Offshore®
SPECIAL REPORT

SUBSEA ENGINEERING

In this 2nd annual report, *Offshore* features in-depth subsea analysis and market outlooks for the sector as well as ROV/AUV/USV updates, a flow assurance joint industry project, real-time monitoring and AI applications, late-life asset recovery, deepwater seismic monitoring, and the proven results of early collaboration.

COURTESY DEEPOCEAN

Demand for subsea equipment holds, but macro headwinds remain

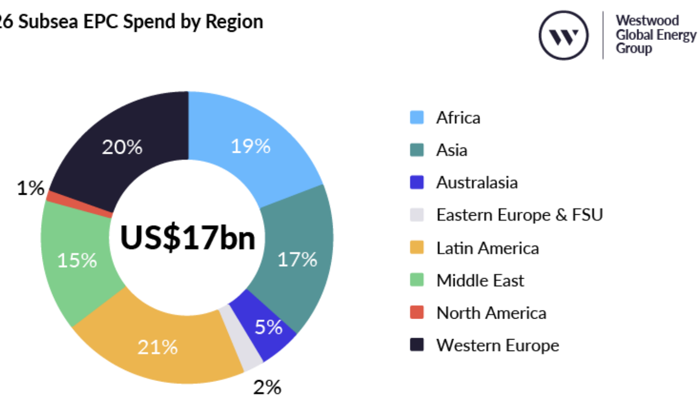
Despite a 20% YoY drop in 2025 EPC awards, the subsea sector shows resilience with strong demand for subsea trees and pipelines across the globe.

MARK ADEOSUN, Westwood Global Energy Group

Subsea engineering, procurement and construction (EPC) award value in 2025 closed at c.US$17 billion, a 20% YoY decline, underpinned by 53 field final investment decisions (FID), c.230 subsea tree units, c.2,200 km of subsea umbilical, riser and flowline (SURF), and c.1,560 km of pipeline. Contracting activity was stifled by the lower-than-expected oil prices and high supply chain costs, which negatively impacted E&P's investment appetite.

The subsea EPC cost index rose by approximately 25% in 2025 compared to the 2021 baseline but was 14% lower compared to 2024. In parallel, selected operators increased their E&P budgets by about 69% compared to 2021, reflecting a continued commitment to project development despite rising costs.

2026 Subsea EPC Spend by Region



Source: Westwood SubseaLogix

However, the average oil price in 2025 declined by 20% relative to the 2021-22 average of US$85.9/bbl. This price contraction has placed pressure on operators' free cash flow, prompting a renewed focus on cost efficiency across the value chain. This led to a revision of the development timelines for projects such as Repsol's Polok and Chinwol fields offshore Mexico and PTTEP's Lang Lebah offshore Malaysia, with operators citing high supply chain costs and the need for project optimization.

In response, the supply chain is under increasing pressure to adopt new approaches and deliver cost reductions of approximately 15-20% from the 2024 subsea EPC cost index. This level of continued cost revision is considered essential, given the expectation of a persistently oversupplied oil market and continued downward pressure on oil prices.

While E&P companies sanctioned major subsea developments that required floating production systems in 2025, such as ExxonMobil's Hammerhead development (Guyana), bp's Tiber (US Gulf), Shell's Gato do Mato (Brazil), Eni's Coral Norte (Mozambique) and Petrobras' SEAP II (Brazil), subsea contracting was widespread with several subsea tieback projects. Those tieback projects included Equinor's Fram Sor, Johan Sverdrup Phase 3 and Isflak, all offshore Norway; ConocoPhillips Previously Produced Fields project (Norway); Chevron's Gorgon Stage 3 (Australia); Beacon Offshore's Shenandoah South (US Gulf); and Shell's Mina West (Egypt). And E&Ps continue to utilize existing infrastructure.

Looking ahead, the demand for subsea production equipment is forecast to remain strong over the next five years, providing up to $90 biilion in EPC contracting opportunities for the supply chain during 2026-2030, with subsea trees demand estimated at c.1,300 units, averaging 260 units annually. However, challenges remain, as an oversupplied oil market, which is expected to reach 3 MMbbl/d in first-quarter 2026, the highest since 2020, continues to put downward pressure on oil prices, which will limit investments by E&P companies, which are poised to stay capital-disciplined, leading to project delays and deferred investment.

In 2026, Westwood anticipates subsea EPC spend will total c.$17 billion, mirroring investment levels seen in 2025. However, the number of field FIDs could increase 13% YoY, totaling 60, as unit cost is projected to continue its downward trend, as seen since second-half 2025, to support planned investment.

Subsea tree demand is forecast at 264 units, with Africa and Latin America accounting for 29% and 32%, respectively, but will only account for 19% and 21%, respectively, for subsea EPC award value, due to demand for rigid line pipe in Asia, Middle East and Europe.

Key projects to watch for Africa in 2026 include Azule Energy's PAJ development (Angola), Chevron's Agbami Infill Program

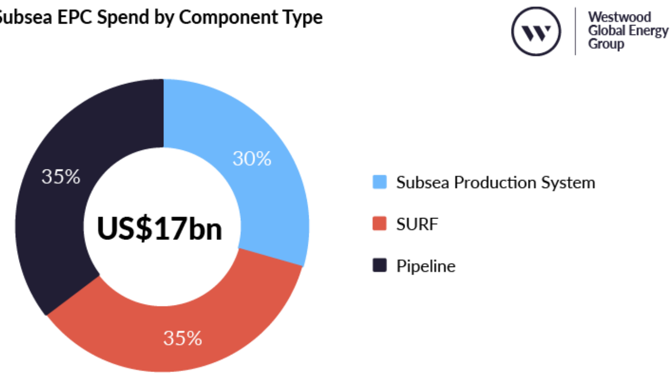
(Nigeria) and TotalEnergies' Venus Phase 1 development (Namibia), following reports that TotalEnergies received attractive bids from contractors for the project's work scope. However, the operator awaits regulatory and fiscal clarity, which could delay the FID, which is anticipated in fourth-quarter 2026, if negotiations are protracted.

