SEN
SUBSEA ENGINEERING NEWS

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Statoil Steps Up Exploration, Subsea Plans

Statoil reported that the Gina Krog development is expected to come onstream during summer 2017. (Source: Statoil)

Statoil plans to drill about 30 exploration wells in 2017, up about 30% compared to 2016, on the back of better market conditions and improvements the company said it has made.

Between 16 and 18 of the planned wells will be drilled on the Norwegian Continental Shelf (NCS), the operator said. Of these, five to seven are planned for the Barents Sea, with the rest spread between the Norwegian Sea and North Sea.

This campaign is already paying dividends as the Cape Vulture probe was revealed as a new oil discovery Jan. 17.

In 2016, Statoil completed 23 exploration wells as operator and partner—14 of them on the NCS.

"Taking advantage of our own improvements and changed market conditions, we have been able to get more wells, more acreage and more seismic data for our exploration investments in later years," said Tim Dodson, Statoil's executive vice president for exploration.

Renewed Confidence

The Norwegian state player was one of the first operators to cut back spending in 2014 before the industry's downturn really kicked in that year. The slump in oil price and resultant massive wave of investment cuts forced the industry to evolve from a high-spend culture to one based firmly on cost control, efficiency and, in the North Sea especially, one where collaboration is the norm and not the exception.

Statoil has certainly been able to slash the cost of its subsea development projects since the crash due to contractor bids coming down by about 30% to 40% in many cases.

When combined with its "own improvements," fields that were borderline marginal are now worth pursuing even if the oil price remains about $55/bbl, although most forecasts suggest this price will climb a little this year and next.

Given Statoil's ability to adapt to the new industry reality, the company clearly feels the time is right to start spinning the drillbit and hunt for new reserves that can be fast-tracked into development.

This view is backed up by the government, which said it must continue to provide operators with new opportunities to explore for oil and gas.

"I will be on the offensive when it comes to awarding new acreage to ensure the continued development of this industry," Terje Soeviknes, Norway's new minister of petroleum and energy, said last week.

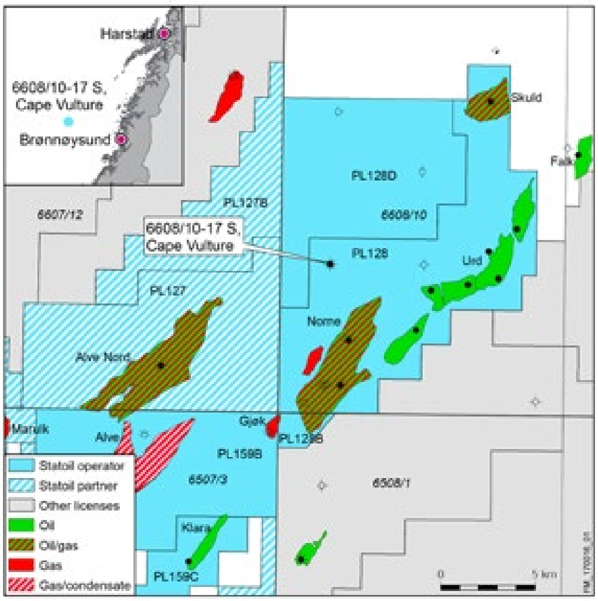
Near Field Success Continues

Looking for hydrocarbons near existing field projects—which enables subsea tiebacks to nearby infrastructure—has been a successful strategy for Statoil and the company intends to mix this strategy with exploring new areas during 2017.

WHAT'S INSIDE

"Exploring new acreage and near-field exploration is important to add new and profitable volumes to our NCS production. Today's Cape Vulture find 6 km (3.7 miles) from the Norne Field is an example of this," Statoil told *SEN* on Jan. 17. "Maturing and identifying new targets near existing fields/infrastructure is part of our exploration scope in 2017 as well.

"Our exploration program this year is a mix of frontier exploration (Barents Sea southeast) combined with near-field exploration in mature basins."



Statoil began drilling the Cape Vulture exploration well in December 2016. (Source: Statoil)

In terms of Statoil's improvements, the operator told *SEN* that "planning for utilization of existing capacity and infrastructure near developed fields in operation reduces costs significantly and allows resources to be planned for development, such as the Byrding prospect near the Troll Field and Utgard near the Sleipner Field, both in the Norwegian North Sea. A key factor is simplification of concepts and strong collaboration across the industry, with operators and suppliers working together."

"Gina Krog is expected onstream during summer this year, Aasta Hansteen in 2018 and Johan Sverdrup is due onstream in 2019 as scheduled," Statoil added in reference to ongoing field development projects.

Buoyed As Cape Vulture Soars

Statoil's 2017 drilling plans were boosted this week as the partners in Production License 128 (PL 128) made an oil discovery with wildcat well 6608/10-17 S on the Cape Vulture prospect in the Norwegian North Sea.

The well was drilled about 5 km (3 miles) northwest of the Norne Field in the northern part of the Norwegian Sea and about 200 km (124 miles) west of Sandnessjøen.

Statoil is the operator of PL 128 with a 63.95% stake, while Petoro holds 24.55% and Eni has 11.5%.

A preliminary estimate of the size of the discovery ranges from 70 MMbbl to 200 MMbbl of oil in place, with a further additional potential to be evaluated. The well will be permanently plugged and abandoned after an extensive data collection and sampling.

Eni said the discovery is in line with its "near-field strategy that, in case of success, allows for a fast exploitation of reserves thanks to the synergies with existing nearby infrastructures."

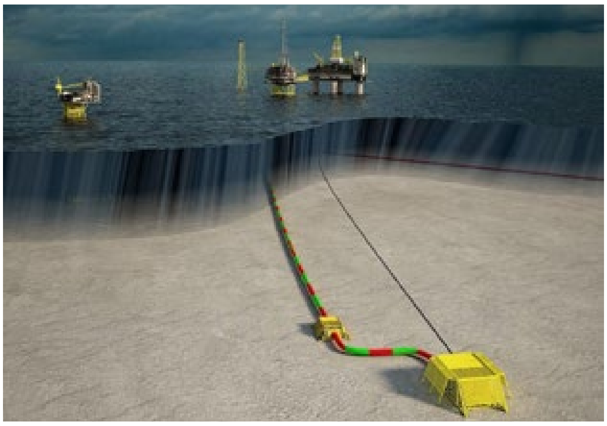
The Norwegian Petroleum Directorate added, "the licensees will consider further delineation of the discovery with regard to a potential development via the *Norne* [FPSO] vessel."

Utgard-Byrding PDOs Approved

Statoil's near-field strategy was given further credence Jan. 17 when a plan for development and operation (PDO) for each of its Utgard and Byrding fields in the Norwegian North Sea were approved by the government.

Utgard is a gas and condensate field that straddles the NCS and the U.K. Continental Shelf. Byrding is an oil and gas field that lies north of the Troll Field.

"These projects will give valuable new volumes to the Sleipner and Troll fields," said Torger Rød, senior vice president for project development at Statoil, in a company statement. "Efficient utilization of existing infrastructure contributes to reducing the costs and makes these developments profitable."


The Utgard Field development includes two wells in a standard subsea concept. (Source: Statoil)

Capex for Utgard is estimated at about $414.1 million, while capex for Byrding is estimated to near $118.3 million.

Utgard's recoverable reserves are estimated at 56 MMboe. Utgard was discovered in 1982 and is located 21 km (13 miles) from the Sleipner Field.

The Utgard PDO includes "two wells in a standard subsea concept, with one drilling target on each side of the median line. The installations and infrastructure will be located in the Norwegian sector," Statoil added.

Utgard is planned to come onstream in fourth-quarter 2019. Utgard partners are operator Statoil (38,44%), Statoil UK (38%), Lotos Exploration and Production Norge (17.36%) and Kufpec Norway (6.20%).

Byrding's recoverable volumes are estimated at about 11 MMboe. The Byrding PDO includes a duo-lateral well drilled from the existing Fram H-Nord subsea template through which oil and gas from Byrding will flow to Troll C.

Byrding is scheduled to come onstream in third-quarter 2017. Byrding partners are operator Statoil (70%), Engie E&P Norway (15%) and Idemitsu Petroleum Norway (15%).

—*Steve Hamlen*

DEVELOPMENT

UK Harrier Takes Off As Catcher Trims Costs

The U.K. North Sea saw a very quiet 2016 in terms of field development activity, but this year has started at a decent pace.

