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'Hub And Spoke' Approach Propels Anadarko In GoM

When it comes to longer cycle investments in the oil and gas industry, offshore developments come to mind along with their hefty price tags.

But Anadarko Petroleum Corp. is working to buck the trend by building on its winning track record of successfully tying back new discoveries to existing infrastructure, cutting costs and time.

"Anadarko plans to continue leveraging its premier infrastructure position in the Gulf of Mexico [GoM] and drill approximately seven development tiebacks during the year," Anadarko spokeswoman Stephanie Moreland told *SEN* in an emailed statement. "At Constellation, the first development well was spud in April, and the subsea facilities contract was recently awarded. First production is expected in 2018, and the well is expected to be tied back to the 100% Anadarko-owned Constitution spar."


Anadarko's 100%-owned Constitution spar in the Green Canyon area of the deepwater U.S. GoM will host production from the Constellation Field roughly 32 km (20 miles) away. (Source: Anadarko Petroleum Corp.)

The Woodlands, Texas-based company aims to not only accelerate its subsea tieback opportunities but also speed execution of such projects.

The goal is to turn "what we believe to effectively be mid-cycle opportunities into shorter and shorter cycle opportunities to continue to deliver the high-margin oil volumes that we have in the U.S. Gulf," Ernie Leyendecker, executive vice president of Anadarko's international deepwater and exploration, said during the recent UBS Global Oil and Gas Conference.

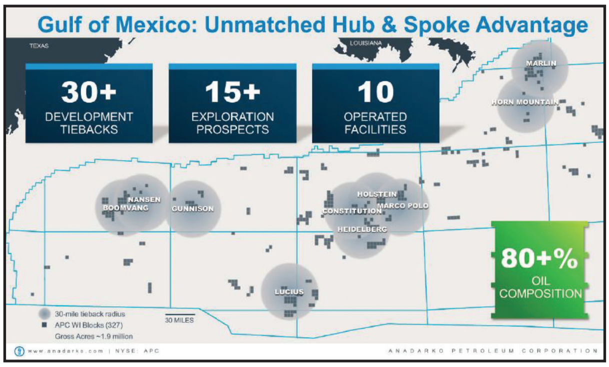
As the oil and gas industry worked to rebound from a budget-crippling downturn in 2016, Anadarko deepened its subsea tieback inventory by about 20 with its $2 billion acquisition of Freeport McMoRan Oil & Gas deepwater GoM assets. The deal also expanded the company's infrastructure.

So far, Anadarko has identified at least 30 subsea tieback opportunities to leverage with its 10 hubs, or operated floating facilities, sprawled across the GoM. Three of the facilities were acquired in 2016—Holstein, Horn Mountain and Marlin.

"We have quite a number of tieback opportunities that are considered development wells or subsea, low-risk development wells, exploration opportunities. We are really in a great position in the U.S. Gulf of Mexico," Leyendecker said.

Deepwater GoM represents one of the three key focus areas for Anadarko—the others being its onshore assets in the Delaware and Denver-Julesburg basins. Anadarko aims to produce about 160,000 boe/d from its GoM assets, which include Lucius and Heidelberg among others, through 2019.

WHAT'S INSIDE



(Source: Anadarko Petroleum Corp.)

Anadarko's GoM developments could generate a five-year expected free cash flow of about $6 billion.

Subsea tiebacks have a starring role with competitive rates of returns.

The average rates of return is more than 75% at $55/bbl oil, Daniel Brown, executive vice president of Anadarko's international and deepwater operations, said during the company's first-quarter 2017 earnings call. The company has more than 30 tieback opportunities "in the cupboard" that it can execute, he said, adding "we actually have a deeper bench than that, but that's our high-graded list."

"We also have platform opportunities that have very high rates of returns that you'll see us executing on as we move forward," Brown said. "Costs within the Gulf of Mexico are sort of stable and perhaps somewhat even deflationary if you think about the rig cost out there. So obviously, as you think about tiebacks, the reservoir that you're drilling into, the length of tieback distance from the platform is going to vary. So the individual cost for a specific project will vary."

Costs for tiebacks are lower compared with stand-alone developments.

"The expected internal rates of return that the tiebacks give us compete very favorably with our two large onshore positions," Anadarko CEO Al Walker said on the call. "So the rate of return because of the costs being minimal for a tieback into an existing infrastructure is part of the equation here for why it makes so much sense from a portfolio perspective."

This "hub and spoke philosophy" not only adds value and enhances rates of return across the GoM, it "also provides future optionality as we continue to make new discoveries and appraise existing ones," Moreland said.

While economics is a major factor in determining whether to pursue a tieback option, Anadarko also considers facility usage, flow assurance, fluid compatibility and future opportunities around each facility, Moreland said. "We take a regional approach to developing the resources near our facilities and try to ensure we make the best economic decision."

The development option, however, is not without challenges.

Flow assurance, fluid compatibility, facility usage and brownfield costs are among these for Anadarko. "We take the facility design life and the ability to extend the life of the facility to accommodate the life of the tieback into consideration," Moreland said, later adding the company has a team dedicated to evaluating flow assurance issues.

Anadarko is also working with other industry players to advance subsea technologies, including in the area of HP/HT drilling.

"The focus of the effort is on the mobile offshore drilling unit, blowout preventer and riser, completion, intervention, and subsea production equipment," Moreland said. "The partners are working together to develop standardized, state-of-the-art subsea systems designed to meet the challenges of producing from reservoirs with pressures of up to 20,000 psi and temperatures of 350 degrees at the mudline."

—Velda Addison

DEVELOPMENT

Trinidad Finds Secure Country's Importance To BP

BP has enjoyed success with the drillbit this month offshore Trinidad and given the green light to a field development project.

This underlines how Trinidad is emerging as vital cog in the BP machine. Production from Trinidad is set to account for about 20% of BP's upstream growth over the next four to five years. Investment in the country between 2012 and 2022 could reach $11 billion.

BP Trinidad & Tobago (bpTT) chalked up "two significant gas discoveries" with the Savannah and Macadamia exploration wells offshore Trinidad. The results of the wells, the first drilled by BP in Trinidad in a decade, unlocked about 56.66 Bcm (2 Tcf) of gas in place, the company said.


BP's Juniper platform sets sail for offshore Trinidad in January. (Source: BP)

"The discoveries mark the start of a rejuvenated exploration program on the Trinidad shelf with a further three exploration wells to be drilled" Bernard Looney, BP's chief executive of Upstream, said during a bpTT exploration and development update in Trinidad last week.

The Savannah exploration well was drilled into an untested fault block east of the Juniper Field in water depths of more than 152 m (500 ft) about 80 km (50 miles) off southeast Trinidad.

"The well was drilled using a semisubmersible rig and penetrated hydrocarbon-bearing reservoirs in two main intervals with approximately 198 m (650 ft) net pay. Based on the success of the Savannah well, bpTT expects to develop these reservoirs via future tieback to the Juniper platform that is due to come online mid-2017," said bpTT, which has a 100% stake in the Savannah and Macadamia fields.

The Macadamia well was drilled to test exploration and appraisal segments below the existing SEQB discovery, which sits 10 km (6 miles) south of the producing Cashima Field. The well penetrated hydrocarbon-bearing reservoirs in seven intervals with about 183 m (600 ft) of net pay.

"Combined with the shallow SEQB gas reservoirs, the Macadamia discovery is expected to support a new platform within the post-2020 time frame," bbTT said.

Norman Christie, regional president of bpTT, called the news exciting.

"We are starting to see the benefits of the significant investment we have made in seismic processing and ocean-bottom seismic acquisition," Christie said.

"Savannah and Macadamia demonstrate that with the right technology we can continue to uncover the full potential of the Columbus Basin. This is a testament to bpTT's ongoing commitment to the development of our Trinidad and Tobago operations and the wider industry, and we look forward to the future portfolio drillout."

BP Sanctions Angelin

Hot on the heels of the two discoveries, BP then moved to sanction development of its Angelin gas project off Trinidad. The project requires the construction of a new platform 60 km (37 miles) off the southeast coast of Trinidad at a water depth of 65 m (21 ft).

The development will include four wells and have a production capacity of about 17.0 MMcm/d (600 MMcf/d) of gas. Gas from Angelin will flow to the Serrette platform hub via a new 21-km (13-mile) pipeline.

