also announced and signed an order creating a new position at the Department of Interior—Counselor to the Secretary for Energy Policy—to coordinate the Interior Department's energy portfolio that spans nine of its 10 bureaus.

DOI Secretary Speaks at OTC

Secretary of the Department of the Interior Ryan Zinke was at the side of President Donald J. Trump as he signed the America First Offshore Energy Executive Order on April 28. Two days later he came to OTC and signed two secretarial orders that will put the President's order into action and intended to further offshore exploration.

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All events in conjunction with OTC 2017 will be held at NRG Park in Houston, Texas, unless noted otherwise.

**Wednesday, May 3**
- 7:30 a.m. to 5 p.m. ................. Registration
- 7:30 a.m. to 9 a.m. ................. Topical/Industry Breakfasts
- 8 a.m. to 10:30 a.m. .......... OTC Energy Challenge
- 9 a.m. to 5 p.m. ................. University R&D Showcase
- 9 a.m. to 3:30 p.m. .......... OTC Poster Lounge
- 9 a.m. to 5:30 p.m. ................. Exhibition
- 9:30 a.m. to 12 p.m. .......... Technical Sessions
- 12:15 p.m. to 1:45 p.m. .......... Topical Luncheons
- 12:15 p.m. to 6 p.m. .......... WISE Event
- 2 p.m. to 4:30 p.m. .......... Technical Sessions

**Thursday, May 4**
- 7:30 a.m. to 2 p.m. ................. Registration
- 7:30 a.m. to 9 a.m. ................. Topical/Ethics Breakfasts
- 9 a.m. to 2 p.m. ................. Exhibition
- 9 a.m. to 2 p.m. ................. University R&D Showcase
- 9:30 a.m. to 12 p.m. .......... Technical Sessions
- 12:15 p.m. to 1:45 p.m. .......... Topical Luncheons
- 2 p.m. to 4:30 p.m. .......... Technical Sessions

**Friday, May 5**
- 7 a.m. to 4 p.m. ................. d5: The Next Big Thing (Rice University)

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**Airport Transportation by SuperShuttle**

When OTC draws to an end later this week, many out-of-town visitors will be making their way to Bush Intercontinental (IAH) and Houston Hobby (HOU) airports. OTC attendees can receive a discounted fare with SuperShuttle. The SuperShuttle ticket counters are located in the baggage claim area of IAH and HOU airports. Attendees can make a roundtrip reservation online at supershuttle.com. For more information or to purchase tickets onsite at OTC, visit the Airport Shuttle Desk in Lobby D of the NRG Center.

SuperShuttle Shared-Ride from IAH is $29 one way, and SuperShuttle Shared-Ride from HOU is $23 one way. The shuttle makes trips to the airport every hour starting at 11 a.m. and runs until 6 p.m. Monday through Wednesday and from 10 a.m. to 6 p.m. on Thursday.

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OTC Video Coverage

See expanded OTC coverage by visiting 2017.otcnet.org and EPmag.com for video interviews with show attendees as well as OTC Chairman Joe Fowler and d5 Chairman John I. Howell III. Visit EPmag.com for additional OTC-related articles. Look for stories tagged “OTC Extra!”
Working in partnership with a major operator in the North Sea, Choicece Associates and Wood Group delivered a subsea asset monitoring and integrity program that identified required interventions, optimized vessel utilization, improved safety and reliability standards, as well as significantly reduced costs and inefficiencies inherent in subsea and pipeline operations.

The operator wanted to restructure its upstream pipeline and subsea operations ahead of establishing a North Sea key facility. Recognizing that its subsea operations had room for improvement in terms of cost, reliability and production, the operator instituted a significant engineering and IT project to deliver the needed improvements. Stage One began in April 2014, when the operator’s subsea leadership team began working with Choicece Associates and Wood Group, suppliers of the NEXUS Integrity Centre (IC) all-of-facility integrity management system.

The first step was to develop a joined-up approach that would establish the intervention scope for October that year and the framework for measuring success. The key issues to be decided were:

- How best to minimize vessel time and related costs that were needed for an intervention on subsea assets;
- How best to schedule the execution of interventions for optimal efficiency, safety and cost; and
- Which interventions were required immediately and how to identify them and optimize the scheduling of future interventions.

Underpinning the project was the need for robust decision-making processes supported by accurate, timely and actionable data. Therefore, the team created an inventory of all data streams and examined methods of accessing and interpreting those data to support decision-making.

The operator had already implemented NEXUS IC and consequently had access to its various historical inspection and reliability data. The system contained an accurate asset register allowing engineers and planners to access its data repository and view every component in the context of its performance and maintenance records.

NEXUS IC gave the operator a single repository for all anomalies. That meant it was simple to assess when an inspection or intervention was necessary or whether it required divers or ROVs. It also allowed engineers to develop “worsening state” models to identify when functionality would be threatened, enabling managers to make evidence-based decisions.

In the first year the team enjoyed significant time and cost savings by using the data and combining those with the intelligence of engineers and the decision-making power of executives. Analysis shows that campaign costs were reduced by 30% year-on-year utilizing this integrated approach.

Based on the current status of the project, the operator decided to adopt a one-in-three-year cycle rather than annual interventions. The intelligence from NEXUS IC enabled the operator to optimize high-cost activity such as diving work, reducing the number of costly vessel days. Overall, the project maintained a 100% planned work completion rate without extending vessel times.

The operator also increased the equipment reliability by taking advantage of an extended work cycle. By using data within NEXUS IC to intelligently assess requirements, define actual needs, prepare the scope of work and sequence it efficiently, the operator reduced unnecessary “touch points,” and associated costs and risks. It did so while maintaining subsea equipment and pipeline availability at more than 97%.

This project represents the transferral of an IT system into an engineering implementation solution. There is no doubt that an operator’s ability to use data effectively can have a positive impact on critical areas such as safety, reliability and cost. But in all value of data conversations, it is vital not to lose sight that data-driven decision-making is a matter of trust. If trust cannot be guaranteed or is compromised, then any system depending on it loses all value.

For this reason, operators should deploy systems that offer continual reassurance as to the validity of their data. Operators must also ensure that everyone who interacts with that system understands their own role in maintaining that trust. If they can do that, then results such as these are more than achievable.
In another time, there was little incentive to allow foreign oil companies to drill Brazil's lucrative offshore presalt fields. It was Brazil's treasure and Brazil's national energy company Petrobras would exploit it.

But after those efforts began more than a decade ago, things went south. Petrobras' drilling results were poor, the company is saddled with debt, and Brazil is reeling from a presidential impeachment and an economy in disarray.

"The opportunities in Brazil are huge, but it's slightly complicated for us to achieve what we need to achieve," said Andre Araujo, president of Shell do Brasil, during a May 1 panel at OTC.

The topic, "Operators Offshore in Brazil: Under a Promising and Positive New Environment," reflected the interest shown by majors like Shell, ExxonMobil, Statoil and Total as Brazil's government has issued directives aimed at encouraging badly needed foreign investment.

Mexico's energy reform is a key driver, with companies now able to pursue different options in the hemisphere. Still, the possibility of 50 Bbbl of crude makes it hard to walk away.

"We are seriously considering opportunities in Brazil," said Carla Lacerda, president of ExxonMobil Brasil. "I hope to show you the perspective of an investor looking for material opportunity, particularly via exploration. We are convinced that the resources here are so significant that there are opportunities for all of us."

As long as the price is right.

"With lower oil prices, less available capital and weaker cash flow, companies have become even more selective in their investment choices," Lacerda said.

Her colleagues on the panel echoed that sense of hesitation. Maxime Rabilloud, president of Total do Brazil, offered two sets of solutions to move Brazil's E&P program forward. In the short term:

• Grant environmental licenses to participants in the Round 11 auction;
• Extend Repetro, the fiscal regime that provided tax breaks to encourage oil and gas activity (Repetro was suspended in February); and
• Give the go-ahead to launch projects that are ready.

"Our view is that there are a lot of barrels of oil and gas to be discovered in Brazil," he said. His suggestions for the long term:

• Keep up with regular bidding rounds;
• Adapt fiscal terms depending on the region;
• Grant upfront licensing and include the licensing conditions into the calls for tender;
• Ease the tax burden at final investment decision; and
• Unlock commercialization of discovered reserves and promote synergies among players in the sector.

