Increasing oil production through horizontal and multilateral wells

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Abstract

Recent developments in drilling technology allow to drill and case horizontal and multilateral wells. The first goal of such wells is to improve the primary production through increasing the reservoir exposure and accelerating recovery. In coning situations, such as production of oil reservoirs with a bottom aquifer or a gas cap, utilization of multilateral wells will reduce the detrimental coning effect, then leading to reduction in investment and operating costs. In combination with enhanced oil recovery methods or with assisted gravity drainage, these wells can provide means to produce more oil at an economic cost. Applications to actual field cases are provided to illustrate the potential of horizontal and multilateral wells and of their synergy with EOR methods.

1. History

Beginning of the sixties many theoretical studies were conducted in the U.S.S.R. to evaluate the productivity of complex drainage systems. They provided a basis to calculate the productivity indices of horizontal wells, either isolated or in groups. The results of these studies being promising, several horizontal wells were drilled, generally with great difficulties and mitigated production success.

The main difficulties encountered were related to the location of the horizontal section inside the reservoir and to the completion of the drainhole. Little follow up was given to these first experiments. In 1978, Elf and IFP launched a big project named FORHOR. The objective was to assess as completely as possible the technology and to implement several pilot wells. The research project was motivated by the development problem, related to a heavy oil accumulation found by Elf in the Adriatic sea: the Rospo Mare field. The oil in place was huge but the recovery and productivity were poor due to the particular nature of the reservoir rock: a fractured carbonate where vertical fracture distribution was so loose that a vertical well had very little chance to cross a fracture and therefore to be productive. End of 1984 four pilot horizontal wells were completed and put on stream. One of these pilot wells drilled in Rospo Mare was a considerable success, overpassing the predicted performances.
Economically the FORHOR project was also a success. If the cost ratio for the first well was huge, around ten times the cost of a vertical well, the subsequent wells showed that the learning curve was leading to cost ratios less than two. Such a figure was paving the way for a large development of the technology.

In 1985 horizontal drilling and production entered into the industrial age.

After a four years period of acceptance, the boom occurred in 1989. This evolution is typical of a major technological breakthrough. The booming occurs after a period of observation during which the technical and economical validity of the technology needs to be proven. Once this step is reached the number of applications sharply rises, this rise being fed by the successes.

The success of horizontal wells remains true, especially today in times of an overall lessened economic situation in the petroleum industry. The explosive increase in the number of horizontal wells drilled in many countries in the last few years is remarkable. For instance more than 10 000 horizontal wells have been drilled since 1990 in the US and Canada alone. The improvements in drilling technology have led to lateral lengths of several kilometres with a toe placement accuracy within a few metres.

Horizontal wells are becoming the norm rather than the exception where they can present advantages over conventional wells: increased productivity, accelerated recovery and reduced coning tendencies.

However, they are already, and will be more and more, replaced by "advanced wells" in those situations. The term "advanced wells" refers to wells that have complex geometries and architecture. The most common (Fig. 1) are cluster wells (slanted or curved branches drilled with different azimuths from the same vertical hole), stacked wells, multilateral wells (composed of several horizontal arms drilled from the same horizontal drains), re-entry wells and 3D wells.

Advanced wells can be considered as a new tool in the toolbox of reservoir engineers. They introduce a new way of thinking through complex well architecture. Instead of developing new methods to move the oil to the wellbore, the wellbore can now be cost effectively taken to the oil by drilling as many laterals as necessary accessing previously trapped oil. In that respect, advanced wells can be considered by themselves as an IOR (Improved Oil Recovery) technique.

The main advantage to the use of multilateral wells compared to conventional horizontal wells is cost reductions. The cost to drill and case down to the productive reservoir can represent as much as 60% of the total cost of a conventional horizontal well. This is only done once on a multilateral well. The cost reduction using a multilateral well instead of several horizontal wells having the same total length in the pay zone has been proven in fact. However, it is all the more important for fields located offshore, on platforms where the number of slots are limited, or in any situation when drilling pads are required (swamp environments for example).

2. Primary production through horizontal and multilateral wells

The following example of the Pelican Lake field in Canada shows the natural evolution to this new technology with anticipated results.