Drilling is due to start in third-quarter 2018, and first gas is scheduled to come onstream in first-quarter 2019.

"The sanction of the Angelin project was made possible due to the execution of a new gas sales contract with the National Gas Co.," Christie said. "Successful completion of these negotiations was important not only to the sanction of Angelin but will also underpin a further $5 billion to $6 billion in potential future investments over the next five years."

Angelin was discovered with the El Diablo well in 1995 and appraised by the La Novia well in 2006.

Looney's Briefing

At the June 1 bpTT briefing in Trinidad, Looney noted five successes in the region:

- Completion of gas contract negotiations with NGC;
- Start-up of two projects—Sercan II with partner EOG and the Trinidad Offshore Compression project (TROC);
- Imminent startup of the Juniper project;
- The Savannah and Macadamia gas discoveries; and
- Sanction of the Angelin project.

"TROC and Juniper are two out of seven major projects that BP promised our shareholders to start up in 2017. This highlights how vital our Trinidad operations are to BP in meeting our investor commitments and reinforcing market confidence," Looney added.

Gas produced from Trinidad "is key to BP delivering on our commitment to provide 800,000 boe/d of new production by 2020," he said, adding it will account for about 20% of BP's upstream growth over the next four to five years.

"And more importantly, for the country, the increased production volumes also mean that we are doing our part to close the gas supply/demand gap, which has been a major challenge for the industry here in Trinidad over the past several years," Looney said.

"In the short term, the startup of Juniper, TROC and Sercan II will greatly assist us in meeting our near-term production goals and help to alleviate gas shortages. In the medium term, the sanction of Angelin ensures that we can maintain production levels past 2019. In the longer-term, the success of the Macadamia and Savannah exploration wells underpins two new field developments post 2021," Looney said.

Trinidad Investment

At the same briefing, Christie said bpTT began an investment program that allocated about $5 billion in capex over five years.

"Through significant economic changes, a challenging gas supply/demand environment and a change in government, that plan has been executed," Christie said. "This has been enabled by successive governments who have worked with us in partnership for the good of Trinidad and Tobago."

This "spirit of partnership with the government" is why BP announced a few weeks ago that it will invest another $5 billion to $6 billion in Trinidad in the next five years.

"For those of you keeping count, that will mean that from 2012 to 2022, we will have invested $10 billion to $11 billion in BP's Trinidad business—even with continued predictions of depressed hydrocarbon prices," Christie said.

—Steve Hamlen

Eni Clears Coral South FLNG Development Offshore Mozambique

Eni signed drilling, construction and installation contracts for production facilities and regulatory and financing agreements on June 1 for the Coral South FLNG development offshore Mozambique. (Source: Shutterstock.com)

Overcoming difficult market conditions, Eni signed contracts and inked regulatory and financial agreements June 1 to pave a clear path toward development of the Coral South floating LNG (FLNG) project offshore Mozambique.

The FLNG development, which had awaited sanction by project partners, marks the first such development offshore Africa in an emerging frontier region known for its potential to help fulfill the world's growing appetite for natural gas. The FLNG unit will be the world's third.

"Using a vessel [to] liquefy gas offshore will allow the partners to realize cash flow from Mozambique earlier," Alasdair Reid, research manager for Southern and East Africa at Wood Mackenzie, said in a statement. "The project will generate annual gross revenues of over US$1.5 billion per year (before tax) for 25 years, utilizing 4.7 trillion cubic feet [Tcf] of gas over its lifetime. With FID [final investment decision] out of the way, the project is now on track for first LNG production in 2022."

The milestone comes about five years after the Coral Field was discovered. Located in the Rovuma Basin's prolific Area 4, the discovery is believed to hold about 450 Bcm (16 Tcf) of gas in place.

Eni CEO Claudio Descalzi said the company sees use of natural gas as "critical to achieving a more sustainable future" as the world moves to a lower carbon energy mix.

"Our ambition to become a global integrated gas and LNG player is based on working alongside key partners such as Mozambique," Descalzi said in a company statement June 1.

Eni called the launch of Coral South a "testament to the quality of the assets in place and to Eni's technological leadership in the development of deepwater gas fields."

Phase 1 of the development plan, which was approved in February, includes drilling six subsea wells and installing an FLNG facility with a capacity of about 3.4 million tons per year. The field is located in a depth of more than 2,000 m (6,562 ft) about 80 km (50 miles) off the Palma Bay.

Construction of the FLNG facilities will be financed through project finance covering about 60% of its entire cost. The financing agreement has been subscribed by 15 major international banks and guaranteed by five export credit agencies, Eni said.

The final investment decision comes as the offshore sector continues to recover from the downturn, which stalled many high-dollar projects as companies awaited higher commodity prices and demand.

Calling 2017 a slow year for the wider LNG supply business with few LNG project sanctions, Wood Mackenzie's global LNG analyst Matthew Day described 2017 as a "big year for FLNG."

"The only two projects we expected to be sanctioned this year, Coral and Fortuna, are both floating LNG. This highlights a positive shift in industry perception toward the FLNG concept," Day said. "Majors Eni, Shell, Exxon and recently BP have all now endorsed the floating LNG concept. With stranded gas resources suited to FLNG elsewhere in Africa, Mozambique offers Eni an ideal regime to test this new approach."

Eni and its Area 4 partners—Portugal's Galp Energia, South Korea's Kogas and Mozambique's Empresa Nacional de Hidrocarbonetos—agreed in October to sell all LNG produced from Coral South project to BP as part of a 20-year deal.

"Smaller-volume projects are moving forward in this oversupplied environment. With an output of 3.5 mtpa [million tonnes per annum], all contracted to BP, Coral has had an easier time of finding a market compared to other megaprojects chasing sanction," Day said. "With global activity levels and costs low, now is a good time to add new capacity, even if the LNG market does presently look oversupplied. By the time Coral produces first LNG in five to seven years' time, new LNG supply is likely to be required in the global market."

In a separate news release June 1, TechnipFMC said the company and its partners JGC Corp. and Samsung Heavy Industries—which make up the TJS Consortium—landed a major integrated contract for the project. The contract was awarded by FLNG facility owner Coral FLNG SA, which is jointly owned by Eni Mozambique, CNODC Mozambique, ENH FLNG, Galp Energia Rovuma and KG Mozambique Ltd.

The contract covers engineering, procurement, construction, installation, commissioning and startup of the FLNG facility along with its risers, subsea flowlines system, umbilicals and other subsea equipment.

Eni is operator of Area 4 via its indirect stake held through Eni East Africa (EEA), which has a 70% stake in the concession. Eni holds 71.4% of the shares of EEA, while China's CNPC holds 28.6%. ExxonMobil Corp. will get half of Eni's shares in EEA if an agreement signed in March gets required regulatory approvals and satisfies other conditions.

—Velda Addison

Kraken Output Imminent, $700 Million Under Budget

The U.K. Kraken development is on track to deliver first oil before the end of June, significantly under budget, while operator EnQuest said it is also making strong progress on other U.K. projects.

When EnQuest sanctioned Kraken the project had a gross capex of $3.2 billion. Following significant cost reductions, it is now estimated that the development will cost only $2.5 billion, a source familiar with the matter told *SEN*. This equates to an overall capex reduction of $700 million, or about 22%.

Though EnQuest has not disclosed the target startup production rate, the forecast gross peak plateau production is expected to be about 50,000 boe/d. The timescale to reach this is uncertain. Enquest noted in its recent financial results that, "as with all developments of this scale, wells will be brought onstream in a phased manner in line with good reservoir management practices, aiming to maximize long-term productivity and value."

On the Kraken development, all drilling is now complete on DC1 and DC2, and the rig has moved to DC3 where "further excellent progress has been made on the drilling program. Drilling performance to date has significantly de-risked delivery of the project to and beyond first oil," the company said. "The project continues to be under budget and on schedule."

DC1 and DC2 subsea commissioning is complete and ready for operation. The turret pipework and emergency shut-down valves have been installed. Nitrogen/helium leak testing has been successfully conducted, and the final rotation testing is complete.

Also, the boiler systems are running well and the water injection and HSP power pumps have been commissioned. Testing and other topsides and subsea infrastructure final commissioning work is ongoing. The handover of FPSO systems from commissioning to operations is ongoing.

"Longstanding discussions with Bumi continue in relation to the remedies of Kraken partners for contractual infringements by Bumi," EnQuest added.