Shell is overly exposed in Brazil at this point, let me tell you that we keep looking for opportunities if the terms are competitive, the fiscal environment is safe and if the products compete globally," said Shell's president of Brazil.

Brazil still has more work to do, Lacerda said, who noted that many countries possess "great rocks." She offered ExxonMobil's wish list:

• Extend Repetro;
• Finalize unitization regulatory framework;
• Ensure that the new production sharing contract is competitive;
• Ensure that fiscal terms are commensurate with the risk and reward of opportunity; and
• Execute and follow through on a bad round schedule.

"What it boils down to are fair terms and conditions for foreign companies to take the risk. As far as the panel appeared to be concerned, the next move is up to Brazil. "Every country around the world is looking for investment," Araujo said. "While hydrocarbons are still important for our industry in the years to come, it's the right time right now to secure and monetize those investments. These are special times we are in. Brazil is potentially a huge place to invest." But not the only place.

"The resources will go where it is simpler and easier to do business," Araujo said. "Every country around the world is looking for investment," Araujo said. "While hydrocarbons are still important for our industry in the years to come, it's the right time right now to secure and monetize those investments. These are special times we are in. Brazil is potentially a huge place to invest." But not the only place.

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Hear comments from Ibsen Lima, president of Pre-Sal Petroleo S.A., when you read this story online at EPmag.com.
Researchers from Baker Hughes, BP, Halliburton and other deepwater drillers presented their latest fieldwork and laboratory experiments in the endless quest to perfect well completions.

During a May 2 technical panel at OTC, researchers presented their findings and hypotheses on specially coated proppant, high-energy propellant and autonomous devices to control water and gas inflows, among other investigations. Baker Hughes’ Naima Bestaoui-Spurr presented her team’s findings on proppant that withstands permeability to oil and water—a primary factor that affects the productivity of fractured wells. The results are promising so far, with increased oil and saved rig time.

Baker Hughes coated lightweight ceramic proppant and evaluated it in the laboratory. Results indicated that the new proppant surfaces not only reduced water saturation but also improved oil mobility. Observations show promise in permanently modifying surfaces as next-generation products for improved flow and decreasing the risk of formation damage due to the fracturing fluids left behind after treatment.

“We eliminated 10.5 hours of flowback [time], and that ended up saving the customer $438,000 in rig time,” Bestaoui-Spurr said. “We had 100% fluid recovery. We successfully modified proppant surfaces to be neither water nor oil wet.”

Data from completion tests in the Gulf of Mexico showed that stimulation fluids pumped into completions were recovered at the end of the treatment—a rare occurrence in surrounding deepwater fields.

In another presentation, Chevron’s Sahil Malhotra shared results of a study sought to quantify the difference in first and second generation propellant performance.

“Before we took out in the field we wanted to see how it performed in the lab,” Malhotra said. Solid propellants are used for perforation enhancement, gravel pack cleanouts and stimulation of injection and production wells.

Propellants are lowered on wireline, electrically inned and use combustion of a high-energy fuel to fracture formations.

Malhotra and his colleagues conducted a large-scale test using a sandstone block to measure stresses in a controlled environment. The propellant showed a rise time of 1.4 ms, much shorter than previous propellant rise times of 35 ms tested in 2006.

Initial peak pressure was observed to be 5,790 psi with a 1-in. diameter and 1-in. length propellant. The case study in 2006 used that used the same diameter propellant, but 3 in. longer.

While the rise time of the propellant fell in the planar fracturing region, the wellbore pressure response showed a saw tooth pattern indicating the possibility it created multiple fractures, Malhotra said.

Pressure probes inserted into the sandstone to measure maximum horizontal stress inside the block did not detect a pressure signal—an indication that fracture expanded perpendicular to minimum horizontal stress.

The sandstone block was cut open after the propellant ignition to identify the fracture pattern. A dominant planar fracture in the direction perpendicular to the minimum principal stress was observed. Much shorter off-plane fractures were observed close to the wellbore in the bottom half of the block.

The existence of these fractures could explain the saw tooth pattern in the wellbore pressure response. The findings and data could serve as important inputs to calibrate physics-based models, which are aimed at modeling the process of propellant ignition and subsequent fracture growth.

But the results also highlight the need to carefully understand the performance of a propellant before deploying it in the field. The objective of deploying the propellant in the field needs to clearly be identified before propellant selection, Malhotra’s paper said. The experiments showed that rise time was much shorter and peak pressure was much higher than the first-generation propellant tested in 2006.

While that could signify deeper fracture penetration in the target subsurface zone as compared to the first-generation propellant, the fracture pattern was dominantly planar. If multiple fracturing is required for success of a treatment or a workover job in the field, the propellant chemistry would need to be altered to attain shorter rise times.
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Standardization of equipment, process and documentation has long been a goal for operators and suppliers. It is a goal that many have embraced in the lower-for-longer market conditions from which the offshore industry is emerging. The need to standardize is great to reduce costs and gain efficiencies. As the oil and gas industry moves farther and deeper offshore, the focus on standardized subsea systems and support increases.

Attendees to the May 1 afternoon OTC technical session, “Standardization: A New Way to Achieve Project Cost and Planning,” were presented technology-focused examples of subsea field applications where standardization has been recognized as an effective method to achieve project cost and planning objectives. The technical session was moderated by Julien Denegre, manager of integration and planning for TechnipFMC, and James Chitwood, senior offshore engineer for Shell International.

Olivier Benyessaad, offshore business development manager, marine and offshore division for Bureau Veritas, offered his insights into how classification societies can be involved in the current cost reduction era with his presentation (OTC-27567).

According to Benyessaad, the concept of classification societies emerged in the second half of the 19th century when marine insurers developed a system to assess the condition of the ships presented to them for insurance coverage. Bureau Veritas was the first, established in 1828 in Antwerp, Belgium. Two other classification societies, Lloyd’s Register and Det Norske Veritas, were founded in 1834 and 1864, respectively.

In the nearly two centuries since the inception of classification societies, the role has evolved from one of condition assessment to that of an experienced voice, offering feedback to improve the safety of vessels, by providing guidance and rules for the offshore industry and technical assessments and inspections to guarantee safety. Classification societies, Benyessaad said, often know more about a vessel or offshore installation than the owner.

Early project involvement by classification societies in a project allows an independent technical, risk, QHSE and performance assessment of the project, encourages the adoption of new technologies and is a facilitator between operators, contractors and government authorities, he said. Benyessaad added that during operation the role the society plays changes to one of performing regular inspections and providing support to determining the types of equipment failure that occur.

A more extensive look into the methods suggested by Benyessaad can be found in the paper (OTC-27567) he and his co-workers authored.

The second speaker of the session was J.J. Jung of Hyundai Heavy Industries, Co., presenting on the standardization of a FPSO hull with 2 MMbbl of storage capacity for use in West Africa (OTC-27687). The concept of standardization is one that provides a significant advantage to the overall development cost, according to Jung. The concept of “design one, build two (or many)” is one that has been deployed in the Gulf of Mexico with the Delta House semisubmersible design based on the Who Dat semisubmersible and the Heidelberg spar design based on the Lucius spar, Jung said.

In West Africa FPSO units commonly have a storage capacity of 2 MMbbl and a similar barge-type hull. Two FPSO units that followed the similar path of “design once, build two” are HHI-fabricated Kizomba A and B, installed in Block 15 offshore Angola and operated by Esso Exploration Angola.

These FPSO units show that a standardized hull in West Africa works best than ones in other sites, Jung said.

With a standard hull model developed, optimization tools have determined what the best dimensions would be if a new model of an FPSO unit is needed in West Africa. Based on a review of characteristics, the typical topside weight of 33,000 dry tons and hull designs that include bow and stern shapes that provide good towing performance have been defined. In addition, Jung stated the main dimensions for the standard hull model are a length of 292 m by a breadth of 63 m by a depth of 33 m (958 ft by 207 ft by 108 ft).
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R&D Collaboration, Standardization Are Key to Lower Offshore Costs

Better collaboration and standardization are needed to improve financial returns, a Chevron executive says.

BY VELDA ADDISON

Pressured by limited budgets and shareholder demands, oil and gas companies are searching for ways to improve returns and better allocate capital, leaving some to wonder whether complex deepwater projects can compete with headline-grabbing, lower-cost shale plays.