In Latin America, Petrobras' continued investment in its presalt basin offshore Brazil will remain key, with equipment callout from several of its global frame agreements (GFA) signed with multiple contractors for subsea trees and SURF, including from the 82 subsea trees and associated services that was awarded to Baker Hughes and TechnipFMC in third-quarter 2025.

In addition, ExxonMobil's activities offshore Guyana will see the sanctioning of its Longtail development, while Karoon Energy plans to sanction its Neon project offshore Brazil.

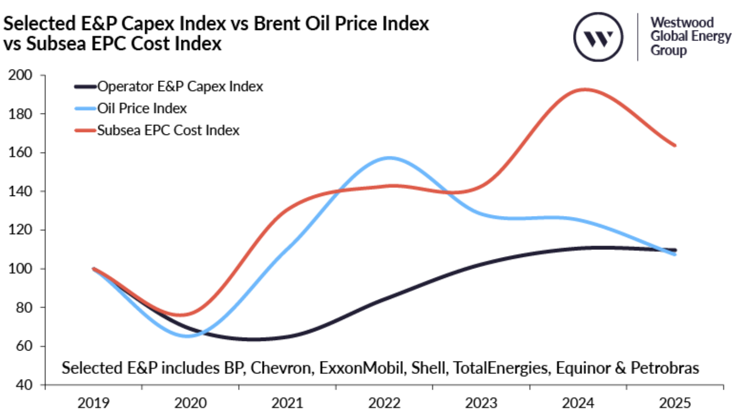
Subsea contracting in the Asia-Pacific region will be weighted toward gas developments, with Eni's Kutei North development (Indonesia) a key project to watch. Inpex is also evaluating the development of the Ichthys Phase 2c project offshore Australia, while CNOOC is expected to sanction its Kaiping 11-4 and Kaiping 18-1 development offshore China, following the prequalification of contractor that commenced in first-half 2025.

2026 Subsea EPC Spend by Component Type



Source: Westwood SubseaLogix

Selected E&P Capex Index vs Brent Oil Price Index vs Subsea EPC Cost Index



Source: Company Investor Relations, Westwood SubseaLogix, Westwood Analysis

Western Europe will account for 20% of forecast subsea EPC award value in 2026, with activities offshore Norway and Cyprus dominating, as the fiscal and regulatory posture in the UK continues to stifle investment appetite in the UK North Sea and the West of Shetlands.

Projects to watch in the region include brownfield investments by Equinor, including the Troll Phase 3 Stage 3 project, the Johan Castberg expansion and the Heidrun expansion. Var Energi plans to sanction the next phase of its Balder project offshore Norway, with greenfield tieback fields such as Dugong/Beta and the Ofelia fields reportedly under consideration to be sanctioned in 2026.

Offshore Cyprus, Eni is advancing its Cronos gas field, having recently signed commercial agreements to connect it to Egypt's infrastructure.

The SURF market and the subsea pipeline sector will each account for 35% of subsea EPC award value in 2026, with activities in the Middle East accounting for 33% (c.$1 billion) of subsea pipeline spend. Key subsea pipeline awards anticipated in 2026 in the region include brownfield infrastructure demand across Aramco's Safaniya, Marjan Berri and Abu Safah developments offshore Saudi Arabia, ADNOC's Belbazem Phase 2, the Umm Shaif project and the Abu Dhabi Offshore 2 development offshore the United Arab Emirates. The Karish to Larnaca Pipeline (Israel) and Durra export pipeline (Kuwait) will also support demand for rigid line pipe in 2026.

Overall, a total of 4,200 km of subsea pipeline is forecast to have an EPC contract award in 2026. The SURF market will remain robust, with a 20% YoY increase in demand, with 3,950 km. Demand from Petrobras will account for 20%, leading demand from E&Ps, while Western Europe will lead regional demand at 30%, accounting for c.1,200 km.

Beyond 2026, contracting opportunities abound across all regions, with exploration successes in the Eastern Mediterranean Sea, offshore Brazil and Namibia, including the recently acquired Mopane discovery offshore Namibia by TotalEnergies from Galp Energia, which could progress in the latter years of the forecast.

Long-delayed projects, such as Equinor's Bay Du Nord (Canada) and Wisting (Norway), Woodside's Browse gas development (Australia), Shell's Bonga SW (Nigeria), and Inpex's Abadi development (Indonesia), are expected to be sanctioned before the end of the forecast. However, these projects are susceptible to delays should downward pressure on oil prices continue, given an oversupplied oil market. ●

Mark Adeosun is currently the Research Director for Westwood Global Energy Group's SubseaLogix and PlatformLogix market analytic tools. Since joining Westwood in 2013, he has worked directly with as well as advised several clients within the oilfield services supply chain, as part of both analytic and commercial advisory projects.

Testing supply and accelerating alliances: Tiebacks drive subsea rebound

The subsea sector is poised for a resurgence in project sanctioning over the next three years, driven by increased final investment decisions and a focus on tieback developments, despite current supply chain constraints and geopolitical uncertainties.

MARIT LENES, Rystad Energy

A rebound in sanctioning activity of subsea projects is expected over the next three years, following a brief dip in 2025. Accelerating subsea final investment decisions (FIDs) are expected to drive increased subsea tree award activity, peaking in 2028. The anticipated upswing coincides with a subsea supply chain already operating under capacity constraints, potentially straining execution capabilities and delaying the progression of some projects.

A key focus for operators moving forward with new subsea projects is the growing emphasis on subsea tieback developments. Leveraging existing infrastructure, tiebacks offer lower costs, shorter lead times and risk mitigation. As a result, tiebacks are expected to represent a significant share of the upcoming near-term increase in subsea tree awards, with a compound annual growth rate (CAGR) of 30% over the next three years.

Despite the advantages of tieback developments, questions remain about the ability of subsea tree suppliers to meet rising demand. Major operators are expected to strengthen their market presence, with an increasing focus on strategic partnerships with subsea tree suppliers to navigate the challenges of tightening availability. The pressure on suppliers to deliver the required volumes may challenge their capacity and test whether current operator strategies and partnership models can meet rising demand.