The Pelican Lake area, 300 km north of Edmonton in the Wabasca region of Alberta, Canada, covers a 230 km^2 area. The primary development focus is the exploitation of oil reserves in the Wabiskaw "A" which is a thin (4-6 m), shallow (409 m true vertical depth TVD), unconsolidated sand with 26% porosity and 3 Darcy average horizontal permeability. The oil has a viscosity between 600 and 1000 mPa.s at reservoir conditions.

Over the period of 1988-1996, CS Resources the operating company at that time drilled 36 horizontal wells in the Wabiskaw formation (Fig. 2) of which 3 openhole and 3 completed multilateral wells (dotted lines indicate wells drilled in 1996). Each of the wells was drilled using a long radius technology with horizontal sections for the main holes ranging from 448 m to more than 1560 m. In 1991, CS Resources was the first in Canada to drill an open hole lateral arm off a horizontal well (11-16). Through the use of chemical tracers, oil production from the end of the lateral was confirmed. In 1993, CS Resources innovated the successful drilling of the first multilateral horizontal well (11-4) utilizing the Lateral Tie-Back System (LTBS^{TM}) jointly developed by Sperry-Sun, CS Resources and IFP. This tool allows the lateral arms to be completed with a liner and maintains liner integrity throughout the entire wellbore network. Reservoir exposure was dramatically and cost effectively increased with almost 2800 m of the formation opened for production. The last multilateral well (IB-3, Fig. 2) has a total length of 5340 m with laterals of 1064, 1048, 1200 and 826 m, respectively.

The relative performance of horizontal wells *vs.* vertical wells, and now of multilaterals *vs.* horizontal wells, is clearly established at Pelican Lake. For this type of reservoir produced under solution gas drive, the longer the horizontal borehole in good quality reservoir, the higher the productivity and reserves with equivalent interwell spacing and drainage areas (Fig. 3).

Figure 4 shows how the costs of drilling per metre have improved over the life of the project. Each of the first eight wells required approximately 9 days to drill. Their average cost was $621 000. The average of the 1996 wells was $500 000. These wells took an average of 7 days to drill with a mean horizontal section of 1500 m. The cost per horizontal metre has dropped from $1240 in 1988 to $340 since 1993. For comparison, the cost of a typical vertical well in this pool is approximately $140 000, or $340 per drilled metre, identical to the cost per metre of the last horizontal wells.

The placement of the wells has evolved since the start of the project. First horizontal wells were drilled in a spoke-wheel fashion (leases 10 and 15 - Fig. 2). Now, multilateral wells with laterals parallel to each other allow a better reservoir management with better possible drainage architecture to sustain production in the future.

3. Coning situations

In coning situations, such as production of oil reservoirs with a bottom aquifer or of an oil pay in the presence of a gas cap, multilateral wells should reduce coning even compared to horizontal wells because they should permit the same rates for larger reservoir exposure and drainage area, and therefore reduced drawdown on the formation.

Numerical studies were performed to confirm the merits of a multilateral well to replace a pattern of parallel horizontal wells to produce an oil reservoir in the presence of an aquifer or of a gas cap.

The basic assumptions for the studies (Fig. 5 and 6) are a same total drilled length from the surface for both production patterns and a homogeneous reservoir. The production of an elementary volume of width a, length L, oil thickness h and depth δ 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 in the case of a bottom aquifer show that the reduction of coning is very important with the multilateral well. For instance, for a 14 m thick oil reservoir located at a depth of 1000 m, the oil recovery with the multilateral well is 1.7 the recovery of its equivalent pattern of horizontal wells. A three times increase in oil recovery is even obtained within a 4000 m deep reservoir indicating that the oil recovery is significantly improved by increasing the number of lateral arms and reducing the drawdown applied to the reservoir (Fig. 7).

Results of the numerical study in the case of a gas cap corroborate that the reduction of gas coning is therefore very important with the multilateral well. Oil recovery is accelerated and final production greatly increased (Fig. 8).

These results confirm the interest of developing and producing an oil field underlaid by an aquifer or overlaid by a gas cap using multilateral wells rather than conventional horizontal wells.

4. Synergy between horizontal wells and enhanced oil recovery

Viscous flooding

Viscous flooding, more specifically polymer flooding, is mainly well suited for layered, heterogeneous reservoirs saturated with oil. One of the main operational difficulties that can be encountered with polymer flooding with a vertical well is the low injectivity of the polymer due to its high viscosity as well as that of the oil, and the degradation of the product because of high shear rate. This usually results in small vertical well spacing and limited economical applications to high permeability reservoirs. Drainage architectures using horizontal wells to inject the polymer and parallel horizontal wells to produce the displaced oil would improve pattern confinement and injectivity/productivity performance. Thus they would lead to enlarged spacing with better economics. Well planned, the synergy between viscous flooding and specific drainage patterns can provide a good opportunity to pursue the development of solution gas drive reservoirs of not too bad permeability, as the Pelican Lake field for instance.

