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## Potential of Multilateral Wells in Gas Coning Situations

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### Abstract

This paper presents the results of a numerical study performed in order to confirm the merits of a multilateral well to replace a pattern of parallel horizontal wells to produce an oil pay in the presence of a gas cap. The basic assumption for the study is a same total drilled length from the surface for both production patterns in an homogeneous reservoir. The production of an elementary volume of width  $a$ , length  $L$ , oil thickness  $h$  at a depth  $\delta$  is simulated considering  $n$  parallel horizontal wells of length  $L$  or just a single multilateral well composed of a main hole of length  $L$  and lateral arms of length  $a/2$  perpendicular to the main hole.

According to the reservoir depth, this assumption implies a ratio of exposed lengths to the reservoir that can be more than three times higher with the multilateral well compared to the pattern of horizontal wells. Results of the numerical study corroborate that the reduction of gas coning is therefore very important with the multilateral well. Oil recovery is accelerated and final production greatly increased. These results confirm the interest of developing and producing an oil field overlaid by a gas cap using multilateral wells rather than conventional horizontal wells.

### Introduction

Development of oil resources located in thin layers in the presence of an overlying gas cap is generally limited or marginally economic using conventional vertical wells. As a matter of fact, conventional wells can not sustain enough high flow rates because quickly they start coning and

producing gas. Increasing the number of wells would be a bad-looking solution due to the unacceptably high development costs, particularly offshore where the number of wells is necessarily limited.

The principal advantages of horizontal wells in such situations, experienced in the Troll field for instance<sup>1</sup>, are: higher oil rates at reduced drawdown, longer production period before gas breakthrough providing high initial oil rates, higher oil recovery per well and fewer wells required. Lower investment costs are a consequence of these multiple advantages. For many years now, they are the basis of the successful and intensive use of horizontal wells to replace vertical wells to produce oil reservoirs in the presence of a bottom aquifer or a gas cap<sup>2</sup>. Undoubtedly, it can be stated that horizontal wells have become the standard procedure to produce these reservoirs.

In the last few years, new developments in drilling technology have allowed the drilling and completion of multiple lateral wellbores from a single, horizontal or vertical, primary wellbore<sup>3-8</sup>. In fact, what is achievable with multilateral wells is the capacity to travel within the formation to steer the well in several directions to the oil. Another obvious advantage of using a multilateral well to replace several conventional horizontal wells is that the drilling of the non reservoir sections before the actual entrance into the reservoir is done only once. For the same total drilled length from the surface, the fraction of the wellbore exposed to the reservoir is therefore greater with the multilateral well. In coning situations, such as production of oil reservoirs with a bottom aquifer or a gas cap, a larger exposure to the reservoir implies a reduced drawdown on the formation and a larger drainage area. Thus, reduction in gas coning effects is expected with a multilateral well, as it is in the case of water coning<sup>9</sup>, with the benefits of greater oil recovery and substantial reduction both in investment and operating costs and in surface environmental exposure.

The objective of this paper is to demonstrate, from a numerical study, the potential of using a multilateral well instead of several parallel horizontal wells to economically increase and accelerate the overall recovery of oil in reservoirs overlaid by a gas cap. The main assumptions considered in this study are: a homogeneous formation, no

aquifer, same drilling and completion cost for the same total drilled length from surface for the pattern of parallel horizontal wells and for the multilateral well.

### Framework of the study

**Figs. 1 and 2** show the patterns which are considered for the study. In both cases, the elementary volume of reservoir is defined by its width  $a$ , length  $L$ , oil thickness  $h$  and depth  $\delta$ . In the figures, the trajectories of the wells are assumed defined by a vertical section and a horizontal section. Taking into account the curved section of the wells will not modify the comparison presented here.

The  $n$  parallel horizontal wells having the same length  $L$ , the total drilled length from surface for the first production pattern is  $n(L+\delta)$ . For the single multilateral well composed of a main hole of length  $L$  and lateral arms of length  $a/2$  perpendicular to the main hole and spacing  $d$ , the total drilled length is  $\delta + L + aL/d$ . The last term represents the total length of the laterals exposed to the reservoir. Assuming that the two patterns are cost equivalent for the same drilled length from surface, implies that the multilateral well can replace  $n$  horizontal wells, with the replacement ratio  $n$  defined by:

$$n = \frac{\delta + L(1+a/d)}{L+\delta} = 1 + \frac{aL}{d(L+\delta)} \quad \dots \dots \dots (1)$$

**Table 1** presents an example of comparison between the two production patterns with  $a=L=1000$  m, for various reservoir depths  $\delta$  assuming a constant drilled length of the multilateral well in the reservoir, *i.e.* 6000 m (10 laterals 500 m long with a spacing  $d$  equal to 200 m). Calculation of the replacement ratio from Eq. 1 shows clearly that the number of horizontal wells drops to low values as the reservoir depth increases. At the same time, the spacing between the horizontal wells to cover the reservoir area increases. Except for a very shallow depth ( $n=5$  in Table 1), for which the use of a multilateral well or horizontal wells would be questionable, the exposure of the multilateral well to the reservoir is far more important than for the pattern of horizontal wells. This exposure is more than doubled as the depth is greater than 1500 m in the proposed example. As shown by the numerical simulations presented in the next section, these differences will imply a beneficial effect on the oil recovery for the multilateral well as the coning will be less severe.