Last year's subsea sanctioning activity has seen a modest decline in greenfield investment commitments. Heightened geopolitical tensions and oil price uncertainty have led operators to adopt a more cautious approach, resulting in delays to FIDs.

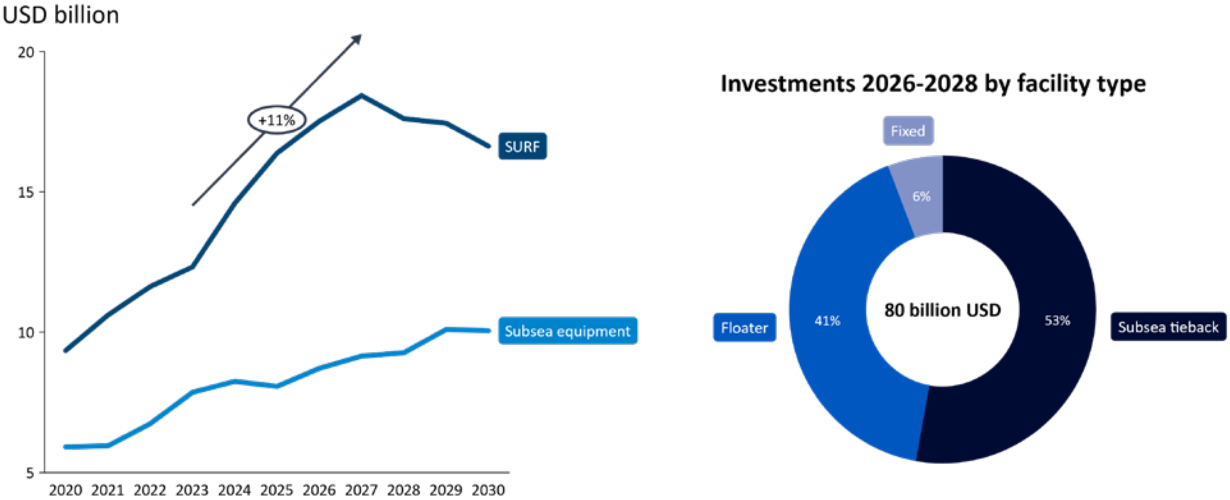
Despite the current slowdown, activity is expected to accelerate over the next three years. Rystad Energy assesses that

What is a subsea tieback?

Rystad Energy defines subsea tiebacks as offshore production facilities that are completely submerged with a wet wellhead located at the seabed, consisting of subsea templates, wells, trees and manifolds. Subsea installations are tied into a floating, fixed or onshore installation for processing and export.

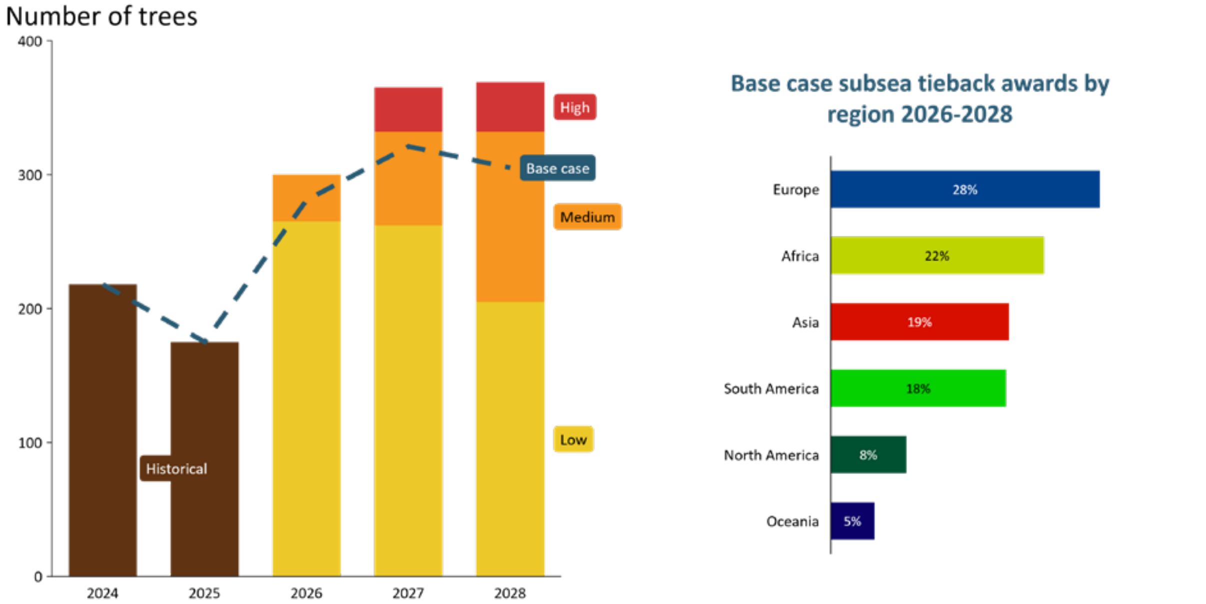
Figure 1: Subsea equipment and SURF investments (capex) by spending year

USD billion



COURTESY RYSTAD ENERGY

Figure 2: Subsea tree awards by risk category and base case view



COURTESY RYSTAD ENERGY

most projects are being deferred rather than cancelled as operators wait for more favorable market conditions. Subsea tieback developments are expected to represent more than 50% of upcoming sanctioning activity in terms of capital expenditures (capex) over the next three years, with an anticipated annual growth rate of 15%. Europe is expected to account for one-third of these investments during this period.

Subsea spending allocations indicate that subsea umbilical, riser and flowline (SURF) capex will experience an 11% CAGR from 2023, peaking in 2027 (Figure 1). This growth is primarily driven by the increased use of subsea tieback developments—a trend expected to continue through 2027. After this peak, SURF spending is anticipated to decline slightly but remain at a relatively high level throughout the decade.

By contrast, subsea equipment capex is expected to increase steadily over the decade. While this growth is also largely driven by subsea tieback developments up to 2027, it is further maintaining its investments beyond 2027 due to a stable share of floater activity expected. Compared to tiebacks, SURF capex is less impacted by floater developments; floaters require fewer kilometers of SURF lines per subsea tree than tiebacks, which contributes to the expected slight decline in SURF spending after the tieback peak in 2027.