Thermal flooding

Thermal flooding like viscous flooding can take advantage of horizontal wells to inject hot fluids with rates several times higher than the conventional wells. Improved injectivity has also the benefit of limited thermal losses between the surface and the reservoir with a corresponding increased fraction of available energy supply to the formation. Lower pressure gradients would also reduce sand production that is a crucial aspect in thermal processes as already pointed out.

Successful application of steamdrive followed by gravity drainage has been performed by Sceptre in its Tangleflags field, Canada, using horizontal producers and vertical injectors. At the present time, Amoco, also in Canada, is testing steamdrive between parallel horizontal wells in its Primrose field.

Assisted gravity drainage

Assisted gravity drainage (AGD) combined with horizontal well technology is certainly the most famous concept developed in reservoir engineering in the last decade. Gravity drainage in itself is not new.

Steam Assisted Gravity Drainage

The concept of AGD was first suggested and studied by Butler as a special form of steamflooding. Butler proposed to use steam, thus the name Steam Assisted Gravity Drainage or SAGD, to assist the movement of oil to a production well by means of only gravity forces. The geometry of the SAGD, in its general form, is quite simple. Steam is injected through a horizontal well low in the reservoir to form a steam chamber. As steam is introduced, it flows through the sand to the interface with cold oil

where it condenses. The liberated heat heats the oil near the interface and allows it to drain by gravity to a second horizontal well placed below the first one.
Screening criteria for the application of steam injection in heavy oil reservoirs using horizontal wells have been derived recently from a numerical study. The goal of this study performed in 2D vertical cross sections (normal to the horizontal wellbores) was to compare the respective merits of steamflooding and SAGD assuming homogeneous reservoir of same pay thickness, sand permeability, oil viscosity. Possible presence of a bottom aquifer was accounted for. Results of this study indicated that these various parameters can be ranked according to their decreasing influence while choosing between the two processes. Undoubtedly, the most discriminating parameter is the presence of a bottom aquifer with high enough thickness as it is very detrimental to steamflooding, steam flowing rapidly to the aquifer. Concerning SAGD, the most limiting parameter is the reservoir permeability. When the value of permeability is lower than about two darcies, the steam chamber cannot develop quickly enough in the reservoir to ensure an economical recovery. Generally speaking, the parametric study indicated that SAGD has a wider domain of application than steamflooding. It must be noted that a final screening study in 3D should be performed to appropriately choose between steam flooding and SAGD.

The successful application of the SAGD process at the UTF site convinced operators of the huge potential of the process. SAGD is at the present time of primary interest to Canadian operators.

In 1995, CS Resources initiated the first application of the SAGD technology for wells drilled from surface in the East Senlac field, Saskatchewan, Canada. In the 3 000 cp oil viscosity, 750 m deep reservoir, three pairs of 500 m long horizontal wells, 5 to 7 m apart, have been drilled with a spacing of 135 m between the well pairs (Fig. 9). The various phases of the project included the reservoir description and characterization using a 3D seismic inversion, location of the wells in the unconsolidated sand formation, drilling and completion of the wells, conceptual facility design including steam generation and production treatment, production lifting design and well monitoring, integrated modelling of artificial lift, twin well start up and reservoir process.
The early operating experience and performance of the well pairs were encouraging. Despite the use of wire wrapped screens, sand influxes in the horizontal wells were experienced, and limited the production. A fourth well pair completed with slotted liners have been drilled recently. Sand production is very limited and results match the numerical predictions. Steam injection and oil production rates for this well pair are shown on Figure 10.

Miscible flooding
Miscible flooding of oil reservoirs with advanced wells looks promising through the use of advanced AGD processes. Following the development of the SAGD process, Butler and co-workers evaluated the injection of vaporized hydrocarbon solvents (ethane, propane and butane) instead of steam to recover heavy oil and bitumen. In the so-called VAPEX process (vapor extraction), the oil mobility is no longer assured by heat transfer but is due to viscosity reduction by solvent dilution into the oil. The problem is that oil viscosity reduction by the dilution mechanism is much slower than by heat diffusion. The injection, as a vapour, of a heavier hydrocarbon with a boiling point well above reservoir temperature can circumvent this problem by combining the heat and dilution effects. A possible additional benefit of hydrocarbon solvent can be the in situ upgrading of the produced oil by asphaltene precipitation and deposition in the reservoir.