"From our view, the answer is a resounding yes," Roy Krzywosinski, vice president of global facilities engineering for Chevron, said May 2 at OTC. "Deepwater resources still represent significant opportunity."

But making the most of the opportunity requires R&D collaboration and standardization among industry players, according to Krzywosinski. It's an area that has seen plenty of action in recent years as the downturn ushered in more partnerships to reduce development costs and cycle times.

Yet there have been challenges, and they less often concern intellectual property. Collaboration can be time-consuming. Krzywosinski pointed out that it has been reported that it can take up to 15 years to develop and deploy a new technology. A fair amount of time is taken before research even begins—establishing the collaborative effort, determining work scopes and building alignment, he said, noting it could take one to three years when the scope is one year or less. Between five and eight years are typically spent on most of the research, and the lack of a funding model plays a critical role.

"We need to provide appropriate funding levels to move the research along in a predictable manner," Krzywosinski added. Deployment could take between three to seven years, but such opportunities should be a focus along the entire timeline.

While the time line may vary depending on the type of technology being developed, the bottom line is essentially the same—the process takes too long. The cycle time needs to be reduced by 50%, Krzywosinski said.

"You can't stand still in this place or you'll get lost. You don't want to get in there and play 'whack a mole' for one or three years," he said in response to questions. It's an area in which the deepwater industry can learn from the shale industry, which has taken a manufacturing approach to operations, shortening drilling times and costs.

Successful R&D collaboration should take a lean, simplified approach to administration, focusing on quick delivery of solutions with targeted development time lines to address specific business needs, Krzywosinski said. "Those involved must also agree on a 'clearly defined scope,' which he admitted is easier said than done with the chances of 'competing interests coming into play.'"

"Too often the critical conversation that underpins a successful deployment is held way, way too late in the R&D development cycle," he said. "In terms of technology, it should go without saying that the more you deploy technology, the higher your return on investment is. If we're not prepared to implement the technology that we develop then we're wasting a lot of time, resources and effort."

As an industry evolves, its R&D collaboration model needs to as well. He used the DeepStar program as an example. The program, a joint industry technology project focused on deepwater technologies, was formed in 1991. Its creation has given birth to several technologies used today such as steel wave rider systems and deepwater mooring reliability. But time has brought changes—some operators involved in the project have moved out of the deepwater space, he said. Targeted assets are different, and new technological obstacles exist.

The environment has led to a new Offshore Operators Committee enhanced program framework. At the framework's center is a smaller and more focused R&D core surrounded by what Krzywosinski called operator-led "a la carte projects" funded by those needing specific solutions.

The new framework will be released soon, Krzywosinski said, after announcing the DeepStar is signing up additional operators.

Standardization also has the potential to lead to higher returns in the current price environment.

Objectives should include prioritizing the highest value opportunities, developing procurement-ready packages and eliminating preferential engineering, according to Krzywosinski. There is a business case in standardization, although the size of the prize may differ, suppliers can help by helping pinpoint areas where cost savings are possible.

"We need to have, as an industry, a sense of urgency. We're essentially in a race to make deepwater resources as cost competitive as possible," Krzywosinski said. "Costs must come down and ultimately recovery must go up. As in the past, technology plays a key role."

Salinity System Increases Flow Assurance

Technology enables instant identification of changes in the flowstream.

BY VELDA ADDISON

Technology collaboration and standardization are needed to improve financial returns, a Chevron executive says.

The Roxar salinity system consists of a salinity sensor mounted flush with the wall of the meter. The microwave resonance technology ensures an instant response to changes to conductivity of the flowstream. (Image courtesy of Emerson Automation Solutions)

The mix of formation water and injected water in the reservoir, for example, can alter the salinity of the produced water with a greater chance of saline formation water entering the flow. This can lead to a potentially negative impact on equipment (hydrates, scale and corrosion), water handling, disposal costs and hydrocarbon production. In worst-case scenarios, it can lead to well shutdowns and have a highly negative influence on the field's economics. In addition, hydrate formation has a critical time window before plugs are formed, in some cases as little as 20 minutes, which requires immediate action.

To counteract these challenges, Emerson Automation Solutions will release the Roxar salinity measurement system—integrated into the Roxar subsea wet gas meter—at OTC. The technology will enable operators to instantly identify changes in the flowstream and detect the smallest amounts of saline water entering the flow at never previously achieved levels. Svein Eirik Monge will provide details in a presentation, "A New Salinity System for Formation Water Detection—Test Results and an Operator Qualification Program," at 11 a.m. on Thursday, May 4.

The system, which consists of a salinity sensor mounted flush with the wall of the subsea wet gas meter and directly connected to its flow computer, is based on microwave resonance technology. It provides quantitative and qualitative real-time salinity measurements in many types of field conditions. The system and the wet gas meter are particularly effective in the high gas void fraction (GVF)/well gas flows that characterize wet gas fields.

The microwave resonance technology behind the salinity system ensures an instant response to changes to conductivity of the flowstream, in seconds not minutes, and the ability to measure water conductivity down to ±0.1 S/m and up to 99.99% GVF and sensitivity in the range of ±0.004 S/m.

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A t a time when the oil and gas industry is intensely focused on lowering capex and opex costs, Subsea 7 is developing several related technologies to enable subsea field architecture for production through the development of long tiebacks, those typically more than 50 km (31 miles) for oil-dominated flowlines. Several of these technological advances are the subject of a technical paper being delivered by Subsea 7 at OTC 2017 and are referenced in the company’s technology magazine Deep 7.

Subsea 7 aims to achieve a situation in which remote fields can be tied back to existing subsea facilities over longer distances than is currently possible, and more economically than with an FPSO unit or platform-based alternatives. To achieve this, Subsea 7 is identifying design drivers to define the optimal distances for passive-insulated, actively heated and cold flow transport pipelines for thermal management, along with its smart integration with subsea pumping technology.

Active heating technologies rely on power distribution from the topside facility, which limits the length of the flowline that can be heated because of a lack of space on the topside. Subsea 7 is combining subsea electrical power distribution with its existing Electrically Heat Traced Flowline (EHTF) technology to greatly extend the range of active flowline heating. EHTF is based on a thermally enhanced pipe-in-pipe design, which requires lower power requirements than direct electrical heating.

Maintaining a constant fluid temperature at every location along a flowline requires a remediation of potential “cold spots.” Given the higher U-values of connections, structures or line-ends—and when compared with the pipe-in-pipe flowline—this can result in overheating, which compromises the power efficiency of the system.

For long distance tiebacks, Subsea 7 has addressed the issue of cold spot management through added insulation, local increases of heating power and the innovative redesign of key components, including the thermally efficient ring arrangement, which complies mechanically with reeling conditions while mitigating heat losses.

Subsea 7 is combining subsea electrical power distribution with its existing highly efficient EHTF technology to greatly extend the range of active flowline heating. (Image courtesy of Subsea 7)

Subsea 7 also extended the reach of EHTF tiebacks by developing efficient subsea electrical distribution systems, based on reliable, low-maintenance components, which supply the EHTF heating elements at regular locations along a flowline. The company’s system extends the length of heated flowlines and offers increased operational flexibility and reliability while also allowing power outputs to adapt to changing heating requirements through simple switching controls.

As tieback distances increase beyond the capability of active heating systems, flow assurance strategy moves from maintaining the temperature above hydrate formation temperature to transporting under ambient temperature conditions. The latter is considered cold flow.

This cold flow technology approach requires subsea processing facilities near the field and is especially valuable for long-distance subsea developments without infrastructure, such as those found in the Arctic. One potential strategy for achieving a safe cold flow condition in the development of large marginal fields is based on using a large-scale subsea cooler, which brings down the temperature to that of ambient seawater. This new subsea processing function denoted wax control unit is based on proven technologies.

Subsea 7 is defining the optimum distances for favorable cold flow systems when compared to actively heated flowlines.

The company is assessing the boundaries of applicability for cold flow systems for various tieback distances and host platform alternatives, but the concept enables longer tiebacks at a lower cost than with an FPSO unit or platform-based processing solutions.

Pre-assembled pipeline bundles are another effective technology for extending subsea infrastructure lifespans and reducing costs.