Ithaca Energy and Premier Oil are pushing ahead with projects; however, Chevron is rethinking its Rosebank plans West of Shetland.

Ithaca Energy has launched the North Sea Harrier Field development program, with development drilling due for completion in 2017. First production is expected in second-half 2018.

On top of this, the project will be developed for half of the original estimate, according to Ithaca.

Investment in the Harrier Field development project will start this year. The development involves drilling a multilateral well into two reservoir formations on the field. The well will be tied back via a 7.5-km (4.7-mile) pipeline to an existing slot on the Stella main drill center manifold for onward export and processing of production on the *FPF-1* unit.

"The Greater Stella Area (GSA) joint venture has contracted with Ensco Offshore UK for the provision of a heavy-duty jackup drilling rig, which is expected to arrive on location in the second quarter of this year," Ithaca noted. "The drilling program is forecast to be completed in the second half of 2017 and the subsea infrastructure installation activities in summer 2018, resulting in the anticipated startup of Harrier production in the second half of 2018."

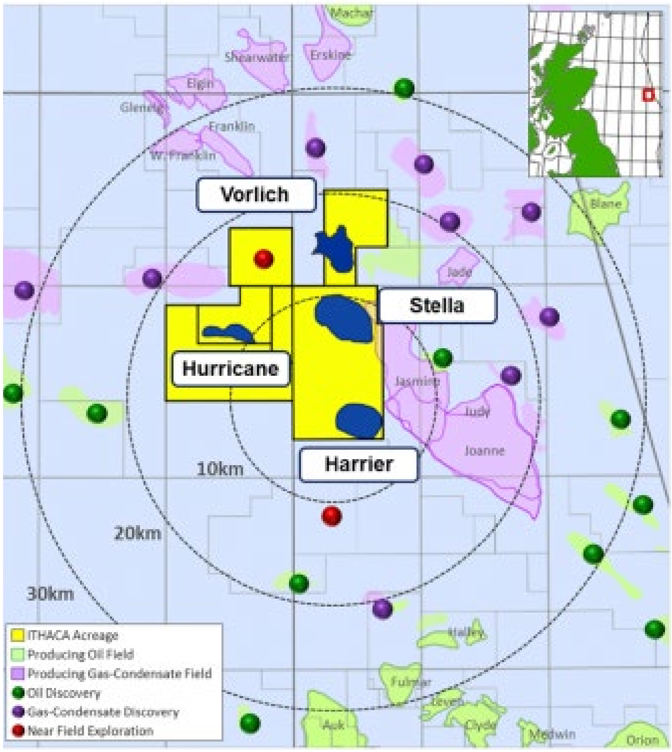
The net capex associated with execution of the development over 2017-2018 is about $75 million, "equating to a development cost significantly less than $10/boe."

"This represents a cost reduction of approximately 50% from that originally forecast. The substantial reduction in [capex] is driven by both detailed well engineering design work that has enabled the move away from drilling two individual wells to one multilateral and securing attractive contracting terms across the supply chain," Ithaca said.

Ithaca's forecast 2017 capital investment program of $70 million is "primarily centered on GSA activities" but includes development drilling on the Harrier Field.

The forecast 2017 unit opex of about $18/boe is down nearly 30% on 2016 due to "the positive impact of low cost Stella volumes on the production portfolio."

"The painstaking electrical inspection program on the *FPF-1* is nearing completion and the vessel will shortly be ready for startup of the Stella Field," Ithaca CEO Les Thomas said. "While this will have taken longer than planned, the transformational step it delivers for the business remains undiminished. The company moves into 2017 in good health, with increasing cash flow, continued deleveraging and the launch of the low cost Harrier satellite development."



Production is expected to start at the Harrier Field development in second-half 2018. (Source: Ithaca Energy)

With the electrical junction box inspection and remediation work program nearing completion, forecast first hydrocarbons from the Stella Field is scheduled for February 2017, Ithaca said.

"Production this year is anticipated to be in the range of 19,000 to 22,000 boe/d, reflecting the updated Stella startup schedule," the company added.

"The producing asset portfolio has performed well over the last 12 months, with production running ahead of guidance largely as a result of solid performance from the Cook Field, for which the company took over operatorship in March 2016.

Ithaca's forecast net capex for 2017 is about $70 million. Most of this is allocated for Harrier development activities, completion of the GSA oil export pipeline investment program and Vorlich Field development planning activities. "The forecast expenditure is also inclusive of any additional Stella startup costs, which are expected to be minimal," Ithaca said.

Premier Cuts Catcher Costs

Premier Oil said costs have been reduced on its North Sea Catcher Field development, while production has increased by nearly 25%.

"The Catcher project continues to progress well and will provide another step change in production, generating enhanced, tax-free cash flows for the group," said Tony Durrant, CEO for Premier.

The operator said that Catcher is on schedule for startup later this year with total capex now forecast at $1.6 billion, 29% lower than the estimate when the project was sanctioned.

Premier also said that approval of the U.K. Tolmount development concept is expected shortly and "will provide a next phase of growth."

The company registered record production of 71,400 boe/d in 2016, a rise of 24% on 2015. The figures are "in line with previously upgraded guidance."

The 2017 production guidance is 75 Mboe/d "before any contribution from Catcher and adjusted for lower Solan profile," Premier added.

Opex per barrel for last year was $15.70/bbl, while Premier's estimated capex in 2016 was $690 million, which was below the guidance of $730 million. The 2017 capex guidance is $350 million, including abandonment spending.

Chevron Rethinks Rosebank

U.S. major Chevron Corp. is considering launching a new tender for an FPSO vessel for its Rosebank development project West of Shetland.

Chevron axed its order for an FPSO vessel with South Korea's Hyundai Heavy Industries (HHI) in December 2016. A termination notice cancelled the deal, which was valued at about $1.85 billion. Chevron signed the original contract in April 2013.

But just one month after the cutting of the HHI deal, Chevron is reported to be preparing to launch a new FPSO tender. The retender will be a cost-saving exercise as 2013 prices were much higher than the present day.

Indeed, a spokesman for Chevron North Sea said recently that the operator "is committed to working with its project joint venture participants and stakeholders to make improve project value and make the right decisions for the Rosebank development."

Chevron also recently said that FEED work for the Rosebank project is continuing.

Rosebank's development plan includes an FPSO vessel, production and water injection wells, subsea facilities and a gas export pipeline.

The Rosebank Field was discovered in 2004 and is estimated to contain recoverable oil equivalent resources of 240 MMbbl. Rosebank is located 130 km (81 miles) West of Shetland.

Chevron operates Rosebank with a 40% stake, while Suncor Energy holds 30%, Siccar Point has 20% and Dong E&P holds 10%.

—Steve Hamlen

Stampede Stays On Track For 2018 First Oil

Improved market conditions have given way to plans for more spending by many oil and gas companies. Hess Corp., which has unveiled a $2.25 billion E&P capital and exploratory budget, is no exception.

The budget is up from the $1.9 billion the Houston-headquartered company spent in 2016.

Of the anticipated spend, $425 million has been set aside to drill two wells and complete three, install the tension-leg platform (TLP) and progress development of the deepwater Stampede Field in the deepwater U.S. Gulf of Mexico, the company said Jan. 12. Resources from the Stampede reservoir, lying at depths of about 8,534 m to 9,449 m (28,000 ft to 31,000 ft), will be produced from subsea wells and injection wells—six producers and four injectors—tied back to the TLP.

Hopes are to achieve first oil in 2018. The field has estimated gross recoverable reserves of between 300 MMboe and 350 MMboe. The topsides have a daily processing capacity of about 80 Mbbl and a daily water injection capacity of 100 Mbbl.

The Stampede hull arrived at Kiewit Offshore Services in Ingleside, Texas, in August 2016. During the company's third-quarter 2016 earnings call, Hess President and COO Greg Hill said "first oil remains on schedule for 2018." At the time, the topsides deck had been lifted and set atop the hull.

"Now the lifts are complete, integration has commenced at Kiewit Offshore Services in Ingleside, and the work is proceeding well," a Hess spokesperson told *SEN*. A timeline regarding sail out was not provided.

Stampede is estimated to have a net production of about 15 Mboe/d with gross production at an estimated 60 Mboe/d.

With a 25% interest, Hess is the operator. Partners are Nexen Petroleum Offshore U.S.A. Inc., Statoil and Chevron subsidiary Union Oil Co. of California. Each holds a 25% interest.

