

# COMPLEX WELL ARCHITECTURE, IOR AND HEAVY OILS

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**ABSTRACT.** In the last few years, new developments in drilling technology have allowed drilling and completion of multiple lateral wellbores from a single, horizontal or vertical, primary wellbore. Initially, multiple laterals were drilled for primary production, increasing the reservoir exposure and accelerating recovery. Today, these wells are paving the way to new complex well architecture. In combination with Improved Oil Recovery (IOR) or Assisted Gravity Drainage (AGD) processes, they can provide economical means to produce a part of the huge reserves of heavy or bituminous oils found all over the world.

The general concerns when implementing IOR or AGD processes are: the reservoir conformance (pattern confinement), the sweep efficiencies (areal and vertical) and problems of injectivity and/or productivity. This paper presents the consequences of using new technologies to gain access to a reservoir in conjunction with well established recovery mechanisms and mobility enhancements to produce low mobility hydrocarbons. Synergy between new well architectures and various processes (IOR or AGD) to improve recovery is presented in detail. Applications to actual field cases are provided to illustrate the potential of this synergy. Finally, specific problems related to multilateral wells are outlined.

## INTRODUCTION

The ever-growing interest in heavy oil resources can be easily explained by their size, potential as a future world energy supply, and because geographically they have a strategic distribution in comparison with the distribution of conventional light and medium world oil reserves. World reserves of heavy [ $^{\circ}\text{API} < 20$  ( $> 934 \text{ kg/m}^3$ )] and extra-heavy [ $^{\circ}\text{API} < 10$  ( $> 1000 \text{ kg/m}^3$ ),  $\mu < 10^4 \text{ mPa.s}$ ] crude oils and natural bitumen [ $^{\circ}\text{API} < 10$  ( $> 1000 \text{ kg/m}^3$ ),  $\mu > 10^4 \text{ mPa.s}$ ] are estimated [1] to about 100 Giga-tonnes (GT). Major reserves are located in Canada, Venezuela and Former Soviet Union (Fig. 1). Canada's natural bitumen reserves are mainly in the Athabasca region. The FSU

natural bitumen resources are concentrated in the Volga-Ural and East Siberia. Venezuela has most of its heavy oil and bitumen in the Orinoco Belt. The cumulative production as of today is close to only 7 GT (Fig. 1), with a major part produced by Venezuela and USA. While these reserves are approximately equal to the identified reserves of conventional crude oil accredited to the Middle East [2] (96 GT), their contribution to the world supply is low, less than 5%. Until recently, this could be explained by the fact that unconventional resources such as heavy oils and bitumen were too expensive to recover at adequate rates of production using conventional vertical wells.

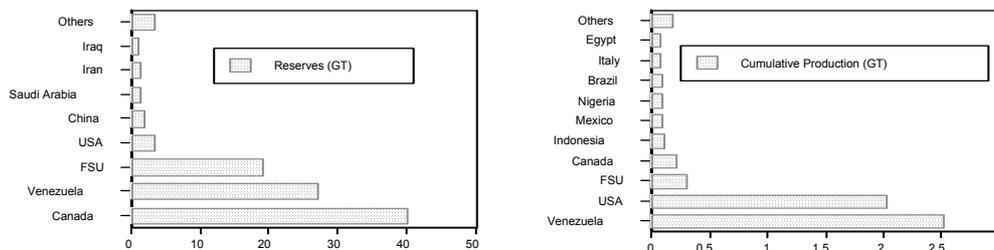


Fig. 1: Estimated reserves and cumulative production of heavy and extraheavy oils and natural bitumen (After Tedeschi<sup>1</sup>)

In the 70s', theoretical studies initiated by IFP and Elf concluded that horizontal wells could be a viable alternative to produce heavy oil reserves. A challenging application of horizontal drilling technology was the economic recovery of a portion of the 160 million m<sup>3</sup> of the 300 mPa.s oil from the Rospo Mare fractured karstic field located in the Adriatic Sea. Following this successful application, more and more companies began to drill horizontal wells which allowed development of fields uneconomically producible with conventional wells. 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 10000 horizontal wells have been drilled since 1990 [3] in the US and Canada alone. The improvements in drilling technology have led to lateral lengths in the range of a kilometre with a toe placement accuracy within a few metres.

**ADVANCED WELL TECHNOLOGY**

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 [4]. The most common (Fig. 2) 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 [5]. They introduce a new way of thinking through complex well architecture. Instead of developing new methods to move the oil to the well-bore, 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.

