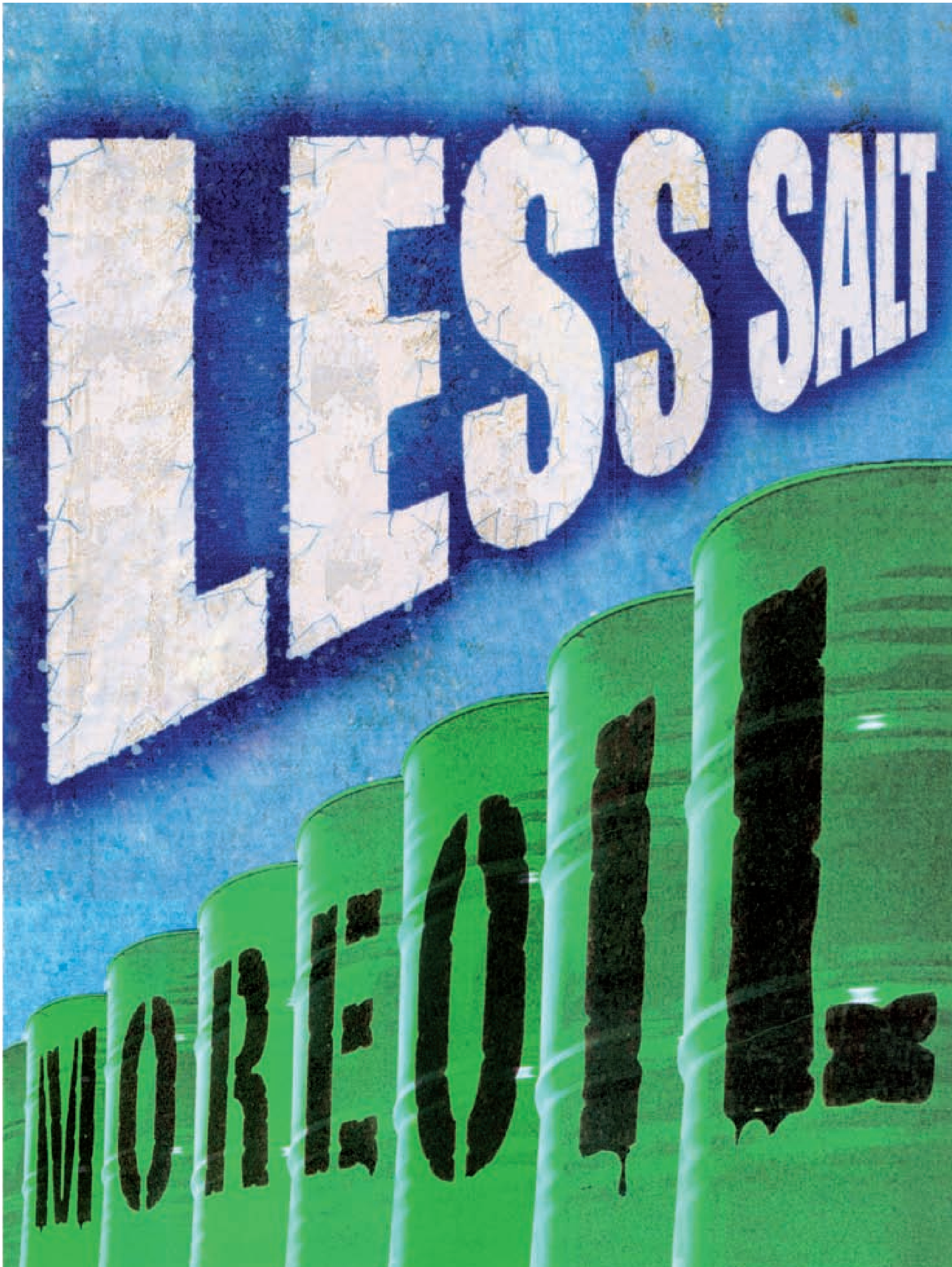

LESS SALT
MORE OIL

When it comes to injecting water into hydrocarbon reservoirs to improve oil recovery, BP has determined that lowering the salinity of the water can have the welcome effect of delivering more oil. *Nina Morgan* finds out how BP has been working to gain greater understanding of this phenomenon, which is now giving the company a competitive advantage

Some journeys of scientific curiosity are short lived, soon hitting the buffers in a dead end. Others may last longer but ultimately share the same fate. And then there is another type of journey, which, although not short in duration, proves to be well worth the effort when judged by the results that it delivers.