### Numerical study

Data presented in Table 1 have been used to compare the performance of a multilateral well with various patterns of parallel horizontal wells. As already stated, the main assumption is an identical drilled length from surface between each pattern of horizontal wells and the multilateral (this length varies between the patterns of horizontal wells, see Table 1). The production of only one

horizontal well has also been simulated, though its total drilled length is necessarily shorter than the total drilled length of the multilateral well, in order to evaluate its performance and extend the comparison to a single horizontal well. The patterns illustrated in Figs. 1 and 2, with  $L = a = 1000$  m, have been studied numerically with ATHOS, the IFP reservoir numerical simulator. The grid (11 $\times$ 16) used to discretize the elementary volume for the horizontal well patterns in 2D-XZ is shown in **Fig. 3** for a replacement ratio  $n$  equal to 3 (spacing of 333 m between the horizontal wells). Gridblock dimensions are indicated in **Table 2** for the various values of  $n$  from 1 to 3. In the 2D grid, the length in the Y direction is equal to 1000 m, the length of the horizontal wells. Dimensions of the blocks of the 3D grid (10 $\times$ 10 $\times$ 16) used to discretize the elementary volume drained by the multilateral well (Fig. 2) are summarized in **Table 3**. The discretization in the vertical direction is the same as that for the horizontal wells (Fig. 3). The wells (horizontal and multilateral) in both grids are located in layer 16, *i.e.* 0.5 m from the bottom of the reservoir. A special treatment has been done for gridblocks in the vertical planes intersected by the wells for symmetry purposes: reduction of porous volume (half or a quarter) and transmissibilities (half or a quarter) in x, y, and z directions when necessary. In the case of the multilateral well, the well is located along the y axis and the lateral branch along the x axis. The grid discretizations in the close vicinity of the wells are very fine. It has been checked that they are fine enough not to alter the results of the simulations.

Rock and fluids properties common to all simulations are listed in **Table 4**. Main data are those of the Troll field<sup>10</sup>, except the absolute horizontal permeability that is higher in the Troll field. Thicknesses of 13 m and 30 m have been considered for the oil pay and the gas cap. In order to study the sensitivity to reservoir permeability and to oil viscosity, these two data have been varied between 100 and 1000 md, and between 1.34 and 13.4 cp respectively. Sensitivity to permeability anisotropy has also been investigated considering an horizontal permeability of 1000 md and a  $k_v/k_h$  ratio varying between 1 and 10<sup>-3</sup>. As the base case, an isotropic absolute reservoir permeability of 500 md and an oil viscosity of 1.34 cp have been assumed.

### Operational condition at the well

All the runs have been performed by assigning a bottom hole liquid flowrate and by reducing this flow rate, when necessary, to avoid the breakthrough of gas in the well. The initial value of the well flow rate has been defined by a trial and error procedure in order to have the maximum free gas production in the first few days of production.

**Fig. 4** shows an example of the evolution of the liquid flow rate for the various simulated patterns during the first 6-months period of production. The initial flow rates that both depend mainly of the reservoir permeabilities and oil

viscosity are quite proportional to the length exposed to the reservoir. As shown in **Fig. 4**, a very high initial oil rate, close to 15000 m<sup>3</sup>/d, is observed for the multilateral well. Afterward, the flow rates decline sharply during the first month of production, more than half their initial values. For instance, the liquid rate of the multilateral well drops to about 7000 m<sup>3</sup>/d after 1 month of production and less than 4000 m<sup>3</sup>/d after 2 months. In field application, there is no doubt that rates greater than 5000 m<sup>3</sup>/d are unrealistic. To keep a reasonable operational production at the well, the initial oil rate would have to be restricted, if necessary, to manageable values. This would allow a constant flow rate for only a few weeks or months before the rate would have to be monitored to avoid gas breakthrough.

## Results

The performance of the multilateral well has been compared to the performance of a pattern of six parallel horizontal wells of same total length exposed to the reservoir, *i.e.* 6000 m, to evaluate the possible interferences between the main hole and the laterals. Results not presented here show that the interferences are very minor and have a very slight impact on the performance of a multilateral well. This is similar to the results obtained when evaluating the potential of multilaterals in water coning situations<sup>9</sup>.

**Figs. 5 to 8** show the oil recovery of the different patterns for various absolute permeabilities: 100 md, 200 md, 500 md and 1000 md, assuming a same fairly low oil viscosity, 1.34 cp. The results are presented in two different manners: as oil recovery versus time on the left diagram of each figure, and as the ratio versus time of oil production of the multilateral well divided by the oil production of each pattern of horizontal wells on the right diagram. The first set of curves, on the left of **Fig. 5 to 8**, points out the sensitivity of oil recovery to absolute permeability of the different production patterns. The greater the absolute permeability, the shorter the time required to produce the recoverable portion of the oil in place whatever the production pattern. However, the multilateral well accelerates the oil recovery by at least a factor of 2 when compared with the pattern of 3 horizontal wells. This is particularly noticeable for high permeability values, 500 and 1000 md, but is also true for other permeability values. At the same time, the final recovery is always higher with the multilateral well. The difference can reach several tens of percents of the original oil in place for the lower absolute permeabilities: 100 and 200 md. The second set of curves, on the right of **Figs. 5 to 8**, indicates that the recovery ratio starts always at a value that corresponds to the ratio of exposed lengths to the reservoir: 6000 m for the multilateral well, 3000 m for three horizontal wells, 2000 m for two wells and 1000 m for one well. Afterward, the recovery ratio declines as time goes on because the multilateral well reaches its final recovery faster than the horizontal wells: about 3 years for a permeability of 1000

md, 7 years for 500 md, 14 years for 200 md and more than 20 years for 100 md. Finally, when the multilateral well has finished to produce, at a final oil rate set at 50 m<sup>3</sup>/d always without gas production from the gas cap, the recovery ratio gives the gain of recovery that can be expected using a multilateral well compared to a pattern of horizontal wells. With the considered data, this gain is between 30 to 40% for a pattern of three horizontal wells and close to 100% for a pattern of two horizontal wells.

The sensitivity of oil recovery of the various patterns to oil viscosity is shown in **Fig. 9 to 11**. Compared to the base case (**Fig. 7**), the oil viscosity has been multiplied by two (**Fig. 9**), five (**Fig. 10**) and ten (**Fig. 11**). Here again results are presented in two sets of curves. Increasing the oil viscosity has the expected consequence of decreased oil rate versus time whatever the production pattern. Thus the time to recover the same amount of oil is increased and final recovery is lowered. However, differences between the multilateral well and the horizontal well patterns remain high. For instance, the oil recovery after twenty years assuming an oil viscosity of 13.4 cp (**Fig. 11**) is close to 46% for the multilateral well and only about 16% and 26% for the patterns of 2 and 3 horizontal wells. The recovery ratios have the same aspect than in the previous set of curves. However, their decline is smoother as the oil viscosity is increased.