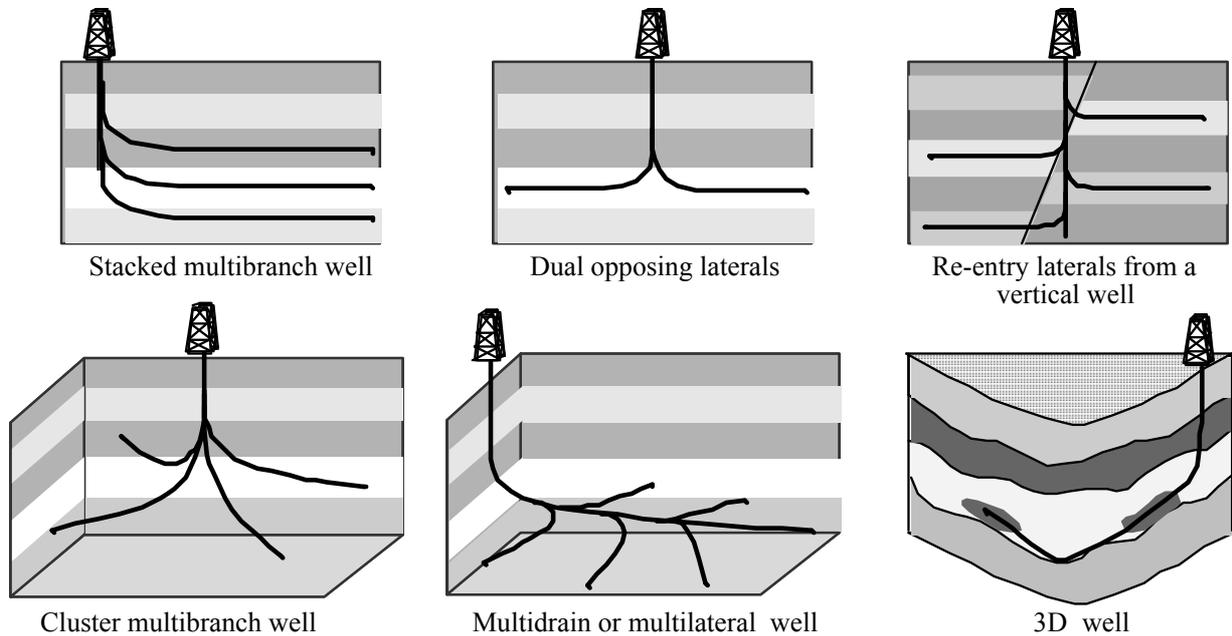


Figure 2: Various types of advanced wells

The main advantage to the use of multi-lateral 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 is ever a matter of fact. However, it is all the more important for fields located off-shore, on platforms where the number of slots are limited, or in any situation when drilling pads are required (swamp environments for ex.).

Many "barefoot" multilateral wells have been drilled in the past few years [3]. The tendency now is to case both the main bore and lateral to develop pure multilateral completions in order to meet operators requirements: branch junction integrity, re-entry, isolation and selectivity. This completion technology is relatively new. Several companies have designed systems that maintain casing integrity between the main bore and each lateral bore (Table 1). At the same time, proven systems are also proposed for re-entry and selective access to carry out operations into lateral wellbores [7] such as logging, undertaking cleaning and stimulation work, opening and closing downhole valves, plugging and/or isolating the lateral bore.

One of the main hopes for complex well architectures is their use to improve reservoir management. Because reservoir management is obviously more than just a question of producing as much as possible from a single well, the actual challenge to the technology of advanced wells is integration of drilling and completion methods that will allow operators to perform future interventions while maintaining control of individual sections and the ability in real time to monitor or actuate production in each lateral. Such operations are essential to evaluate the performance of each component of the well and eliminate or reduce detrimental gas/water production. If successful, they would significantly reduce operating expenditures and optimise production rates, recovery and well life. Preferably, monitoring and control of production would have to be operated remotely from the surface [8].

Table 1: Companies offering multilateral drilling and completion systems [6].

Company	Multi Lateral System
Baker Hugues	Seal Root System™
Halliburton Energy Services	Multilateral System 3000™
Schlumberger - Anadrill	Re-entry and Production Improvement Drilling (RAPID™) Multidrain
Sperry-Sun Drilling Services	LTBS™ RMLS™

### THEORETICAL PERFORMANCE OF ADVANCED WELLS

As far as reservoir engineering is concerned, it is not so easy to evaluate the performance of advanced wells, especially multilaterals, except in some simple cases. Theoretical productivity of multilateral wells have been derived analytically [9-11] or numerically [12] assuming reservoirs with homogeneous properties. Conclusions of these studies assuming a fixed total producing length are that usually a pair of laterals that extends in opposite directions will provide the maximum productivity, but that the productivity of a spoke-wheel multilateral system can be significantly enhanced by increasing the distance between laterals, i.e. by increasing the offset of laterals to the center of the system. These conclusions emphasize that multilateral systems may exhibit interferences as long as the laterals are too close to each other.

