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OIL & GAS PRACTICE

Navigating in deepwater: Greater rewards through narrower focus

Even before the fall in oil prices, deepwater project returns were under pressure. To stay in the game, deepwater players should focus on scale in a single basin.

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The deepwater oil sector is at a crossroads. Deepwater production (defined as oil produced in water depths of greater than 450 meters) has had a spectacular run over the past decade as major oil companies broadened their portfolios worldwide. Global investment has soared from \$16 billion in 2003 to more than \$70 billion in 2013, and production has more than doubled over the past ten years to almost 6 million barrels per day, or 7 percent of the world's total oil supply.

The major oil companies have seen deepwater as an attractive business that can deliver large

volumes at high margins, more than offsetting its handicaps of tying up immense amounts of capital and technical challenges. They have doubled down, betting on deepwater across the globe: the average number of countries in which the supermajors¹ participate in deepwater projects has increased from three to seven over the past decade.

In the past 12 months, however, deepwater has come under new scrutiny. Even before the recent drop in oil prices, many big oil companies have been coming under pressure from investors to rein in their capital investment. Deepwater

¹ Includes investments made by BP, Chevron, ExxonMobil, Shell, Statoil, and Total.

projects, which typically cost billions of dollars² and have been seeing sharp cost inflation in recent years, are being reviewed more critically, as onshore unconventional oil and other projects now appear to offer more capital efficiency.

The heightened scrutiny is coming at a bad time for deepwater operations. Setting aside the inherent volatility of oil prices, a number of well-recognized trends are now in place that could seriously affect the value-creation potential of deepwater over the next decade compared to its historical performance. First, costs have been increasing rapidly, and project delays are recurrent. Not only are shortages endemic for certain types of equipment, but also supply-chain constraints in certain basins are causing steep cost inflation. Second, deepwater players know from experience that pushing the frontiers of exploration into more challenging geological areas at ever-greater depths further from shore slows development and incurs higher costs: rigs need to be hired for more days to drill each well and require more support vessels.

Third, oil companies also know that government requirements across the major basins are increasing and these requirements will be determining factors in the financial prospects of future projects. While the precise nature of the government requirements varies in different basins—whether it be degrees of operatorship control, local content requirements, new environmental regulations, or the share of revenue taken by governments³—they all tend to reduce margins.

The impact of these trends is substantial. The industry is already only too aware of the rise in project costs. What's less well recognized is that as these trends come together and gain momentum, they challenge the way that companies conduct their deepwater business.

As the industry has expanded rapidly over the past decade, it has by and large applied the same playbook across the world. The industry is continuing to adopt a global approach, with oil companies typically bidding on promising acreage in the key basins, and partnering with the leading oilfield services and equipment (OFSE) companies, often in global service contracts, to support them in development, following a standardized model regardless of where in the world the new project is located.

However, the constraints on capital expenditure coupled with new basin-specific pressures on value creation mean that this global approach may no longer be adequate. Experience in one basin cannot be taken as a passport to success in other basins. The new caution in capital expenditure will require companies to choose the projects best suited to their strengths, which in turn means not only thinking hard about capabilities, but also knowing more precisely the financial impact that the different factors have in each basin. Much is at stake: matching up an oil company's area of strength with appropriate challenges offers the opportunity for the company to truly establish a competitive advantage and keep its value creation in deepwater on course. The same pressures are affecting the OFSE companies, making a similar reflection timely.

Quantifying each basin's cost drivers

To understand the implications of these trends on each deepwater basin's economics, we have studied data from across the industry for planned deepwater projects through 2025,⁴ and conducted our own analysis to model how the costs of projects will evolve in different basins. We have focused on Brazil, the US Gulf of Mexico, and Angola and Nigeria, the two largest producers in the West Africa basin; together these basins represent more than two-thirds of current global deepwater production.

² The average cost of the ten most recent deepwater projects in the Gulf of Mexico is \$12 billion.

³ The share of revenues that accrues to the government over the life of the project includes revenues accruing to the state through royalties, taxes, and other fiscal and quasi-fiscal levies as well as revenues accruing to a country's national oil company. "Government take" is the general term used in the industry to describe the government share.

⁴ For our modeling, we analyzed data from the industry and from Wood Mackenzie's Global Economic Model (GEM).