Considering subsea trees specifically, a peak in awards is expected in 2027-2028. As demand rises, uncertainty grows over whether industry supply capacity can keep pace, raising the risk of annual delivery shortfalls.

In Rystad Energy's base case for the next three years, approximately 12% of all awards—representing roughly 40% of medium- to high-risk awards—may not materialize. Several subsea projects face elevated risks of deferral or cancellation, primarily due to high breakeven prices that can render some developments uncommercial. These projects are particularly vulnerable to delays if oil prices decline or if supply chain costs increase.

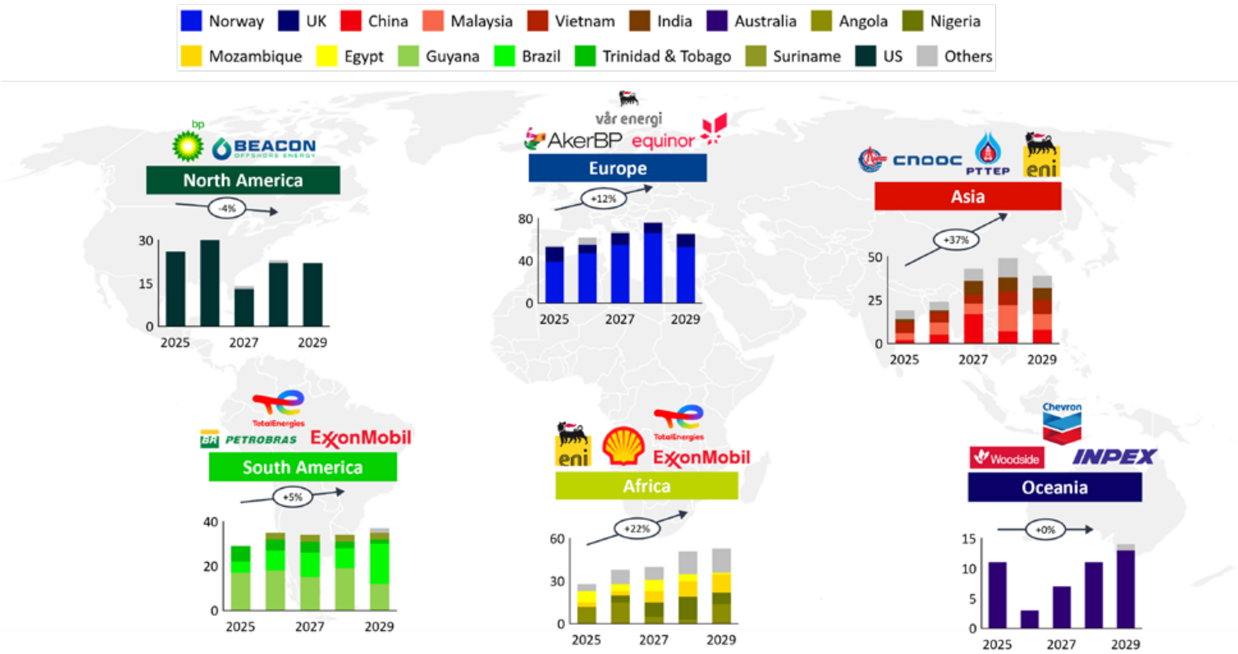
Additionally, portfolio prioritization may lead companies to defer smaller or higher-risk projects in favor of focusing on flagship developments. Impacted developments mainly include projects in Angola, Nigeria, Indonesia, Malaysia, the US and Brazil. A significant number of these awards are linked to large floating production, storage and offloading (FPSO) vessel projects and fixed-platform developments.

By contrast, tiebacks dominate the base-case pipeline: 65% of low- to medium-risk awards between 2026 and 2028 are subsea tieback projects. Norway accounts for approximately 15% of these projects, with major subsea tiebacks on the Norwegian Continental Shelf (NCS) driven by the Equinor-operated Troll, Johan Castberg and Grosbeak projects, as well as Var Energi's Balder-Ringhorne and Gjoa schemes. Other notable upcoming tieback projects include Area 4 LNG Phase 1 in Mozambique, the Turbot and Tripletail projects in Guyana, both of which are tied back to the ExxonMobil-operated *Longtail* FPSO, and the Preowei project in Nigeria, tied back to the TotalEnergies-operated *Egina* FPSO (Figure 2).

Major oil companies and national oil companies with international operations are expected to lead the majority of upcoming tieback projects. Subsea tieback tree installations are projected to experience significant growth toward the end of the decade, with a CAGR of 14% globally from 2025 to 2028.

Norway is expected to account for 26% of the global market share during this period, driven by a CAGR of 12% in the number of tieback trees installed from 2025 to 2028. As demand for these installations' surges, certain operators are likely to take the lead. Norwegian operators are increasingly focused on utilizing

Figure 3: Subsea tieback tree installations by country and top operators
Number of trees



COURTESY RYSTAD ENERGY

existing infrastructure at mature fields on the NCS, as large standalone discoveries are becoming less common.

Equinor, with its extensive field base in Norway, is expected to account for 14% of global tieback installations over the next three years. ExxonMobil follows closely, with a 10% share, due to its extensive tieback projects in Guyana, but the US major is also expected to extend its regional exposure over the next years, particularly in Angola and Mozambique. TotalEnergies rounds out the top three, contributing 7% of the global share through upcoming installations, with the French major also set for regional expansion into key countries Nigeria, Angola, Mozambique and Suriname. These operators are increasingly focused on maximizing the value of existing offshore infrastructure and expanding regionally, driving higher demand for subsea tieback solutions in key regions.

Despite an extensive base of operators driving the upcoming demand for subsea tieback trees, the number of tree suppliers is limited, with only four key providers: TechnipFMC, OneSubsea, Baker Hughes and newcomer Trendsetter Engineering, which in 2025 acquired the subsea tree product line from Innovex International.

The SURF market has a wider range of players, but only a few dominate, with TechnipFMC, Saipem and Subsea7 together holding 60% of the market share. The growing demand will put significant pressure on these suppliers to meet the required volumes driven by subsea tieback developments.