At startup, 13 wells will be available comprising seven producers and six injectors. EnQuest's CEO Amjad Bseisu said Kraken is on track to reach first oil by the end of June and hit opex and capex targets.

"First production from the Kraken development will give EnQuest its seventh operated hub and will mark a turning point in EnQuest's progress from a period of heavy investment to one focused on cash generation and deleveraging the balance sheet," Bseisu said.

Production Plans

EnQuest also reaffirmed its 2017 guidance for average production of between 45,000 boe/d and 51,000 boe/d, "which reflects the Kraken contribution in the second half of 2017."

Production averaged 37,856 boe/d from January through the end of April 2017, down from the 42,752 boe/d in the same period in 2016, reflecting natural declines in existing producing assets, the operator said.

"EnQuest's proposed acquisition and operation of interests in the Magnus oil field and the Sullom Voe Terminal is on schedule for completion around the end of the year. This transaction recognizes EnQuest's differential operational capability in managing mature assets and infrastructure, essential in the North Sea Basin at this point in its evolution," Bseisu said. "Magnus will be EnQuest's eighth operated hub and provides the potential for significant future growth."

The Magnus/SVT transition and acquisition program will see no cash outlay for EnQuest.

Project Updates

EnQuest also reported on the performance of its assets in the U.K Northern North Sea and Central North Sea.

Northern North Sea

- Thistle/Deveron fields: A program improving the reliability of water injection is being implemented and is already having a positive impact.
- Don fields: Well performance has been particularly good at Don Southwest, with high levels of production efficiency across the fields.
- Heather/Broom fields: The 2017 Heather/Broom production is progressing "broadly according to plan."

Central North Sea

- Greater Kittiwake Area (GKA) and Scolty/Crathes fields: The work program in GKA for 2017 is focused on optimizing production from the existing well stock, including the Scolty and Crathes fields. Good production has been delivered from the GKA fields, with very high levels of plant uptime. Initial rates on Scolty and Crathes for first-half 2017 have been constrained due to operational issues. Work is ongoing to restore the rates.
- Alma/Galia: As expected at the time of EnQuest's results announcement in March, 2017 production from Alma/Galia has been lower than 2016, given two wells are shut in, production outages in first quarter due to storm damage and natural decline. Discussions are ongoing with the electrical submersible pump supplier on rectification plans to address pump reliability issues.
- Alba Field (non-operated): Production from Alba benefitted from the A49 well coming back online in March.

—Steve Hamlen

Husky Approves $1.6 Billion West White Rose Project

Canada's Husky Energy Inc. said on May 29 it is proceeding with its long-delayed $1.6 billion West White Rose project off the Atlantic coast, even as the energy downturn makes the high-cost project less attractive.

In its statement announcing the West White Rose plans, Husky said first oil is expected in 2022 and the project could achieve a gross peak production rate of about 75,000 bbl/d by 2025.

The company, which is controlled by Hong Kong billionaire Li Ka-shing, also said a new oil discovery has been made at the Northwest White Rose production area.

Husky's decision to proceed with the investment comes at a time when several global energy majors have scaled back from Canada's expensive oil sands assets, though offshore oil and gas projects are also losing attractiveness due to their high costs. So far, there hasn't been any large scale exodus from offshore oil and gas projects.

Reuters reported in February, citing people familiar with the matter, that Husky was mulling paring down its stakes in some eastern Canadian offshore assets, in a move that could fetch several billion dollars.

Even if those sales materialize, Husky may remain a major player in the Atlantic region. In February CEO Rob Peabody said Husky's Atlantic operations were important and declined to comment on what he said was speculation.

It is unclear how Husky's potential divestiture plans are currently going. When asked about the plans on May 29, a company spokeswoman repeated Peabody's comments from February.

The company has previously said it will consider a final investment decision for the West White Rose Field, a satellite of White Rose, in 2017.

—Reuters

DEVELOPMENT BRIEFS

TechnipFMC Wins Well Intervention Contract In Australia

TechnipFMC will provide riserless light well intervention (RLWI) and subsea services for Woodside Energy Ltd. in Australia after entering a three-year frame agreement.

According to a news release, the agreement includes intervention, installation, and plug and abandonment services.

Under the agreement, TechnipFMC will initially perform installation and RLWI services in the Greater Western Flank Phase 2 (GWF-2) development northwest of Dampier, Western Australia. The company will install subsea trees and deploy its deepwater RLWI stack for well intervention services on up to eight subsea wells in the GWF-2 development.

McDermott Awarded Angelin EPCIC Contract From BP Trinidad And Tobago

The Angelin project is a dry gas development in the northern Columbus Basin. (Source: McDermott)

McDermott International Inc. said June 5 it has been awarded an engineering, procurement, construction, installation and commissioning (EPCIC) contract from BP Trinidad & Tobago (bpTT) for the Angelin gas field offshore Trinidad and Tobago.

This EPCIC contract follows the completion of a multiphase engineering contract, including pre-FEED, FEED and pre-execution engineering contracts previously awarded by bpTT to McDermott for the initial design and execution planning of Angelin. McDermott's team in Houston led the engineering and execution planning efforts with support and work share from the company's engineering center in Chennai, India.

Building off its pre-FEED and FEED work, McDermott will provide a turnkey EPCIC solution to design, procure, fabricate, transport, install and commission a six-slot wellhead platform and 26-in. subsea pipeline using its project management and engineering team in Houston. The 992-ton, four-legged main pile jacket and 1,323-ton, four-deck topside for the Angelin project will be constructed at the Altamira, Mexico, fabrication facility. The platform and pipeline are scheduled to be installed by McDermott's *DLV 2000.*

Amec Foster Wheeler Wins Aramco Oil Field Expansion Deal

Amec Foster Wheeler has won a five-year contract to provide design and project management for the expansion of Saudi Aramco's Marjan offshore oil field, the British oil and gas services company said June 1.

Amec Foster Wheeler will deliver engineering and design, overall program management and other support services for a new gas-oil separation train, which will boost production by 300,000 bbl/d, the company said in a statement. Amec will also offer the same services for a new gas processing plant, a co-generation facility and add a NGL fractionation capacity to an existing facility.

The company did not give the value of the contract, the cost of the work involved nor the amount of gas capacity being added.

Aramco declined to give further information.

Aramco has an oil production capacity of 12 MMbbl/d. Saudi officials have said its expansion plans were to compensate for declining fields elsewhere, rather than to add to total capacity.

The Marjan oil field is located off Saudi Arabia's east coast. (Source: Amec Foster Wheeler)

Bibby Offshore Lands Subsea Work At Eider Field

Subsea services provider Bibby Offshore has won a six-month contract from TAQA for subsea construction work in the Eider Field northeast of Shetland, according to a news release.

The project involves connecting the existing Otter production pipeline to the existing Eider oil export pipeline, and connection of the existing Tern-Eider water injection pipeline to the existing Otter water injection pipeline using subsea bypass spools, Bibby said in the release.

In addition, the company will provide spool piece metrology, barrier testing, removal of existing production and water injection spools and pre-commissioning support. The team will also manage procurement, fabrication and installation of new bypass spools.

Aiming to finish the job by this summer, the company plans to use its *Olympic Ares* subsea support and construction vessel and its *Bibby Polaris* diving support vessel.

BP Aims To Sign Azerbaijan Oil Field Extension Deal In June

BP expects to sign a contract at the end of June extending its production-sharing deal for Azerbaijan's biggest oil fields until 2050, the company's regional head said on May 31.

The existing deal is due to expire in 2024, and BP-led consortium and Azeri state oil firm SOCAR signed a letter of intent in December to continue developing the giant Azeri-Chirag-Guneshly (ACG) offshore fields until 2050.

"End of June is a very reasonable time for it," Gary Jones, BP's regional head for Azerbaijan, Georgia and Turkey, told reporters when asked when the contract was due to be signed. "It's a big deal. We want to get it right."

The shareholders in the consortium include BP, SOCAR, Chevron, INPEX, Statoil, ExxonMobil, TPAO, ITOCHU and ONGC Videsh.

Azeri President Ilham Aliyev said on May 31 he expected the contract to be signed soon.

"We are thinking about development of the ACG Block, and I think we will reach a final agreement with investors," Aliyev said at the annual Caspian Oil & Gas conference in Baku.