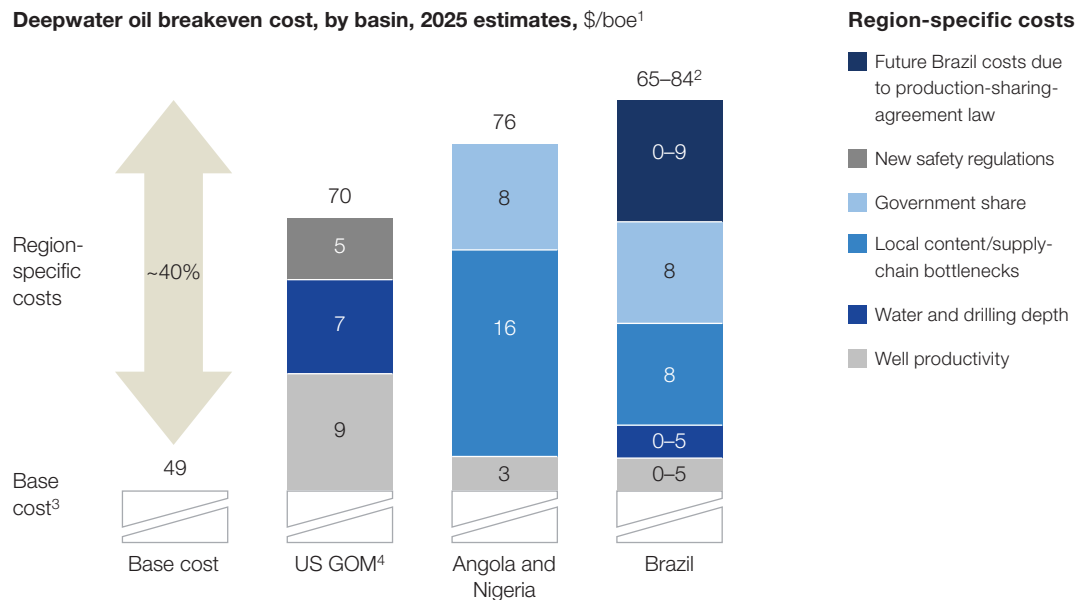
For our modeling, we grouped the costs into categories that reflect the impact of the trends described above on the specific basin's economics. These categories include well productivity, water and drilling depth, government share of revenues, local content requirements, and supply-chain bottlenecks. To create a basis for comparison, we have taken the lowest cost achieved by any of the basins in each category and constructed a hypothetical low-cost basin; this hypothetical basin has costs of \$49 per barrel. We then compared the costs of each of the actual basins against this base case (exhibit).

The results indicate a striking degree of divergence set to emerge through 2025 in cost drivers between the basins. Leaving aside government share of revenues (over which the oil companies have no control apart from exiting the country), the greatest divergences are the additional costs associated with supply-chain bottlenecks and local content requirements, most notably in Angola and Nigeria, but also in Brazil. In contrast, the next two major challenges are disproportionately weighted to the US GOM: well-productivity issues, and new environmental regulations (this last currently exclusive to the US).

Exhibit

There is a striking degree of divergence among cost drivers.

Deepwater oil breakeven cost, by basin, 2025 estimates, \$/boe¹



¹Barrel of oil equivalent.

²The range in the projected Brazil costs is due to uncertainties about (i) well productivity and water & drilling depth of the sub-salt, estimated at \$0–\$10/barrel of oil equivalent (boe) in additional cost, and (ii) the impact of new production-sharing-agreement terms in Brazil; the \$9/boe shown here is an estimate based on the differential between Iara project government take and average government take in Brazil.

³Base cost of \$49/barrel of oil equivalent represents the cost for a hypothetical project made up of the lowest cost in each of the cost categories from any of the three basins. Thus, because the US Gulf of Mexico (GOM) has the lowest government share of the basins shown, the US GOM figure is used in the base cost, and there is no government share shown for the US GOM among the region-specific costs. The figure shown for government share in Angola and Nigeria and in Brazil is the amount in excess of the US GOM figure.

⁴US Gulf of Mexico.

The need for basin-specific approaches

The diverging developments in each basin suggest that oil companies and OFSE companies need to take a different set of steps in each basin to get ahead:

US GOM. The shift in development from the Miocene geology, where production is plateauing, to the more technically challenging Paleogene geology further off the coast and in greater depths is eroding value creation—even though the average Paleogene discovery is three times larger than the average Miocene discovery. This is because deeper water and wells add drilling days, while the geological complexity makes well-productivity rates more volatile.

New regulations enacted since the 2010 Macondo accident are also contributing to significant cost increases. These include stricter permitting requirements (such as regulations on blowout-preventer testing), higher insurance costs, and a push to design an additional margin of safety into installations. Together these have increased capital and operating expenditures by 10 to 15 percent compared to pre-2010 levels. In all, GOM projects now in development are expected to cost about 40 percent more than those onstream five to seven years ago.

What should oil companies do? These trends are likely to spur specialization in GOM basin-specific services and equipment, such as dual-gradient drilling capabilities to address the particularities of the Paleogene formations recently announced by some players. Additionally, in view of the expertise and very extensive financial resources required to be a player in the Paleogene, risk-sharing partnerships with larger numbers of participants may become even more prevalent, and there may be a reduction in the number of independents and smaller companies active in the area. OFSE companies are likely to experience similar pressures.