For operators, building strong relationships with market leaders through long-term partnerships, integrated contracts and framework agreements will be crucial to securing reliable supplies.

In recent years, only TechnipFMC and the Subsea Integration Alliance between Subsea7 and OneSubsea have been awarded integrated contracts, primarily due to their ability to deliver complete end-to-end subsea packages, covering both subsea trees and SURF scopes. During recent years, these two suppliers have supplied mainly the major players Petrobras, Equinor, ExxonMobil, bp and TotalEnergies—a scenario that is set to continue. In contrast, Baker Hughes, with expertise in both subsea production systems and SURF through its alliance with Ocean Installer, has managed to maintain a strong position in the subsea market by serving a broader range of mid-market operators, including Var Energi, Azule Energy, India's Oil & Natural Gas Corp., China National Offshore Oil Corp. and Eni.

As demand increases, secondary suppliers may find new opportunities to provide integrated subsea equipment and infrastructure to both major and smaller operators. With supply capacity becoming increasingly critical, smaller suppliers could gain a competitive edge as operators face longer lead times and potential delays in securing key subsea equipment. Consolidation strategies, such as alliances or partnerships, could strengthen these suppliers' subsea portfolios by combining capabilities, enhancing delivery capacity in a supply-constrained market and aligning more closely with operator strategies and market trends. Alternatively, rising demand could force operators to adapt their strategies to better align with the portfolios and business models of suppliers. This could lead to a shift away from integrated contracts and long-term partnerships, with greater focus on maximizing the potential by utilizing a broader set of suppliers. ●

Marit Lenes is a supply chain analyst with Rystad Energy.

COURTESY ISLAND OFFSHORE

Rapid recovery completed of a CAN-ductor system in the North Sea

The Mermaid Subsea Services (UK) recovery campaign involved seabed excavation, controlled severance and environmentally compliant waste management.

SCOTT CORMACK, Mermaid Subsea Services (UK)

The North Sea has never been a forgiving workplace. Weather windows narrow without warning and infrastructure ages unevenly, meaning routine operations can soon become complex with little notice.

Against this backdrop, subsea teams often find themselves working not only underwater, but under the pressure of time, conditions and expectations.

Subsea campaign built around quick mobilization

Earlier this year, a major UK operator engaged Mermaid Subsea Services (UK) to deliver the rapid recovery of a CAN-ductor and associated equipment from the Central North Sea.

Developed to lower the cost of well construction, a CAN (Conductor Anchor Node) system allows the top-hole section to be installed using light vessels, so the subsea well foundation is ready before the drilling rig arrives.

All CAN systems start with the CAN-basic, which is a suction anchor with a guide pipe running through it. The CAN-ductor builds on this by adding one joint of conductor into the anchor. When it is installed, the suction anchor pushes the conductor into the seabed, giving the well immediate structural support.

The recovery project called for the internal and external severance of casing, conductor, guide pipe and cement lines, which is work that must be highly controlled to protect both personnel and assets. To support this activity, Mermaid carried out local seabed excavation before lifting and recovering the CAN-basic structure.

Once the hardware was safely brought to deck, the team assumed responsibility for waste and materials management, ensuring all recovered items were handled and disposed of in accordance with environmental and regulatory requirements.

Final operations included backfilling the excavation site so an overtrawl survey could confirm a clear seabed.

The fast-track CAN-ductor recovery campaign resulted in a complex job executed precisely, safely and on schedule.

Other regional subsea programs

That recovery campaign followed a series of technically demanding subsea programs that occupied the Mermaid team throughout 2025.

Earlier in the year, the company carried out a scale inhibitor treatment on the Teal P2 well in the Anasuria Cluster of the Central North Sea, a task central to maintaining the well's long-term integrity. The operation required precise chemical handling and deployment from the vessel, delivered during a narrow opportunity in the offshore schedule.

Around the same time, Mermaid executed a complex wellhead severance program in the Southern North Sea. The scope brought together multiple specialist vendors, from tooling providers to vessel support teams, creating a program that depended as much on coordination as on technical capability. Despite the logistical demands, the operation was completed seamlessly.

Photo (above): Mermaid has chartered the Island Valiant vessel for the second year.

Conclusion

For Mermaid, the approach in the last year has been shaped in partnership with clients and reflects the increasingly dynamic nature of regional subsea work. The company is seeing a wider range of operational challenges as operators address both late-life assets and targeted optimization projects.

A consistent enabler of these deliveries has been the *Island Valiant*, the multi-role offshore vessel from which Mermaid has conducted several of its most recent North Sea projects. Now in its second year under charter, the vessel has taken on a variety of scopes, from chemical treatments to mechanical cutting and recovery operations. Its versatility has allowed Mermaid to maintain project continuity and retain familiar vessel teams, an advantage when working in tight operational windows.

As the North Sea transitions into a new era, defined by late-life asset stewardship, decommissioning commitments and selective field reinvestment, the need for safe, efficient subsea intervention will take on a whole new level of importance. ●

Scott Cormack is the regional director with Mermaid Subsea Services (UK).

ROV technology alone isn't enough for successful subsea operations

Clear communication among offshore personnel, vessel crew and ROV operators is crucial for adapting to changing subsea conditions and ensuring safety.

MATT SIMPSON, Forum Energy Technologies

Photo (above): Regular ROV maintenance checks and collaborative problem-solving are vital for minimizing downtime and addressing unforeseen issues.