BP came under fire from Aliyev earlier this decade when the country's leader criticized the oil firm for lower than promised output levels. Oil output at ACG totaled more than 7.1 million tonnes in the first quarter of this year.

Alpha Taps GE For Cheviot Oil Field Subsea Equipment, Services

GE Oil & Gas has been named the exclusive supplier of early engineering, project management and procurement activities for the Cheviot oil field development in the U.K. North Sea, according to a news release.

Petroleum Equity-backed Alpha Petroleum said May 26 it reached an agreement with GE concerning the field's subsea infrastructure. As part of the agreement, GE will supply subsea trees, a full control system, three manifolds, flexible jumpers, flowlines, risers and umbilicals. The company will also provide subsea construction and installation services, and support commissioning.

In addition, GE Energy Financial Services is helping to raise debt financing for the project and is discussing making a significant capital investment, the release said. A final investment decision for the project is expected in fourth-quarter 2017.

The Cheviot oil field, which is fully owned by Alpha, will consist of 18 firm and five contingent wells. Development plans include use of Teekay Offshore Partners' *Varg* FPSO unit. First oil is expected in 2019 with an expected rate of at least 30,000 bbl/d of oil, Alpha said.

Aquaterra Installs Platform At Amal Field Offshore Egypt

Aquaterra Energy has designed, fabricated and installed a new Sea Swift platform for PICO Petroleum Integrated Services, the lead contractor for Amal Petroleum Co.'s (AMAPETCO) Amal Field in the Gulf of Suez offshore Egypt, a news release said.

"The Sea Swift platform is a modular system that unites the advantages of a platform with the rig-run benefits of a subsea development," Aquaterra said. "The field proven technology helps customers achieve reduced platform costs, lower installation and intervention costs, and simplified project management. It can also rapidly increase production from platforms constrained by existing slots enabling wells to be drilled, completed with dry trees and installed before the arrival of the main processing platform."

The conductor-supported platform, which is installed in 23 m (75 ft) water depth, has a 385-tonne topside with a helideck and emergency accommodation and provision for six wells. The new topsides facility for the Amal-C platform involved designing process, piping, electrical, instrumentation, control system and technical safety scopes of work, the project also included the design of the new subsea production pipelines to the Amal-A platform.

Aquaterra said the project took 18 months from design to installation. The work involved building a bridge link to the neighboring Amal-B platform and reconfiguring the topside pipework to create a new and improved production profile.

The Sea Swift was installed in 23 m water depth and from design to installation took 18 months to complete. (Source: Aquaterra Energy)

AMAPETCO operates the field for shareholders Egyptian General Petroleum Co. and Cheiron Amal Petroleum Corp., the release said.

Add Energy Wins $1.3 Million West Nile Delta Contract

Add Energy, an international consultancy for the energy industry, has secured a maintenance build contract worth more than about $1.3 million with BP for work on the West Nile Delta development offshore Egypt.

The contract will see Add Energy carry out the development of a full asset maintenance build, the company said in a news release. Work includes the delivery of an asset register and functional hierarchy build, equipment criticality assignment, development of maintenance strategies for critical and non-critical equipment, job plans and procedures.

Add Energy appointed Damon Bowler to oversee the 18-month project.

Central Processing Facility Arrives At Ichthys Field

Ichthys Explorer, the massive central processing facility (CPF) for the Ichthys LNG project, has made its way to Western Australia's Browse Basin where it will be put to use, according to Inpex.

The semisubmersible platform weighs 120,000 tonnes and has topsides that are 130 m (427 ft) by 120 m (394 ft).

"The safe completion of the 5,600-km [3,480-mile] tow of the Ichthys Explorer from South Korea to the Ichthys Field, located 450 km [280 miles] north of Broome, is another significant milestone for the Ichthys LNG Project," said Louis Bon, managing director for the Ichthys project.

The tow took 34 days. After mooring the platform in 250-m (820-ft) deep water in the Ichthys Field, Inpex said hookup and commissioning will begin.

Ichthys Explorer will be the hub for initial offshore processing of well fluids delivered from a 130-km (81-mile) network of subsea well infrastructure, a news release said. Gas from the CPF will travel through an 890-km (553-mile) subsea pipeline to the onshore LNG facility, at Bladin Point, near Darwin for processing. Most of the condensate and water from the CPF will be transferred to the nearby *Ichthys Venturer* FPSO unit.

—Staff & Reuters Reports

TECHNOLOGY

Pre-engineered Solutions Incite Industry Change

Amid the disconcerting economic news of the past several years, a quiet revolution has been taking place. Pre-engineered, capital-efficient solutions are carving a niche in the industry product roster. This is in direct response to operators' need for qualified, field-proven, flexible solutions at lower cost than bespoke solutions that leverage the lessons learned of the past to ensure future reliability.

Major operators and independents are embracing these capital-efficient designs as a project viability enabler. In the words of one major subsea operator, standardization is the new innovation.

During the most recent period of high oil prices that occurred before the downturn, the industry required engineered solutions to bespoke customer specifications as a means to reduce perceived operational risk. But over time these bespoke specifications have taken on a boomerang effect, with inefficient and complex project-specific solutions becoming a contributor to operational risk, high cost and long lead times. Now operators are becoming open to consider capital-efficient solutions with flexible functionality rather than bespoke equipment and systems. Supplier-led innovation is paving the way to new solutions options.

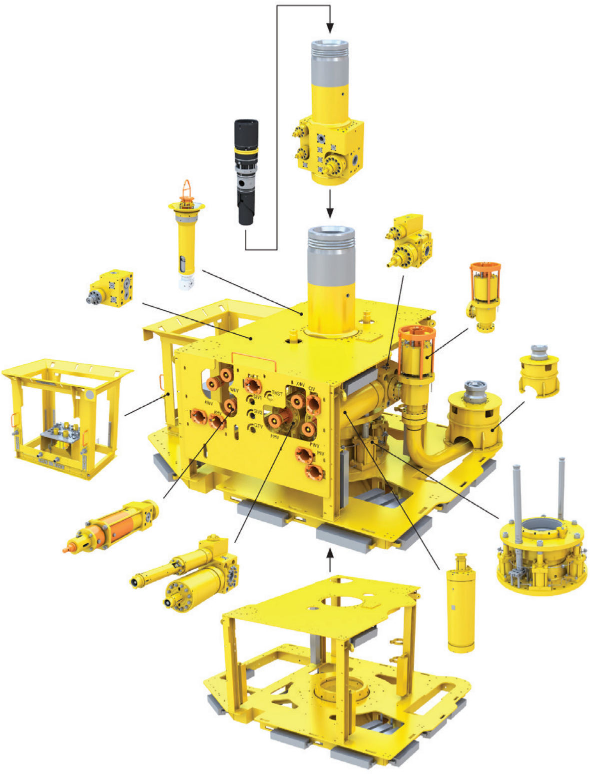
Pre-engineered Solution Advantages

Suppliers have been working on innovative ways to help operators address viability challenges. By collaborating with operators early in the project life cycle, suppliers are learning that while cost is the current major barrier to project progression, other critical objectives such as safety, reliability and operational efficiency are still top of the agenda. Companies such as OneSubsea, a Schlumberger company, are leveraging wider capabilities to address these objectives.

Pre-engineered solutions configured to meet true project needs offer a cost-effective, reliable way to meet unique project challenges and vastly improve cycle time. Optimization is achieved by standardizing processes, documentation, manufacturing and design across projects, enabling the most efficient use of engineering, project management and plant resources. At the heart of capital-efficient equipment is a suite of preauthored material specifications, weld specifications, coating specifications and quality plans that leverage standardized execution processes from engineering, procurement, manufacturing, inspection, assembly and testing.

Pre-engineered common core components combined with repeatable processes help to reduce risk. Through ever closer customer engagement, lessons learned are being incorporated into standard designs and maintained as part of a standard offering; this allows a repeatable manufacturing process, further increasing reliability and quality. Once the process is repeatable, it can then be optimized.

A subsea tree comprised of cost-efficient equipment components. (Source: Schlumberger)



Pre-engineered components designed for subsea application reduce costs while retaining reliability. (Source: Schlumberger)

When considering functional requirements, suppliers are coming up with innovative solutions and flexible functionality. For subsea trees, functional requirements can be met by utilizing common core components from efficient modular layouts and designs, allowing the operator to choose functionality from a menu of standard options.