Conclusion

Usually oil is found in new places with old ideas. But also oil can be found in old places with new ideas.

Today, highly advanced drilling systems with real-time measurements create complex downhole well architectures, taking the well and its branches to the hydrocarbons, rather than hoping for the hydrocarbons to find the well.

In many cases, smart wells drilled at reasonable cost will contribute to an increase in oil recovery rate and in oil production in primary recovery as well as in enhanced oil recovery.

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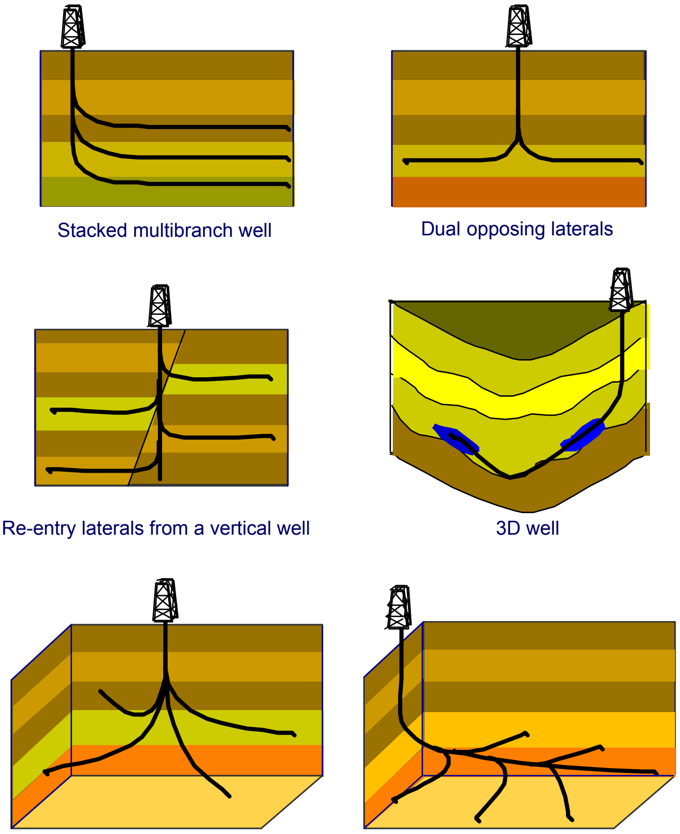

Stacked multibranch well

Dual opposing laterals

Re-entry laterals from a vertical well

3D well

Cluster multibranch well

Multidrain or multilateral well

Fig. 1—Various types of advanced wells.

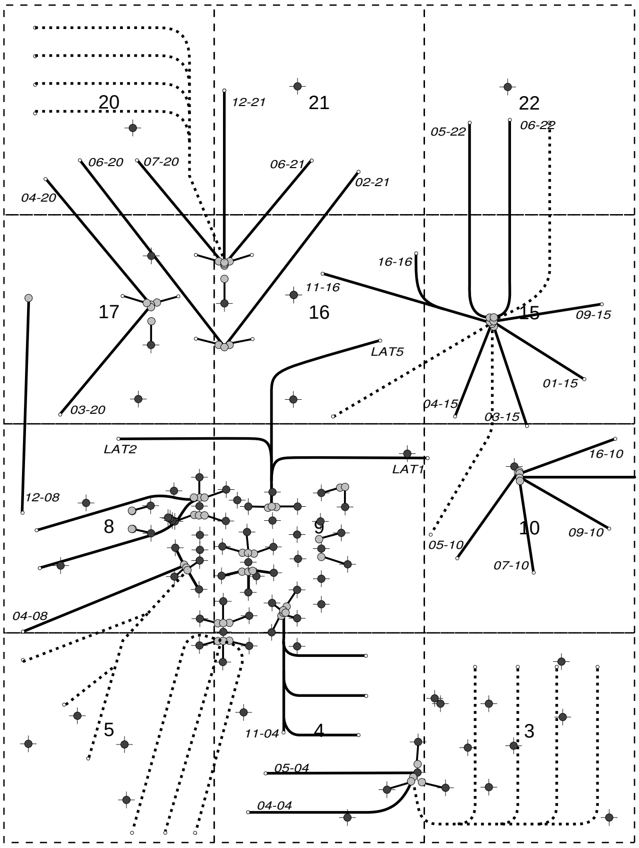


Fig. 2—Pelican Lake field area.