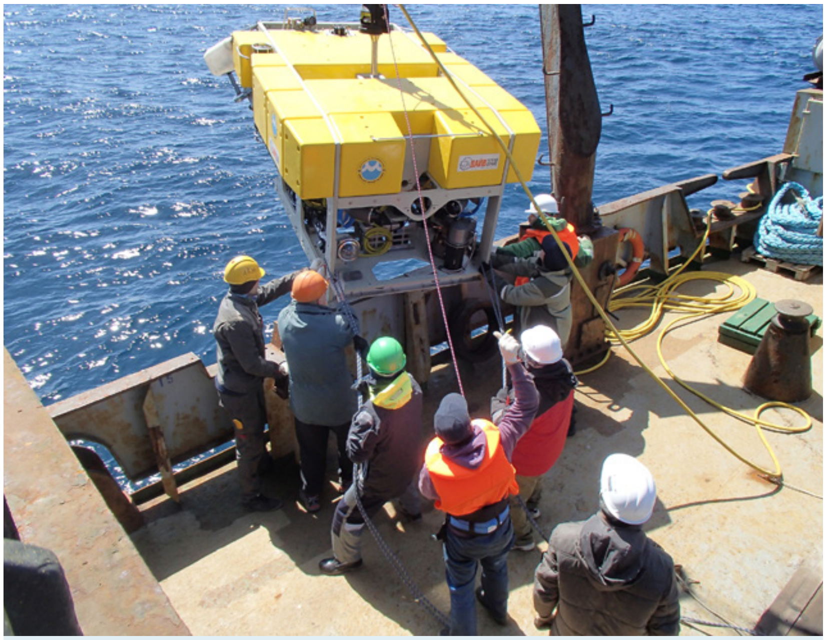
ID 141694023 © FLINTHARD | DREAMSTIME.COM

No matter how advanced ROV technology becomes, the success of any operation always comes down to teamwork. It is easy to focus on the vehicles themselves—the thrusters, manipulators, sensors and software—but these are redundant without the correct people at the controls. ROV work is demanding and constantly shifting, and it relies on a group of individuals who communicate, support and adapt to each other's strengths in high-pressure environments.

A typical ROV team is made up of a pilot, co-pilot and supervisor, though roles are rotated depending on the job and length of shift. Piloting requires intense concentration, and while an hour in the chair is usually enough before swapping out, there are days when the pilot sits for much longer periods because the work demands it. What matters is that everyone's understanding goes beyond their own role. The team needs a shared understanding of the task, the conditions and the sequence of events, especially when two ROVs are in the water at the same time. In those situations, ROV operators must remain aware of their own tether and the other vehicle's too, along with the crane and vessel movements, as well as deck crew activity.

Communication ties it all together. Offshore, personnel are constantly talking—to the offshore construction supervisor on the bridge, sometimes the crane operator and even the variable lay system team. There is also the rigging crew in the back deck and other ROV to consider.

Most vessels use a shared control room so everyone can follow the same operational picture. Even then, clear communication is essential because subsea conditions change quickly. Currents and visibility shift, and equipment can behave differently than expected, meaning plans must be adapted. When the communication works, the whole team moves as one; when it doesn't, things unravel very quickly.



Tether management in offshore ROV operations refers to the controlled handling and positioning of the vehicle's umbilical cable to prevent entanglement, minimize drag, and ensure reliable power and data transmission during subsea tasks. ID 113719615 © YS7485 | DREAMSTIME.COM

Tether management

Much of the risk revolves around tether management. If a tether is damaged or lost, the operator can lose the vehicle. So, everyone stays alert to sea state, current direction and how the vessel is behaving.

Recoveries are often the most challenging moments. Surface currents can be far stronger than those at depth. So, just as the ROV reaches the splash zone, it may try to drift away from the vessel.

Docking into the tether management system can also be challenging. Some vessels have heave-compensated systems that make the process easier, but many older ones do not, and it is important to time the docking process correctly and guide the vehicle back into the tether management system without impact.

Maintenance checks

Maintenance also depends heavily on collaboration and shared knowledge of the system. Pre-dive and post-dive checks are carried out regularly, but offshore maintenance is rarely straightforward. The right balance must be struck to avoid overworking a system and potentially taking it offline unnecessarily. That is why every task is discussed as a team, considering both the benefits and the risks. When faults arise, such as oil leaks, mechanical jams or electrical ground faults, it becomes a joint effort between the offshore crew and sometimes onshore support to narrow down the cause.

FET's VisualSoft system is designed for survey and inspection of underwater assets. COURTESY FET

Case study

During a recent subsea project, a hydraulic cutter developed a loose fitting on the seabed, and recovering it to deck would have meant an hour and a half of lost time. Someone on the team, however, was mindful of the intricacies of the tool and had stowed a spanner in a work basket from an earlier task. The FET team was able to guide the ROV to the basket, pick up the spanner with the manipulator and tighten the fitting subsea. This resulted in hours saved, and it only worked because several people pieced the solution together.

Next gen advice

For anyone entering the industry, learn the system, stay curious and rely on your team. Technology helps the industry reach incredible depths, but it is the people communicating and thinking ahead who make the work possible. Offshore operations succeed because no one does them alone. ●

Matt Simpson is systems support manager at Forum Energy Technologies (FET).

JIP aims to cut subsea flow assurance costs in deepwater environments

With promising trial results showing 85-90% thermal efficiency, a new subsea pipeline heating technology offers reductions in capex, opex and CO2 emissions.

ANDRIES FERLA, DeepOcean

This artist illustration depicts a subsea pipeline inspection operation. COURTESY DEEPOCEAN

A new joint industry project (JIP) aims to commercialize a subsea flowline heating technology that is designed to reduce manufacturing and installation costs by up to 35% through the separation of pipeline and heating installation.

TotalEnergies, Equinor, Aker BP, DeepOcean, Tenaris and LS Cable & System have teamed up to develop FlowHeat, a new method for subsea pipeline heating.

Tieback flow assurance pickle

Subsea tiebacks are essential to offshore oil and gas production, connecting subsea wells to processing facilities via pipelines. While they reduce infrastructure costs and accelerate development, they face challenges in cold deepwater environments where hydrates and wax can form, blocking flowlines and leading to expensive interventions.

Traditionally, chemical-based solutions (e.g., methanol and MEG) were used, but these proved expensive and space-consuming. This resulted in the introduction of electrical heating systems such as direct electric heating and electric trace heating. While effective in some cases, these systems have issues with efficiency, redundancy and high installation costs, especially as more subsea tiebacks are developed in deeper waters, where hydrate formation from long tiebacks is a serious risk.

The market potential for more cost-efficient flow assurance solutions is substantial as operators pursue new tiebacks. There is already a strong demand on the Norwegian Continental Shelf, where subsea tiebacks have become the rule rather than the exception. Other deepwater regions, such as Brazil, the US and Africa, face similar challenges, with more than 300 potential electric heating projects identified by 2030.