Today, standardization does not mean less functionality; in fact, the opposite is true.

Standardization allows operators to have the functionality they really need, delivered by utilizing repeatable, common core components from existing, qualified and field-proven technology. A modular platform allows functional flexibility while avoiding bespoke redesign for every new piece of equipment. Utilization of those common core components can offer significant lead time benefits. Recent examples include subsea production trees that have been configured, manufactured and delivered within 12 months to multiple global locations.

Standardization Helps Project Viability

An operator of an Australian brownfield had been trying to develop the field as a standalone project, but it had been determined that the project was not financially viable based on the field architecture despite oil prices being significantly higher. In search of a solution, the operator engaged OneSubsea to explore potential opportunities to make the field viable.

Part of this discussion included the use of capital-efficient equipment, such as a standard horizontal tree configuration and connectors using standard components where possible. Twelve subsea trees' sub-assemblies were configured with standard spool bodies and wing valves. Subsequently, the solution was refined over time to remove subsea transformers that were part of the original development scenario and to include capital-efficient equipment, simplifying the subsea architecture. It was estimated that project costs were cut in half and the project was proven to be technically and economically viable.

— Wayne Hand, OneSubsea, a Schlumberger company

Six Unique Challenges Of Subsea Cylinders

During recent decades the world has seen a decrease in coal mining, and many nations have raised concerns about the environmental impact of other types of land-based fuel sources. This has resulted in a move toward farming the sea for its rich energy sources— tidal energy, ocean energy and the piping of deepsea liquefied gas and oil. All of these resources need to be gathered with the greatest of care for the sake of the precarious oceanic environment and respect for the dangers that the oceans can pose for personnel working in these remote locations.

Fabrications placed on the seabed need to be durable and reliable to ensure the safety of personnel while avoiding any environmental disasters that could result from faulty machinery.

Highlighted below are six of the most challenging issues companies might face when producing hydraulics to be used within the subsea industry.

The locking mechanisms of subsea connectors use hydraulics to move locks into place and can stay locked for up to 25 years. They need to be fully functional to be unlocked at the end of this period. (Source: Apex Hydraulics)

Remote Locations

Many oil and gas wells are located off the coast of remote parts of Australia or South America, thousands of miles away from the cities where the hydraulic cylinders are manufactured. The main base is often an oil rig or floating LNG station many miles out in the sea. Beneath this base the fabrication being placed on the seabed can be hundreds of meters under water. The hydraulics used in these fabrications are among the most remote hydraulic systems in the world, and this means all hydraulic cylinders need to be precisely designed, manufactured and stringently tested to ensure they work the first time with no room for error. There is no scope for simply returning faulty machinery to the factory for repairs.

Long Operating Periods

Many subsea fabrications will be in place for decades. Hydraulics need to be able to work at the end of this time, sometimes having been immobile for the operation's duration. For example, the locking mechanisms of subsea connectors use hydraulics to move locks into place. These can stay locked for up to 25 years and then need to be fully functional to be unlocked at the end of this period. Therefore, any machinery needs to be manufactured to last, with highly robust systems requiring very little and preferably no maintenance. This means that all coatings have to be of the utmost quality. Hydraulic cylinder manufacturers might make use of a special Everslik coating that has a solid lubricant in the top layer, giving a top-quality resistance to abrasion from the friction of moving parts. This can be used both on the outside and on interior valves to make the system remain in good working order for long periods.

Marine Growth, Corrosion

Long operating times present another challenge—corrosion from sea salts as well as natural marine growth, which can overpower fabrications, rendering them immobile. There are several materials that can be used to prevent both of these problems. Ceramic hydraulic rods resist the growth of algae and other marine plants. Coatings such as Corex are twice as hard as standard hard chrome plating and up to five times less porous, making them far less susceptible to corrosion. They also offer a high resistance to cracking in the event of an impact such as a piece of debris dropping from above. Seals need to be tough and durable so that any marine growth that does occur can be scraped off by the seals as the rods retract without damaging the seals themselves.

Remote Operating

Subsea hydraulic systems often are placed many hundreds of meters below the surface of the sea at depths that are impractical for a diver to reach. In these cases, the cylinders need to be operated remotely by an ROV. Cylinders with hot stab connections have been designed that allow an interface with an ROV, meaning the hydraulic system can be operated independently subsea.

Water Pressure

Every 10 m (33 ft) under water exacts an additional 14.5 psi on a structure. This means the materials used need to be extremely strong. In most cases, cylinder mandrels are made using forged steel, so the mandrels are thick and strong with no weaknesses that might result from parts being welded together. Any water that enters the hydraulic system will contaminate the hydraulic fluid, causing system breakdowns, so it is vital that seals are particularly strong to resist the force of the water.

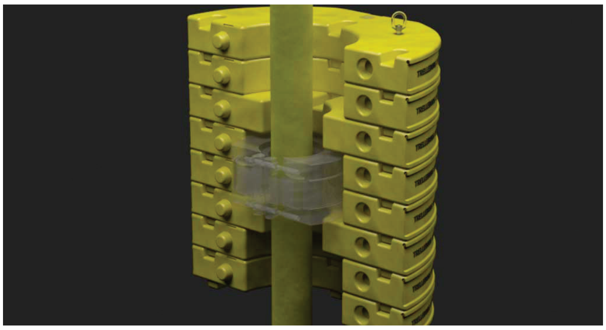
Future of subsea hydraulics

As the resources of the sea continue to be mined with a push toward harnessing renewable energies, there will be an influx of money, skills and time invested in finding new and innovative ways to overcome the challenges of installing high-quality hydraulics in fabrications used on the seabed. The industry is likely to see many new technologies and materials developed in the coming years.

—Steven North, Apex Hydraulics

TECHNOLOGY BRIEFS

Trelleborg Develops Standardized Buoyancy Module System



(Source: Trelleborg)

Trelleborg has developed a standardized buoyancy module system that aims to lower lead times.

The company said the system is made up of small elements that stack together, increasing the uplift of the complete distributed buoyancy module. "The buoyancy segments are designed to mechanically lock around the clamp to securely attach the assembly to the desired location on the riser."

The adjustable system can operate in water depths of up to 2,500 m (8,202 ft).

"We recognized a requirement to deliver buoyancy products in less time for projects with short lead times. Through our customized innovation process, we were able to qualify and standardize a buoyancy module for subsea or surface applications that can be delivered in around half the time of a typical buoyancy module," Jonathan Fox, senior product development engineer with Trelleborg's offshore operation, said in a news release. "In addition, we were able to ease handling of the buoyancy modules by incorporating synthetic rubber feet to the bottom of the finished assembly to prevent handling damage and reduce assembly time."

Sercel Releases HR3D Streamer

Sercel has released Sentinel HR, a high-resolution solid streamer designed to meet the specific imaging needs of shallow-target applications such as oceanology, civil engineering and reservoir characterization as well as high-resolution 3-D (HR3D) seismic surveys for detailed mapping of geological features, a press release stated.

The latest Sentinel streamer has been developed with a close channel separation of 3.125 m (10 ft) to achieve reliable and cost-effective high-resolution surveys. Recent enhancements available in Sercel's new-generation Seal 428 marine seismic recorder allow a higher channel count, enabling up to 6 km (3.7 miles) of Sentinel HR to be deployed with full data and power redundancy to ensure nonstop acquisition, opening up new possibilities for HR3D survey configurations.

The Sentinel HR also adapts to all types of survey spreads, from comb deployment to larger configurations integrating the Nautilus steering system. In addition, Sentinel HR can provide marine mammal monitoring when combined with Sercel's QuietSea passive acoustic monitoring system, which is seamlessly integrated into the seismic streamers.

Deloitte Targets Threats With Expanded Cyber-risk Platform

Deloitte plans to expand its cyber-risk platform for end-to-end industrial control systems (ICS) and operational technologies (OT) security with next-generation technology enabled by Dragos, a press release stated.

ICS and OT threat monitoring technology can facilitate a better understanding of the vulnerabilities embedded in these systems, thus allowing industrial concerns with such interconnected networks to gauge the likelihood of an event and adequately scenario-plan.

Deloitte Risk and Financial Advisory Cyber Risk Services' end-to-end ICS offering can help organizations manage their cyber risks in the ICS and OT environments by using a combination of cybersecurity products and services. This combination brings hunting and reconnaissance capabilities that allow organizations to look beyond internal data to threat documentation found in external databases. This combination of cyber-risk services and technologies also can provide a more complete picture of an organization's ICS and OT threat landscape through active monitoring that can better inform scenario planning and response.