For BP, the latter is the case – and a very welcome one – for an investigation which the company began in 1992, delving into a phenomenon which appeared to hold out the attractive promise of helping BP produce more oil from its reservoirs. The investigation, which sought to find out why water of lower salinity than that normally used in reservoir waterflooding operations seemed to coax reservoir rocks into releasing more oil, recently culminated in a significant success on the North Slope of Alaska.

'We have been conducting a carefully designed and monitored field trial in the BP-operated Endicott field in Alaska for more than a year now,' says Andrew Cockin, research and development manager within BP's *Pushing Reservoir Limits* (PRL) team in the company's exploration and production technology group. 'The purpose of the Endicott trial was to determine if injection of reduced salinity water is as effective when applied at scale in the field as it has shown to be in the laboratory. This has proved to be the case – the additional oil production has exceeded what we would expect from conventional waterflooding techniques.'

Such is the confidence in the effectiveness of this approach to enhanced oil recovery, backed by BP's in-depth understanding of how it works and how best to apply it, that the company has trademarked its know-how as LoSal™ enhanced oil recovery (EOR) technology, a proprietary technique which is now a technology leadership area within BP's exploration and production portfolio.

Since BP's research work began, initially in a small way in the early days, there have been many steps along the way, accompanied by a steady increase in confidence that controlled salinity waterflooding held much potential. For example, four years ago, when BP's production team at the Milne Point field on the North Slope tapped into a freshwater aquifer, they already had a shrewd idea by that stage that the move would generate more oil based on earlier laboratory and other trials. The freshwater from the aquifer was subsequently injected into the Milne Point oil reservoir, resulting in a small rise in oil output, combined with a drop in the amount of water being produced along with the oil.

'We saw a real difference in recovery at Milne Point and it confirmed ideas we had about the advantages of controlling the salinity of injected water,' says reservoir engineer Kevin Webb, low salinity subsurface project manager in the PRL team. 'The events at Milne Point added to the growing evidence that we were on the right track.'

Extensive experiments

Waterflooding is commonly used in reservoirs to increase oil recovery beyond the primary recovery achieved if only the natural pressure in the reservoir is relied on – this pressure soon diminishes, causing wells to stop flowing after perhaps only 10 per cent of the oil in place has been recovered. The technique, which

Below: Production facilities in the Endicott field, where inter-well field trials have proven the effectiveness of LoSal EOR technology at scale

Inset: Map showing Endicott's location off the North Slope coast of Alaska

GOOD CHEMISTRY – HOW LOSAL EOR TECHNOLOGY WORKS

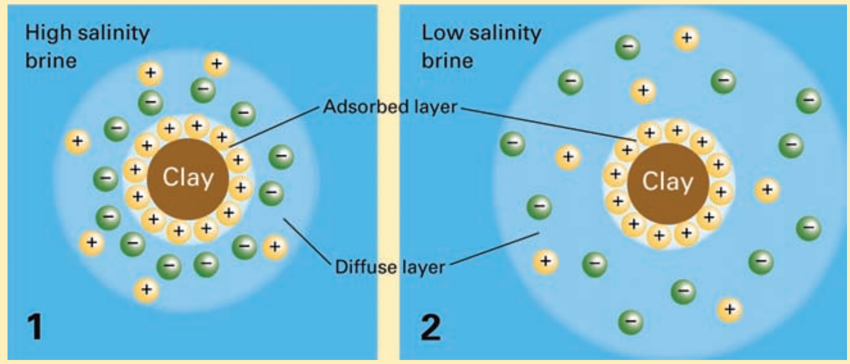
In most reservoirs, a significant proportion of the original oil present remains in the reservoir after production operations, and a variety of techniques, collectively known as enhanced oil recovery (EOR), can be employed to try to capture it. Understanding the chemistry behind oil wetability – or how oil ‘sticks’ to the surfaces of the grains in reservoir rocks – is an important effect when it comes to EOR. BP’s proprietary LoSal EOR technology draws on an understanding of the science behind wetability to take advantage of the chemical interactions that occur between oil, rock and water.