The *Ocean BlackLion* drillship performs drilling work at the Stampede development in the U.S. Gulf of Mexico. (Source: Hess)

The project is one of two offshore projects with Hess at the helm as operator.

The other, North Malay Basin, will receive about $275 million this year as the company works to complete the initial full field development. North Malay is nine natural gas fields located in shallow-water offshore the main Malaysian peninsula.

Installation of the topsides at three remote wellhead platforms has been completed for North Malay, where Hess has 50% interest with partner Petronas Carigali holding the rest. Overall, the project is on track for third-quarter 2017 completion.

"Our 2017 budget reflects our balanced approach to investing in short cycle and long cycle growth options while maintaining our financial flexibility," CEO John Hess said in the Jan. 12, 2017, company statement. "With our leadership position in the Bakken, two offshore developments—North Malay Basin and Stampede—that will become significant cash generators starting in 2017 and 2018 respectively, and the world-class Liza discovery on track for sanction in 2017, Hess is well positioned to deliver sustainable growth, cash generation and returns for our shareholders."

The company has allocated $125 million for development work at the ExxonMobil affiliate-operated Liza Field offshore Guyana, where an FPSO unit will be used to develop the field believed to hold more than 1 Bboe. Hess is ponying up another $350 million from its exploration and appraisal budget for additional appraisal drilling and seismic acquisition and processing on the Stabroek Block where the field is located.

—Velda Addison

Energean Will Use Separate FPSO Vessel For Tanin, Karish

Greek company Energean Oil & Gas plans to build its own production system in the eastern Mediterranean at a cost of up to $1.5 billion to tap two Israeli offshore gas fields, the group's CEO said on Jan. 11.

Energean, Greece's only oil producer, wants to bring a financial partner into the project to develop the Tanin and Karish fields, which are situated in deep waters about 100 km (62 miles) off Israel's coast and have combined gas reserves estimated at 68 Bcm (2.4 Tcf).

Energean bought Karish and Tanin in August 2016 for $148 million from U.S.-Israeli partners Delek Group and Noble Energy Inc., which are developing two much larger fields nearby and were required by Israel to sell off other discoveries in an effort to open up the sector to competition.

Rather than piggyback off that group's infrastructure, an idea previously suggested by some experts, Energean plans to lease its own FPSO vessel and build a separate pipeline to Israel.

"We are going to be a totally independent system," CEO Mathios Rigas told Reuters, adding that a combination of local and international banks will help finance the $1.3 billion to $1.5 billion that is needed.

Before making a final investment decision, which is expected in December, the Israeli government must first approve the development plan and Energean needs to secure sales contracts for 3 Bcm (106 Bcf) of gas per year, Rigas said.

Israel has determined that gas from Tanin and Karish must be sold domestically.

The Israeli fields are Energean's biggest assets and the company is looking to lighten the load.

"In the next three to six months, maximum, we will bring in a financial partner ... that will work with us to share the risk and help us develop the project," Rigas said.

He expects gas production to begin in 2020.

—Reuters

Ichthys Completes Subsea Installation

The successful installation of the complex network of subsea infrastructure and equipment to safely and efficiently extract gas and condensate from the Ichthys Field for the Ichthys LNG Project has been completed, INPEX said Jan. 13.

The final laying of 49 km (30 miles) of umbilicals and flying leads marked the last placement of an intricate subsea network, spread across a 400-sq-km (154-sq-mile) area of the Ichthys Field, in the Browse Basin, about 220 km (137 miles) offshore Western Australia.

Ichthys Project Managing Director Louis Bon described the safe execution of a number of installation campaigns to complete the subsea infrastructure milestone on schedule as an "outstanding achievement."

"Since October 2014, hundreds of people have worked offshore without any significant safety incidents to install the Ichthys LNG Project's 133,000-tonne subsea network," he said in a statement. "Carrying out this work more than 200 kilometers (124 miles) out to sea in water depths of around 250 m (820 ft) involves substantial planning and logistical challenges to manage crew changes and equipment transportation."

Included in the extensive subsea gathering system is a 110-m (361-ft) high riser support structure, five manifolds, 139 km (86 miles) of flowlines, 49 km (30 miles) of umbilicals and flying leads, 2,640 tons of production and MEG spools, five subsea distribution units and a subsea distribution hub.

Finalizing the subsea installation, a key milestone, signified the project was now ready for the arrival of the central processing facility (CPF) and FPSO facilities, currently under commissioning in South Korea.

Once all commissioning activities in the South Korean shipyards are finished, the offshore facilities will be towed to the Ichthys Field and moored for their 40-year operational life by 40,000 tons of chain secured to more than 25,000 tons of foundation piles.

News for the development kept flowing in January.

In a Jan. 13 news release, Fugro said it landed a five-year contract for subsea inspection, repair and maintenance services from INPEX for Ichthys facilities in the Timor Sea.

In addition, Solstad Offshore was awarded a subcontract from McDermott to provide light construction vessel services related to the Ichthys gas field development project. Solstad said *Normand Reach* will be used to help with FPSO hookup, subsea work, pre-commissioning and survey scopes.

—Staff Reports

Serica: Columbus Development Planning Continues

Serica Energy is working to find "optimal development and offtake solutions" for the Columbus Field in the central North Sea.

Current plans are for a single well development that could deliver an estimated 6.2 MMboe of contingent resources net to Serica, the company said in a Jan. 10 update. The company and its partners are working on a full development plan for the field this year.

"The steadily improving reliability of the Lomond facilities provides encouragement for Columbus to use these facilities, an approach that Serica's management believes would deliver the best economic value for other facility users," Serica said in the release. "In addition to lowering operating costs per barrel for all parties, this can extend the economic life of the facilities thus maximizing total reserves recovery."

Also this year, Serica aims to reach agreements on the offtake route and drilling plans.

The Columbus Field is located in blocks 23/16f and 23/21a.

—Staff Reports

FLOATERS

FPSO Outlook: Long Time Lag Creates 'Seeming Prosperity'

Rising oil prices are boosting hopes that more FPSO units will join the workforce following years of lackluster activity caused mostly by spending cutbacks driven by the downturn.

But a quick turnaround is not expected, considering the long lead time needed for offshore infrastructure.

A report released Jan. 9 by Stratas Advisors forecast that additions of new, operative FPSO units will wane, with six vessels added in 2018 and only four in 2019. However, more FPSO vessels will go to work between the years 2020 and 2023, with each year seeing about 10 more FPSO units put to sea.

"Geographically, Latin America is booming in terms of FPSO usage in the next 10 years, driven by the ongoing investment in Brazil presalt developments," Stratas said. "The region is expected to more than double its FPSO vessel count by 2025 from the current 42 to 88. Most of the new additions (40 of 46) are designated to Brazil."

In December, the FPSO *Cidade de Caraguatatuba* became the latest Petrobras vessel to commence operations. The vessel, which is capable of processing 100 Mbbl of oil and compressing 5 MMcm/d (176.5 MMcf/d) of gas, began producing oil from the Lapa Field in the Santos Basin on Dec. 19.

The FPSO vessel, which is connected to the field via production well 7-LPA-1D, marked the third major Petrobras production system to start operating in 2016. The other two were FPSO units *Cidade de Saquarema*, which is connected to the 8-LL-81D-RJS production well in the Santos Basin's Lula Field, and *Cidade de Maricá* in the Lula Alta area of the Lula Field. Both vessels are owned by the consortium of SBM Offshore, Mitsubishi Corp., Nippon Yusen Kabushiki Kaisha and Queiroz Galvão Óleo e Gás.

Petrobras has said the Libra Consortium—which includes Petrobras, Royal Dutch Shell, Total, CNPC and CNOOC—expects to hire an FPSO unit for the Libra Pilot project during 2017 with startup scheduled for second-half 2020. In October 2016, the consortium started a new bid process for the FPSO unit after prices came in "abnormally" higher than expected given market conditions.