—Staff Reports

EXPLORATION

Brazil's Independent Oil Companies Aim For Growth As Auctions Approach

RIO DE JANEIRO—As Petrobras shrinks its global E&P activities with farm-outs and asset sales, other oil majors such as Total, Statoil and BP have extended their presence in the country. But smaller operators are also looking for E&P investment opportunities in Latin America's largest oil producing country.

An oil platform is shown at Guanabara Bay in Rio de Janeiro, Brazil. More independent oil and gas companies are expected to participate in Brazil's upcoming bid rounds. (Source: Attila Jandi/Shutterstock.com)

Brazil's oil and gas regulator ANP has scheduled two additional bidding rounds: one in September for blocks under concession and one in fourth-quarter 2017 for presalt areas. Market analysts believe the number of independent companies participating in the upcoming bid rounds will grow as operators increase investments in Brazil following recent regulatory changes for the oil industry.

For the 14th licensing round on Sept. 27, the rules of the concession regime were simplified to attract more small- and medium-sized oil companies. According to the ANP, the tender will allow a single exploration phase with an option to extend for technical reasons. In addition, Brazil eased local content requirements. Changes also include lower taxation policies for new frontiers and the allowance for investment funds to participate in the round.

Queiroz Galvão Exploração e Produção (QGEP), the largest independent oil operator in Brazil and the first independent oil company to operate in the presalt, is enthusiastic about this new phase for the oil industry in Brazil.

"This accelerated level of activity should serve as catalyst for investment by a number of major global oil companies," the company said in a statement released in May. "Our current asset base provides QGEP with exposure to the key exploratory basins in Brazil, but we are also flexible and willing to take advantage of opportunities to add value to our portfolio."

QGEP, which has been authorized to operate in deepwater and ultradeep water since 2000, has assets in eight of the main sedimentary basins along the Brazilian coastline. QGEP is the only Brazilian independent oil company that operates in the presalt.

In Brazil's 13th bidding round, QGEP acquired 100% ownership of two concessions in the Sergipe-Alagoas Basin: the SEAL-M-351 and SEAL-M-428 blocks, which combined cover 1,512 sq km (584 sq miles). The blocks are between 80 km and 100 km (50 miles and 62 miles) off the coast in ultradeep waters with water depths ranging from 2,800 m to 3,300 m (9,186 ft to 10,827 ft).

Barra Energia do Brasil CEO Renato Bertani called Brazil's basins the "most prolific in the world." The independent oil company has a 10% interest in the giant Carcará Field, which has roughly 8 Bbbl of recoverable oil, and a 30% interest in the Atlanta Field. Both fields are in the Santos Basin.

"The new rules that have been implemented represent a significant change in the attitude of the government, which create an environment for investments in the [oil and gas[segment," Bertani said. "There is also a lot of capital in the international financial system seeking investment opportunities. Thus, the improvement of the regulatory and fiscal framework will make Brazil much more competitive to attract these international investors."

Bertani added that Brazil must continue efforts to get more medium-sized companies to invest in the Brazilian oil market. "The policy changes and the scheduled auctions are very important in order to reinforce credibility in this process."

However, work is needed in other areas, he added, noting these include taxes and environmental licensing processes, which have delayed operations. "Yet, the changes are on the right track," he said.

Eneva, pioneer in the reservoir-to-wire business model in Brazil, is also optimistic about the future of the oil and gas industry in the country.

"Due to the reservoir-to-wire model, Eneva can produce energy more efficiently and be more competitive in upcoming auctions, [while] contributing to the security and reliability of the Brazilian power system," Eneva E&P Director Lino Cançado said.

Cançado explains that Eneva's business model is strategic, considering Brazil's need to evolve its energy supply model. "These discussions are very timely, as important outcomes have already been delivered. The 14th licensing round already includes important improvements," he added.

Eneva holds more than 27,000 sq km (10,425 sq miles) of assets in the Parnaíba Basin in northeast Brazil's Maranhão state. The thermal power plants are next to natural gas production facilities, which reduce costs and improves logistics.

The company operates seven natural gas fields with a daily production of up to 8.4 MMcm (3 Bcf).

—Brunno Braga

EXPLORATION BRIEFS

PGS, TGS Take On Fourth 3-D Seismic Project Offshore Eastern Canada

Petroleum Geo-Services (PGS) and TGS are pursuing their fourth 3-D seismic project offshore Eastern Canada for 2017.

Long Range 3-D will comprise about 9,100 sq km of 3-D GeoStreamer data in the Eastern Newfoundland region, a news release said. The survey will be included in the November 2018 licensing round under Newfoundland Labrador's Scheduled Land Tenure system.

Following the surveys' completion, the jointly owned library will have more than 175,000 line km of 2-D GeoStreamer data and 28,500 sq km (11,004 sq miles) of 3-D GeoStreamer data, the release said.

"Our increased data library coverage in the Newfoundland Labrador region will be of benefit for oil companies exploring this high potential area," PGS CEO Jon Erik Reinhardsen said in the release. "We will operate three 3-D vessels and one 2-D vessel offshore East Canada this year, which is more than ever before and reflects high customer interest."

ExxonMobil Acquires Deepwater Acreage In Equatorial Guinea

ExxonMobil Corp. signed a production-sharing contract with the government of Equatorial Guinea for deepwater block EG-11 for an undisclosed amount, the Houston-based company said June 5.

Deepwater block EG-11, located west of Malabo, measures about 1,242 sq km (480 sq miles) and is adjacent to the Zafiro Field located in Block B.

"Block EG-11 is the jewel among a group of already very prospective blocks that we are signing in 2017," said Gabriel Obiang Lima, the minister of mines and hydrocarbons in Sub-Saharan Africa's third-largest producer.

Following ratification of the contract by the government, ExxonMobil will carry out the work program as operator with an 80% working interest. GEPetrol holds a 20% working interest.

The agreement also includes a commitment to acquire new and reprocess existing 3-D seismic data. In addition, ExxonMobil will work with the government of Equatorial Guinea to further develop the national workforce, according to the release.

Mobil Equatorial Guinea Inc. operates the Zafiro Field with 71.25% interest. GEPetrol has 23.75% interest and Equatorial Guinea has 5%. The field is in water depths between 122 m and 853 m (400 ft and 2,800 ft) and has produced more than 1 Bbbl in its more than 20 years of production, the release said.

ExxonMobil already operates the Zafiro Field, the largest oil producing field in Equatorial Guinea, and Obiang Lima said the deal was not part of the 2016 licensing round.

Winners for the licensing round were announced during the Africa Oil & Power conference. In addition to ExxonMobil, winners included:

- Ophir Energy, Block EG-24;
- Offshore Equator Plc, Block EG-23;
- Clontarf Energy, Block EG-18;
- Elenilto, Block EG-09;
- Taleveras, Block EG-07; and
- Atlas Petroleum and Strategic Fuel Fund for Block EG-10.

Petronas Moves To Second Round Of Offshore Gas Asset Sale

The sale by Malaysian energy firm Petronas of an estimated $1 billion stake in a local upstream gas project has moved to the second round and is set to attract interest from about half a dozen bidders, including Royal Dutch Shell and ExxonMobil Corp., four sources familiar with the matter said.

State-owned Petroliam Nasional Bhd (Petronas) had kicked off a process to sell a stake of up to 49% in the SK316 offshore gas block in Malaysia's Sarawak state, Reuters reported in February.

Prospective buyers are expected to submit second round financial bids this month, and a final decision on the successful bidder is expected later this year, two sources said.

Sources said Total, PTT Exploration and Production Pcl and some Japanese firms are also among those keen to bid for the asset.

The transaction, if completed, would mark Petronas' biggest upstream stake sale since oil prices started falling more than two years ago.

—Staff & Reuters Reports

FLOATER NEWS

Equatorial Guinea Sees Fortuna FLNG Offtaker Decision In August

Equatorial Guinea has short-listed Royal Dutch Shell and oil traders Gunvor and Vitol for an offtake agreement at its Fortuna floating LNG (FLNG) export terminal and expects to make a final decision by August, its oil minister said June 5.

