Abstract

Horizontal wells have seen a dramatic rise in the range of applications and the number of wells completed during the past decade. However, horizontal wells have been primarily drilled as producers maximising the benefit from the large reservoir contact which such boreholes allow. To date there have been only a handful of reported applications of horizontal wells as injectors. The potential benefit of horizontal injectors could lie in improving the sweep efficiency and enhancing the degree of pressure maintenance characteristics of reservoirs as they enter an advanced stage of depletion in redevelopment projects.

With the above in mind the Horizontal Well Technology Unit in Edinburgh has been conducting a two year research programme looking at the potential for improving hydrocarbon recovery efficiency using horizontal injectors, with the overall aim being to establish a sound business case for the utilisation of horizontal injection wells. The investigation has concentrated on both water and gas injection. The first part of the study used a box type reservoir simulation model, to compare horizontal and conventional vertical injection wells in different depositional environments.

Horizontal water injectors were found to improve sweep efficiency and achieve production acceleration in certain reservoir environments. These included extreme permeability distributions (fining upwards/downwards in rock properties) and high viscosity oils. Higher NPVs were achieved in these cases.

For gas injection, it was found that, because the high mobility ratio completely dominated the displacement process, improvements in recovery were limited.

In the third phase of the project, the focus switched to applying the technology to real North Sea field datasets. The studies have confirmed the conclusion from the earlier work that horizontal injectors seem to function best in low permeability environments due to the much superior injectivity. In higher permeability environments, viscous driving forces can lead to increased recovery in favour of vertical injectors.

Introduction

At the start of this two year long project (January, 1995), there were few field developments relying on horizontal injection wells and a paucity of description of their performance in the literature. This prompted the study to investigate the reservoir environments/conditions in which horizontally completed injection wells would perform better than conventional vertical injectors in terms of ultimate oil recovery, rate of recovery and resultant net present value (NPV). The work was undertaken in three phases: model validation, theoretical sensitivities and study of actual fields. In all cases, where possible, the numerical simulation results were checked against analytical calculations.

Phase I - Initial Water Injection Sensitivities

This phase consisted of calibrating the horizontal well model used in the Eclipse simulator against acceptable criteria for the aspect ratio and well isolation. Output from a simple simulation model
was then compared with the results of Buckley-Leverett analytical displacement equations, which showed the results from the numerical model to be in reasonable agreement with analytical calculations. Finally a simple simulation model was run to compare horizontal versus vertical water injection performance for different reservoir thicknesses varying between 50 ft and 150 ft in a 100 mD reservoir. As expected, the horizontal well proved better than the vertical in the thinner reservoir. Its superior injectivity led to an acceleration and increase in oil recovery. As the thickness increased towards 150 ft, the difference between the injectors diminished, since the required injection rate could be maintained in both types of well completion. (Figs 1-2).

**Phase II - Geological Environment Studies for Water Injection**

As a continuation of the initial scoping sensitivities, it was decided to carry out a full set of geological environment sensitivities with the aim of determining the most suitable environment for horizontal injectors. Each of the scenarios was studied using voidage replacement and a maximum oil production rate. The main factors considered were the total amount of oil recovered, recovery time, possibility of production acceleration and the effect these had on the economics. The environments studied included reservoir thickness, kv/kh ratio, layering, coarsening up, fining up, dipping reservoirs, faulted reservoirs and viscous oil. The results indicated that when the reservoir was produced using voidage replacement and a constrained production limit, the oil recovery resulting from the use of horizontal and vertical injection wells was similar. Provided conditions are favourable, such that the vertical well can inject sufficient water to meet the required production rate, then there is no advantage in using horizontal injectors. It is only when the reservoir conditions deteriorate that the superior performance of horizontal injectors is evident. In all the above cases, it is the vertical well that fails to maintain the required injection rate and the horizontal wells, typically with injectivities four times greater, that prove advantageous in the adverse conditions.