The sensitivity to a permeability anisotropy of the reservoir has been studied for the multilateral well considering four values of the  $k_v/k_h$  ratio: 1, 0.1, 0.01, 0.001. The horizontal permeability is always the same: 1000 md. The oil viscosity is equal to 1.34 cp. Assigning initially the maximum bottom hole oil rate with the maximum free gas production in the first few days of production leads to the curves shown in **Fig. 12**. Oil recovery for the two higher values of the anisotropy ratio are very close to each other. Influence of the anisotropy of permeability is particularly significant for vertical permeability values lower than a few tens of millidarcies. For a vertical permeability between 10 and 100 md, oil production is delayed over time. However the final recovery is still high. For a vertical permeability lower than 10 md, there are both a delay in production recovery and a strong decrease in final recovery. Results for the patterns of horizontal wells are not displayed but they can be easily inferred from those presented here above for the sensitivities to absolute permeability and to oil viscosity knowing that the initial values of the recovery ratios are always proportional to the lengths exposed to the reservoir.

## Discussion of the results

The assumptions made to perform the numerical study have to be discussed. These assumptions are: first, the same equivalent cost of a multilateral well with a pattern of horizontal wells of same total drilled length from surface, then the influence of pressure drop neglected in the wells and finally considering an homogeneous reservoir.

Concerning the first assumption, experience gained in the learning curve while drilling an increasing number of horizontal wells in a given reservoir is the achievement of equivalent drilling and completion costs per drilled metre when comparing with conventional wells. For instance, in the Pelican Lake field operated by CS Resources<sup>11,12</sup>, the average costs per drilled metre of vertical and horizontal wells are the same. In the last few years, CS Resources has drilled and completed several multilateral wells using the LTBS technology<sup>5</sup>. These wells have been very successful with productions as high as expected<sup>11</sup>. The actual drilling and completion cost of a multilateral well in the Pelican Lake field is about 20% higher than the same pattern of horizontal wells of same total drilled length from surface. However, drilling and completing multilateral wells can be considered as a new technology still in its infancy, as was horizontal drilling 15 years ago. There is no doubt that the various phases of drilling and completion of laterals will improve in the future as more experience will be gained. An important aspect in favour of multilateral wells is the decrease in the number of wells at surface. In a swamp environment as for the Pelican Lake field, multilaterals are also beneficial as they imply fewer drilling pads. The reduced number of wells has a very strong impact on investment and operating costs and must be taken into account when evaluating the overall benefit of using multilateral wells. The costs indicated as an example for wells drilled onshore must be corrected in favor of the multilateral wells for wells drilled offshore from platforms where there is a constraint of limited available slots and where wells are very expensive. Drilling and completing subsea multilateral wells will allow significant cost savings in subsea wellheads, templates, flowlines, control umbilicals and subsurface wellbores as experienced by Norsk Hydro in the drilling and completion of the first multilateral wells drilled in 1996 in the Oseberg field<sup>13</sup> and in 1997 in the Troll field<sup>14</sup>.

The study has been done assuming a same drilled length from surface whatever the patterns of wells: multilateral well or several parallel horizontal wells, with the results in favour of the multilateral well. However, it would be interesting to investigate the benefit that could be gained by increasing the length of the multilateral well into the reservoir. This could be possible due to the flexibility of this new well architecture even by increasing the length of the laterals from 500 m to at least 1000 m, or by increasing the number of laterals, or both. This aspect would have to be looked at with associated economics.

As already mentioned, realistic flow rates have to be considered during the initial production phase of the multilateral. Neglecting the influence of pressure drop can therefore be justified by the relatively low production rates imposed in each lateral branch. This is a positive aspect of multilateral wells. For instance, for a multilateral well producing 5000 m<sup>3</sup>/d from a pattern of 10 laterals, the rate of each lateral would be limited to only 500 m<sup>3</sup>/d. This rate

is relatively low as far as pressure drops influence is concerned and the only possible reduction of oil recovery of the multilateral well would be effective due to frictional pressure loss in the main hole. However, this effect could be minimized by choosing an adapted completion of the main hole<sup>9</sup>.

Concerning the assumption of homogeneous reservoir, there is no doubt that it is far from reality. The more wells are drilled in the reservoir, the more they find out heterogeneities. Perhaps, some of these heterogeneities will have a negative impact on the performance of the multilateral well. Therefore, it is probable that there would be a need to be capable of isolating parts of the multilateral well that could contribute to abnormally early gas breakthrough and production. A proposed solution to this problem is to consider the main hole as a collector non-opened to the reservoir and completed with external casing packers (ECPs) located apart of junctions between the laterals. This completion would enable a selective production of individual laterals or group of laterals, if necessary.

The oil recovery with the downwards gas-displacement process due to the presence of the gas cap corresponds in fact to a natural drive or oil gravity drainage by the gas from the gas cap. Results presented here show that it can be a very efficient process as far as the well length exposed to the reservoir is important, several thousands of meters. A very attractive application of multilateral wells could be therefore the implementation of a downwards displacement of oil by gas in thick enough reservoirs even in the absence of a gas cap. The gas would have to be injected at the top of the oil pay. The longer the multilateral, the lower the drawdown along the well, the more stable the gas/oil interface and much larger the drainage rate.

Results presented here and in a companion paper<sup>9</sup> have evaluated the potential of multilateral wells in water or gas coning situations. Occurrence of both a bottom aquifer and a gas cap will of course necessitate a special study.

## Conclusions

Multilateral wells can be envisioned as a good production tool to recover oil in reservoirs in the presence of a gas cap. The gain in oil recovery using a multilateral well instead of a pattern of several parallel horizontal wells can be very significant with recovery ratio increasing as the well length exposed to the reservoir is increased.

Gravity drainage by downwards gas-displacement of the oil can be an attractive application of long multilateral wells in thick enough oil reservoirs having fairly good horizontal and vertical permeabilities.