Fortuna FLNG will be Africa's first deepwater floating liquefaction facility, with production capacity of 2.2 million tonnes per year and an estimated startup in 2020.

"Our criteria for selection (of the preferred offtaker) is very simple—whoever gives more money. So, whoever provides the biggest cash and good terms and alternatives to the state," Gabriel Obiang Lima, minister of mines and hydrocarbons, said at a press conference June 5 in Cape Town.

"Clearly the ball is with the offtakers. We have already had discussions with them," he said.

British oil and gas explorer Ophir Energy said in May it plans to borrow $1.2 billion from Chinese banks to back the development of Fortuna.

Addressing delegates at an African oil and gas conference earlier, Obiang Lima said he saw scope for adding another two FLNG terminals by year-end 2017, as demand for LNG grew particularly on the continent.

He said the latest OPEC member, who joined the oil producing cartel in May, has entered a binding agreement with OneLNG SA to explore the liquefaction and commercialization of natural gas in offshore blocks O and I. OneLNG is a joint venture between Golar LNG and Schlumberger to rapidly develop gas reserves into LNG.

"That combination will give us a lot of flexibility," Obiang Lima said.

He also named the winners of the 2016 licensing round for onshore and offshore blocks, with Ophir Energy among seven companies that included firms from Israel, Ireland and South Africa, who were awarded seven blocks.

Earlier Equatorial Guinea, a former Spanish colony and Sub-Saharan Africa's third largest oil producer, signed a production-sharing contract for offshore Block EG-11 with U.S. oil major ExxonMobil, for one of the blocks on offer.

"Block EG-11 is the jewel among a group of already very prospective blocks that we are signing in 2017," Obiang Lima said in a statement.

ExxonMobil already operates the Zafiro Field, the largest oil producing field in Equatorial Guinea, and Obiang Lima said the country intended raising oil output to 300,000 bbl/d by 2020.

—Reuters

US DOE Gives Approval To First Floating LNG Terminal

For the first time, the U.S. Department of Energy has granted approval for a floating gas terminal to export LNG to countries not in a free-trade agreement with the U.S.

Fairwood Peninsula Energy Corp.'s Delfin project will ship 51 MMcm/d (1.8 Bcf/d) beginning in 2020, *Bloomberg* reported in early June. The Trump administration is encouraging construction of more LNG terminals on U.S. coasts and increased exports.

The action will "continue to strengthen the United States as a dominant energy force," U.S. Energy Secretary Rick Perry said in a statement. "Investing in American natural gas not only helps our economy and our jobs but also helps our allies maintain their energy security."

As an offshore operation, Delfin is the only terminal that does not require approval from the Federal Energy Regulatory Commission. It does, however, require OKs from the Maritime Administration and the U.S. Coast Guard.

Delfin consists of four floating LNG vessels. Several other floating export terminals are in the works because they are seen as a way to engage with countries that have built floating import terminals.

—Joseph Markman

VESSELS

Wärtsilä, MGM Extend Maintenance Deal On LNG Fleet

Wärtsilä and Maran Gas Maritime Inc. (MGM) agreed to a five-year extension to their maintenance agreement covering MGM's 21 tri-fuel diesel electric (TFDE) LNG carriers equipped with Wärtsilä 50DF engines.

MGM, the LNG shipping unit of the Angelicoussis Shipping Group, operates 33 LNG vessels globally, 21 of them in the TFDE class. The parent company operates a fleet of about 130 merchant vessels around the world.

Wärtsilä will provide maintenance to Maran Gas Maritime's 21 TFDE LNG carriers. (Source: Wärtsilä)

The agreement includes dynamic maintenance planning, condition-based maintenance services and remote operational support, all part of the digital Wärtsilä Genius services portfolio.

Remote product support in technical and operational issues and remote monitoring of equipment performance will allow MGM to further enhance the reliability of the Wärtsilä 50DF tri-fuel engines installed on its vessels. The new agreement also includes spare parts for maintenance along with technical expertise and workshop services for overhauls.

The advanced 50DF tri-fuel engines can be operated with heavy fuel oil , marine diesel oil or natural gas. Wärtsilä's support will allow for streamlined maintenance planning and enable the vessels to adhere to their schedules.

"The technically advanced LNG installations require professional maintenance to ensure operational reliability," said Yiannis Christopoulos, managing director of Wärtsilä Greece, in a statement.

—Joseph Markman

VESSEL BRIEFS

Oceaneering Lands 10-Year ROV Vessel Services Contract

Oceaneering Canada Ltd. has entered an agreement with a major international oil and gas company to provide ROV services and equipment for projects offshore of Newfoundland and Labrador, Canada, according to a news release.

As part of the contract, Oceaneering will provide two ROV systems onboard a multifunction platform support vessel. The scope of work contemplates subsea construction, inspection, maintenance, and repair services on existing and future infrastructure, the release said.

Oceaneering said it will also supply tooling and project support, including project management and associated engineering services.

Solstad Lines Up Work For *Normand Leader*

ConocoPhillips Skandinavia has awarded Solstad Offshore a long-term contract for *the Normand Leader* platform supply vessel.

The contract is for four years, but has options for extensions. The contract will begin in April 2018.

The Norway-headquartered company's fleet includes about 61 fully- and jointly-owned platform supply, anchor-handling and construction service vessels.

Swan Hunter Finishes Flexlay Spread Onto *Lewek Constellation*

Swan Hunter said it has completed the mobilization and commissioning of a flexlay spread onto EMAS Chiyoda Subsea's multi-lay vessel *Lewek Constellation* for flexible risers installation.

The lay equipment comprises Swan Hunter's newbuild loading tower with tensioner, a 26-m (213-ft) basket carousel provided by a joint venture partner plus various project-specific components, the company said.

The spread will be used for spooling the flexible products in Kalundborg, Denmark, before installation offshore Ghana later in June, the release said.

ELA Delivers Offshore Control Room For VBMS *Ndeavor*

VBMS recently received an offshore multipurpose room for its 4-year-old 7,500 DWT DP-2 *MV Ndeavor* cable-laying vessel. The subsidiary of Royal Boskalis Westminster N.V. specializes in subsea, umbilicals, riser and flowline installation.

ELA delivered the offshore multipurpose container for use on VBMS' MV *Ndeavor* cable-laying vessel. (Source: ELA Container Offshore)

The container was delivered to the VBMS warehouse in Moerdijk, The Netherlands, then transferred to a state-of-the-art control room to operate ROV trenchers, which lay and bury power cables in shallow and deep water. The control room has space for two people to monitor the ROV on multiple screens.

"Since the lead time was very short and the deadline of the project was approaching rapidly, we were able to deliver the container from stock on very short notice," Frank ter Haak, business development manager at ELA

Container Offshore, said in a statement. "The container was painted in VBMS house colors, enabling our customer to install all their equipment and run tests before starting the project on board."

"After arrival of the container we were very pleased with the high quality finishing and the superb insulation," said Jan Bes, subsea equipment supervisor at VBMS. "We were particularly pleased with the fact that both A60 marine doors were equipped with a window in order to have day light entering the room during work shifts."

—*Staff Reports*

BUSINESS

Despite More FIDs In 2017, Delayed Oil, Gas Projects Tally Rises

(Source: Shutterstock.com)

Oil and gas companies have taken some stalled projects off the shelves, pushing the number of developments reaching final investment decisions (FID) so far in 2017 above that of last year, according to Norway-based energy consulting firm, Rystad Energy.

But that doesn't mean the tide has turned.

"In spite of this apparent positive momentum, the FID delay list has continued to grow," Readul Islam, research analyst for Rystad Energy, said in a news release.

Commodity prices might have recovered some of the loss incurred since 2016, but not enough to give all investors enough confidence to proceed with stalled projects.

The consultancy said it has been tracking FID delays since the second-half of 2014—when the supply and demand imbalance began to send commodity prices tumbling—to post-appraisal, pre-sanctioned upstream projects. Of the delayed projects, Rystad said 17 have since been launched. Combined, these projects—which include onshore and offshore projects—account for an estimated $78 billion of development spending, according to Rystad.

Making up a large chunk of this amount is the nearly $37 billion Tengiz future growth and wellhead pressure management project in Kazakhstan. The project, led by Chevron Corp. affiliate Tengizchevroil, a joint venture with ExxonMobil Corp., KazMunayGas and LukArco, aims to more than triple production at the oil field to 850,000 bbl/d.