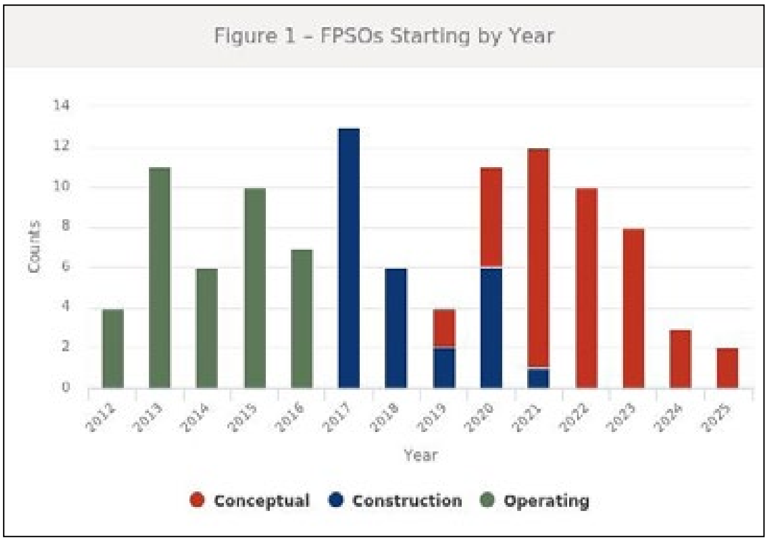
Stratas expects the Latin American region to surpass the Asia-Pacific region's number of operating FPSO units. With 48 FPSO units deployed, Asia-Pacific currently outnumbers any other region, the consulting firm said.

MODEC, a Houston-based builder of FPSO units, installed or operates about seven units in southeast Asia and another three in the Oceania region, its website stated—nearly as many as Stratas predicts to join the global fleet in 2018.

Growth is also expected offshore West Africa, a region where 37 FPSO units are currently operating, Stratas said. The FPSO *Prof. John Evans Atta Mills* is among the most recent vessels to start production, flowing oil from the Tullow Oil-operated Tweneboa, Enyenra and Ntomme fields offshore Ghana. Another 12 FPSO units are in the conceptual planning stage and five more are currently being built offshore West Africa.

Another region likely to see more FPSO units: offshore Europe. Stratas' forecast indicates seven more units are in store for northwest Europe, where 23 are now operating.

"The industry had about 140 FPSO units actively employed globally in 2015. Operators added seven FPSO



Source: Stratas Advisors

units to the global fleet in 2016. In 2017, 13 FPSO units are looking to start first production," Stratas said in its report. "Because of the long investment cycle on offshore developments, the long time lag has created a seeming prosperity of the FPSO market."

—Velda Addison

Finding A Place For 'Homeless LNG'

Watch out for the impact of floating LNG (FLNG) storage in 2017 and 2018, particularly during the seasonal "shoulder months," Genscape advised.

In a piece by LNG and natural gas analyst Ted Michael, the firm expects an increased global need for floating offshore storage as U.S. and Australian liquefaction trains continue to ramp up.

"With the 40% rise in global supply will come an increased need to track floating offshore storage and the total volume of LNG at sea, for a more complete understanding of global supply and demand," Michael wrote.

Global production was about 991 MMcm/d (35 Bcf/d) at year-end 2015, Genscape said. By 2019, with U.S. and Australian plants completing construction and shipping output, plans are for production to hit about 1.4 Bcm/d (50 Bcf/d). The problem is that traditional markets—Europe and Northern Asia—are not offering demand growth as a result of regulations, competition from other fuels and price controls.

But the supply will increase, which may turn LNG ships into floating storage units, similar to crude oil tankers in that segment of the industry.

Michael cited an article in PortVision: "Low prices and abundant supplies have created what is being called 'homeless LNG:' liquid natural gas without committed buyers being housed in tanker ships roaming the high seas."

Genscape sees two classes of FLNG storage: ships delayed offshore, like those that have been observed backing up in Tokyo Harbor; and floating storage and regas units (FSRU).

The first is caused by lower-than-expected demand and has occurred recently offshore Japan and South Korea. In this situation, utilities are reluctant to be caught short until winter peaks.

FSRUs have a dry dock build turnaround time of 12 to 18 months and can be leased or installed for less than $300 million. This gives them a significant cost advantage over land-based regasification plants and storage facilities that can take up to four years to build and cost as much as $1 billion.

—Joseph Markman

VESSELS

Global Energy Development Dives In Subsea Vessel Business

In a strategy shift that focuses on subsea oilfield services sector, Global Energy Development has conditionally agreed to purchase 11 offshore subsea service vessels and a barge vessel, the company said Jan. 16.

The transaction represents a reverse takeover of subsea service vessel owning companies, pending shareholder approval.

All of the vessels, most of which are capable of operating in depths of up to 91 m (300 ft), are currently located in Louisiana.

"We are very pleased to have committed to these acquisitions of the offshore service vessels in the Gulf of Mexico," said Mikel Faulkner, chairman of Global Energy Development. "This represents the company's first step towards delivering on the company's new strategy of increasing shareholder value by targeting investment and acquisition opportunities in the subsea services sector with the potential for significant upside.

The deal involves two transactions. Under one transaction, three vessels will be acquired from Everest Hill Group through the purchase of all of the issued shares in three vessel-owning companies, Global Energy said. Consideration for these vessels include $8 million upfront, satisfied through the forgiveness of $8 million of the principal amount of an existing $12 million secured loan note agreement.

Another transaction involves $10.5 million in new cash proceeds to acquire eight vessels, a barge vessel and other equipment through the purchase of shares in two vessel-owning companies from McLarty Capital Partners, Caleura Ltd. and Alan Quasha, the company said.

In addition, Global Energy said it seeks to change its name to Nautilus Marine Services to reflect its new business strategy. John Payne, a master mariner with more than 25 years of subsea sector experience, will serve as director of operations.

—Velda Addison

Hybrid LNG-Diesel-Battery Powered Ferry In Service In Canada

The world's first hybrid LNG-fueled and battery-powered vessel has gone into service on Canada's West Coast. *Seaspan Swift* is also the first LNG-fueled vessel operating on the Canadian coast and North America's first onboard bunkering of LNG from a truck trailer.

Seaspan Ferries Corp.'s (SFC) new dual-fueled/hybrid-diesel, LNG and battery-powered ferry was

Seaspan Swift, the first hybrid LNG-battery-powered vessel in service, operates on Canada's West Coast between the British Columbia mainland and Vancouver Island. (Source: Bureau Veritas)

designed by VARD Marine, and is the first of two to be constructed at Sedef Shipbuilding in Turkey.

The 148.9-m (488.5-ft) *Seaspan Swift* underwent pre-operation regulatory checks and crew training in December following its 10,661-nautical mile delivery voyage to the SFC Tilbury Terminal in Delta, Vancouver. A sister vessel, *Seaspan Reliant*—also classed by Bureau Veritas—is scheduled to arrive on the West Coast early this year.

"We are happy to be working with Bureau Veritas on this technical LNG/Hybrid project," said Steve Roth, vice president of Seaspan Ferries. "Their partnership with Seaspan Ferries has helped make the design, approval, production and delivery of the vessels a success."

Bureau Veritas is a world leader in LNG marine projects across a range of specialized ship types.

"We know how pleased Seaspan are and we share their excitement seeing this ship now in service," said Philippe Donche-Gay, president, Bureau Verital marine & offshore. "We are now looking forward to helping Seaspan ensure that this new low-emission ferry works efficiently and safely for many years to come."

—Joseph Markman

VESSEL BRIEFS

Subsea 7 Reports Early Termination Of Vessel Contract

The day rate contract for Subsea 7's pipelay support vessel, *Seven Mar*, was terminated earlier than planned—on Jan. 16, the company said.

The vessel had been working for Petrobras and was set to expire in 2018.

"Brazilian maritime law prioritizes Brazilian-flagged vessels over international vessels of a similar specification," Subsea 7 said. "As a consequence, the operating licence for Seven Mar has expired, which resulted in the early termination of the contract."

The termination reduced Subsea 7's backlog by about $106 million.

Petrobras Hires *Skandi Victoria* Pipelay Vessel

Petrobras has awarded a 532-day contract for the *Skandi Vitoria* pipelay vessel, which is capable of working in depths of up to 3,000 m (9,843 ft).

Features of the vessel, which was built in Brazil, include vertical and horizontal pipelay systems, a 250-m (820-ft) crane and two work ROVs, DOF Subsea said.

The contract began in January.

SMD Completes Curvetech Components Tests For Deepwater ROV

SMD has completed its work to allow Curvetech subsea components to function at depths of up to 6,000 m (19,685 ft).

The work followed the award of an order from Shanghai Salvage for a 6,000 m Quasar Work Class ROV. The Curvetech range now includes compensators and electrical control principal circuit boards (PCBs) rated for 6,000 m depth operations. Successful testing means that these components can be purchased directly from SMD Services. "Hyperbaric testing of critical components is an expensive operation but by performing this testing our clients can be confident that our ROVs will operate reliably right from delivery," said Mark Collins, managing director for SMD ROVs. "SMD's aim is always zero vehicle downtime."