Subsea 7 is defining the optimum distances for favorable cold flow systems when compared to actively heated flowlines. (Image courtesy of Subsea 7)
One of the holy grails in marine geophysics has been the attempt to reduce costs without sacrificing data quality. Unfortunately, the best data quality often results in the highest costs. A new technology is aiming to reverse that trend. Called autonomous marine vehicles (AMVs), these unmanned vehicles offer a host of advantages, including cost-effective operations and access to data; reduced HSE exposure and footprint; less downtime due to poor weather conditions; increased access to restricted, remote or frontier areas; and protection of environmentally sensitive areas.

In a presentation May 2 at OTC Sudhir Pai of Schlumberger Robotic Services outlined recent successes with the use of AMVs. The systems have multiple uses, including for metrology, hydrocarbon seep monitoring, subsea data communications, water quality and particle suspension monitoring, offshore magnetic measurements, and marine mammal monitoring. But Pai focused primarily on seismic data acquisition.

“Seismic is a business that excites us a lot,” he said. “This has gone from being nascent to starting to have a life. We’re convinced that this is the future.”

So far the company has done 38 operations with the AMVs, of which eight have been seismic surveys (a ninth is nearing completion). The systems have spent 3,879 days at sea, and the company has had nine repeat clients already.

The systems consist of the “wave glider,” which includes solar panels and a battery, GPS and a communication link, a vertical management computer, and a mini-acquisition system for acquiring seismic data. The glider is connected to a submerged glider with wings and a rudder for propulsion and heading. A motion-isolating cable tows a 3-D sensor array. Each 3-D sensor had five arms with three hydrophones each, and it also has an accelerometer, gyroscope, magnetic sensor and depth sensor.

In one case study in the United Arab Emirates the company acquired an AMV study simultaneously with an ocean-bottom cable (OBC) operation to provide a data comparison between the two. Additional goals were to evaluate the safety operational performance and to ensure that the systems could be deployed without interference with other ongoing operations.

The experience taught the team that communication is key and led to a recommendation that in the future support vessels should have improved network communication. There were also visibility issues due to fog.

But the data from the survey were impressive. While Pai’s talk was more about operations than data quality, a comparison between the OBC data and the AMV data was impressive, and the AMV data lacked the ghosting effects found in the OBC data.

An additional survey was acquired as part of a multiclient streamer survey being shot in the Green Canyon area in the Gulf of Mexico (GoM). Seventeen AMVs towing 3-D sensors were deployed around several platforms in the area, and 10 of those sensors were deployed 20 km (12 miles) away from the coil shooting operations to provide long-offset data. This was the first time that any vehicle in the GoM was allowed to come within 100 m (328 ft) of a platform, and it promises to help solve one of the problems in obstructed areas, that of needing to undershoot a structure.

While the data had a good signal-to-noise ratio, a key challenge included ocean conditions and sea state, causing the vehicles to drift off station. This required auxiliary thrusters, which used extra power and drained the batteries more quickly. Issues with the umbilicals have led to reinforcements in the construction to prevent them from tangling.

In spite of these learning curves, Pai concluded that the tests were successful and the vehicles provided consistent performance. They bring unique capabilities to marine seismic that can’t be matched by existing systems, he said.
Managing the Risks of Integrating IT, OT Systems

Cyberattacks to operational technology systems impact operations and can cause process failures.

Todays owners and operators of data-driven offshore assets are becoming increasingly concerned with addressing cyber threats and understanding this evolving risk as part of their overall security risk management strategy. Many companies have long recognized the need to increase cybersecurity and keep pace with technology advances, with a majority having invested in improving their cyber risk management programs. Although most companies have implemented an information technology (IT) cybersecurity program, far fewer are extending their cybersecurity programs to address their operational technology (OT) systems. Historically, OT systems have been isolated, whether virtually or physically, from IT networks. Within an organization, there is a need to verify the availability of critical business systems by implementing a robust strategy that considers both IT and OT systems and includes the following components:

- Executive-level oversight by a chief information security officer;
- Governing policies and procedures;
- Cybersecurity training;
- Cyber vulnerability assessments;
- Design of a secure architecture;
- Configuration and maintenance of hardware and software; and
- Incident response plans.

Risks to OT systems

Research has indicated that many companies have inadequate OT cybersecurity and lack the controls that are commonplace in IT networks, such as configuration management, contingency plans, access control policy and authentication policy.

IT and OT systems exist for different purposes, use different technologies and require specific protocols. There are also very different consequences if they fail. OT systems detect or cause changes through the direct monitoring and control of physical devices, processes and events. Common OT systems are industrial control systems, SCADA systems and distributed control systems. Successful cyberattacks against IT systems can impact a company’s bottom line, compromise private information and affect the performance of a variety of key business functions.

On the other hand, OT systems can fail due to operational processes, which can result in physical consequences, property damage and environmental impacts, such as a spill. Because IT and OT have different purposes, they have nearly the opposite system priorities. OT systems emphasize integrity, availability and confidentiality in that order, whereas IT systems prioritize confidentiality, followed by availability and then integrity. As the sophistication and integration of OT systems have increased, companies depend on equipment vendors to maintain and upgrade their systems. For offshore assets, there is generally integration across multiple systems spanning multiple vendors, which introduces the potential for operational upsets as changes to one system can affect the performance of others. Cybersecurity provisions in vendor support contracts could help ensure vendors are not introducing variability that could affect other systems during their software upgrades.

Cybersecurity for IT, OT systems

The isolation of OT systems has traditionally been viewed by engineering/operations groups as the ultimate safeguard against outside threats, but the days of physical isolation of OT systems and manual process control are coming to an end. With the rise of Big Data, data analytics and data management, companies have started to integrate their IT and OT systems to improve operational efficiency and remain competitive.

To guard against vulnerabilities being introduced during integration, companies must carefully design and implement cybersecurity programs with robust protections that reduce the likelihood of serious consequences. ABS Group can help clients develop a cyber risk framework and understand the common risk, vulnerabilities and potential consequences of cyber exploitation of critical systems on offshore assets.

Cyber risk framework

Cyber systems are widely used in marine and offshore operating environments for navigation, propulsion, machinery and power control, communication and monitoring. To support the development of risk-informed strategies, and to promote safer, more reliable industry practices related to maintaining cybersecurity systems in these environments, ABS Group analyzed marine and offshore related cyber risk, vulnerabilities and consequence scenarios to develop a comprehensive cyber risk framework for navigation and control systems.

The results of the company's assessment will contribute to more reliable decision making, which will also enable more effective management of cyber risk and security across a broad spectrum of high-performance, data-driven assets.

Integrated Platform to Deliver EPCI Solutions for Project Life Cycle

New system enables customized project lifestyle management.

McDermott International Inc. will implement a new software platform based on Dassault Systèmes’ 3DEXPERIENCE platform. McDermott’s system is expected to improve efficiency and productivity throughout the life cycle for McDermott’s global engineering, procurement, construction and installation (EPCI) projects.

The platform will enable McDermott to digitize and standardize its processes, driving down costs by eliminating legacy systems and simplifying work processes into a single integrated, software-agnostic engineering platform. The new platform will enable customized project lifecycle management for subsea and offshore energy projects.

The new offering brings an integrated approach from project inception to decommissioning for life-of-field services, making McDermott the first energy-focused EPCI company to implement such an advanced industry solution and to offer the industry’s first true “digital twin.” The creation of a digital twin combines mechanical design, 2-D drawings, specification sheets, finite element analysis, quality documents and tests reports, maintenance procedures and other operational data to enable life-of-field services for the physical asset including:

- Predictive maintenance through analysis of data;
- Optimized maintenance and turnaround planning through smart work package preparation;
- Facility optimization and debottlenecking through use of operating facility data to unlock further efficacy and operating margins;
- Single source for all information about the facility, continually updated throughout the life of the facility;
- Operator training through virtual reality;
- Operator training and infield maintenance technician assistance through use of mixed-reality platforms; and
- Rapid engineering for brownfield modifications through a single, integrated, software-agnostic engineering platform.