## Nomenclature

- $a$  = width of elementary reservoir volume, L, m
- $B$  = formation volume factor, vol/vol
- $C$  = compressibility, Lt<sup>2</sup>/m, 1/bar
- $d$  = spacing between laterals, L, m

$\delta$  = reservoir depth, L, m  
 $h$  = oil pay thickness, L, m  
 $HW$  = horizontal well  
 $k$  = permeability,  $L^2$ , md  
 $L$  = length of elementary reservoir volume, L, m  
 $ML$  = multilateral well  
 $n$  = replacement ratio  
 $\rho$  = fluid density,  $m/L^3$ ,  $t/m^3$   
 $S$  = spacing between horizontal wells, L, m  
 $Rs$  = solution gas-oil ratio,  $L^3/L^3$ ,  $m^3/m^3$   
 $Sor$  = residual oil saturation  
 $Swi$  = irreducible water saturation  
 $\emptyset$  = porosity  
 $\mu$  = dynamic fluid viscosity,  $m/Lt$ , cp

### Subscripts

$g$  = gas  
 $h$  = horizontal  
 $o$  = oil  
 $r$  = rock  
 $s$  = surface  
 $v$  = vertical

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### SI Metric Conversion Factors

bar  $\infty$  1.0\* E+05 = Pa  
 cp  $\infty$  1.0\* E-03 = Pa . s  
 md  $\infty$  9.869 233 E-04 =  $\mu m^2$   
 t  $\infty$  1.0\* E+03 = kg

\*Conversion factor is exact.

**TABLE 1—COMPARISON OF A MULTILATERAL WELL (ML) WITH A PATTERN OF N PARALLEL HORIZONTAL WELLS (HW) -  $L=a=1000m$ .**

Replacement Ratio, $n$	Length of the multilateral well in the reservoir (m)	Reservoir depth, $\delta$ (m)	Total drilled length of both patterns from surface (m)	Length of horizontal wells in the reservoir (m)	Ratio of drilled lengths in the reservoir (ML/HW)	Spacing between horizontal wells, $S$ (m)
5	6000	250	6250	5000	1.2	200
4	6000	667	6667	4000	1.5	250
3	6000	1500	7500	3000	2.0	333
2	6000	4000	10000	2000	3.0	500

TABLE 2—DISCRETIZATION OF THE XZ GRID IN METRES (HORIZONTAL WELLS)	
X	$4 \infty 1., 2 \infty 2., 5., 10., 25., 50., x^*$
Z	$13 \infty 1., 3., 7., 20.$

\* $x=68.7(n=3), 152. (n=2), 402. (n=1)$

TABLE 3—DISCRETIZATION OF THE 3D GRID IN METRES (MULTILATERAL WELL)	
X	$2 \infty 1., 2., 5., 7., 10., 20., 50., 100., 304.$
Y	$2 \infty 1., 2 \infty 2., 5., 7., 10., 15., 25., 32.$
Z	$13 \infty 1., 3., 7., 20.$

TABLE 4—ROCK AND FLUIDS PROPERTIES COMMON TO ALL SIMULATIONS					
$k, md$	100 - 1000	$S_{or}$	0.253	$\rho_{os}, t m^{-3}$	0.883
$\emptyset$	0.30	$\rho_{gs}, t m^{-3}$	$7.5 \infty 10^{-5}$	$R_s, m^3 m^{-3}$	69
$C_r, bar^{-1}$	$1.7 \infty 10^{-4}$	$B_g, vol/vol$	$6.5 \infty 10^{-3}$	$\mu_o, cp$	1.34 - 13.4
$S_{wi}$	0.066	$\mu_g, cp$	0.018	$B_o, vol/vol$	1.165

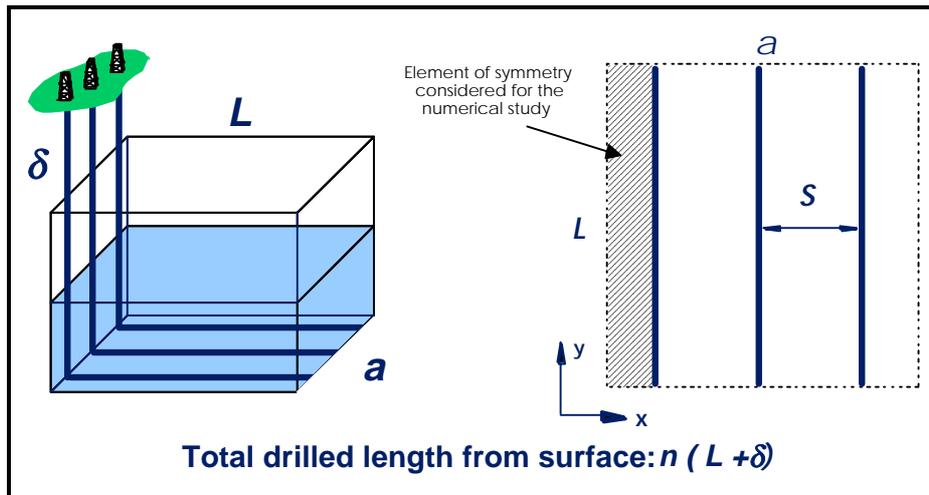


Fig 1—Production of a reservoir with n parallel horizontal wells.

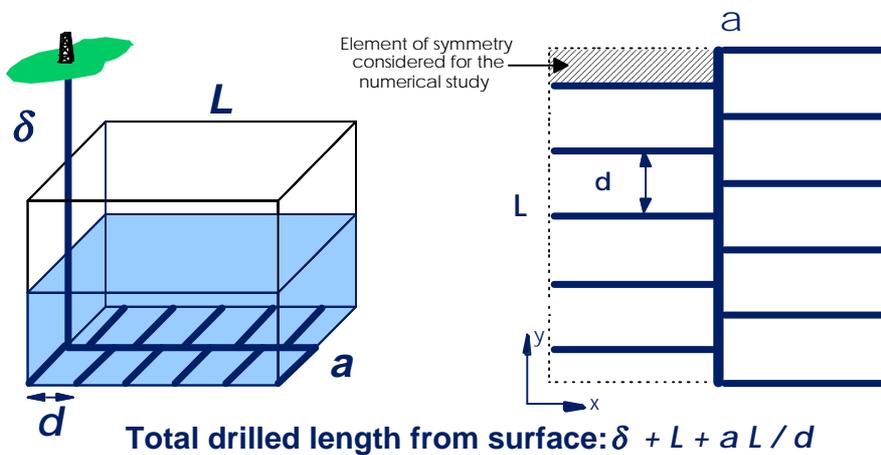


Fig 2—Production of a reservoir with a multilateral well.

