Norway plans to spend over $100bn projects over the next decade

Brownfield E&P projects are becoming increasingly important on the Norwegian Continental Shelf

Wood Mackenzie analysts anticipate that incremental projects will account for about half of Norway's $200bn (NKr1,250bn) upstream development spend over the next decade. Considering the balance between the anticipated cost per barrel versus risk, the company believes that incremental projects will 'stack up favourably with new projects'.

Speaking at ONS 2014, Lennart Koch, Senior NW Europe Upstream research analyst, said: 'As the Norwegian Continental Shelf is maturing and the government wants to increase overall recovery rates from 50–60%, brownfield incremental projects are becoming more important. We estimate that incremental projects – such as compression installations, infill drilling programmes and field redevelopments – will account for almost half of the estimated $200bn of upstream development spend over the next 10 years.'

Faced with tighter economic constraints, oil companies are increasingly scrutinising project economics with a keen eye on increased recovery rate targets combined with stringent capital cost discipline across the global upstream sector, maintains Koch.

Wood Mackenzie compared the economics of Norwegian greenfield developments against those of five large incremental projects – Åsgard subsea compression, Heidrun Nord Flank, Hod development, Ormen Lange subsea compression and Valhall Vest Flank. Together, these projects accounted for $11bn (NKr69bn) investment and will add estimated reserves of 1bn boe, raising the recovery factor of the initial fields by an average of 9% and greatly contributing to the overall increase in the recovery rates of Norwegian fields.

Research shows that investment capex per barrel for incremental projects is 30% lower than greenfield projects and the average rate of return is 18%, reducing economic and subsurface risk significantly. However, Koch noted that several incremental projects have already seen large increases in estimated costs, which eroded their value and shows they are 'just as much at risk of being cancelled as low value greenfield developments'.

Although the Norwegian government's express objective is to optimise recovery rates, Wood Mackenzie says it was a surprise when the 2013 tax change hit these projects hard. 'Although Åsgard subsea compression was exempt from the tax change, the average post-tax value of the other projects we compared was lowered by an average of 14%.' There are no plans to change the tax regime or to incentivise incremental projects. However, 'their lower cost per barrel and their time-critical nature may push the [Norwegian] government to stimulate such projects with improved fiscal terms', noted the analyst.

> *'Research shows that investment capex per barrel for incremental projects is 30% lower than greenfield projects and the average rate of return is 18%, reducing economic and subsurface risk significantly.'*

Yet to be developed resources

In a further presentation at ONS 2014, Wood Mackenzie suggested that 10bn boe of discovered oil and gas resources within 206 discoveries, worth about $106bn, are yet to be developed in the Norwegian Continental Shelf. The resources range from 1mn boe to the giant 2.4bn boe at Johan Sverdrup field – with half located in the Norwegian Continental Shelf and the remainder divided equally between the Norwegian Sea and the frontier Barents Sea. Although these resources are at different stages of evaluation, Wood Mackenzie says over half could be commercialised and generate significant returns.

Wood Mackenzie NW Europe Upstream analyst James Webb said: 'We consider 4.8bn boe are likely to be economic... whilst the remaining 3.6bn boe is not commercial and, therefore, will remain undeveloped. Economic discoveries represent $22bn (NKr135bn) of potential value for companies in the sector and $84bn (NKr514bn) in tax revenue alone for the Norwegian government – excluding the profits of Statoil and the State Direct Financial Interest [SDFI].'

However, Wood Mackenzie cautions that significant challenges will need to be overcome in order to maximise the value of these projects. According to Webb: 'Not all undeveloped discoveries will reach commerciality. A considerable number of technical and commercial challenges could threaten the development of these discoveries.' The roster of challenges on the horizon include low reserves, lack of infrastructure and/or complex geology.

Webb also stressed that many companies are committed to stricter capital discipline. 'Capital intensive projects are particularly being scrutinised. This means more difficult projects could be delayed, and in some circumstances will simply remain undeveloped,' he said.

Indeed, the pace of development of some of these incremental

IN BRIEF

Statoil has signed a cooperation agreement with Petronic to develop oil and gas activities off Nicaragua's Pacific coast. Petronic has also sent a request to the Nicaraguan Ministry of Energy to start negotiations for concession contracts offshore Nicaragua.

Rising US unconventional oil and natural gas production is expected to boost US energy exports by 6% a year through to 2030, according to a recently published report from HSBC Global Connections Trade Forecast. China and India are predicted to be the best trade prospects for the US energy exports.