From project inception to decommissioning, the life-of-field services digital documents will permit a more open exchange of information that will improve productivity, cross-functional collaboration and ensure on-schedule delivery of complex projects with improved safety, quality and greater efficiency. The life-of-field services will focus on technical and operational data management, process optimization, predictive maintenance, operations management and asset integrity management.
Understanding fluid properties at all stages of the life of a reservoir is key to estimating reserves, enhancing completions and achieving production goals. However, these datasets are traditionally available only after performing conventional formation sampling in a laboratory setting. In the ideal scenario, mapping the entire reservoir’s fluid characteristics—as opposed to obtaining individual samples of the reservoir fluids—would address this challenge by giving the ultimate reservoir insight in real time.

Introduced at OTC, the new SpectraSphere fluid mapping-while-drilling service provides critical data about fluid composition in real time. By delivering reliable characterization of fluid properties, the new service enables an improved understanding of the reservoir potential, which is essential for estimating well deliverability and producible reserves, optimizing well placement and completions, designing surface facilities and meeting production goals. The service’s capability to deliver these data while drilling in real time contributes to reduction in overall well construction cost.

In exploration, the new fluid mapping-while-drilling service helps operators gain an early understanding of untapped reservoir potential and reduce exploration costs by acquiring laboratory-quality samples while drilling. In the appraisal and development phase, which can include highly deviated or extended-reach wells, the new service ensures optimal positioning of wells to mitigate wellbore risks, enable better completions, and, ultimately, more production from the field.

The service can be used with the GeoSphere reservoir mapping-while-drilling service to combine structural information with reservoir fluid data, resulting in a true reservoir structural and fluid map. Using deep directional electromagnetic measurements, the GeoSphere service reveals subsurface bedding and fluid contact details more than 30 m (100 ft) from the wellbore.

This combined reservoir-scale view of rock and fluid properties provides a new depth of investigation, enabling operators to optimize landing, maximize reservoir exposure and refine field development plans.

Case study: Gulf of Mexico
In the Gulf of Mexico, the SpectraSphere service was used to improve understanding of reservoir potential through fluid composition.

By taking high-quality fluid samples and accurate pressure measurements while drilling, the SpectraSphere service enables real-time decisions that help improve geosteering outcomes, guide wells to the ideal trajectory and access more reserves. (Photo courtesy of Schlumberger)
D
uring the past 30 years offshore oil and gas developments have moved into increasingly deep, remote and technically demanding regions. However, while riser system development has not been static in the persistent lower-for-longer price environment, there is continuing pressure to develop these fields safely while reducing capex and opex.

In short, a technological step change is needed to open up less accessible or currently uneconomic fields. The development of challenging oil and gas fields with minimal or no infrastructure typically requires the deployment of floating facilities combined with storage capabilities. Here, FPSO units are the preferred option, accounting for about 70% of the floater market.

Semisubmersible units, spar platforms and tension-leg platforms (TLPs) are also common in deepwater regions. TLPs are particularly suited for water depths less than 1,500 m (4,921 ft). But FPSO units and floating LNG (FLNG) vessels have the distinct advantage of having the associated high opex adds to overall field development costs.

New system could open up previously inaccessible fields.

BY ALAA MANSOOR, INTECSEA (WORLEYPARSONS GROUP)

Fundamentally, for FPSO and FLNG applications the technology vastly improves field economics through the ability to deploy these vessels with large-diameter SCRs and TTRs in remote, challenging environments in addition to reducing costs by eliminating the maintenance turret and swivel system.

The LM technology consists of a solid ballast tank (SBT) attached to the floater’s hull by groups of short tendons. The SBT has dedicated compartments for port fluids between the seabed and floating platforms. The technology is less sensitive to weight and vertical motion response means reduced deck steel and vessel mass.

The SBT is designed for a single direc- tional deployment of floating facilities combined with storage capabilities. Here, FPSO vessels are the preferred option, accounting for about 70% of the floater market.

Semisubmersible units, spar platforms and tension-leg platforms (TLPs) are also common in deepwater regions. TLPs are particularly suited for water depths less than 1,500 m (4,921 ft). But FPSO units and floating LNG (FLNG) vessels have the distinct advantage of having the required storage and offloading capability, while other floating production units—such as semisubmersible units, TLPs and spar platforms—need a separate storage vessel or existing infrastructure to export production to shore.

However, there are substantial limitations with conventional FPSO and FLNG vessels that, if overcome, could considerably broaden their reach and lead to a significant reduction in field capex and opex.

Dry-tree applications

Using top-tensioned risers (TTR) for direct vertical access to production wells ensures all drilling and completion can be carried out from one floater, enhancing reservoir recovery and mitigating flow assurance issues while reducing costs. However, the stroke limitation of existing tensioner technologies means TTRs require a floating system with minimal heave response, so they cannot be hosted on FPSO units.

Wet-tree applications

Steel catenary risers (SCR) are considered the most robust riser solution because of their simplicity, long life cycle, extensive in-service history and relatively low combined capex and opex. But the high motion of FPSO units makes them unsuitable for SCRs. As such, less robust and more complex and expensive riser systems such as flexible risers are typically adopted with these vessels.

The need for a turret and swivel system

The salient area of the conventional ship-shaped FPSO/FLNG vessel in relatively harsh and multidirectional environments mandates the use of a turret system to help facilitate the mooring design. Turret capex normally ranges from $500 million to $700 million, and the associated high opex adds to overall field development costs.

Low-motion technology

INTECSEA’s low-motion (LM) floater technology is set to significantly reduce field development capex and opex. This robust and low-tech tool comprises field-proven components and can be applied to newbuild or conversion floaters.

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The LM technology consists of a solid ballast tank (SBT) attached to the floater’s hull by groups of short tendons. The SBT has dedicated compartments for high-density material, which provides weight in water that maintains tendon tension for all design conditions. The technology is less sensitive to weight and vertical center of gravity variation during construction, historically one of the highest risk elements for project execution. It maintains quasyside integration and, once the floater reaches its location, the SBT is flooded and lowered using the mooring chains. The tendons are thenBundled and installed. And its high stability and superior motion response means reduced deck steel and piping weight and enhanced habitability, crew safety and helicopter operability.

In case studies the design consistently demonstrated an economic advantage in both wet- and dry-tree applications, with capex savings estimated between $500 million and $1.2 billion over conventional designs.

The challenge for the industry is whether it can reconcile dissimilar requirements to develop fields in increasingly greater depths and hostile conditions, while—at a significantly reduced cost—deploy robust riser systems that can safely drill, produce and transport fluids between the seabed and floating platforms.

INTECSEA’s LM capability potentially opens up a wealth of prospects across the world, stretching from marginal fields in the U.K. continental shelf to the gas basins of the Antipodes.

INTECSEA’s LM technology helps reduce field development capex and opex. (Image courtesy of INTECSEA)

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Changing the Landscape of LNG Production

PFLNG Satu facility will boost Malaysia’s LNG output.

BY SERGE DOMINICHINI, TechnipFMC

Successful completion of the Petronas Floating LNG facility (PFLNG) Satu is a milestone for the oil and gas industry and for the Malaysian energy giant. Designed by consortium leader TechnipFMC and fabricated at the Daewoo Shipbuilding and Marine Engineering yard in South Korea, PFLNG Satu achieved the first-ever production of LNG offshore in December 2016.

The 365-m-by-60-m (1,197-ft-by-196.8-ft) facility processes, produces and offloads LNG in situ, directly above natural gas reservoirs. FLNG allows the monetization of remote, marginal and stranded offshore gas fields that cannot be developed economically via conventional means. This approach avoids the expense and potential environmental impact of building and operating long-distance pipelines and extensive onshore infrastructure.

Located on the Kanowit gas field 180 km (111.8 miles) off Bintulu, Sarawak, Malaysia, PFLNG Satu will produce 1.2 million tons of LNG annually during its 20-year design life. The facility’s topside consists of 22 modules that comprise gas treatment, liquefaction, storage and offloading systems. All of these systems have been installed on top of a hull that is longer than the Eiffel Tower is tall.

The core of PFLNG Satu is a system that liquefies natural gas to -163 C (-261 F) using a new process that shrinks the LNG volume by up to 600 times. A two-row arrangement of eight membrane-type LNG cargo containment systems and two condensate storage tanks is located below deck. The tanks can store up to 177 Mcm (6.2 MMcf) of LNG and 20 Mcm (706 Mcf) of condensate with a total storage capacity equivalent to about 79 Olympic swimming pools.