—Staff Reports

EXPLORATION

ExxonMobil Scores Again Offshore Guyana

ExxonMobil Corp.'s persistent ultradeepwater pursuit of oil has led to its second discovery on the Stabroek Block offshore Guyana.

The Houston-based company announced Jan. 12 that its Payara-1 well, which targeted reservoirs of similar age to the Liza discovery, hit more than 29 m (95 ft) of oil-bearing sandstone reservoirs. The well was drilled to 5,512 m (18,080 ft) in 2,030 m (6,660 ft) of water in the Payara Field, northwest of the Liza discovery, the company said in a news release.

The discovery was made as companies are stepping up E&P activity and moving forward more efficiently with the aid of technology, following a hydrocarbon oversupply-driven downturn that gutted exploration budgets. For ExxonMobil, the discovery helps solidify the area offshore Guyana as an "exploration province," according to Steve Greenlee, president of ExxonMobil Exploration Co.

"These latest exploration successes are examples of ExxonMobil's technological capabilities in ultradeepwater environments, which will enable effective development of the resource for the benefit of the people of Guyana and our shareholders," Greenlee said in the news release.

The Payara discovery is estimated to hold between 100 MMboe and 150 MMboe.

To better gauge resource potential, ExxonMobil said the discovery is being evaluated, with two sidetracks drilled. A well test is underway.

Success at Payara-1, which was drilled by the *Stena Carron* drillship, follows the "world-class" Liza discovery made in 2015.

In addition to the Payara-1 well striking oil, the company said the Liza-3 appraisal well has identified a deeper reservoir below the Liza Field.

"The Payara-1 results further demonstrate the prospectivity of the Stabroek Block," said John Hess, CEO of Hess Corp., which also holds an interest in the Stabroek Block.

"We are excited about Payara as well as the deeper reservoir identified below the Liza Field," Hess added. "While further appraisal is required, we believe that the resources recently discovered are significant and will be accretive to the more than 1 billion barrels of oil equivalent already confirmed at the Liza discovery."

In addition to more exploration drilling, seismic analysis is planned for 2017, Hess Corp. said. Next steps include moving the drillship to the Snoek prospect, also located on the Strabroek Block about 10 km (6 miles) south of Liza-1.

ExxonMobil's play-opening Liza discovery offshore Guyana was drilled by the *Stena Carron* drillship, with the operator estimating minimum recoverable reserves of 1 Bboe, which will initially be developed via an FPSO unit subject to final sanction. (Source: Hess)

The latest discovery could add to resources destined for an FPSO unit lined up for the field.

On Dec. 20, ExxonMobil said it selected SBM Offshore to carry out FEED work for the FPSO vessel that will be used at the Liza Field. If a final investment decision (FID) is made on the project, the company would also build, install and operate the vessel. An FID is expected in 2017.

Payara marks the third exploration well drilled offshore Guyana by ExxonMobil, following Liza and Skipjack. The latter, drilled 40 km (25 miles) northwest of Liza, was unsuccessful.

The 26,800-sq-km (10,347-sq-mile) Stabroek Block is operated by ExxonMobil affiliate Esso Exploration and Production Guyana Ltd., which holds a 45% interest. Partner Hess Guyana Exploration Ltd. holds 30%, while partner CNOOC Nexen Petroleum Guyana Ltd. holds a 25% interest.

Norway Awards 56 Oil, Gas Licenses In Mature Areas

Norway awarded 56 offshore exploration licenses on Jan. 17, matching its 2016 record number, as it seeks to boost output from acreage located near existing oil and gas fields.

A total of 29 companies won stakes in the annual award of blocks in mature areas—areas already opened for exploration. The allocations aim to ensure maximum utilization of past investments in platforms, pipes and other infrastructure.

The biggest winner was Statoil with 29 licenses, including 16 operatorships, while Aker BP came in second with 21 licenses, of which 13 were operatorships.

"This shows that there still is a lot of interest for the Norwegian Continental Shelf and that new players are coming in," Statoil's CEO Eldar Saetre told Reuters on the sidelines of an industry conference.

Aker BP CEO Karl Johnny Hersvik told Reuters the company had to a large extent been awarded the areas it had applied for.

"Hopefully some of them will be a part of our 2018 exploration campaign," he said.

A total of 33 firms applied for acreage, down from 43 companies in the previous round a year ago, when the ministry also awarded 56 exploration licenses to 36 companies.

Others to win one or more operatorships in the latest round included Lundin Petroleum, Eni, ConocoPhillips, Shell Total and Wintershall.

Of the licenses, 36 were awarded in the North Sea, 17 in the Norwegian Sea and three in the Barents Sea.

Minister of Petroleum and Energy Terje Soeviknes said the government has started to work on its latest licensing round for new areas, and had received much interest. Results are due before July.

Oil production in Norway increased for the third consecutive year in 2016, beating official forecasts, and gas production stood close to the record levels of 2015, the Norwegian Petroleum Directorate said in a statement on Jan. 17.

—Reuters

TECHNOLOGY

Dual System To Tackle HP/HT Challenges

Plexus' POS-GRIP surface exploration wellhead was being prepared to be run through the rotary table and installed on the riser during recent operations in the North Sea. (Source: Plexus Holdings)

Danish operator Maersk Oil, together with its project partners BP and JX Nippon, is developing one of the largest gas discoveries of recent years—the HP/HT Culzean Field on the U.K. Continental Shelf.

There are currently less than 100 HP/HT wells producing around the world, with Culzean to eventually feature six such production wells. Drilling of the first well was underway in September 2016.

Faced with engineering complexity and cost challenges associated with such large independent jacket-based operations, there is a growing trend toward small- to medium- sized developments that can produce to an existing facility or dedicated floating facility.

This is especially important in regions that do not support HP/ HT projects that would otherwise be uneconomic without government incentives, similar to that used on Culzean, which is due onstream in 2019.

In today's cost-constrained climate there is now an increasing move toward marrying complementary systems that can combine field-proven technologies to reduce cost and time-to-field implementation.

Changing Mindset

Aquaterra Energy and Plexus Holdings have developed a lightweight dual-barrier HP/HT riser system that can be deployed by a jackup rig and is a viable and cost-efficient alternative to semisubmersible installation for HP/HT well operations. Though the dual-barrier system has not yet been deployed in the field, all of its component parts already are well-established.

The jackup-deployable system is suitable for water depths of up to 150 m (492 ft) and harnesses the attributes of the companies' respective subsea technologies by combining Aquaterra's HP/HT riser system and Plexus' POS-GRIP wellhead engineering technology. This enables an inner riser string to be installed inside a conventional high-pressure riser (HPR) to provide full 20,000-psi capability without compromising safety, integrity and operational performance.

Jackup Advantages

Semisubmersible units have traditionally been used to perform drilling, completion, intervention and abandonment services on subsea wells.

However, in comparison to semisubmersible units, heavy-duty jackup drilling units rated for up to 150 m water depth can now undertake such activities at reduced cost and risk when the jackup-deployed HPR is used to span the gap between a dry surface BOP and a subsea tree.

As top-tensioned risers and lower jackup rig offsets impart lesser loads onto the wellhead and other subsea components, an additional benefit is the possibility for improved wellhead/low-pressure housing/subsea tree loading performance. This results in less fatigue damage, thereby extending the service life of equipment, increasing safety margins and improving operational envelopes.

Moreover, typical HPR systems are designed to withstand 50-year storm conditions under a well control situation. Unlike semisubmersible units, the use of a jackup rig removes the need to disconnect from the well in extreme weather conditions, eliminating unnecessary nonproductive time.

As new-generation jackups are now capable of operating in increasing water depths, the range of subsea wells that are a viable option for a jackup-deployed HPR also continues to increase. This alternative means of deployment has the potential to access about 60% of the total number of subsea wells worldwide.

It's A 'Keeper'

The most significant benefit to the operator is the ability to convert exploration or appraisal wells into a "keeper" or production well. The U.K. government, in particular, has identified this as a key issue, and the jackup-deployable dual-barrier HP/HT riser system directly addresses this challenge.

As current mudline suspension hanger technology does not provide a means of safely suspending HP/HT wells, it is not possible to reenter or tie back exploration or appraisal wells to existing platform-based or FPSO infrastructure.