Consequently, the industry has been challenged to develop new methods that lower capital expenditure (capex) associated with both the heating and pipeline installation method, cut operating expenditure (opex) through lower energy consumption, and reduce CO_2 emissions.

This illustration highlights how the FlowHeat system is installed on a pipeline. COURTESY DEEPOCEAN

How the technology works

FlowHeat aims to overcome these challenges by using an insulation coating with internal conduits for post installation of heating cables, which reduces tieback installation costs and emissions.

The technology simplifies cable installation, and its hydraulic and water pressures system allows efficient deployment of these heating cables even after pipeline installation, making it more flexible and easier to repair and maintain. The cables can be monitored real time via optical fiber.

Offshore trials and onshore demonstration

TotalEnergies, DeepOcean, Tenaris and LS Cable & System have already invested years in the project and have achieved results of 85-90% thermal efficiency in trials as well as the successful completion of a 3-km onshore installation that demonstrated the system's ability to handle bends and bumps.

However, there are still critical issues that need to be addressed to finalize the development of the system, such as extrusion of the coating with embedded conduits. Scaling up the technology will require improvements in the method of manufacturing pipelines with hollow channels within the wet insulation layers of the coating, which will have to withstand direct contact with the seawater and subsea hydrostatic pressure.

While small scale extrusion trials have already been validated, the FlowHeat demonstration will focus on scaling up the process to a 10-inch pipeline, addressing the complex balance between extrusion and cooling to enable longer cable installation lengths.

The technology also offers reduced topside weight, lower power consumption and less complex installation. The system is capable of contributing to a 30% reduction in carbon emissions by minimizing the need to install additional power infrastructure and hydrate mitigation measures and by reducing the amount of installation days required and enabling the use of smaller vessels (e.g., ROVs).

In total, these improvements can realize an opex cost reduction of up to 30% compared to traditional methods for subsea flow assurance.

System deployed after pipe laid on seabed

FlowHeat applies methods derived from the telecommunications industry, specifically the floating method used to install fiber-optic cables in pipes. This method allows power cables to be installed safely and efficiently in pipes using water as a medium. This is one of the main advantages of the FlowHeat system, where the power cables are installed after the pipe has been laid on the seabed, reducing the risk of damage to the power cable and, as mentioned above, providing significant emissions/cost savings in terms of subsea installation.

The system can be deployed after a pipeline has been laid and is suitable for distances of up to 30 km with a potential to increase to 50 km, in water depths of 3,000 m. This makes it an ideal system for long subsea tiebacks. ●

Andries Ferla is the ocean solutions and technology director at DeepOcean, where he has spent the past 15 years in various technology, innovation and engineering roles. He holds a master degree in civil engineering from KULeuven in Belgium.

On-demand OBN system enhances surveillance of Brazil's presalt fields

A new system allows seabed nodes to remain operational for years, enabling on-demand seismic data collection without repeated deployment or retrieval.

SHAUN DUNN and **GIORGIO MANGANO**, Sonardyne International

Photo (above): Saipem's FlatFish AUV was developed under a separate ANP program supported by Shell.
COURTESY SAIPEM

Brazil's presalt reservoirs lie in more than 2,000 m water depth, plus another 3,000 m beneath the seabed, making seismic imaging particularly challenging. A new approach to acquiring 4D seismic data, promising more efficient and cost-effective surveillance of complex presalt fields, is being tested offshore Brazil.

Traditional seismic surveys using ocean-bottom nodes (OBNs), while providing high-quality seismic data, are often expensive and logistically complex, involving the large-scale deployment and recovery of nodes using remotely operated vehicles (ROVs). These factors can limit the frequency and economic viability of frequent 4D seismic campaigns, which are essential for understanding reservoir dynamics over time.

This is particularly challenging for monitoring large presalt carbonate fields where production by alternating water and gas injection generates subtle and complex 4D signals that are difficult to measure. These signals require on-demand monitoring with sufficient fidelity and repeatability to overcome the high levels of survey noise prevalent in conventional node-based surveys.

The "On-Demand Ocean Bottom Node" (OD OBN) program is addressing these challenges by providing a disruptive approach to time-lapse seismic data acquisition. At its core is a long-term OBN system that can remain on the seabed for several years, capturing seismic data that can be recorded and harvested on-demand using autonomous underwater vehicles (AUVs), without the need for repeated deployment and retrieval cycles.

Launched in 2018, the research and development program is a collaboration between partners Shell, Petrobras, SENAI CIMATEC and Sonardyne, supported under the Research Development and Innovation funding clause of the Brazilian National Agency for Petroleum, Natural Gas and Biofuels (ANP).

Vast quantities of seismic data are harvested wirelessly using an AUV, such as Saipem's *Flatfish,* that implements the through-water optical interface to interrogate the OD OBNs, as developed under a separate ANP program sponsored by Shell.

This AUV data harvesting approach eliminates the need for node recovery, dramatically reducing vessel time, operational complexity and associated costs.

Key Sonardyne technologies include wireless acoustic communications required for long-range recording control and node clock time offset measurement and extremely high-speed optical communications for short range data harvesting to a nearby AUV or ROV.

More than 2,000 days of trials of pre-production nodes have been conducted across various presalt fields including Sapinhoá, Itapu and Buzios, successfully demonstrating acoustic control, high-fidelity data acquisition and optical data harvesting as well as comparing OD OBN data with that of other commercial nodes.

The final round of tests concluded successfully in 2025, with results presented at the IMAGE conference in Houston and SBGf Rio'25 conference in Rio de Janeiro.

A pilot array of 660 pre-production nodes are currently being produced at a new manufacturing facility in Camaçari, near Salvador, Brazil. Hundreds of these nodes will soon be deployed at the Petrobras-operated Mero Field for extended testing and performance evaluation.