PFLNG Satu can accommodate LNG carriers between 130 Mcm and 157 Mcm (706 Mcf and 5.5 MMcf). The combined weight of the facility’s topsides and hull is 132,000 tons, making it six times heavier than a conventional LNG carrier. It houses about 1,600 km (994 miles) of electrical and instrument control cables, equal to the distance between Berlin and Moscow.

Petronas, together with the engineering expertise of TechnipFMC and its partners, was pivotal to the project’s execution. Detailed design of the topsides and procurement of topside equipment were executed by TechnipFMC’s operating center in Kuala Lumpur, Malaysia, and the hull design was performed at Daewoo’s yard in Okpo, South Korea. Design safety, space constraints and marinization of equipment to accommodate the motion effects of sea waves, wind, currents, tides and storms were among the greatest technical challenges.

The success of the PFLNG Satu can be attributed to a combination of factors including engineering skill, experienced fabricators, efficient interface management and an experienced and committed project management team. PFLNG Satu achieved first drop of LNG on Dec. 4, 2016, and it is moored at its final location. Once fully operational, the facility will boost Malaysia’s LNG production capacity and change the landscape of the LNG business.
Fluor is developing capital efficient solutions on the Malampaya Phase 3 Project operated by Shell Philippines Exploration, B.V., on behalf of the Malampaya joint venture partners Chevron Malampaya LLC and Philippine National Oil Co. Exploration Corp.

The Malampaya Project, located about 50 km (31 miles) off the coast of Palawan Island in the western section of the Philippines, was a strategically important project for the country. The gas field is the country's largest energy source, providing continuous power to a third of the homes and businesses on the island of Luzon.

The natural pressure depletion of gas at Malampaya's reservoir required a compression platform to be installed during the field life to maintain production plateaus from the existing wells as was anticipated in the original field development plan.

The depletion compression platform, with gas turbine-driven compressors and supporting equipment, maximizes gas recovery from the reservoir and maintains production levels as reservoir pressure drops and gas is depleted. With production capacity of 15.5 MMcm/d (550 MMcf/d) of compressed gas, the field can continue to provide the critically needed levels of gas to support the Philippines' power generation needs.

Fluor Philippines performed front-end engineering, detailed engineering, procurement and construction support for the depletion compression platform, as well as modifications to the existing platform. Fluor also provided engineering support and material management for onshore and offshore fabrication, prepared work scopes for transportation and installation, and improved integration and collaboration between phases.

Location on the Pacific Ring of Fire, along the typhoon belt, makes the Malampaya Project location prone to earthquakes and typhoons, creating unique design and procurement challenges. The project's piping and structural features needed to withstand 100-year-storm and 1,000-year-earthquake conditions. These design criteria added an additional layer of complexity.

The depletion compression platform used a self-installing platform concept and gravity base foundation design to accommodate the extreme site conditions. This design was unique, and only a handful of these types of platforms have been installed around the world.

The depletion compression platform is bridge-linked to the shallow-water platform with more than 1 m (3.2 ft) of relative movement between the platforms during extreme weather. The design team ensured that all the process, utility, power and control systems tie-ins between the two platforms routed across the bridge could accommodate the movement.

The platform operates as an unmanned facility with its operations run remotely from the adjacent shallow-water platform. Because of the criticality of the platform, and the requirements of the gas sales contract, the facility has availability approaching 100%, and brownfield tie-in activities during construction were well-planned to minimize interruption to the adjacent shallow-water platform.

The limited number of offshore projects in the Philippines also yielded a challenge in terms of access to installation vessels. Through the self-installation platform design, the Fluor team mitigated this challenge and successfully demonstrated a technique that can be used on future projects without the reliance on heavy-lift vessels. During installation, the platform was towed offshore and the legs were jacked down to elevate the platform.

Malampaya Phase 3 was the first offshore project designed and fabricated in the Philippines, completed safely, ahead of schedule and gas continues to fuel three power stations.
The inherent challenges of offshore drilling operations are intensified in wells with high bottomhole temperatures. In addition to the battle to maintain drilling parameters, operators face the tall task of placing the well precisely in the pay zone without real-time formation evaluation data.

Developing reliable technology

Operators in the Gulf of Thailand encounter extreme downhole temperatures. These wells present significant challenges to acquiring reliable openhole logging data, including requiring extensive temperature-mitigation measures that can result in additional operating time and expense during drilling.

Weatherford and a major E&P company jointly designed new LWD technology that provides reliable, real-time petrophysical data. The technology delivers dependable, high-quality reservoir characterization data, locates formation pay zones and enables on-the-fly drilling adjustments in the world’s hottest wells.

The HeatWave Extreme (HEX) service provides LWD data in temperatures up to 392 °F (200 °C) and pressures up to 30,000 psi. This service reliably acquires gamma ray, resistivity, neutron porosity, bore and annular pressure and density data at high temperatures without extra trips or temperature mitigation.

To eliminate the need for cooling trips, each HEX component—from electronics to elastomers—was completely redesigned for optimal reliability while withstanding ultrahigh temperatures and vibration. The development team split the project into two phases.

Development phase

In Phase 1 the team developed the measurement-while-drilling system. This includes a directional measurement sensor that uses orthogonally mounted triaxial accelerometers and magnetometers to provide rotating inclination and azimuth.

For bore and annular-pressure measurements, quartz transducers provide data that determine equivalent circulating density (ECD). This sensor also transmits pump-off minimum and maximum ECD data during connections, which can be critical in wells with tight pore-pressure/fracture-gradient windows. It also can transmit downhole computed differential pressure measurements that are calculated from simultaneously acquired samples, which eliminates the need for surface computation.

Radially mounted Geiger Mueller tubes obtain real-time and recorded gamma ray data. Phase 1 concluded with neutron porosity measurements. The team devised radially mounted Helium-3 tubes that measure the reaction between matrix and pore fluids and Americium-241/Beryllium neutrons to determine formation porosity.

Resistivity, density systems

In Phase 2 the development team created a fully compensated, dual-frequency resistivity tool. The tool features two centrally mounted receiver antennae with three transmitters both above and below each antenna at 20-, 30-, and 46-in. spacing. Operating at 2 MHz and 400 KHz, the tool provides a range of curves with differing depths of investigation and vertical resolution.

The team upgraded the neutron porosity insert to include density measurements. The density tool features scintillation detectors that measure gamma ray scatter from chemical source mounted in the collar. The density detector comprises a near- and far-measurement system, which includes tungsten shielding to...
Field Joint Coating Defends against Cracking during Reeling

System allows operators to expand wet installation technologies to deeper water.

BY SURESH CHOUDHARY, SHAWCOR

As oil and gas companies push the boundaries of existing technologies, pipelines must also evolve to address these new operating parameters. Along the length of all pipelines, one of the most critical and vulnerable areas is the welded joint between the fused pipes. Ultradependable pipelines, requiring an extremely thick layer of thermal insulation coating, need to mitigate against material cracking at the field joint during the reeling process. Excessive cracks during the reeling process result in expensive repairs offshore because of additional vessel time. In addition to the cost, operators are also concerned about the integrity of repairs for the design life.

Hybrid field joint coating

To address material cracking during the reeling process, Shawcor has released its NEMO Hybrid Field Joint Coating. The Hybrid Field Joint consists of an hour glass-shaped layer of injection-molded polypropylene (IMPP) insulation coating to about 30 mm thickness, which acts as a heat barrier. This is followed by NEMO 1.1 infill to complete the body of the field joint and achieve the required ductility needed during reeling without creating added stress in the parent coating. NEMO 1.1 infill is an epoxy-urethane hybrid system, processed similarly to existing polyurethane materials.

This coating underwent rigorous installation (using reel vessel) and subsea operation testing. This is a technically, operationally and commercially viable coating that combines with existing footprint on the spoolbase without increasing cycle time of the process. It has been successfully deployed in the Gulf of Mexico (GoM) for a major operator.

IMPP field joints have been used in the industry for decades as a compatible field joint for five-layered syntactic and foamed polypropylene line pipe. During the last couple of years, the industry has seen a higher frequency of cracking of IMPP field joints during the reeling process. A pipe-in-pipe system could be technically viable alternative but commercially less attractive for deep water, rendering projects economically unfeasible. The NEMO Hybrid development started as a potential solution for a commercial project facing severe cracking issues and was successfully deployed in 2016 with issues resolved.