However, when combined with an HPR and a jackup, using a subsea wellhead allows such wells to be converted to a keeper, and the cost base during the exploration phase, compared to a semisubmersible unit, is considerably reduced. Deploying a dual-barrier riser in such wells allows them to be reentered or put into production, potentially saving an operator millions of dollars.

Dual-barrier Capabilities

The challenge of expanding incumbent technologies into HP/HT environments is simply increasing the pressure and temperature rating of fullbore risers, which is outside current manufacturing limits.

According to research, at pressures of about 10,000 psi and elevated temperatures in excess of 121 C (250 F), the required material chemistry, available manufacturing techniques and capital cost of large-bore dynamic HP/HT steel pipe could become prohibitive. It also can increase the cost of HPRs by more than 400% from that of a standard 5,000-psi system. This, in turn, has limited the advance in HPR deployments to projects with lower temperatures and pressures due to the technical and commercial restrictions and the trend toward thicker walled riser joints.

This issue is of particular importance for a subsea HPR as the riser is exposed to tension, environmental loading via wave action and—during well control events—wellbore pressure. Systems subsequently have much heavier walls to withstand this combined loading, and typical subsea HPR codes, such as American Petroleum Institute RP 2RD and International Organization for Standardization (ISO) 13628-7, account for design and qualification at 1.5 times the working pressure of the riser.

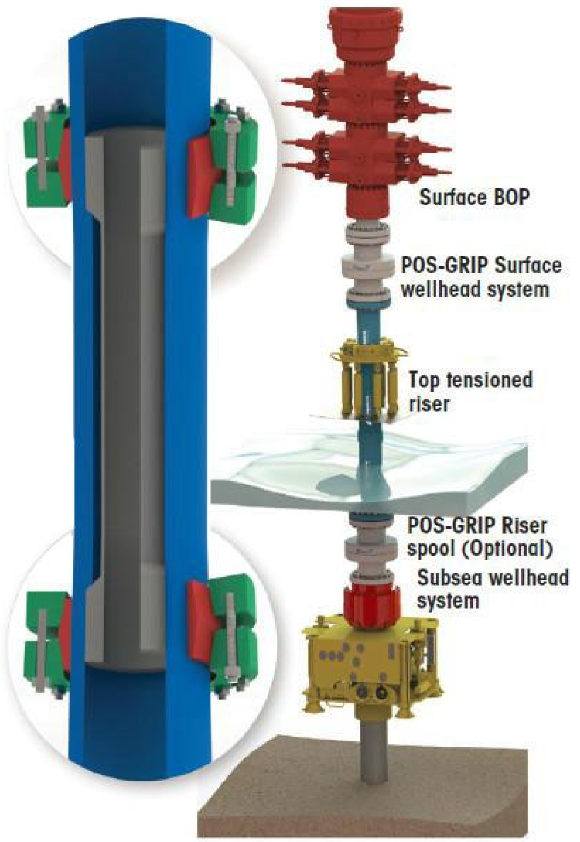
The dual-bore system addresses this by using a standard outer HPR for lower pressure/temperature zones in the well. Once HP/HT zones are about to be encountered, a protected inner HP/HT riser string is run inside the outer HPR between the surface BOP and the subsea wellhead. This philosophy allows the inner riser string to have a thinner wall due to the protection provided by the outer string and its qualification to casing codes such as ISO 13679 CAL IV.

Incremental Step Forward

The joint system developed by Aquaterra and Plexus represents an incremental step forward in subsea capabilities as it facilitates safe and effective drilling operations in HP/HT conditions and provides a structurally sound pressure-retaining conduit between the subsea wellhead or tree and the rig's surface BOP.

Rather than increasing the pressure rating of the outer riser, POS-GRIP allows an inner riser string to be temporarily installed, allowing full HP/HT capability from the subsea wellhead all the way to the surface BOP. The latter can then remain in place for the entire project once nippled up.

The pressure-retaining well control inner riser string will see a reduced environmental load, with the main riser supporting the majority of the bending. At surface the POS-GRIP surface housing allows the inner HP/HT riser string to be terminated inside. Subsea at the wellhead, the HP/HT riser string is connected to the POS-GRIP, creating an HP/HT conduit.



The dual-barrier HP/HT riser system provides a means of accessing HP/HT wells with a subsea riser system deployed from a jackup rig. (Source: Aquaterra Energy)

The dual-barrier HP/HT riser system eliminates the issues associated with surface wellhead developments that contain elastomeric seals, particularly those located between the mudline and surface. Due to the flexible placement of the POS-GRIP to surface and subsea systems (+/-4 in.), this negates challenges with setting the inner liner space out between two points.

Field-proven Technology

Over the last 20 years POS-GRIP has been used on more than 300 wells drilled by jackup rigs, with full metal sealing capability and pressure ratings up to 20,000 psi at 190.5 C (375 F).

The dual-barrier HP/HT riser system is based on field-proven technology using all metal-to-metal gastight seals on both the external and internal riser strings. It is capable of withstanding environmental and operational conditions expected during the HPR service life and can be used in drilling, completion, intervention and abandonment modes.

Amid the ever-increasing industry focus upon HP/HT operations, this methodology represents an innovative and cost-effective alternative while maintaining safety, integrity and operational performance.

Aquaterra's engineers developed the first HPR systems deployed in the North Sea in the 1990s, which were typically used on lower pressure wells. With increased well pressure requirements of more than 5,000 psi and for those more than 10,000 psi, the dual-barrier HPR system can offer significant financial savings and safety benefits over single-barrier systems.

—Ben Cannell, Aquaterra Energy

Hempel Releases New Coatings For Offshore Assets

Hempel has released two new coatings that aim to increase the service life and reduce on-station maintenance requirements of offshore assets.

The coatings, Hempadur Quattro XO 17820 and 17870, are pure epoxy uni-primers that provide corrosion protection.

"The coatings are part of a series of two-component epoxy primer coatings, which provide advanced crack resistance using Hempel's patented fiber technology," Hempel said in a news release. "They can be applied in immersed and non-immersed areas of any offshore asset, from offshore platforms and drilling rigs through to support vessels."

The coatings can also be applied to multiple areas above and below the waterline, including ballast water and oil cargo tanks, and can be applied year-round with workability from -10 C (14 F) to 45 C (113 F), the company said.

"For asset owners, the key benefits of Hempadur Quattro XO are that fewer variations of protective coating are required across the structure; life-cycle maintenance is greatly simplified and downtime for recoating is significantly reduced, saving time and money," Hempel's Oil & Gas Segment Manager, Simon Daly, said in the release. "For yards and coatings applicators, the fact that the product is quick drying and can be applied even during winter months, means that project schedules can be maintained without painting activities being interrupted."

Hempel said Managing Director of Meuhlhan B.V. Guy Tanguy endorsed the use of Hempadur Quattro

Hempel aims to simplify offshore asset maintenance with new coating range. (Source: Hempel)

17870 XO on the ballast tanks of the *Saipem 7000* semisubmersible vessel.

"The aluminum and fiber pigmented pure epoxy has proven its excellent characteristics. The recoat intervals were very short, which made it possible to work around the clock in order to finalize the tanks within the schedule despite the low winter temperatures and high volume solids in the product."

The coatings are compliant with IMO Performance Standard for Protective Coatings regulations, Hempel added.

—Staff Reports

BUSINESS

E&P Budgets Swell, But Rising Service Costs Loom

E&Ps appear to be back in the business of spending money.

After unprecedented back-to-back years of double-digit spending declines, upstream spending is set to increase, led by North American (NAM) E&Ps. But analysts caution that service costs will also make up part of the spending increase.

While E&Ps have benefitted from oilfield service pricing near or below breakeven levels, a survey by Barclays released Jan. 9 shows that 79% of E&Ps expect oilfield service costs to increase in 2017. A majority of operators, about 55%, expect modest increases of up to 10%.

Overall, global upstream spending is expected to increase 7% after back-to-back declines of 26% in 2015 and 23% in 2016, according to Barclays' survey.

Barclays' survey shows spending in NAM will see a sharp increase, with E&Ps upping their budgets by 27% in

2017 after slashing 38% in 2016. However, only about 15% to 20% of E&Ps have formally announced their 2017 budgets so far.

"Buoyed by lower cost structures, higher prices, the need to grow production and just more optimism post-OPEC, we expect operators to step on the accelerator as we enter 2017," said David Tameron, senior analyst with Wells Fargo Securities.