**Phase II - Geological Environment Studies for Gas Injection**

As a continuation of the work carried out for water drive, it was decided to investigate the use of horizontal gas injection wells in different depositional environments. As for waterdrive, comparison was made with vertical injection wells, the emphasis being on the total amount of oil recovered and the effect this had on simple well economics. However the results were not as anticipated. It was expected that spreading the injected gas along the horizontal well length (6000 ft) at the crest of the structure would reduce the velocity of frontal advance in the downdip direction, thus stabilising the flood and increasing the recovery. This did not happen! Practically without exception, the vertical injectors provided better recoveries and NPVs. The reason for this is because the gas injection per unit length of the horizontal completion was so low that the viscous driving forces were practically eliminated, gravity predominated and the gas rose to the top of the reservoir in the vicinity of the well, causing severe override and premature breakthrough of gas. In the vertical injectors, the viscous forces were much greater leading to a more favourable sweep efficiency. In considering this result, it should be noted that the average permeability in the models was about 300 mD.

**Phase III - Thermal Fracturing**

A short literature review was undertaken to assess the impact of thermal fracturing on horizontal injection wells. Contact was also made with relevant companies within the industry who had expertise in completion technology and fracture simulation.

Thermally induced fracturing is believed to be a widespread phenomenon, particularly in deep water injection wells. It is commonly accepted that the injection of cold water into the formation cools the reservoir around the wellbore. This has the effect of reducing the ultimate tensile stress of the rock. The main issue to be dealt with in relation to thermal fracturing and cold water injection is control of the injected water profile. Experience shows that fracture initiation/propagation will not occur along the whole length of the exposed wellbore section but will occur at the point where the stress reduction is greatest. Injected water will preferentially travel through the fractured zones which may lead to an inefficient sweep of the reservoir and premature water breakthrough. (Fig. 3) Control of the fracture initiation along the length of the horizontal section will lead to a more even spread of fractures, aiding in linearisation of the inflow profile of injected water, leading to a better
sweep of the reservoir. Fig. 4 shows an example of completion equipment that could be used to isolate high and low permeability zones in order to regulate the injection of water and produce a more linear injection profile.

Phase III - Field Studies

In this final phase of the study, horizontal and vertical injection wells were compared in actual reservoir environments, the sponsors of the project (who operate the separate fields) providing the geological/petrophysical/reservoir data together with their latest numerical simulation model. A sector of each field was then selected in which to study injection well performance, usually with just one producer and one injector. Choice of the field sector was mainly based on the value of the average permeability and permeability distribution. In several cases, following the basic injection well comparison, various “liberties” were taken in varying the field data (permeability, oil viscosity) to follow interesting leads. This was with the consent of the individual sponsors.

Field H

This is a field with excellent reservoir quality. Even though the sector chosen for study had the lowest permeability of any cored well, the average permeability was still 1300 mD. The reservoir was 64 ft thick and displayed a fining upward in permeabilities from 2300 mD at the base to 500 mD at the top.

For water injection, it was found in this reservoir environment that the performance of the vertical injection well was slightly better than that for a horizontal well. The reason for this result was that the kh-product was just too high. The viscous forces were reduced to such a level for the horizontal well that the injected water immediately slumped into the higher permeability basal layers, affording a poor sweep of the upper. The viscous forces were greater in the vertical completion providing a better volumetric sweep. Five sensitivity runs were performed in which the permeability was reduced by factors of one third to one hundredth of the original value. At a reduction factor of one tenth, a threshold was reached at which the horizontal injector performed better than the vertical (Fig. 5). When the lowest value was reached (k=13 mD) the recovery factor and NPV for the horizontal well were 45% and 50% higher than for the vertical.

Gas injection was studied using the same simulation model for Field H. In all the runs with the original model (k=1300 mD), the performance of a horizontal gas injector was somewhat better than for a vertical well, a result that completely contradicts the findings of Phase II. The reason for this is because for this high level of permeability, it is like injecting gas into a “tank”. The viscous forces for the vertical well are reduced to such an extent that the horizontal well completed in the basal layer proves the better type of injector, due to the improvement in sweep efficiency.