Angola and Nigeria. There have been significant increases in the level of the government share of revenues since new terms were imposed in the mid-2000s; government take now represents 70 percent of post-cost revenue in Nigeria and 60 percent in Angola. In addition, in Nigeria, local content requirements have tightened over the past decade, requiring the full manufacturing of certain components and the execution of complex works in-country. Angola also has local content requirements for labor, equipment, and services, but the more severe challenge is dealing with skilled-labor shortages and procurement and supply-chain bottlenecks that have resulted in steep cost increases. Our analysis finds that local content requirements and supply-chain bottlenecks will likely add 30 to 40 percent to project costs in both countries during the next decade.

To manage these challenges, the base of local suppliers would need to grow and develop greater capabilities. Some international oil companies are already actively partnering with local suppliers to help them develop capabilities and are supporting or leading employee skills-development programs. In certain cases, oil companies are also helping local supplier and service companies obtain financing, or providing financing themselves, to enable the local partners to expand and develop. Other oil companies and OFSE companies that decide they want to make a long-term commitment to this region should consider following these examples.

Brazil. Greenfield-project costs are as low as \$65 per barrel due to the abundant hydrocarbon reserves of the pre-salt resource base, the scale of operation, and Petrobras's accumulated learning in deepwater. But costs in Brazil are escalating because of the new production-sharing rules for pre-salt developments, which mandate that a



share of revenues be taken by the government, as well as the impact of tighter requirements for sourcing oilfield services and equipment from Brazil-based companies—intended by Brazil’s government to help build a local oilfield-services industry. As a result, projects could face additional costs of as much as \$20 per barrel over the next decade, according to our research.

Players considering Brazil should carefully evaluate whether the benefits from participating there are in line with their objectives. The 2010 regulation that Petrobras must be the sole operator of all pre-salt and “strategic” fields and have at least a 30 percent stake in all fields means that other participants have limited control over field development and no access to the additional returns that operators normally earn. On the other hand, for players such as national oil companies that see oil-supply security as a higher priority than investment returns, such equity stakes could be attractive. For OFSE companies, it will be necessary to have Brazil-incorporated subsidiaries or local partners that will be able to bid on the major volume of business that could emerge as the pre-salt fields are developed.

How to reap rewards in deepwater’s new era: A checklist

The challenges are extensive and sharply differentiated between basins. With limited capital expenditure and new constraints to value creation, even the largest oil companies need to consider in which basins their strengths will best equip them to create value.

We believe there are three principal areas where oil companies and OFSEs must carefully evaluate what they can bring to each basin in the deepwater game:

Competitive strengths. Deepwater success requires being above-average on such key dimensions as exploration, access to capital, contracting strategy, and cost management. External qualitative and quantitative benchmarks can help producers see what their competitive advantages are relative to competitors, and they should then ask where can they best exploit that advantage? OFSEs need to identify the basins and stages of discovery and field development where their proprietary technologies provide an edge.

Long-term commitment to the region. Given the divergent trends among basins, oil companies can no longer take a short-term, asset-by-asset approach, but instead must increasingly make a long-term commitment to basins. Once an oil company has identified its priority basin or basins, it must make sure it is able to invest sufficient time and resources to maintain its local presence and relationships with the government and local companies that will be critical to success. It must also decide what its government-relations strategy should be, and how far it is willing to assume national-oil-company (NOC) execution risks. Beyond this, oil companies and OFSEs must decide what their role should be in building local supply-chain relationships and developing local suppliers and skilled workers.

Partnerships. In many deepwater developments, partnerships can bring benefits. For example, in emerging regions like East Africa, partnerships between nimble, low-cost explorers and well-capitalized majors and NOCs can maximize value creation across the project life cycle. In the US GOM, partnerships offer a way to share risks and bring in specialized capabilities. Looking back to their competitive strengths, oil companies and OFSEs must consider in which basins their strengths constitute distinctive advantages that will make them a desirable partner. At the same time, producers must think about what capabilities they want to bring in from other players, and what will be the role of partnerships across the life cycle of a field. OFSEs in turn should consider how partnerships could enable them to play in one or several regions over the long term.



Deepwater oil is expected to continue to play a critical role in global oil supply growth over the next decade. Producers and OFSEs understandably want a piece of the action. But in a rising-cost and volatile-oil-price environment where the requirements to win are diverging sharply between deepwater basins, they need to reflect carefully on their strategic priorities, capital position, and capabilities. In this new era for deepwater, players should focus on achieving scale in a single basin, rather than trying to achieve scale globally. As the drivers of success become more basin-specific and players look to make long-term commitments and partnerships in those basins, a basin-specific strategy should position companies to capture greater rewards. ○

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