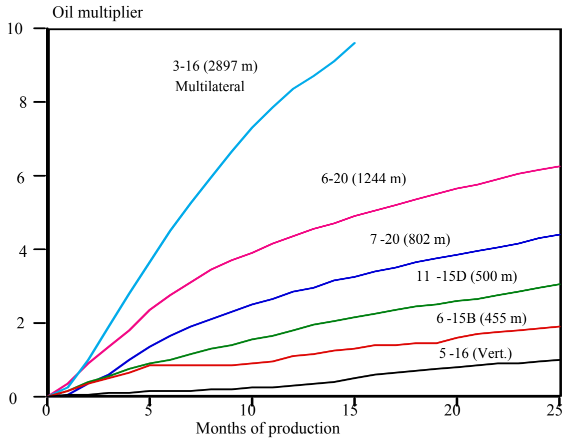


Fig. 3—Pelican Lake field: Performance of horizontal wells
(Oil production multiplier over vertical wells).

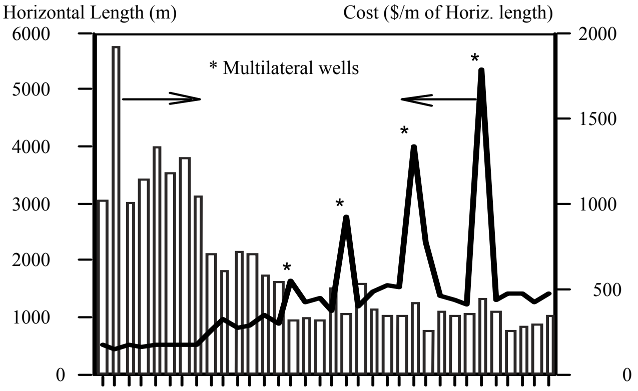
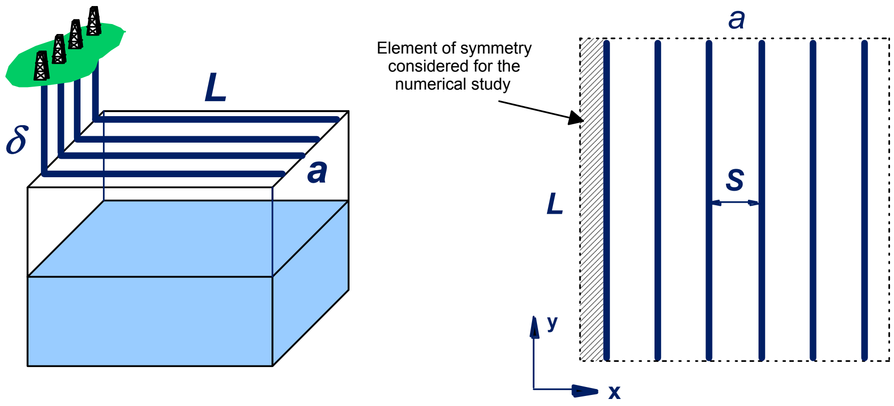
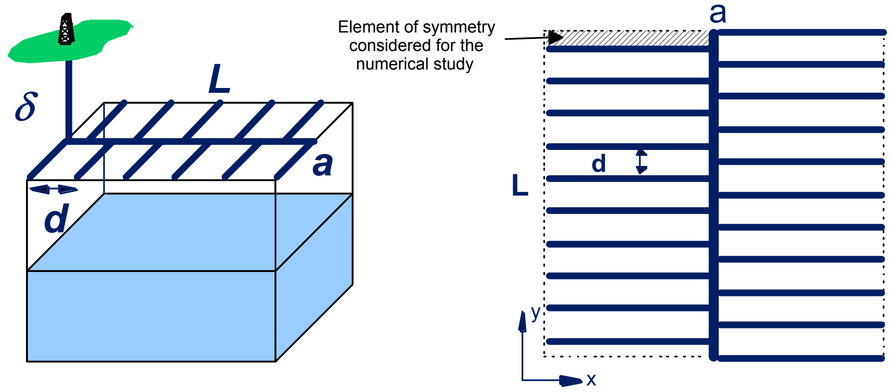


Fig. 4— Pelican Lake field: Capital expenditure per horizontal length.