Deeper water solution

The NEMO Hybrid Field Joint Coating allows operators to expand the capability envelope of wet insulation technologies to deeper water. Without this solution, fixing the field joint cracks offshore will result in additional vessel time. Alternative technologies such as pipe-in-pipe may be used but requirement of two thick-walled pipes for deep water will also require higher load capacity vessel. The NEMO Hybrid Field Joint Coating uses new epoxy-urethane material that has improved ductility but is processed using existing process footprint, removing the need for additional capex.

Proven technology

The technology development started in 2014 as part of problem solving for a commercial project in the GoM. For two years, the product underwent rigorous laboratory scale, prototype reeling testing, prototype simulated subsea vessel testing, actual offshore vessel testing and has been successfully deployed for a major operator in the GoM. Its testing has included:

- More than 15 reeling simulation trials in winter conditions in Norway for different reeling radius ranging from 7.5 m (24.6 ft) to 9.75 m (31.9 ft).
- Four subsea simulated service vessel testing validating the thermal performance of the system;
- Two tensioner trials determining installation capacity; and
- Long-term material aging tests.

The concept of a dual-layer field joint system is not only limited to polypropylene line pipe systems but can be extended to polystyrene and other extreme temperature polymeric materials. The solution is a different way of incorporating materials within the field joint system that combines high temperature-resistant material with a low temperature ductile material. This technology will allow broader use of wet insulation technology for deeper water and improving economic feasibility of deepwater projects.

Shawcor's NEMO Hybrid Field Joint Coating provides a solution to a challenge that has existed in the deepwater environment for years.

For more information about the NEMO Hybrid Field Joint Coating and other end-to-end pipeline solutions, visit Shawcor in booth 2453.

Industry News

GoM Deepwater Exploration Remains Strong

A new report from Stratas Advisors notes that the year 2015 saw a record 101 exploration wells spudded in deepwater areas, including water depths between 1,000 ft and 5,000 ft (305 m and 1,524 m) and ultradeep water with water depths up to 100 m (328 ft). The main components are GE liquefaction trains powered by marinized GE LM2500 gas turbines, aluminum FSP storage tanks and marine loading facilities.

The PLNG facility comprises a number of different fixed offshore platforms joined to form a unit for the production, storage and shipment of LNG. The facility is designed to withstand weather conditions on the U.S. GoM shelf but can be adjusted to most offshore conditions in water depths up to 100 m (328 ft). The main components are GE liquefaction trains powered by marinized GE LM2500 gas turbines, aluminum FSP storage tanks and marine loading facilities.

GE Oil & Gas has designed the liquefaction trains as well as the power platform, which supplies electric power to the LNG pumps, marine facilities and accommodations.

The FSP storage tanks were developed by TankTek Ltd., a HongHua subsidiary, in conjunction with Braemar Technical Services and GE Oil & Gas. The tanks were developed to accommodate storage-space ratio as well as provides a low-profile design suitable for offshore weather conditions. The lightweight tanks can be fixed to the jacket in the yard and transported by heavy-lift vessel directly to the site where they are “floated over” the fixed pilings for installation.

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INDUSTRY NEWS
Minimizing formation damage during drilling is critical for offshore operators aiming to lower their completion costs and increase production rates. Baker Hughes has developed a solution with its reservoir drill-in fluids (RDIFs), specialized fluid solutions engineered to protect the pay zone during wellbore construction, simplify cleanup processes and optimize hydrocarbon recovery.

The RDIF formulations are designed with all the properties required of drilling fluids but also work to protect reservoirs in formations ranging from unconsolidated sandstones to fractured limestones. RDIF systems offer thin, tight filter cakes that are easily dispersed and removed, leaving clean brine in the hole to commence production. They are also fully compatible with pre-pack and gravel pack completions.

**Versatile applications**

RDIF formulations find application as combination drilling and completions fluids in a variety of well construction scenarios. A water-based RDIF system is a one-trip drill-in and completion fluid that has proven effective in various coring applications and gravel pack completions.

An invert emulsion RDIF formulation is also an option when maximum temperature, lubricity or inhibition is required. The system can be blended using any approved external-phase oil and is suited for the most difficult drilling environments.

**Increased production from unconsolidated sandstone**

RDIF technologies have been successfully applied to more than 350 reservoirs in major producing fields around the world, including an unconsolidated sandstone reservoir in an offshore field in Mexico’s Campeche Bay. The operator wanted to lower the risk of formation damage and production screen plugging during a standalone screen completion in a horizontal openhole well.

As part of the solution, Baker Hughes recommended its 9-lb/gal water-based RDIF in conjunction with its Mudzyme enzymatic filter cake breaker system. This combination was tested in laboratory trials, where it demonstrated improved filter cake removal and increased production.

The operator then evaluated this combination in two openhole applications. The first, a reentry well, was drilled about 152 m (500 ft) into the 4-1/2-in. section with a 40-degree inclination. Following two potassium chloride (KCl) brine displacements to ensure a solids-free environment, the water-based RDIF was added to the well prior to running the completion screen. Coiled tubing was used to place the enzymatic treatment inside the screens and cover the entire openhole interval. The enzyme system was then soaked for 12 hours to degrade the filter cake in a single treatment.

The second well, the first horizontal openhole standalone screen completion application in Campeche Bay, proved more challenging. The well’s upper section was drilled with an 8.9-lb/gal oil-based mud, which had to be removed and the oily residue and debris cleaned out prior to drilling the reservoir section with a water-based fluid. A wellbore-cleaning spacer system was first used to clean the well followed by circulating the water-based RDIF. Throughout the drilling of the 6-in. openhole horizontal section, the RDIF maintained wellbore stability, improved hole cleaning and avoided losses into the formation.

The RDIF system was then displaced from the well, and the openhole section was filled with viscosified...
BRAZIL (continued from page 1)

“Everybody here knows that Brazil has at least 10, 15, 20 points that we need to solve immediately, but we can’t face all the problems at the same time,” said Mike Jeffries, noting that the president has not yet presented a comprehensive reform package.

Earlier this year, Brazil dropped the requirement mandating companies to buy equipment locally by about 50% for operations and production onshore. The figure was lowered to about 30% for exploration offshore and to 25% for construction of wells. Brazil also lowered the fines against oil companies that do not meet local content percentages from a 60% minimum to 40%, and from a ceiling of 100% to 75%

It was one of several moves Brazil made in an effort to boost its economy and attract foreign investment. The environmental ministry is working on a bill to send to Congress to speed up the environmental licensing process for oil and gas development.

The minister said he is optimistic about the years to come, especially after recent gains in prices for oil and gas. Halliburton, Trendsetter Engineering and C-Innovations have added 14 additional full bbl/d of oil brought online in less than four years from final investment decision to first oil. Total announced in March 2017 that production had started up at Moho Nord.

The operator is the owner of the project with a 53.5% interest, Chevron Overseas (Congo) Ltd. (31.5%) and Société Nationale des Pétroles du Congo (15%) are partners in the project.

Hear comments from Philippe Charlez, senior technical adviser for Total, when you read this story online at EPmag.com.

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said the company has come a long way from Girassol, with advances in technologies like subsea processing and subsea separation making offshore production possible. Moho Nord is no exception, he added.

With a production capacity of 100 Mboe/d, Moho Nord is the biggest oil development to date in the Republic of the Congo. Developed through 34 wells tied back to a new tension leg platform (TLP)—a first for Total in Africa—and to the Likouf floating production unit (FPU), oil is processed on the Likouf and then exported by pipeline to the Total-operated Dyonos off- terminal.

Moho Nord is, according to Goiffart, two subprojects—producing from three reservoirs. One subproject includes the Moconoe and Albian reservoirs found in northern area of Moho Nord and includes the TLP and FPU facilities. The waters produced from the Moconoe and Albian reservoirs are incompatible due to barium sulfate scales. Because of this, the company has two separate water processing trains, Goiffart said.

Production from the southern area of Moho Nord was made possible via a subsea tieback to the Moho Bilondo FPU Alima that has been in operation since 2008.

Virtual Reality Supports Training and Knowledge Transfer

Lloyd’s Register (LR) has released its Virtual Reality (VR) Safety Simulator to help further support training and knowledge transfer in the energy industry. LR has built a virtual environment to help illustrate the need for a continued focus on safety and risk assessments in the industry.