Most sandstone reservoirs are made up of a mixture of sand and clay particles, and contain a mixture of water and oil. The oil molecules are held on the surface of the negatively charged clay particles mainly by divalent cations – these are positively charged ions, such as calcium (Ca^{++}) or magnesium (Mg^{++}), which act as tethers to hold the oil molecules onto the rocks (see graphic, right). When flooded with water that has a lower salinity than the reservoir’s formation water, free cations in the flood water, for example monovalent sodium ions (Na^{+}), exchange with the divalent cations holding the oil in place and release the oil molecules, allowing these to be swept out of the rock pores.

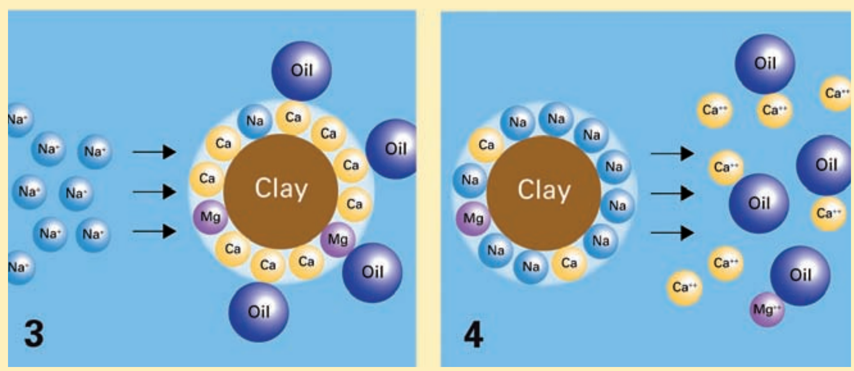
‘Because of the way the ion exchange operates, the more clay present in the reservoir, the greater will be the benefit of using low salinity water,’ explains reservoir engineer Kevin Webb.

Getting the salinity of the injected water right is crucial to LoSal EOR success. The composition of the rocks – and hence the chemistry – can vary greatly between reservoirs. For optimum results, it is important to use water of compatible salinity for the reservoir being produced.

‘If, for example, the salinity is too low, clay particles can swell, plugging the voids between sand grains and damaging the permeability of the reservoir,’ explains process engineer Dale Williams, LoSal EOR facilities project manager, who is evaluating the desalination facilities and equipment that will be needed for LoSal EOR. ‘The optimum water salinity is below 6000 parts per million (ppm) for most reservoirs. For comparison, seawater in regions where BP operates typically has salinities ranging from 33,000 to 38,000ppm, while the standards for salinity in drinking water can be to less than 500ppm.’



When a negatively charged clay particle in the porous rock structure of an oil-bearing reservoir is immersed in water, an electrical ‘double layer’ forms around it. The double layer consists of an inner adsorbed layer of positive ions, and an outer diffuse layer of mainly negative ions. The thickness of the double layer depends on the ion concentration in the surrounding water. In the case of high salinity water containing more ions, the double layer is more compact (1), but when low salinity water is introduced, the double layer expands (2).



The adsorbed layer of positive ions contains divalent calcium (Ca) or magnesium (Mg) ions, which act as tethers between the clay and oil droplets. Injecting reduced salinity water opens up the diffuse layer, enabling monovalent ions such as sodium (Na), carried in the injection water, to penetrate into the double layer (3). Here, the monovalent ions displace the divalent ions, breaking the tethers between oil and clay particles, thus allowing the oil to be swept out of the reservoir (4).