Total drilled length from surface: $n\,(L + \delta)$

Fig 5—Production of a reservoir with n parallel horizontal wells (water coning situation).



Total drilled length from surface: $\delta + L\,(1 + a/d)$

Fig 6—Production of a reservoir with a multilateral well (water coning situation).

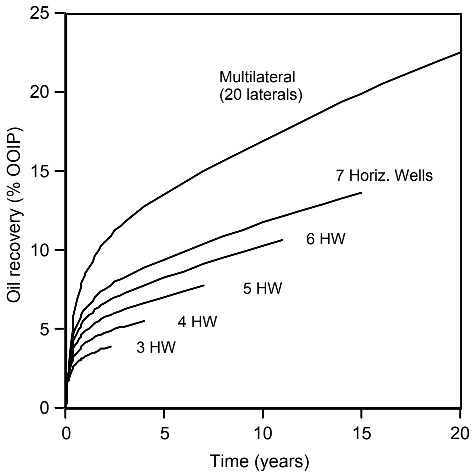


Fig. 7—Oil recovery of a multilateral well in a water coning situation compared to that of *n* parallel horizontal wells (*n*= 3 to 7). Same total fluid flowrate (2000 m^3/d). Kv=Kh=6000 md. Oil viscosity 600 cp

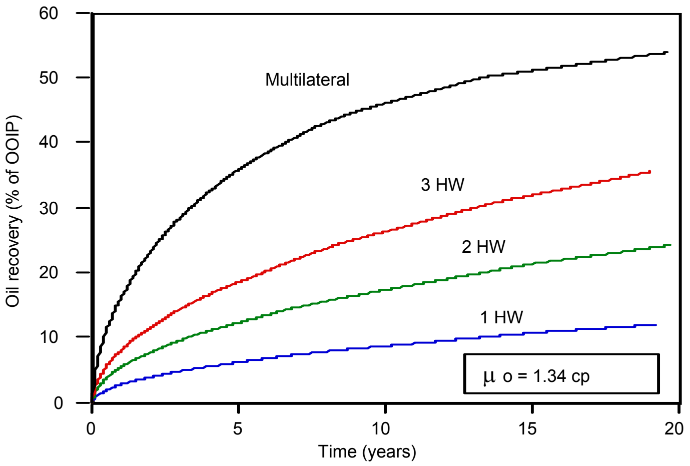


Fig. 8— Oil recovery of a multilateral well (10 laterals) compared to that of 1, 2 or 3 horizontal wells (gas coning situation). Flowrates monitored to avoid gas breakthrough. Kv=Kh=100 md. Oil viscosity 1.34 cp.