Field G

There are three main sands in this field with average permeabilities of less than 100 mD in the top and basal layers and a 500 mD sand in-between. The three layers were not considered to be in vertical communication. On account of the physical separation, the focus in this study was on determining the best form of well completion for both injectors and producers: horizontal (high angle), vertical and multi-lateral. A sophisticated well model, devised by the HWTU, was used for the producers. Only gas injection was considered in this field, which is the operator’s intention. The most suitable well configuration was a multi-lateral producer completed in the top and basal layers, with a horizontal producer in the high permeability middle layer.

Field B

Although permeabilities in this field are generally quite “reasonable” an, as yet, undeveloped region was selected for study which had an extremely low average permeability of 0.06 mD; the intention being to test the lower limit at which horizontal wells might prove beneficial. Matters were complicated, however, by the fact that the oil was highly undersaturated (3335 psi) and overpressured (2800 psi), so that depletion to the bubble point gave an exceptionally high recovery factor of 13% STOIP. Under these circumstances perhaps the decision would be made not to consider any form of injection, simply deplete. Indeed, injection of water in either horizontal or
vertical wells improved little on this recovery since the permeability proved too low to inject any significant volume of water. It was decided, as for Field H, to run simulation sensitivities varying the permeability. In this case, average permeabilities were raised by factors of 10, 20 and 40, the highest value being 2.4 mD. Comparison of horizontal and vertical injection well performance (comparison of injection versus depletion is not considered relevant) for waterdrive demonstrated that the horizontal well proved the better type of completion and the favourable difference improved as the permeability increased.

Gas proved more favourable than water injection, in this very low permeability environment, on account of its much more favourable mobility and higher wellhead injection pressure. Again as the permeability level was raised, the horizontal injector performed increasingly better than the vertical.

Field A

The area of interest in this field was a dual permeability section extending between two appraisal wells (Well A and Well C). A 100 ft low permeability section is overlain by a 130 ft section which contains high permeability intervals. (Fig. 6) The permeability in the area of the downdip appraisal well is roughly an order of magnitude less than that around the updip appraisal well. Water injection studies showed that horizontal and vertical injectors were comparable in performance. This was due to the higher permeability intervals dominating the displacement, leading to an accelerated watercut development, at the production well. Sensitivity runs were performed in which the low viscosity oil was replaced with a high viscosity crude. A horizontal injector was compared with a fully perforated vertical injector. The results showed that the horizontal injector was the most favourable injection well type. The reason for this was that the horizontal injection well was kept furthest away from the high permeability layers, thus reducing the watercut development, whilst still being able to provide an adequate degree of pressure maintenance. The vertical injector performed best when it was only partially perforated, again due to the watercut development being reduced. Fig 7. shows a Buckley-Leverett history match plot for this sensitivity comparing the amount of oil produced against the amount of water injected for both injection well types.

Conclusions

1. In some instances the results obtained in the various stages of this study defied intuition, which is not surprising considering the number of parameters involved in the calculations for the cases considered.

2. If, for whatever reason, the reservoir conditions or fluid properties are not conducive to injection, horizontal wells are likely to perform better than the vertical.

3. The most important parameter is the permeability thickness, though permeability distribution and oil viscosity are other factors. From the studies undertaken, a working range for permeability where horizontal injectors seem to show the most benefit is 1 - 50 mD.

4. The reduction in viscous forces in horizontal injectors has generally been a disadvantage in the cases considered in the study.

5. Horizontal injectors do not offer a universal panacea (any more than horizontal producers) and every case must be studied in detail before committing to their use.

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Recovery Efficiency Factor

Figure 1: Comparison of recovery factors for different reservoir thicknesses

Production Profile for the 100 ft Reservoir

Figure 2: Comparison of horizontal and vertical injectors for 100 ft reservoir

Figure 3: Uneven flood front profile resulting from thermal fracturing

Figure 4: Completion equipment used to isolate high and low permeability zones
Figure 5: Effect of permeability reduction on recovery difference (Field H)

Figure 6: Permeability distribution at injection well for Field A

Figure 7: Buckley-Leverett history match plot for high viscosity oil sensitivity (Field A)