The reality of bringing in less money from hydrocarbon resources produced, as oil and gas prices dropped, sent companies back to the drawing board to find savings. In some instances, the efforts are bringing down project costs enough to make them economic in today's market conditions. In other cases, such as BP's latest project to reach FID, firming up sales contracts is playing a key role.

News of three project sanctions was delivered just last week, which could be considered a rarity in itself.

Among these was the BP Trindad and Tobago-operated Angelin gas project offshore Trinidad and Tobago. BP announced the sanction of the $500 million four-well development on June 2, more than two decades after the field was originally discovered by the El Diablo well, and about 11 years after it was appraised by the La Novia well. First gas is expected in first-quarter 2019.

The development, which will include a new platform, will have the capacity to produce from Angelin about 600 million standard cubic feet of gas that will flow to the Serrette platform hub via a new 21-km pipeline, BP said June 2.

Just a day earlier Eni and its partners shared word of their decision to fund the massive Coral South floating FLNG project offshore Mozambique. Rovuma Basin's Coral Field, believed to hold about 450 Bcm (16 Tcf) of gas in place, was discovered about five years ago. The development is part of Eni's plan to become a "global integrated gas and LNG player," according to the company's CEO Claudio Descalzi.

Husky Energy also said last week that it was moving forward with its $1.6 billion White Rose West project offshore Newfoundland, Canada.

"We've made significant improvements to the project since it was first considered for sanction, including identifying numerous cost savings, achieving a 30% improvement in capital efficiency and increasing the expected peak production rate by 40% over our initial estimate," Husky CEO Rob Peabody said. "Moving forward with this project is a significant milestone for Husky, while creating jobs, royalties and other benefits for Newfoundland and Labrador."

Plans for the deepwater project include a fixed wellhead platform tied back to the SeaRose FPSO vessel. With first oil expected in 2022, the project is expected to have a peak production of about 75,000 bbl/d in 2025.

Others reaching FID this year have included BP's Mad Dog Phase 2 in the U.S. Gulf of Mexico and Noble Energy's Leviathan offshore Israel in the Medi-

Rystad Energy's delayed FID tracker
Number of delayed (non-sanctioned) projects*

	Jul 15	Jan 16	Jun 17
Deepwater	9	14	27
Heavy oil	2	2	6
LNG	4	5	10
Offshore gas	2	7	9
Oil sands	9	9	8
Onshore	3	9	17
Shallow water	10	16	28
Count	**39**	**62**	**105**
Reserves (Billion boe)	**20**	**26**	**35**
Capex (Billion USD)	**166**	**230**	**299**

Source: Rystad Energy research and analysis
**projects delayed since second half of 2014*

terranean. Rystad pointed out that other developments in China, Iraq and Vietnam have also reached such milestones.

However, "since we last published in January 2016, the list has grown in almost all themes, except oil sands, which is not surprising since oil sands projects are largely confined to one province in Canada, while all other themes have a global candidate pool," Islam said. "The ongoing results of the oil price pain [are] clear to see—still over 100 projects delayed."

The delayed projects account for about 35 Bboe and an estimated $30 billion in spend, Islam added.

The price for a barrel of West Texas Intermediate has dropped from more than $107/bbl in the summer of 2014 to as low as $26/bbl in February 2016. In recent months, the oil price has held steady around $50/bbl.

—Velda Addison

BUSINESS BRIEFS

Wood Group Names President Of Strategy, Development

Wood Group has appointed Dean Harwood as president of strategy and development for the Western region, a new position, according to a news release. He will handle strategy, M&A, business development, marketing and proposals.

Prior to joining Wood Group, Harwood was executive vice president of operations for Parsons Corp. and president of Parsons Enterprises, an engineering, construction and management services firm. He has 30 years' experience in finance, strategy, operations and executive leadership in the engineering, construction, technology, telecommunications and infrastructure sectors, the press release said.

Harwood earned a bachelor's degree from the University of North Carolina and a master's of business administration degree from Emory University. He is a certified public accountant, the press release said.

OSRL, Trendsetter, Halliburton Sign Subsea Well Capping Memorandum

Oil Spill Response Ltd. (OSRL), Trendsetter Engineering and Halliburton signed a memorandum of understanding for integrated subsea well capping response solutions, a news release said.

Under the terms of the agreement, OSRL will remain responsible for providing members access to an industry-owned global capping and containment capability, and ensure that subsea well intervention service-related (SWIS) equipment is maintained and response-ready. It will also mobilize the equipment and provide members with preparedness services, the press release said.

Trendsetter, a subsea solutions provider, and Halliburton's Boots and Coots well control division will provide access to trained personnel and subject matter experts to support SWIS members, and will support source control, well control, relief well planning, and engineering and other preparedness activities through OSRL.

The new agreement enhances the policies and procedures established through the Global Industry Response Group and adopted by the Subsea Well Response Project consortium by establishing an integrated, best-practice approach to managing global subsea well control incidents.

Oil Spill Response Ltd. is the largest international industry-funded cooperative and has offices around the world.

CGG GeoConsulting Will Supply Digital Well Products To UK's OGA

CGG GeoConsulting received a contract to supply digital well products to the U.K. government's industry regulator, the Oil & Gas Authority (OGA). The contract is part of a wider tender for comprehensive subsurface databases and information sources supporting exploration in underexplored U.K. Continental Shelf (UKCS) areas, according to a May 31 press release.

The datasets will support the OGA's work across the E&P life cycle including promoting future licensing rounds and undeveloped discoveries, regional exploration projects, area strategies and asset stewardship.

The digital well products supplied by CGG GeoConsulting will be used internally by the OGA and released into the public domain via the OGA's website during 2017 to be used freely by E&P companies looking for potential new prospects in the UKCS.

EU Clears GE, Baker Hughes Megamerger Without Conditions

The European Commission (EU) cleared General Electric Co.'s purchase of oilfield services firm Baker Hughes Inc. without conditions on May 31, the EU competition authority said in a statement.

In October GE and Baker Hughes said they will merge into a new oilfield technology company with a value of $32 billion.

The merger is set to create a "new Baker Hughes," with GE owning a 62.5% majority interest in the company. Baker Hughes would hold the remaining 37.5% of the company.

The EU concluded that the merger of the two U.S. companies would not harm competition in European markets for various products where both were active, including electrical submersible pumps, refining chemicals and drilling sensors.

Baker Hughes said the companies will continue to work constructively with regulators and expect to close the transaction in mid-2017.

Leadership Team Revealed For New Baker Hughes

Baker Hughes Inc. announced on June 5 the executive team that will lead the company following the expected closing of its merger with General Electric Co.'s oil and gas business later this year.

GE Oil & Gas boss Lorenzo Simonelli will head the new Baker Hughes as president and CEO. Martin Craighead, currently chairman and CEO at Baker Hughes, will serve as vice chairman of the board of directors and GE CEO Jeff Immelt will serve as chairman of the board.

The combined executive team will include:

- Lorenzo Simonelli, president and CEO;
- Maria Claudia Borras, president and CEO of oilfield services;
- Belgacem Chariag, chief global operations officer;
- Rod Christie, president and CEO of turbomachinery and process solutions;
- Harry Elsinga, chief human resources officer;
- Jennifer Hartsock,CIO;
- Matthias Heilmann, president and CEO of digital solutions;
- Jack Hinton, chief HSE officer;
- Nicola Jannis, chief business development officer;
- Derek Mathieson, chief marketing and technology officer;
- Jody Markopoulos, chief engineering and supply chain officer;
- Will Marsh, chief legal officer;
- Neil Saunders, president and CEO of oilfield equipment;
- Uwem Ukpong, chief integration officer; and
- Brian Worrell, CFO.

Wood Group Signs Global Agreement With Hess

Hess Corp. and Wood Group are building on their more than 25-year relationship by signing a nonexclusive 10-year global agreement.

Under the agreement, Wood Group will provide engineering, project management, construction, commissioning, operations and maintenance, integrity management, subsea, and decommissioning services, a news release said.

"This agreement further solidifies the strong relationship we have with Hess," Wood Group CEO Robin Watson said in the release. "The ability to consolidate the full breadth of our services under one agreement offers an exceptional level of continuity to Hess and all our clients."

—Staff & Reuters Reports

UPCOMING

The next issue of *Subsea Engineering News* will be distributed June 22. Until then, visit *epmag.com*.

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