VR technology helps to reduce the costs of non-productive time measured in hundreds of millions of dollars annually across the industry due to operating downtime and inefficiencies.

LR’s VR Safety Simulator uses the latest high-power computing to simulate real-life situations with a high degree of interactivity for the user. Its training allows both young and experienced trainees at its Global Academy Training Centers and in Houston to explore training possibilities by building on the remote learning allows both young and experienced trainees at its Global Academy Training Centers and in Houston to explore training possibilities by building on the remote learning center’s curriculum. The software platform is a reliable sampling service capable of generating clean samples and good measurements while demonstrating a time and budget savings.

For more information about the Spectrarex service, visit Schlumberger booth 2415.

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Subsea Alliance To Provide Well Intervention Packages

Halliburton, Trendsetter Engineering and C-Innovations have formed a strategic alliance to provide Gulf of Mexico customers with technologically advanced, integrated offshore well intervention packages. The alliance leverages the companies’ strengths to create subsea solutions for hydraulic interventions. The combined package will improve operator efficiency while addressing infield production and subsea challenges.

“Our combined approach has already resulted in successful campaigns that have reduced project costs, enabling operators to conduct more work and create value in a traditional high-cost environment,” said Marto Lugo, chairman and CEO of Trendsetter. “To date, the alliance’s projects have included complex hybrid remediation, large acid stimulations, pipeline flushing, and inspection, maintenance and repair work in water depths up to 10,000 ft (3,048 m).”

Gulf Publishing Co. Acquires Oldiom Publishing

Gulf Publishing Co. has acquired Oldiom Publishing Co. of Texas Inc. Through the acquisition, Gulf Publishing Co. enhances its presence in the mainstream and utility sectors with three well-known industry trade journals and two major industry conferences.

Last year, Gulf Publishing Co.’s management team completed a buyout of its energy information business from its former London-based parent to create an independent Houston-based company. The company continues to publish its three energy magazines: World Oil, Hydrocarbon Processing and Gas Process, and through its management buyout, added Petroleum Economist. The acquisition of Oldiom adds Pipeline & Gas Journal, Pipeline News and Underground Construction to Gulf Publishing Co.’s portfolio.


While Brazil's energy ministry has made strides, Filho admitted there are still many challenges ahead. Brazil is working to increase gas production as the country's agreement with Bolivia nears its end, and the environmental ministry is working on a bill to send to Congress to speed up the environmental licensing process for oil and gas development.

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acquire and analyze samples in real time and measure formation pressure from the wildcat exploratory Mississippi Canyon well. The service was added to the downhole drilling assembly to collect reservoir-representative samples while perfoming accurate and reliable formation fluid analysis while drilling. Traditionally, sampling happens about a day after drilling, which often results in contamination of the reservoir by the drilling fluid filtrate.

The new service collected and analyzed six samples downhole in real time, setting an industry-first for the transmission of drilling fluid and reservoir fluid properties. The service estimated contamination and time to clean up, performed fluid identification and typing, and measured the gas-oil ratio and fluid composition (C1 to C7, C8+C9 and CO2).

These results were verified 10 weeks later by laboratory results, which showed good agreement with field results on every measure. Contamination was estimated in real time and tracked to within +/- 2% of the laboratory-determined values. Pretests, pressure measurements and fluid gradients were also successfully taken during the operation. A total of 28 pretests were taken—17 while drilling and 11 while pulling out—that provided the operator a full description of the reservoir pressure and fluid gradients.

By delivering laboratory-quality results while drilling, it was concluded that the Spectrarex service is a reliable sampling service capable of generating clean samples and good measurements while demonstrating a time and budget savings.

For more information about the Spectrarex service, visit Schlumberger booth 2415.

OEG Offshore Merges with Paragon Industries

OEG Offshore, a global provider of cargo carrying units (CCUs) and A60 modules to the oil and gas industry, has merged its U.S. business with Louisiana-based cargo unit and logistics specialist Paragon Industries Inc.

The multimillion-dollar merger confirms the continued growth and success of both companies with a global offshore container suppliers serving the Gulf of Mexico. The deal expands OEG’s U.S. fleet by more than 1,400 units and includes a number of new container designs as well as extending its current repair and maintenance service to a number of new full service locations.

All of Paragon’s 14 experienced staff will join with OEG’s U.S.-based employees.
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“We have to make sure we are streamlined, and we have to restore trust,” he said. “We won’t change the rules after you have invested.” Zinke is an advocate working with you, not against you, because we understand that investment is our only answer to a great nation.”

The Trump administration said the executive order is intended to boost U.S. domestic production and to reverse bans set by former President Barack Obama on drilling in areas of the Atlantic, Pacific and Arctic oceans as well as the U.S. Gulf of Mexico (GoM).

At OTC Zinke reiterated those intentions and stressed the importance of energy to the American economy.

“There is a cost, a social cost, to not having a job in this country,” Zinke said. “The economy as good, bad or indifferent is on energy. We have to make sure that our energy is reliable, abundant and affordable. I can tell you, if you don’t have a good economy under the hood then the rest of it doesn’t matter.”

He also emphasized energy’s importance to national security.

“I can tell you from a guy whose seen war up close and personal, I don’t want your children to ever go to war over a resource that we have in America,” he said. “As it turns out, we do have resources.”

He also addressed environmental concerns over opening offshore leases in the Outer Continental Shelf and the GoM.

“I’m a Teddy Roosevelt Republican and Teddy was about multiple resources,” Zinke said. “Roosevelt was the one who said, conservation is as much about development as it is about preservation.” You can have preservation, conservation and economic development all at once by using sound practices, science and technology.

“The President and myself, we don’t pick winners and losers,” he continued. “We don’t favor oil and gas over any other industry. We just want to make sure the field is even and America can use its resources.”

He also reiterated comments he made in a statement released shortly after Trump signed his executive order pointing toward energy as a driver of revenue for the country.

“We made $15 billion more a year in 2008 than last year, and that’s just in offshore. Now, some of that is market driven, but dropping $15 billion a year, year after year, has consequences,” he said. “But dropping $15 billion a year, year after year, has consequences,” he said. “I’m also in charge of the Land and Water Conservation Fund—great program. That’s funded by offshore.

“You hear conversation this country about this program being cut, that program being cut, how expensive medical coverage is. Well, if you have money in the bank, those problems go away.”

He also said Americans are the stakeholders in how public lands are used and must have a seat at the table.

“We want to make sure it’s value added, that there is a rec- lamation plan in place, and like good Boy Scouts, we want to leave our campfire site in the same or better position than when we found it. That’s why I’m confident in you,” he continued, addressing industry delegates directly. “The United States has the most stringent, toughest, best regu- latory framework for safety and environmental extraction of resources in the world.

“We have good people, we have good technology, [and] we have unbelievably good safety practices.”

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ensure gamma rays are emitted only into the formation.

Development activity also included a new preventive maintenance program that tracks temperature and vibration rates and adjusts maintenance schedules accordingly. The result is an LWD string that can acquire LWD data during 200 hours of operation at 392 F.

Case study
The LWD system logged several wells as part of an extensive offshore HP/HT drilling campaign in the Gulf of Thailand. The system proved a reliable means of acquiring gamma ray, resistivity, neutron porosity, bore and annular pressure and density data at temperatures up to 392 F.

The drilling team reached total depth in each well without temperature mitigation efforts or other NPT.

The technology reduced drilling time by 20 hours per well, which is valued at $150,000 per well and $6.9 million during the campaign.

The HEX service is featured in Weatherford booth 1839.

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9-lb/gal KCl brine and clean completion brine. A 4-1/2-in. standalone screen completion assembly was run in hole without incident, and the enzymatic system was placed inside the screens to degrade the filter cake. As with the first well, the combination of the water-based RDF and the enzymatic filter cake breaker system provided excellent reservoir productivity results for the unconsolidated sandstone formation.

Both wells indicated U.S. skin factors of nearly zero, and the production rate increased by 150%.

In this and other field applications the solution consistently has proven its ability to protect a well’s pay zone by replacing skin damage, flow restrictions and losses with high-integrity wellbores that deliver improved production rates.

To learn more, visit the Baker Hughes booth during OTC.

For more information, visit www.bakerhughes.com.

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