The long-term vision is to use autonomy and communications technologies to enable operators to conduct more frequent on-demand seismic surveys, with higher fidelity data, at a fraction of the cost of conventional seismic survey methods. This capability will provide clearer insights into fluid movements and pressure changes within the reservoir, helping to optimize production strategies, improve decision-making and enhance recovery rates in one of the world's most challenging offshore provinces. ●

Shaun Dunn is projects director and **Giorgio Mangano** is program leader of special projects with Sonardyne International.

Trials of the OD OBN technology were undertaken in Trieste, Italy, prior to trials offshore Brazil. COURTESY SONARDYNE

More than 600 pre-production nodes are being produced at a new manufacturing facility in Camaçari, near Salvador, Brazil. COURTESY SONARDYNE

Offshore projects: Vår Energi and OneSubsea shift to early engagement and standardization

Vår Energi partnered with OneSubsea to overhaul its project delivery approach, emphasizing early involvement, integrated teams and standard solutions to reduce delays and improve predictability, leading to faster project completion.

CONCI MADULI-BUSH, SLB OneSubsea

In 2022, Vår Energi set a target for its future developments: deliver more projects and deliver them faster. Meeting that ambition required early visibility into cost, schedule and feasibility, right when key decisions were being made. However, this can be difficult, because in the traditional contracting model, scopes are fragmented and multiple handovers occur, slowing decisions and adding complexity.

"What we see is that the process gets cluttered," said Frode Sivertsen, vice president of project development at Vår Energi. "There are too many interfaces and too much back and forth before we see real progress, and that's what creates delays and extra work."

Suppliers like OneSubsea face the same issues. Repeated bidding cycles add uncertainty, and each new project starts with a new team and new assumptions, making alignment more difficult.

In short, the traditional model disrupts continuity and hinders delivery.

Photo (above): The first template for Aker BP's Yggdrasil project was installed offshore in the Norwegian sector of the North Sea, between the Alvheim and Oseberg fields.

COURTESY AKER BP / SLB ONESUBSEA

The partnership approach

To address these challenges, Vår Energi chose to partner with OneSubsea as its primary supplier. Instead of restarting with every new project, the two companies now work through an integrated setup that brings the supplier in earlier and removes unnecessary steps.

This approach is not new; it's proven. For nearly a decade, OneSubsea has used a similar model with Aker BP. The Subsea Alliance between Aker BP, OneSubsea and Subsea7 has demonstrated that early engagement and standardization improve speed, efficiency and predictability.

"Over the years, we've seen that projects are not just moving faster, they're also more stable," said OneSubsea Project

Director Kai Erlend Aas, who has managed the Subsea Alliance for OneSubsea from the start. "With early commitment, we avoid the repeated resets that can otherwise hold projects back."

The partnership between OneSubsea and Vår Energi is built on four principles:

1) START EARLY AND STAY CONNECTED

OneSubsea joins the team well ahead of the first decision gate. Cost, schedule, risk and feasibility are assessed together, giving Vår Energi a clearer picture early on—improving the chances of a project being sanctioned—and enabling a leaner organization.

2) WORK AS ONE TEAM

Integrated teams collaborate from the start, helping issues surface sooner and solving them faster. This camaraderie also builds stronger ownership, creating an "all for one and one for all" dynamic.

"The real change is how quickly teams start moving once they start sharing information," said Theis Stray-Pedersen, OneSubsea senior project manager. "When people see the same picture at the same time, the pace picks up naturally, and we are all delivering together."

3) USE PROVEN STANDARD SOLUTIONS

Vår Energi bases new developments on the NCS2017 standard subsea production system (SPS) portfolio. Standard, pre-qualified equipment reduces engineering work, accelerates procurement and improves reliability. In addition, reusing the same building blocks across multiple projects strengthens consistency and creates scale benefits.

4) ALIGN EXECUTION ACROSS THE FULL CHAIN

Standard equipment and familiar teams make each phase more efficient. Packages move to manufacturing earlier, and fewer bespoke components mean fewer delays.

Early gains and impact

Since adopting the model, more than 20 early-phase studies have been completed, the first full deployment is underway and five new projects are planned for 2026.

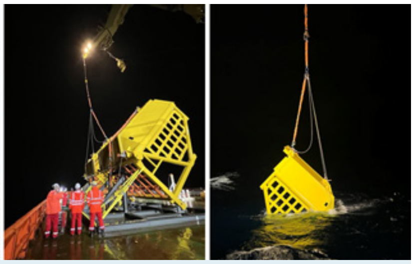
The "Balder Next - New Wells" project provides an early example. Vår Energi had set a schedule that many considered unrealistic, but through early commitment on equipment and standardized equipment, the joint team confirmed it was achievable.

"What the Balder Next - New Wells project has showed us is that the constraint wasn't the schedule; it was the way we used to work," Sivertsen said. "If the teams are aligned early, the path forward becomes much clearer."

Is this approach competitive enough?

Some question whether a partnership model reduces competitiveness. Vår Energi takes a broader view: gains in speed, predictability and the likelihood of a project being sanctioned often outweigh any theoretical savings from repeated competitive studies and bids.

"Competitiveness is, of course, key, and we actively use benchmarks to ensure costs are at the right level," Sivertsen said. "But if you only focus on achieving



The first manifold for Aker BP's Yggdrasil project was installed in the Norwegian sector of the North Sea. COURTESY AKER BP / SLB ONESUBSEA

COURTESY AKER BP / SLB ONESUBSEA

the lowest bid number, you miss the real value. This approach reduces uncertainty, and that's what keeps projects moving instead of stalling."

This collaborative approach also creates room for joint optimization and cost savings in offshore installations, drilling and life-of-field operations.

Conclusion

As expectations for predictable delivery grow, operators are rethinking how projects should be structured. OneSubsea's experience with Aker BP and Vår Energi shows that a partnership model built on early engagement, integrated teams and standard solutions can meaningfully improve execution.

The approach requires trust and new ways of working, but the benefits are becoming clear across multiple developments.

"We've learned over the years that teams adapt quickly once they see the proof that the concept works. The approach removes noise from the process, and that gives everyone more time to focus on what actually moves the project," Aas concluded.

For Vår Energi, partnership remains the most reliable path to delivering more projects, delivering them faster and reaching first oil earlier. ●

Conci Maduli-Bush is global communications manager at SLB OneSubsea.