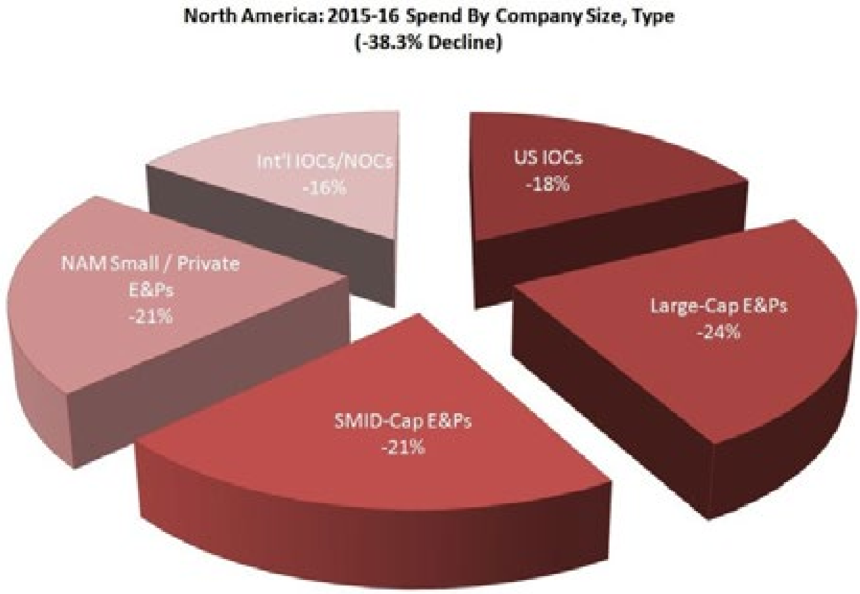
International spending will increase 2% in 2017 while offshore spending is poised to fall by up to 25%.

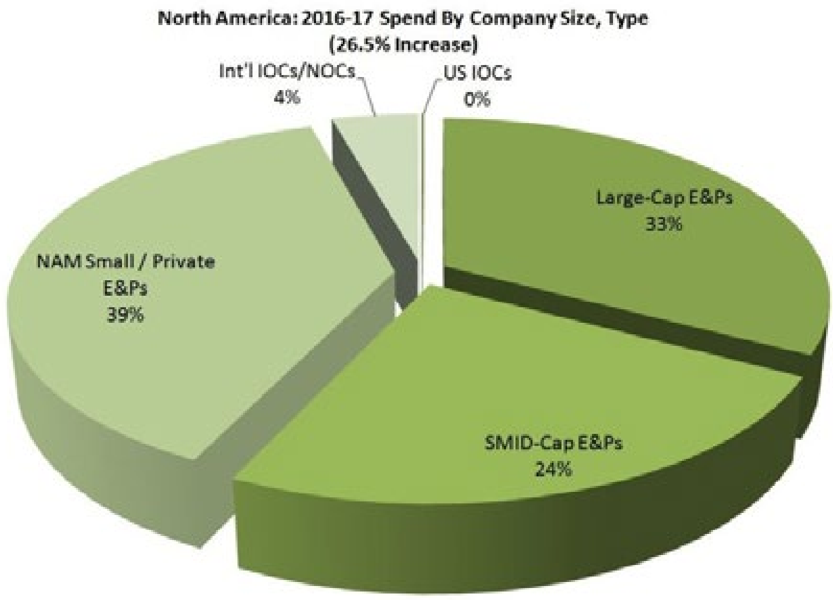
Offshore spending is estimated to fall by 20% to 25% in 2017, following declines of 12% in 2015 and 34% in 2016.

Because companies don't break offshore out of North American and international spending budgets, Barclays used assumptions to get a good read on offshore spending.

"Offshore is at the opposite end of the spectrum as the downturn took place more slowly after oil prices collapsed in late 2014" because of multiyear contracts on offshore rigs and the longer-term nature of offshore developments, Barclays said.

The sector is also slower to recover. However, 2017 may be the final year of three years of consecutive spending declines as rig contract cancellations have slowed and the impact of structural cost reductions for offshore projects could lead to deepwater project sanctioning as early as second-half 2017.





Source: Barclays; Hart Energy

Barclays forecasts contracted the offshore floater rig count to bottom at 120 by year-end 2017 before rebounding to 140 in 2018.

The next upcycle may see the size of the offshore business become meaningfully smaller.

"We believe the era of mega-deepwater projects is over and that IOCs [independent oil companies] now want more phased-in, bite-size developments to capture first oil earlier and minimize project risk, which will result in 2017 growth in subsea tree orders," Barclays' report said.

Wood Mackenzie estimates an increase of about 150% in subsea trees to 185 off a low base of 75 trees in 2016 — far below the 2013 peak of 550. The trees will largely include tiebacks, step-outs and potentially some intervention work.

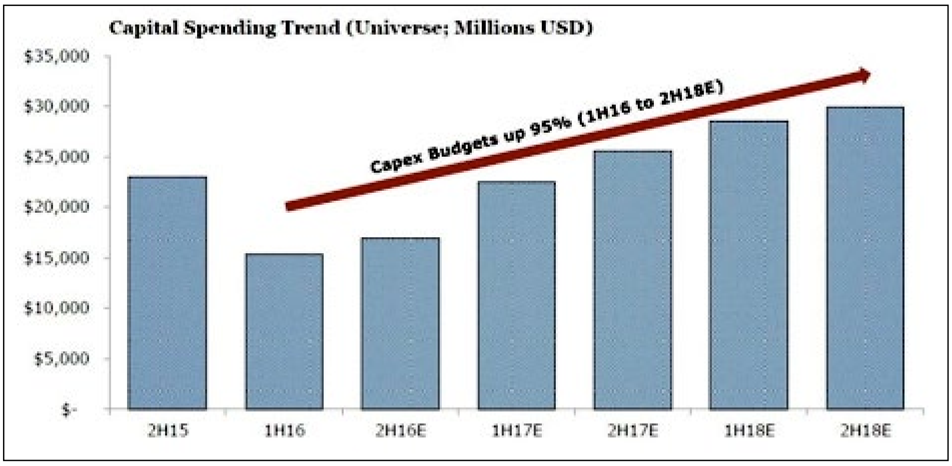
"Operators see speed to market as a crucial factor, which requires changes in the OFS complex like standardization, modular designs and integrated packages for equipment and installation," Barclays said.

OPEC's decision to compete for market share in the past few years may have a couple of major, unintended consequences. While U.S. shale production may not have been the target of OPEC's production frenzy, well costs in the U.S. have fallen by 40%, J. David Anderson, Barclays' oilfield services and equipment analyst said during a Jan. 10 press call.

"The industry has seen step changes in efficiencies over the last two years in drilling and completions," he said. "OPEC is about to find out just how efficient U.S. shale has become over the last two years."

Spending Change, By Region And Company Type				
($MM)	**2016E**	**2017E**	**2015-2016**	**2016-2017**
Middle East	57,138	58,642	8.1%	2.6%
Latin America	34,500	37,529	(37.4%)	8.8%
Russia/FSU	35,263	38,750	(5.3%)	9.9%
India, Asia & Australia	62,527	70,335	(19.8%)	12.5%
Europe	21,680	20,359	(23.6%)	(6.1%)
Africa	17,642	17,912	(18.4%)	1.5%
International				
Majors	62,234	51,025	(22.1%)	(18%)
NAM Independents	4,327	6,858	(50.9%)	58.5%
Other E&P	4,042	4,834	(11.3%)	19.6%
Total:	$299,352	$306,244	(18.3%)	2.3%
Worldwide E&P Total:	$377,065	$404,571	(23.4%)	7.3%

Source: Barclays Research, company reports



Source: Wells Fargo Securities, LLC estimates and company filings

NAM large-cap companies in particular are ramping up their spending by 58.5%, the largest percent increase among any group Barclays surveyed.

"The important number here is large-cap E&Ps," Anderson said. "We see large-cap E&P spending up almost 60% in 2017. That is offset by major oil companies spending being flat, which tend to be more Gulf of Mexico driven."

However, NAM upstream spending is dictated by the cash flow generated by producers, making most of their spending oil-price sensitive. It's also one of the most cyclical of any region because companies tend to spend all of their cash flow—and often more than their cash flow—on drilling and completing wells.

The Spendthrift Industry

In the past four years, large-cap E&Ps spent 120% of cash flow and small- and mid-cap companies have spent 154% of cash flow.

However, in 2015 and 2016, E&Ps raised about $40 billion through equity, turning upstream leverage levels to more healthy proportions, said David Deckelbaum, an analyst at KeyBanc Capital Markets.