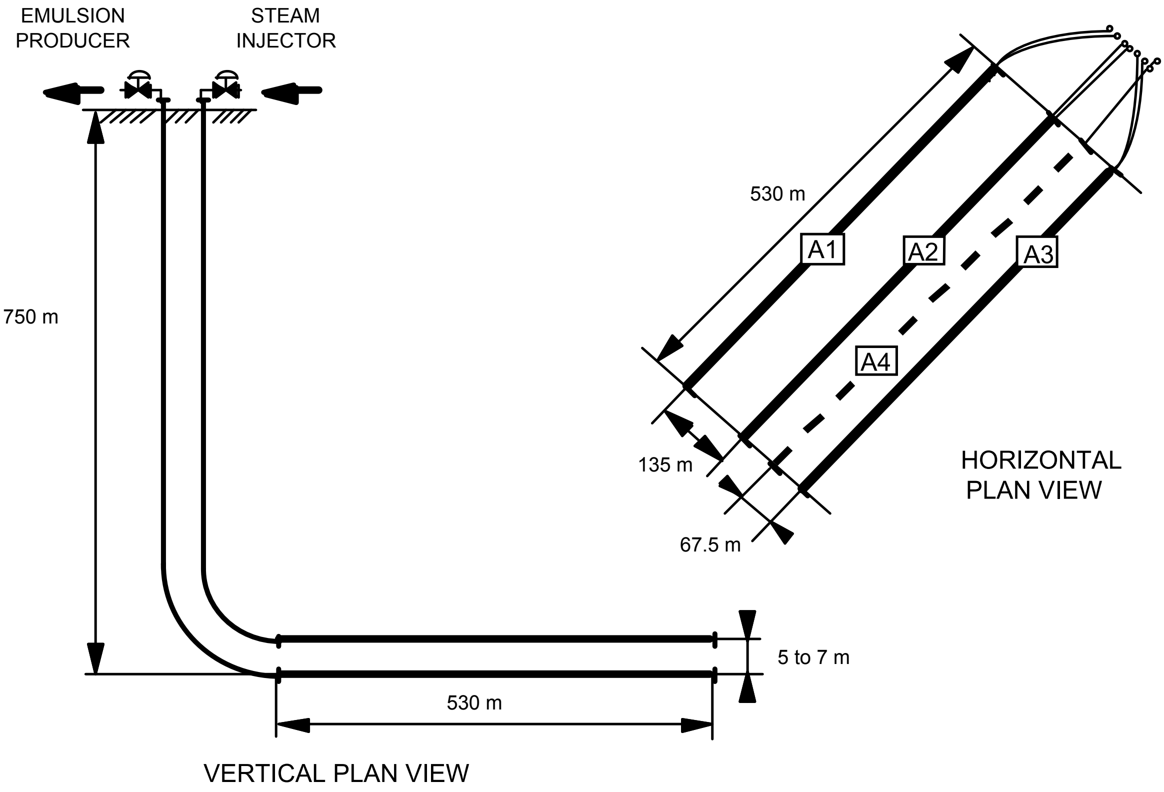


Fig. 9 – East Senlac SAGD well pairs configuration.

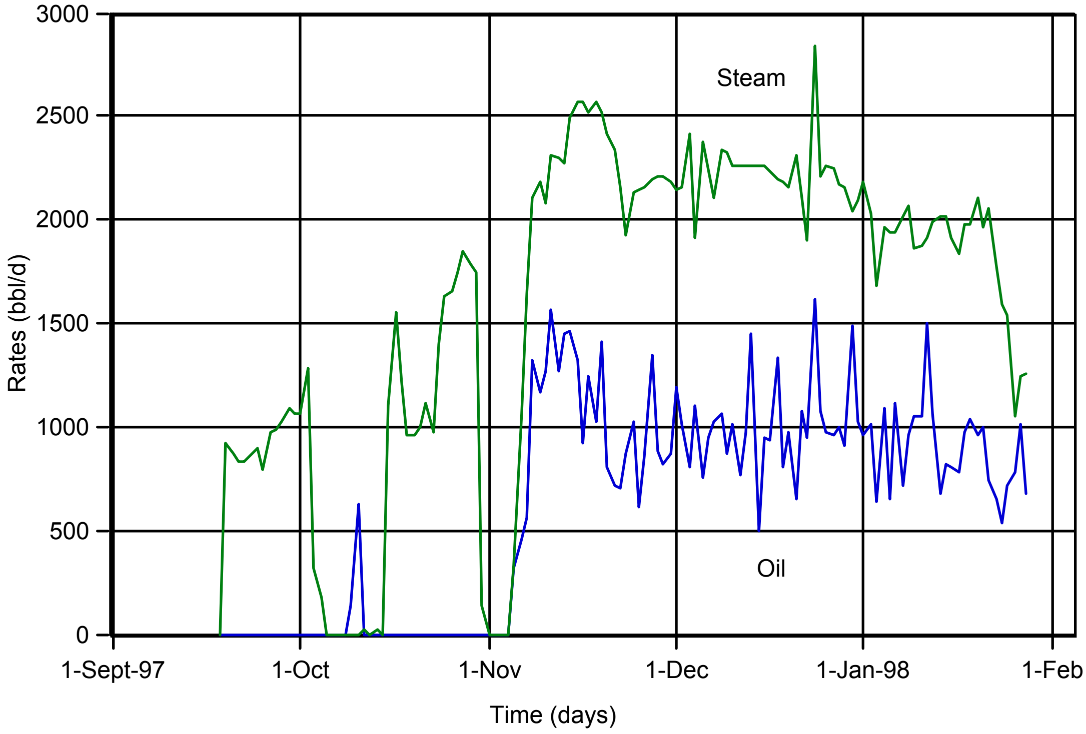


Fig. 10 – East Senlac field. Performance of the SAGD A4 well pair.