

Keeping it going

A new well for water alternating gas (WAG) injection on Ula late this year marks a further step in extending the life of this North Sea field, which could yield big extra volumes of oil towards 2040.

Nick Terdre and Bjørn Rasen

WAG is already keeping Ula going for longer than would be possible with water injection alone. Before it was introduced, the field's declining production curve pointed towards a shut-down in 2005.

Through upgrading, the current drilling programme and the injection of gas from Tambar and Blane as well as Ula itself, operator BP could in the best case maintain output towards 2020.

So far, 45 per cent of the field's oil has been produced. With gas from the Dong-operated Oselvar satellite, however, BP expects to boost recovery to a minimum of 55 per cent.

The forthcoming WAG injector will be followed by another after Oselvar has been tied back in 2012, says Grete Block Vagle, who has served as reservoir team leader for Ula.

Both these wells will be fitted with a new type of completion technology, which helps to spread the water and gas more evenly through the reservoir.

Ms Vagle, who became head of renewal for BP on the NCS from 1 October, notes that this approach has also transformed Ula's economics.

BP has thereby decided to go after more difficult barrels in the Triassic reservoir basement. Four additional wells are planned in 2009-12 and more could be drilled if these are successful. That would call for a new wellhead platform.

Ula could thereby stay on stream until around 2040, and final recovery could be as high as 65 per cent.

Estimated reserves have more than tre-

bled since the field came on stream in October 1986.

Platform facilities have also been upgraded, with gas handling capacity doubled to 3.4 million standard cubic metres per day, water injection capacity up and the drilling rig refurbished.

Four wells

BP introduced WAG on Ula in the years 1997-2002 by converting four vertical water injectors on the flanks for this technique and recovering WAG oil through three producers on the crest of the reservoir.

It has taken time for the effect to be seen – the first sign of increased recovery came in 1998, but it was not until 2005 that WAG oil began to flow through all three producers.

A WAG injector drilled in 2006 yielded valuable data from coring and logging. No less than 100 metres of cores were taken and more 800 rock samples were analysed in various laboratories.

This work showed that the technique had effectively cut the proportion of immobile oil in parts of the reservoir from 35-50 per cent to 10 per cent.

To drain the residual oil fully, however, more gas will be needed along with extra injection points in the form of long horizontal wells.

Additional gas has been supplied by satellite tiebacks, first BP's own Tambar development in 2001 and then Talisman's Blane – which extends into the UK sector – since 2007.

The deal to buy Oselvar gas could

mark the breakthrough for WAG on Ula. Due to come on stream in 2011-12, this field will send its whole wellstream to the BP installations for processing.

Too expensive

Several solutions were considered by BP for its Ula strategy. These included the purchase of gas from the Statpipe line, which passes nearby, but that proved too expensive.

When export solutions for Oselvar came up for discussion, Dong and BP reached agreement that this field could supply 75 per cent of the external WAG gas to be used in Ula.

"We invited the Oselvar licensees to talks and have had a good dialogue," she says. "A stand-alone development would have cost them too much. Financially, we've now got a win-win outcome."

Dong is also a licensee on Ula, with a 20 per cent stake. BP used to be a licensee on Oselvar, which was proven in 1991 by Elf, but the licence was relinquished.

Several smaller oil companies subsequently took a look at the field, but it was Dong which ultimately submitted a plan for development and operation last March.

This calls for a three-well subsea development tied back by a multiphase-flow pipeline to Ula, which represents the best gas export solution in any event.

The alternative for Dong would have

been to use Ula simply as a hub and sell the gas to the market. Oselvar's oil will be transported away.

Force

Using Oselvar gas on Ula is an example of the commercial inter-licence collaboration promoted by Force, a partnership embracing all Norway's large offshore companies (see www.force.org).

Ms Vagle emphasises that the agreement is commercially based

and functions in this case because both sides stand to benefit.

"This wasn't time-critical yet for Ula – we could have waited a few more years to find a solution – but Oselvar is unquestionably timely," she concedes.

In her view, increased inter-licence collaboration also represents a challenge. Since Statoil holds more than 80 per cent of the portfolio on the NCS, much depends on that company. ❄

Like a laundry

The challenge on Ula is that "sticky" crude becomes glued to the pores between the sand grains in the reservoir and is thereby rendered immobile. Water injection alone leaves large quantities of such residual oil in the reservoir pores. But replacing it with gas loosens the crude's grip. Injecting water again then shoves both oil and gas towards the production wells. The WAG method is conducted in pulses, each lasting about six months.