Among E&Ps that KeyBanc covers, companies' outspent cash flow by $36 billion from 2013 to 2015, or about 54% annually. In 2016 overspending cash flow lessened to about 17%. In 2017, those companies are expected to spend within cash flow.

Deckelbaum expects to see debt to continue compressing in 2017 and to a lesser extent in 2018.

"Healthy leverage metrics combine with over $37 billion of liquidity in our coverage, a 20% increase since the end of 2015," Deckelbaum said. "This setup should allow for palatable rig additions and increased M&A activity."

KeyBanc estimates capex for companies covered will rise by 28% in 2017 and another 30% in 2018. Meanwhile, production will grow in the double digits both years.

—Darren Barbee

BUSINESS BRIEFS

Subsea 7 Makes Offer For Seaway Heavy Lifting

Subsea 7 S.A., through one of its subsidiaries, has made an offer to acquire K&S Baltic Offshore (Cyprus) Ltd.'s 50% shareholding in Seaway Heavy Lifting Holding Ltd.

Subsea 7 already holds a 50% interest in the joint venture company, a specialist offshore contractor that operates two heavy-lift vessels. The subsea company is initially offering $279 million on completion and deferred consideration of up to $40 million to be paid by the end of first-quarter 2021 if certain performance targets are met, Subsea 7 said in a news release. The offer terms are binding until July 1.

"Subsea 7's strong market position in offshore energy services is complemented by Seaway Heavy Lifting's expertise in three areas of offshore activity: renewables, heavy lifting operations and decommissioning of oil and gas assets," Subsea 7 CEO Jean Cahuzac said in the release. "We believe that this acquisition will allow us to strengthen Subsea 7's position in businesses where we expect increased activity and opportunities for long-term growth."

Headquartered in the Netherlands, Seaway Heavy Lifting employs about 550 employees.

TechnipFMC Begins Operations As Combined Company

TechnipFMC began operations as a combined company following the completed merger of FMC Technologies and Technip, according to a Jan. 17 press release.

Doug Pferdehirt is CEO of TechnipFMC, and there are 44,000 employees, according to the press release.

The merger creates a global leader in oil and natural gas projects, technologies, systems and services, particularly subsea, onshore/offshore and surface.

The company began trading on the New York Stock Exchange and on the Euronext Paris Stock Exchange under the ticker "FTI."

Sapurakencana, Proserv Form Asia-Pacific Pact

SapuraKencana Technology Sdn Bhd and Proserv are teaming up in an effort to provide enhanced technology services in the Asia-Pacific region.

The two companies will jointly provide services across the drilling, production, maintenance and decommissioning market sectors with a focus on subsea production and subsea maintenance services, according to a news release.

The partnership intends to leverage Proserv's subsea production equipment and controls and SapuraKencana Technology's technical support, resources and assets.

Fugro Attains Internationally Recognized AEO Status

Through its operating company Fugro Subsea Services, Fugro recently received Authorized Economic Operator status, highlighting its role in the international supply chain, a Jan. 17 press release said.

The accreditation process began in second-half 2015, and the award was received Dec. 11, 2016.

The HMRC department in the U.K. government examined logistics, warehousing, purchasing, supply chain management, accounts and IT activities to ensure that they complied with all customs and tax requirements. Detailed checks and assessments were also carried out on key personnel, the press release said.

Rodger & Hartnolls Service Firm Names Partner, Managing Director

Rodger & Hartnolls, which provides support services for offshore, subsea, renewables and technology markets, said Jan. 9 that Nick Search was appointed as a partner and managing director, effective Jan. 3.

He will oversee global business activity and will be based in the South London office. Search has 36 years' experience in the offshore energy and marine industries.

Most recently, Search was the business development director for Promineo AS, based in Stavanger, Norway.

Halliburton, Petrobras Will Study Solutions For Complex Reservoirs

Halliburton and Petrobras entered a multiyear agreement to facilitate solutions for geophysics, drilling and completions, reservoir characterization, well testing, flow assurance and production in deepwater presalt areas, mature fields and other complex reservoirs, according to a January press release.

The companies aim to reduce well construction investment, focus on long-term reservoir monitoring and increase well productivity.

This multiyear collaboration is the second phase of a technology collaboration between the companies in Brazil, the company said, noting that during the first phase—which began in 2009—they collaborated on 11 projects including prestack seismic attributes for carbonates, new algorithms for better estimation of fluid sampling contamination, and a new cementing system for salt and CO_2 environments.

Neuhaus Returns To MicroSeismic As Vice President Of Engineering

Houston-based MicroSeismic Inc. said on Jan. 10 that Carl Neuhaus is returning to the company as vice president of engineering, after working for two years at DrillingInfo as the director of petroleum engineering. Neuhaus will oversee MicroSeismic's technical quality and innovation for engineering services, communicating about them to the oil and gas industry.

During his prior tenure at MicroSeismic, Neuhaus managed a multidisciplinary completions evaluation team. He also helped optimize wellbore spacing, completion design and treatment design by developing solutions using completions and reservoir engineering, geomechanics, geophysics and geology.

MicroSeismic also said its board elected William B. (Bill) Barker as vice president of analysis, and Eric Bourdages as vice president of operations.

NADL Extends Delivery Deferment For Semisubmersible Unit

North Atlantic Drilling Ltd. (NADL) said on Jan. 9 that the delivery date deferral period for the *West Rigel* semisubmersible unit was extended to July 6, 2017, allowing time for NADL and Jurong Shipyard Pte Ltd. to explore commercial opportunities for the unit.

NADL said that, as previously agreed, it will form a joint asset holding company with Jurong to jointly own *West Rigel* if no employment is secured for it.

Dril-Quip Continues Growth With Acquisition Of OPT

Dril-Quip Inc. said Jan. 6 it acquired The Technologies Alliance Inc., doing business as OilPatch Technologies (OPT), for about $20 million.

Based in Houston, OPT is a provider of offshore riser systems and components, proprietary threaded connections and other products, with a focus on deepwater Spar and tension-leg platform systems. The company was founded in 1990.

The deal will complement and further strengthen Dril-Quip's position as "a leading provider of dry tree systems and associated riser products," Blake DeBerry, the company's president and CEO, said in a statement.

Acteon Acquires Bruce Anchor

Subsea services group Acteon acquired Bruce Anchor, boosting its ability to provide temporary and permanent mooring systems. The acquisition was completed Dec. 21, 2016.

Bruce Anchor will remain independent within the Acteon portfolio, providing anchor technology to the oil, gas and renewables sectors.

Steve Broadbent will manage the business. He is Anchor's director of sales and will report to Bernhard Bruggaier, executive vice president of operations for Acteon. Broadbent will be supported by the founder, Peter Bruce, during the transition into Acteon.

Schlumberger Expands With Peak Well Systems Acquisition

Schlumberger Ltd. acquired Peak Well Systems from growth equity investor Summit Partners and the company's founders and management team for an undisclosed amount, Schlumberger said Jan. 5.

Peak Well Systems designs and develops advanced downhole tools for flow control, well intervention and well integrity. Its products include tools that can be used in HP/HT wells. The company has offices in the U.K., Australia, the United Arab Emirates and Malaysia.

Peak's technologies will give Schlumberger the opportunity to offer fully integrated well intervention solutions on electric line, mechanical slickline or digital slickline to its customers, Hinda Gharbi, president of the company's wireline group, said in a statement.

Existing Peak customers will continue to have access to the company's well intervention products as well as Schlumberger's wider distribution network and delivery platform in all global markets.

Tullow Says Finance Head On Medical Leave; Names Interim CFO

Tullow Oil Plc named Les Wood, vice president of finance and commercial, as interim CFO as its finance chief Ian Springett takes an extended leave of absence for medical treatment.

The Africa-focused oil producer did not specify how long Wood would remain the interim CFO.

In response, CEO Aidan Heavey has tightened spending.

Tullow slashed its full-year spending budget in November and lowered the forecast for its oil production in West Africa, even as a delay in ramping up output at TEN oil fields also weighed on outlook.

Wood, who joined Tullow in 2014, previously spent 28 years at BP Plc, including in regional CFO roles in Canada and the Middle East.

Springett, also an ex-BP regional finance head, has been in Tullow's top finance job since 2008.

—Staff & Reuters Reports

UPCOMING

The next issue of *Subsea Engineering News* will be distributed Feb. 2. Until then, visit *epmag.com*.

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