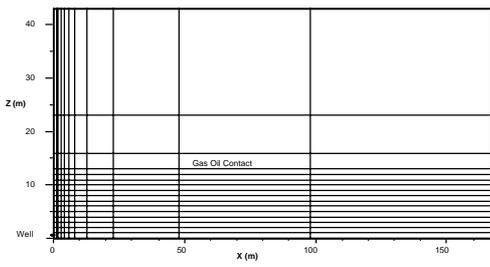


Fig. 3 — 2D-XZ grid used to simulate the performance of the patterns of horizontal wells.

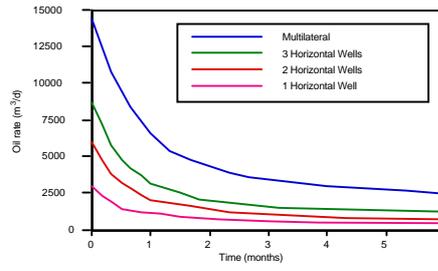


Fig 4—Example of evolution of the liquid well flowrate versus time.  $K_v=K_h=500$  md - Oil viscosity 1.34 cp.

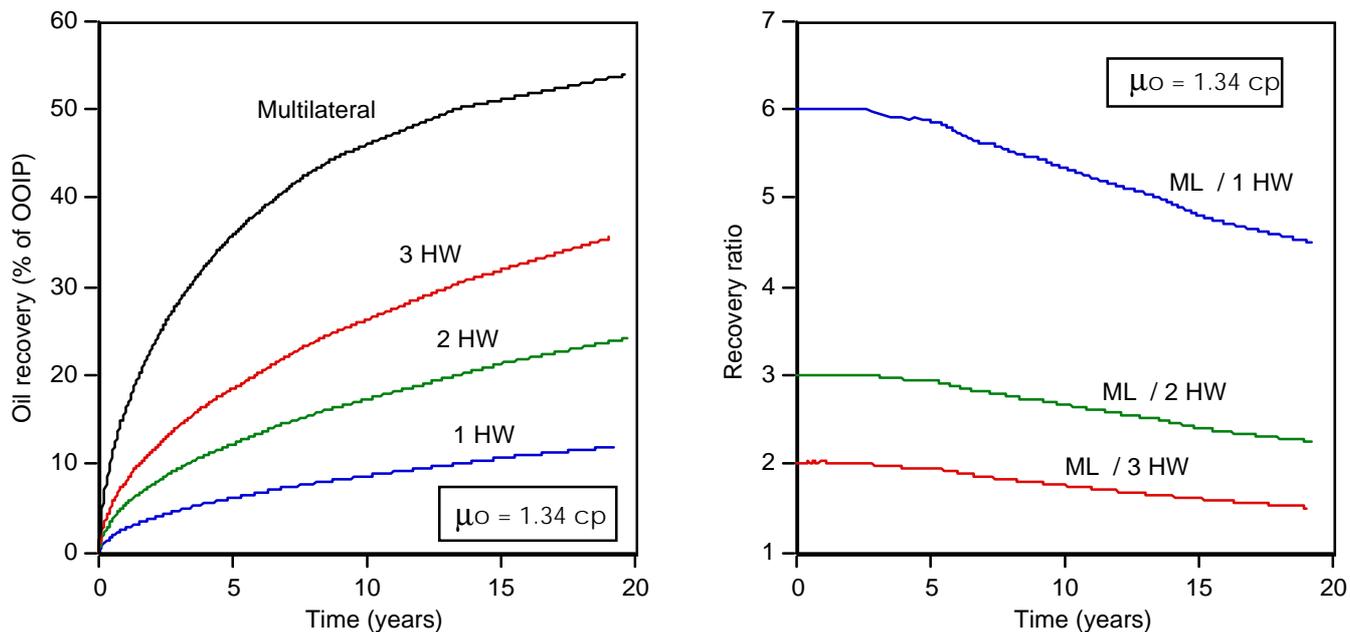


Fig. 5— Oil recovery and recovery ratio of a multilateral well compared to 1, 2 or 3 horizontal wells.  $K_v=K_h=100 \text{ md}$ . Oil viscosity 1.34 cp.