Mature field

Ula lies in Norway's southern North Sea sector, was proven in 1976 and came on stream in 1986. Its recoverable oil was originally estimated at 154 million barrels, later upgraded to 546 million. In addition come almost four billion standard cubic metres of gas and some natural gas liquids (NGL). The present vision is to recover more than 625 million barrels (100 million standard cubic metres) of oil.

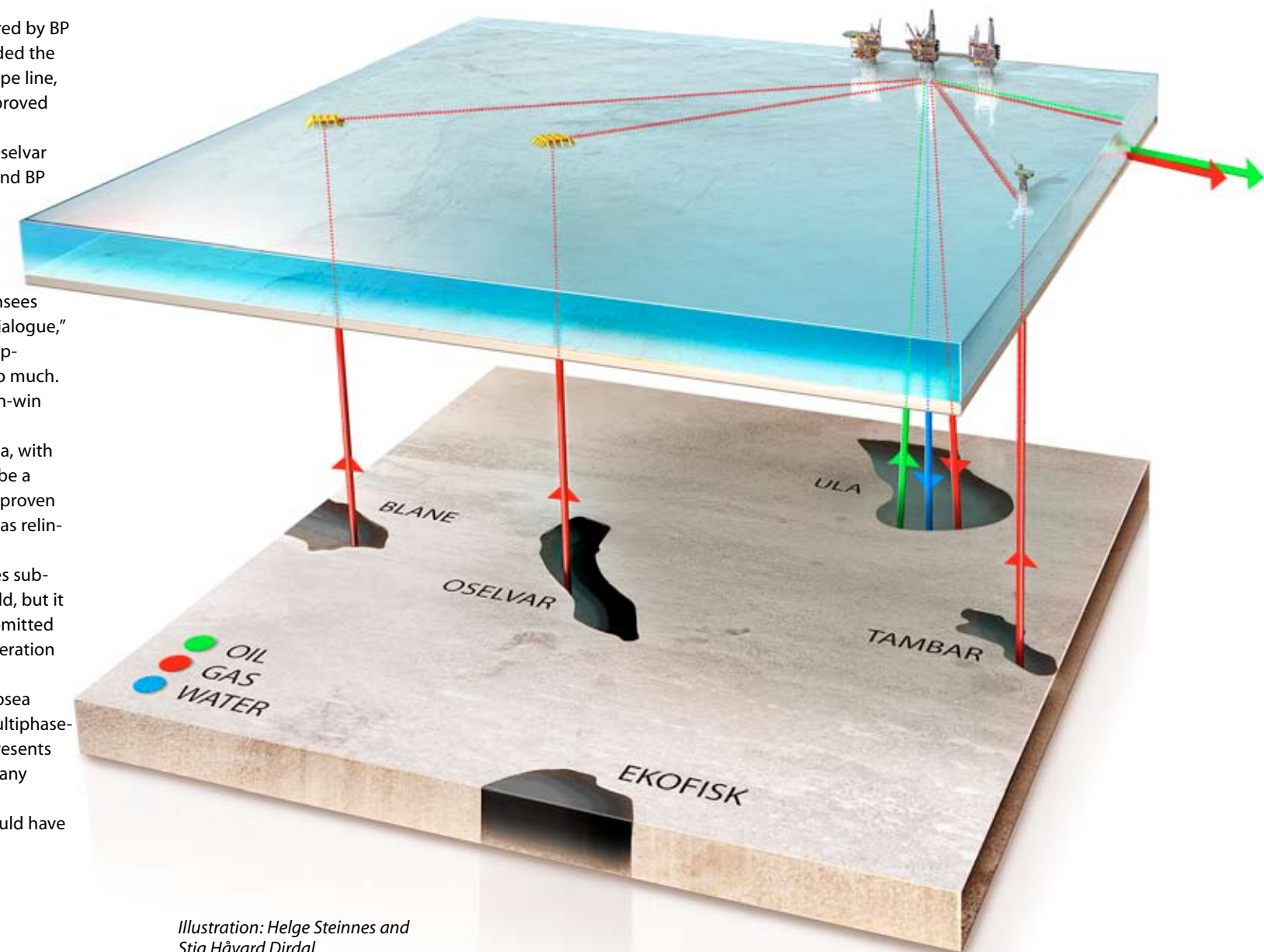


Illustration: Helge Steinnes and Stig Håvard Dirdal