India's ONGC Videsh has signed a letter of intent with PetroVietnam for exploration of 23 blocks off Vietnam. ONGC made its first foray into Vietnam in 1988 with an exploration licence for block 06.1, followed by blocks 127 and 128 – the latter is currently under exploration. Russian-Vietnam joint venture partner Vietsovpetro has discovered oil with a flow of about 2,000 b/d offshore southern Vietnam.

on incremental

developments has been hindered by recent major exploration success in Norway. 'Over the last five years the average size of new discoveries has been greater than the average undeveloped field and, therefore, new fields have been prioritised. In keeping with the capital discipline theme, complex developments such as high pressure/high temperature (HP/HT) projects are also being delayed in favour of more straightforward projects.'

Ormen Lange pilot compressor train in seawater basin prior to flooding

Source: Shell

Strong future prospects

Despite the obstacles, Wood Mackenzie maintains that the prospects for future developments in Norway are strong. 'Undeveloped resources account for much of the remaining value for several companies, including Lundin Petroleum, Det Norske and Faroe Petroleum. This creates an incentive to commercialise the finds quickly and bring them onstream. However, we see increased cooperation between the companies, the SDFI and Norwegian government as vital in order to achieve the $106bn prize,' remarked Webb.

Field development

First oil from Cardamom

Cardamom has produced first oil, the second major deepwater facility Shell has brought onstream in the US Gulf of Mexico this year, following the start-up of Mars B in February. Oil from the subsea project is piped through Shell's Auger platform, the company's first deepwater tension leg platform (TLP). When at full production of 50,000 boe/d, Auger's total production capacity will increase to 130,000 boe/d. Cardamom is Auger's seventh subsea development, since the TLP was first commissioned in 1994. Discovered in 2010, the Cardamom field is located in Garden Banks block 427.

Other deepwater Gulf of Mexico growth for Shell includes the Mars B (Shell 71.5%) development, which continues to ramp up production; the ultra-deepwater Stones (Shell 100%, 50,000 boe/d) project, which is under construction; front-end engineering and design is progressing for the Appomattox (Shell 80%) project; and, in a recent exploration success, Shell announced a major discovery at its Rydberg (Shell 57.2%) well in the Norphlet play. Shell also discovered oil at its Kaikias (Shell 100%) well in the Mars Basin, which will require further appraisal in 2015. The company also started oil production from its Bonga North West (Shell 55%, 40,000 boe/d) deepwater development off the coast of Nigeria in August. It recently announced a natural gas discovery at its Marjoram-1 (Shell 85%) deepwater well in Malaysia, where the Gumusut-Kakap (Shell 33%) deepwater platform is also on track for production this year.

Petroleum law

Mozambique E&P

On 14 August, the Parliament of the Republic of Mozambique approved a revised version of the Petroleum Law that revoked the existing Law nr. 3/2001 of 21 February, write *Julian Nichol*, Managing Partner and *Ana Becker-Weinberg*, Senior Associate, Bracewell & Giuliani (UK). In the context of the significant discoveries and rapid growth of the country's oil and gas industry, the emphasis of the new Petroleum Law has been to ensure that Mozambique and its population benefit from the exploration and production of these discoveries. However, the newly approved law was a significantly different version than that which had been heavily discussed between industry players and regulating authorities and subsequently submitted to Parliament. Where the Ministry of Natural Resources in the initial draft law had hesitated to impose concrete measures and/or restrictions in relation to local content and domestic consumption requirements, Parliament showed a heavier hand. There is now a requirement for foreign operators to 'associate' with local companies in the acquisition of goods and services, as well as a requirement for 25% of all oil and gas produced to be delivered to the market in Mozambique.

As a result of the government's guarantee to the Mozambican population of equitable compensation in relation to its rights to use the land and sea that may be affected by petroleum operations, concessionaires can expect a higher cost arising from land expropriation (eg for pipeline corridors) and population re-settlement. What's more, oil and gas companies will be required to enter into a tripartite 'memorandum of understanding' with the government and the local communities as a condition precedent to obtaining an oil and gas concession. The detail of such a document is yet to be worked out.

Under the new law, the government has the power to directly or indirectly carry out any activities related to the scope of any phase of petroleum operations, from E&P to marketing and refining of hydrocarbons. In implementing this increased state participation, the new law makes the national oil company Empresa Nacional de Hidrocarbonetos (ENH) the government representative in 'oil and gas transactions'. Whereas this isn't necessarily innovative within the context of management of upstream operations, the ability of ENH to participate in the 'commercialisation of oil and gas and derived products, including LNG and GTL in Mozambique and abroad' could potentially impact the dynamic of negotiation of petroleum sales in the foreign market by operators.

The question still remains, however, whether this new legal framework will impact the government's regulation of a special regime for the proposed LNG projects in Areas 1 and 4 of the Rovuma Basin, whose enabling law was approved in the same parliamentary session. This is an exciting energy market in a state of regulatory flux. It will be interesting to see whether the new regulatory developments bring with them much needed clarity or whether, as some are suggesting, they add more opacity as the oil and gas industry begins to get to grips with their translation into day-to-day activities.