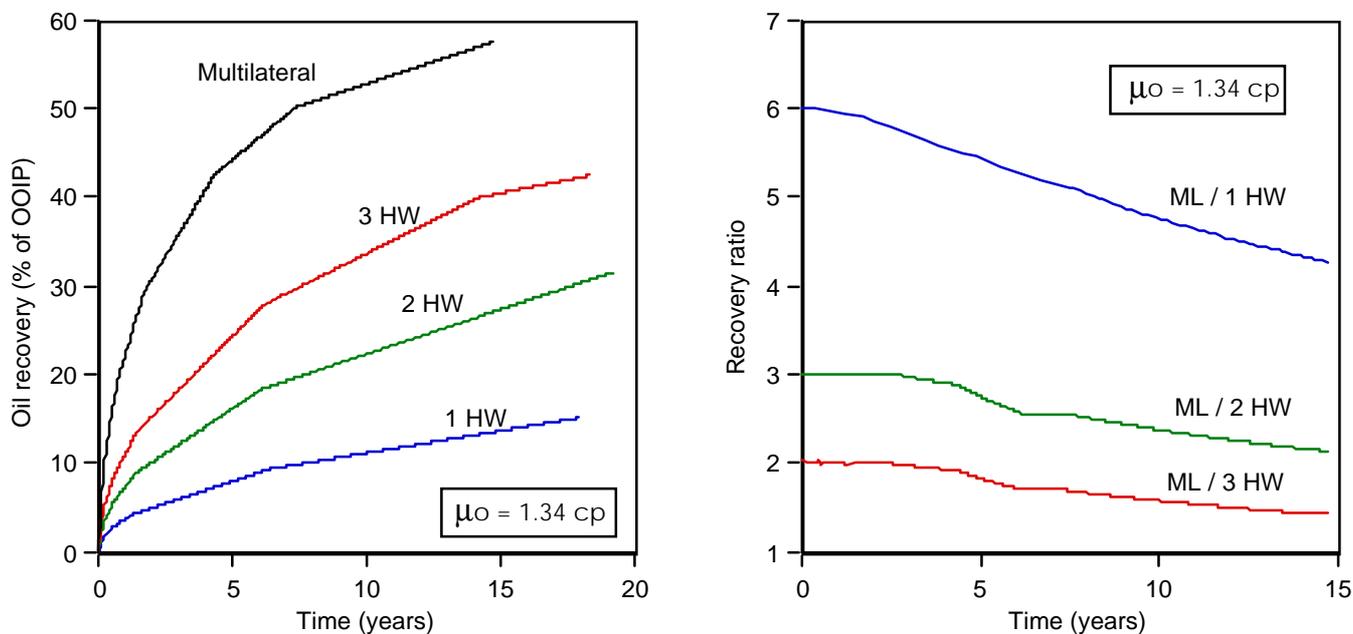


Fig. 6— Oil recovery and recovery ratio of a multilateral well compared to 1, 2 or 3 horizontal wells.  $K_v=K_h=200 \text{ md}$ . Oil viscosity 1.34 cp.

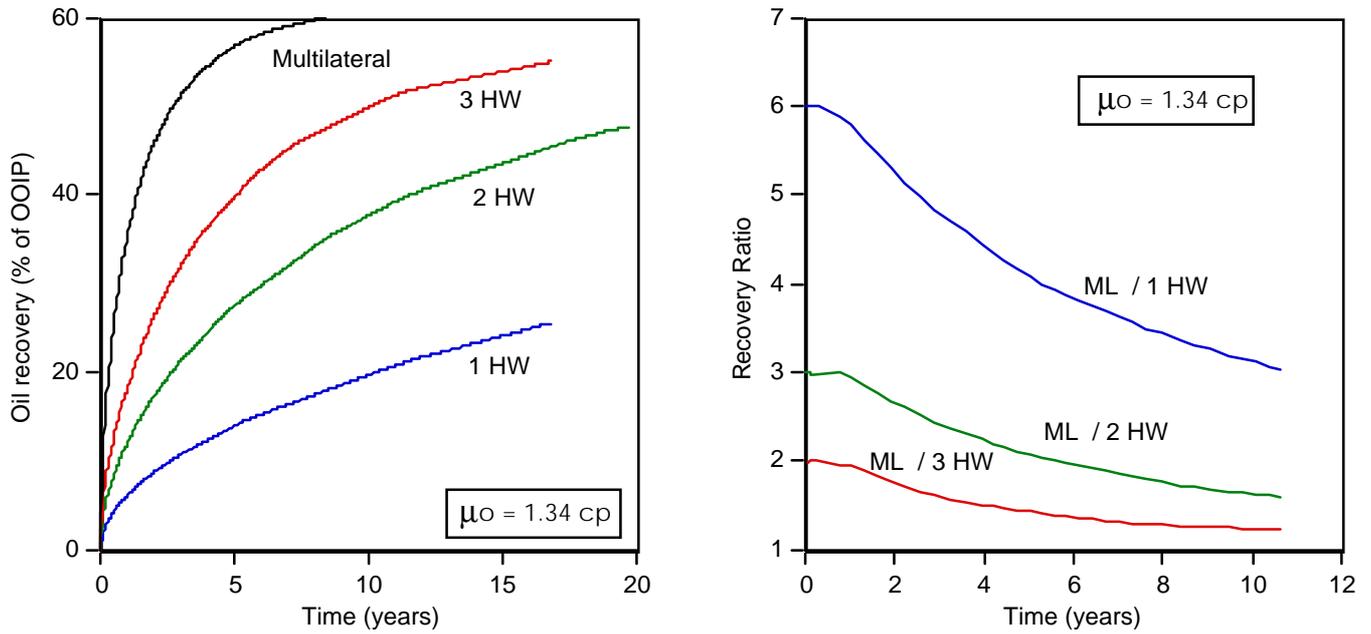


Fig. 7— Oil recovery and recovery ratio of a multilateral well compared to 1, 2 or 3 horizontal wells. Kv=Kh=500 md. Oil viscosity 1.34 cp.