As a general rule, Williams and his colleagues will initially be aiming to generate water that contains 500ppm or lower salinity for use in LoSal EOR operations by using reverse osmosis desalination plants – an established membrane technology but one which will be engineered to BP’s requirements – equipped with a pre-filtration system to minimise membrane fouling and the frequency of cleaning. As LoSal EOR technology comes into use in more locations, the team will be working with suppliers to find the best equipment for desalination under a variety of conditions, including in offshore applications.

> was first applied as long ago as the 1890s, involves injecting water into wells to maintain pressure within the reservoir and to push oil towards producing wells. Typically, the water produced along with the oil can be reinjected for this purpose – in offshore fields this is often augmented by the addition of treated seawater. For onshore developments, additional water gathered from other locally available sources, such as water produced from non-oil-bearing formations, may be used.

For much of its history, the major mechanism behind waterflooding was considered to be a physical one – where the pressure of the injected water is used to sweep oil out of the reservoir and into the producing wells. Polymers, for example Bright Water™, were developed to improve the physical mechanisms behind the sweep – Bright Water was based on a BP idea and co-developed by BP and other companies, including Nalco (*Frontiers*, December 2007).

When it comes to the chemistry of waterflooding, there is good understanding of some aspects of the chemistry of the injection water – seawater, for instance, contains sulphates which can combine with elements such as barium and strontium present in formation water to create unwanted sulphate scales that can precipitate in plant facilities or in the reservoir itself, requiring scale inhibitors to be applied. But generally, less consideration has been given to how the chemistry of the injection water itself could influence the mechanism and degree of oil recovery.

This began to change in the early 1990s when work conducted as part of a joint industry project to study the fundamental ‘wetability’ of reservoir rocks, suggested that water chemistry influences the way that oil, held in the pores of reservoir rocks, is released during waterflooding (see panel on page 8). This implied that changing the chemical composition of the injected water might provide a way to enhance the effectiveness of waterflooding.

The conceptual breakthrough came during a study designed to elucidate why some rocks tend to become more 'oil wet' while others lean towards being more 'water wet'. Laboratory experiments conducted during the course of the research hinted at an increase in oil production when the salinity of injected water was reduced. These observations were later confirmed at BP's Sunbury laboratories by flooding tests of oil-bearing rock cores taken from a reservoir. The combined evidence indicated that the benefits of using reduced salinity water for waterflooding were potentially significant.

Appreciating the possible impact of the findings, from the late 1990s onward BP continued to work with researchers at the University of Wyoming, led by Professor Norman Morrow, to explore this hypothesis further. After carrying out more than 30 flood tests using reduced salinity water on core samples from different reservoirs around the world, Webb and his colleagues at BP were excited.

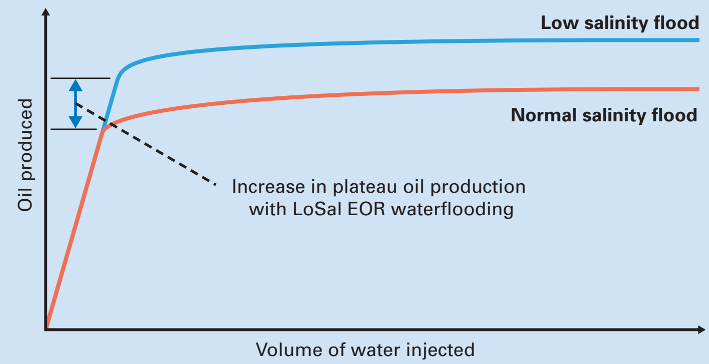
'Every time we carried out a core flood test we saw more and more benefits,' Webb recalls. 'Our test results showed that reducing the salinity of the injected water resulted in improvements in oil recovery ranging from two to three per cent in some reservoir rocks to over 40 per cent in others.'