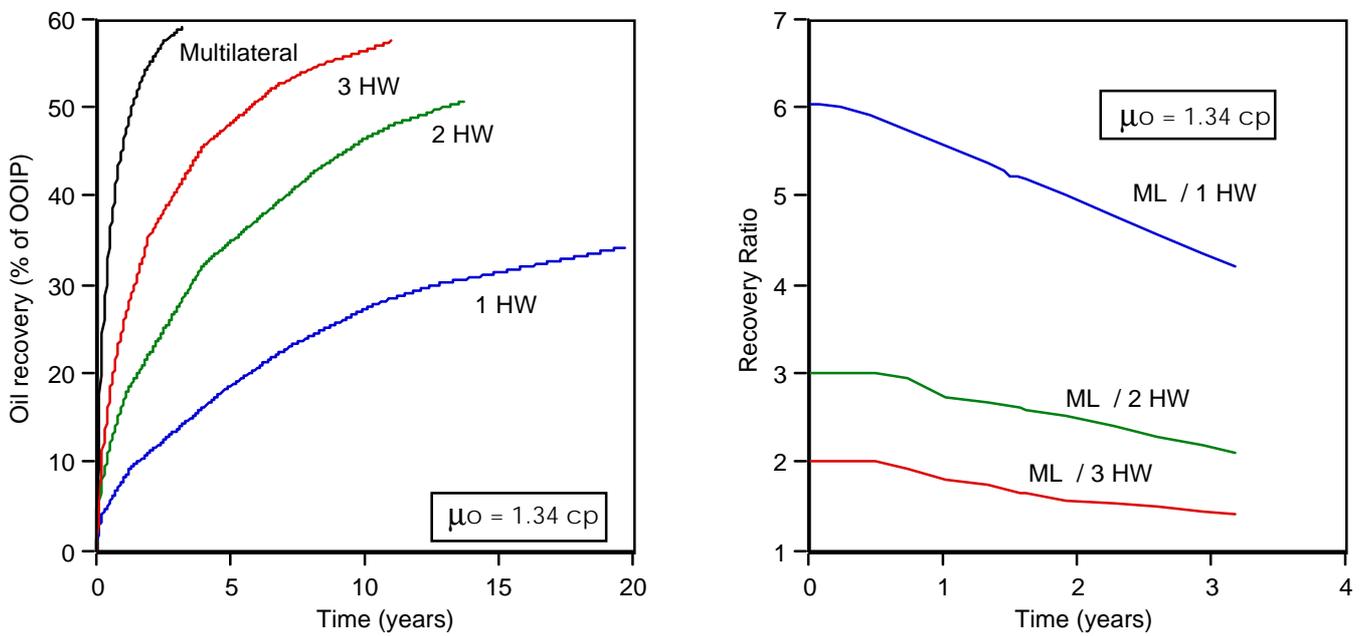


Fig. 8— Oil recovery and recovery ratio of a multilateral well compared to 1, 2 or 3 horizontal wells. Kv=Kh=1000 md. Oil viscosity 1.34 cp.

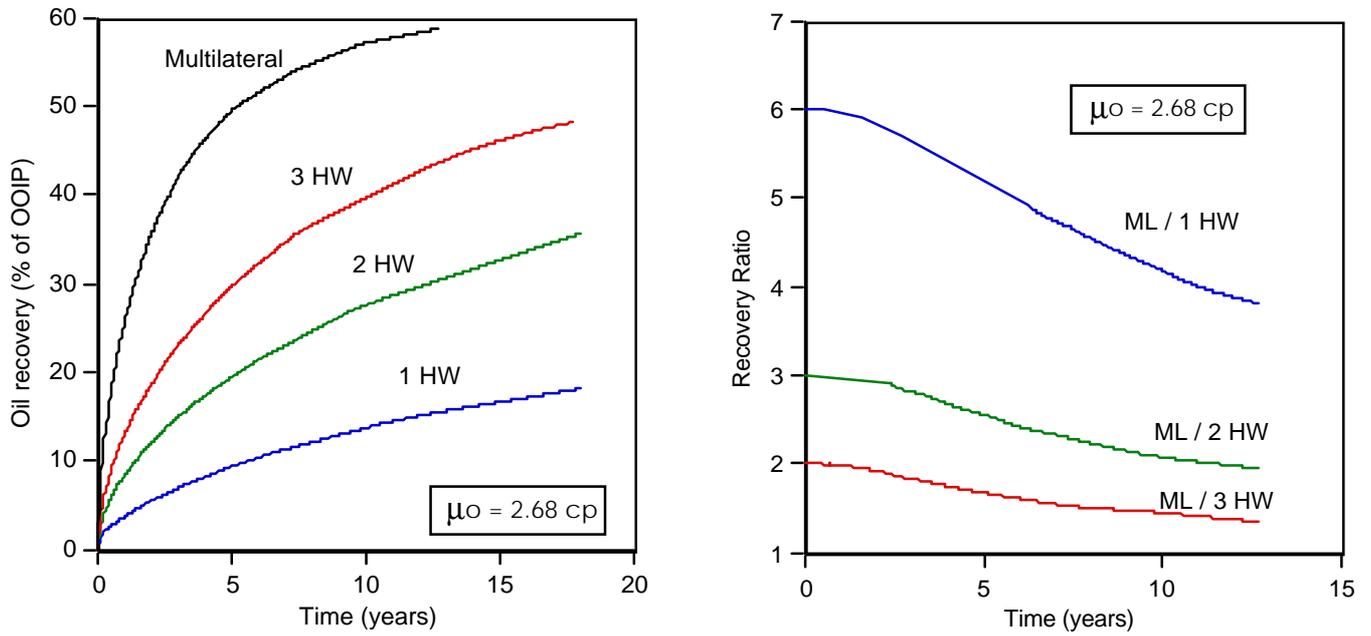


Fig. 9— Oil recovery and recovery ratio of a multilateral well compared to 1, 2 or 3 horizontal wells.  $K_v=K_h=500$  md. Oil viscosity 2.68 cp.