The laboratory results were supported in 1999 in an actual reservoir when the group carried out a 'log-inject-log' test in a well in Kuwait. Well logs record changes in the rocks which occur within about 15 centimetres from the wellbore, on a centimetre-by-centimetre basis down the well. By using a series of well logs the team was able to compare variations in residual oil saturation – the amount of oil remaining in the pores of the reservoir rock – after brines of varying salinities were injected into the reservoir. This test also revealed that more oil was released when low salinity brines were used.

To understand the effects on a larger scale, in 2003 the team began carrying out single well chemical tracer tests in a number of BP reservoirs around the world. These tests, which inject a chemical tracer into a reservoir and can measure the amount of oil left in the rock, make it possible to analyse the effect of different salinity brines on oil recovery up to six metres into the reservoir. They revealed that controlling the salinity of injected water could improve oil recovery by up to 54 per cent.

BP's LoSal EOR technology looks set to change the world of waterflooding

LOSAL EOR CORE FLOOD RESPONSE



Waterflood tests on reservoir core samples at BP's Sunbury laboratories demonstrated that reduced salinity water produces significantly more oil

The road to Endicott

With such positive results coming in, all of which were adding to BP's understanding of the recovery mechanisms involved, the next step was to test the performance of LoSal EOR technology at the field level in an inter-well test. Two wells in the Endicott field in Alaska were chosen, one a producer and the other an injector. The test involved injecting low salinity water into the injector, then monitoring the resulting changes in oil recovery in the producer over a timescale of many months.

The Endicott field, located on the Alaskan North Slope adjacent to the giant Prudhoe Bay field, is the first 'offshore' development in the Arctic – the field is operated from a man-made island connected to the mainland by a causeway. Endicott came on stream in 1987. The field, which produces from a high porosity, high permeability sandstone reservoir, had estimated oil in place of just over one billion barrels, plus some 30 billion cubic metres of gas. Around 500 million barrels of oil have so far been produced.

'Sand quality, the proportion of clays and the amount of residual oil after waterflooding combine to make Endicott a well-suited place to employ the LoSal EOR mechanism,' says John Denis, BP's resource manager for the Endicott field, based in Anchorage.

'The Endicott team had the appetite to take on the challenge of testing and proving this new technology but the logistics involved in carrying out such carefully controlled tests in an Arctic environment were very challenging.

'We were employing new or developing technology on several fronts. Working with vendors and co-ordinating this work from Anchorage with the field teams on the North Slope required a constant focus, but we received great support and engagement in what we were doing.'

Enthusiasm, he notes, was certainly needed, pointing out that water of the required salinity for the tests was sourced from a lake 16 kilometres from the well where the injection was taking place. 'We were trucking water round the clock for 11 months, sometimes in blizzards and temperatures of 30 degrees below freezing,' he recalls. 'And we did it safely and without incident.'

The injection of reduced salinity water ended in May 2009, says Chris Mair, a reservoir engineer who works with BP's LoSal EOR deployment team.

'The results were exciting. We saw an increase in oil output in the producing well, combined with a drop in water cut,' he reports. 'The Endicott team is continuing to monitor the effects of LoSal EOR water injection in nearby wells, but the data so far confirm that the mechanism works at the reservoir scale – not only to release oil from the rock, but also to allow more of that oil to reach the producing well. It's a great result.'

BP's believes its fundamental understanding of the technology and accumulation of know-how, supported by its growing intellectual property portfolio, has made its LoSal EOR technology distinctive.

'The results of the inter-well tests at Endicott,' concludes Webb, 'are the keys to unlocking other LoSal EOR developments. Endicott is now a candidate to benefit from the full scale deployment of LoSal EOR, and BP is also studying other offshore applications of the technology.

'Our vision when we started was to make low salinity water the water of choice in BP's sandstone reservoirs. The 10 years and more we've spent working on LoSal EOR technology encompass a whole sequence of events and a technology which could change the world of waterflooding as we know it.' ■