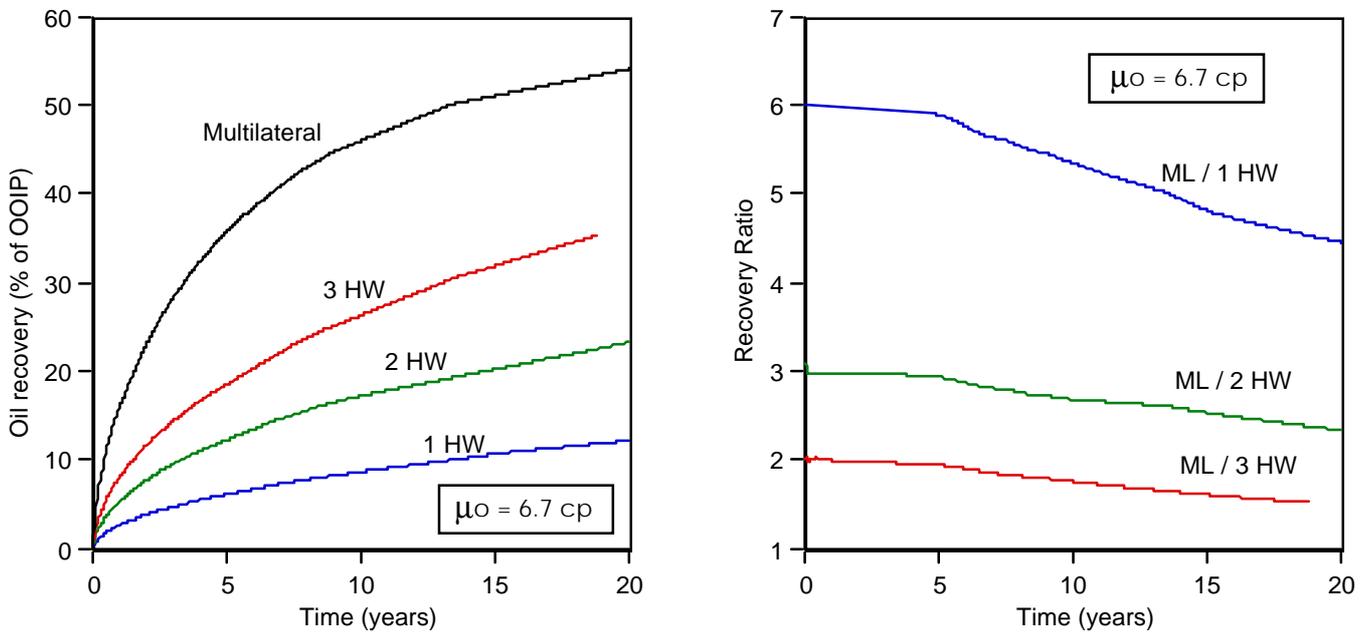


Fig. 10— Oil recovery and recovery ratio of a multilateral well compared to 1, 2 or 3 horizontal wells.  $K_v=K_h=500$  md. Oil viscosity 6.7 cp.

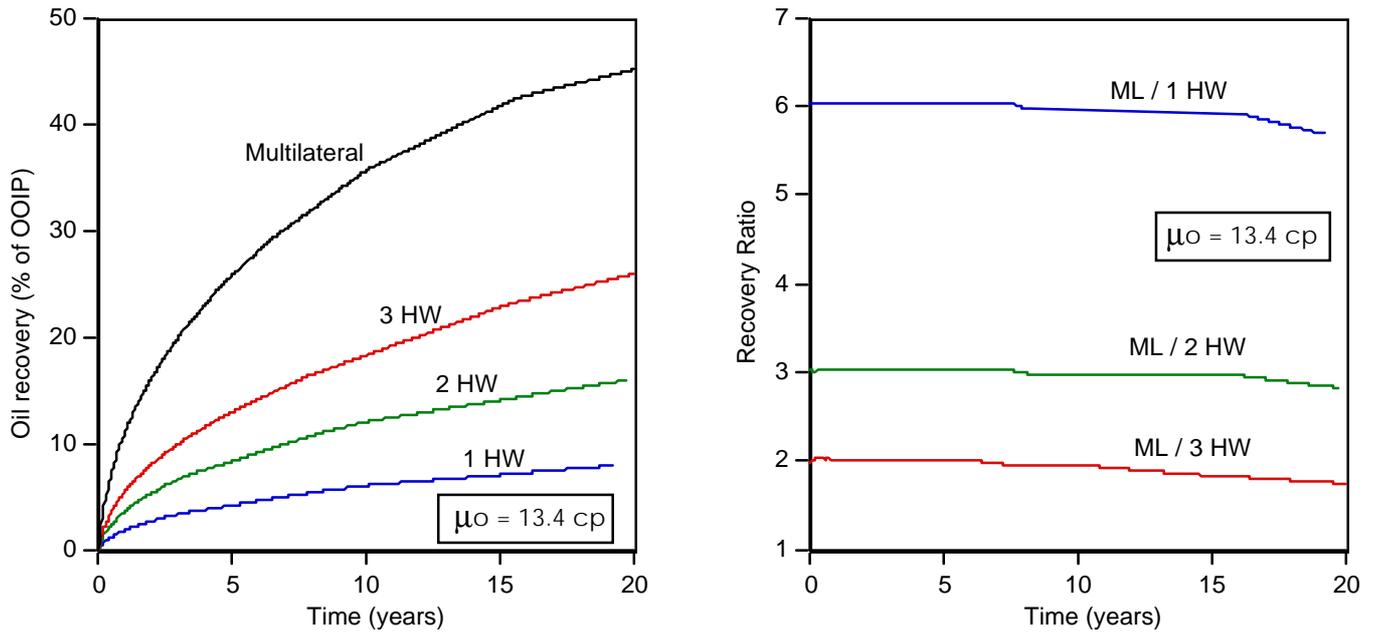


Fig. 11— Oil recovery and recovery ratio of a multilateral well compared to 1, 2 or 3 horizontal wells.  $K_v=K_h=500 \text{ md}$ . Oil viscosity 13.4 cp.

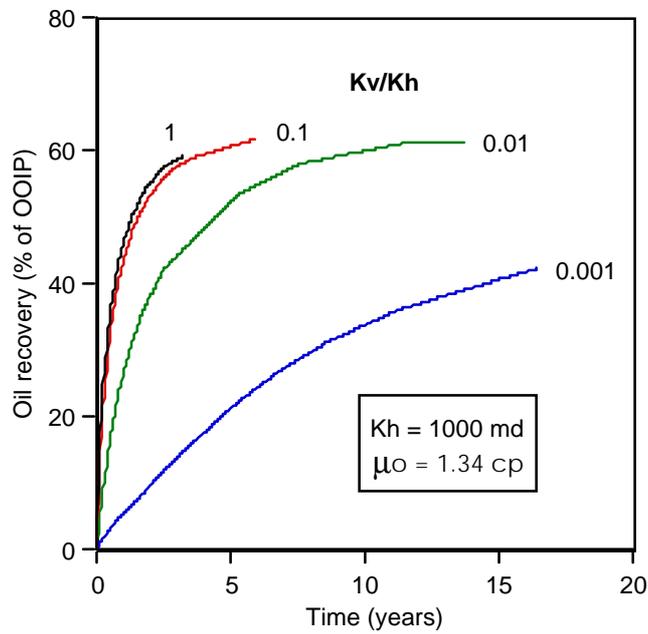


Fig. 12 — Performance of a multilateral well. Sensitivity to the anisotropy of permeability  $K_v/K_h$ .