Data are not readily available to analyze the performance of existing multilateral wells due to their small number. However, such analysis has been made for several hundreds of horizontal wells [13-16]. For instance, Beliveau [16] found out that the productivity improvement factor of horizontal wells compared to vertical ones approximately follows a log-normal distribution. He explained this result by the fact that most reservoir parameters are log-normally distributed around their mean value. Therefore, the performance of horizontal wells essentially reflects the presence of geologic heterogeneities, indicating that in many cases portions of the wells may have been drilled to no avail. Delamaide *et al.* [5] confirmed the observations made by Beliveau using a statistical approach randomly

generating heterogeneous reservoirs and thousands of locations for various types of wells (horizontal, trilaterals, multidrains) in each reservoir. Doing so they provided a simple method for a given reservoir to assess the influence of heterogeneities on productivity for various types of wells and compare their respective merits. A result of Delamaide's *et al.* study is that, in hetero-geneous reservoirs, trilaterals (120° cluster wells) behave better than horizontal wells or multidrains of same total length in the reservoir.

What has come achievable with multilaterals is the capacity to travel within the formation to direct the branches toward the best places and avoid the others provided that these places can be located. Therefore, most available data from geological studies, formation evaluation, 3D seismic and production must be put together to give the best reservoir characterization that is crucial to know where to place the wells. Moreover, as indicated, the influence of heterogeneities have to be taken into account when comparing the benefits of various well architectures. In that respect, advanced wells in heterogeneous reservoirs correspond to a new challenge for three dimensional numerical modelling due to the complexity generated both by the necessary requirement of adapting grids to the reservoir heterogeneities and by the complex well trajectories. Simple and fast methods, like the one presented by Delamaide *et al.* [5] have to be developed in order to prevent excessive computation time with conventional numerical models when dealing with the choice of well type according to reservoir description, fluids in place, etc., and at the same time help in the evaluation of the "geological" risks involved in the drilling of each type of well, *i. e.*, the chance that the well does not deliver what it was expected to.

#### **MAIN ENGINEERING CONCERNS WHEN DEALING WITH HEAVY OILS OR BITUMEN**

The production and recovery of heavy oils or natural bitumen is difficult due to their high viscosity at reservoir conditions and because of their much larger content of asphaltenes, a nondistillable residual material, compared to conventional oils. The consequence of high initial viscosity of heavy oils and bitumen is their low to extremely low mobility (expressed by the

ratio  $k/\mu$ , where  $k$  is the effective permeability and  $\mu$  the oil viscosity) or ability to flow naturally through the porous medium at initial reservoir conditions. Low fluid mobility implies:

- Low productivity and flowrates of conventional wells on primary production.
- Low injectivity due to pressure gradient limitation in shallow reservoirs as usually experienced for heavy oil pools. Therefore, difficulty to assist the recovery by injecting fluids into the reservoir to displace the fluids in place to production wells or to bring them energy to lower their viscosity.
- Low flood efficiency. Differences in viscosity and density between injected fluids and reservoir fluids lead generally to viscous and gravitational instabilities (override), fingering, bypassing, and thus to inefficient displacement with poor areal and vertical sweep. Large scale lithological heterogeneities will increase these phenomena by developing preferential flow paths.

For these many reasons, production and recovery of heavy oils and bitumen are generally uneconomic with conventional wells.

Another characteristic of heavy oils and bitumen is that they assure the cohesion of sand grains in unconsolidated sandstones (>30% porosity). In such reservoirs, permitting sand to enter the wellbore along with fluids has experienced significant improvement in cold heavy oil production by factors of 10 and more [17]. Production mechanisms are supposed to be enhanced drainage radius, grain movement, gas bubble expansion and continuous pore deblocking by the formation of the so called "wormholes". This process is limited to vertical wells where sand flushes can be performed without major equipment when sanding occurs.

It is important to note that during cold production, sand is produced to the surface due to drag forces, grains being squeezed in the heavy oil. It is no more the case if the viscosity of the oil is reduced by any means, for instance heat adjunction or solvent dilution. In such cases, risk of sand plugging is real and has been experienced in many fields.

#### **NEW OR REVISITED PROCESSES PERMITTED BY NEW WELL ARCHITECTURES**

Advantages of advanced wells, primarily multilateral wells, over conventional wells and even compared to single horizontal wells are multiple. As already pointed out, the first one is cost savings in drilling only once non reservoir sections before the entrance in the reservoir.

Among other advantages are:

- Their larger exposure to the reservoir for a given total drilled length. This implies increased productivity and injectivity, and lower flow velocity in the surroundings of each borehole.
- Ability from a main bore to place several boreholes at the bottom of the reservoir to take maximum advantage of gravity forces.
- Reversely, ability to place several boreholes at the top of the reservoir to have the maximum stand-off to a bottom aquifer.
- Finally, ability to develop confined patterns combining advanced wells with essentially horizontal wells to form new drainage architectures.

These advantages offered by new well architectures are detailed in the following sections and their impact is shown on new or revisited production processes.

**Primary production** assisted by solution gas drive of thin pays saturated with heavy oil has been one of the main targets of horizontal wells since their advent. Where these wells have proven to be profitable, there is no doubt that multilateral wells with their larger exposure to the reservoir will behave even better. The following example of the Pelican Lake field operated by CS Resources 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<sup>2</sup> 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.

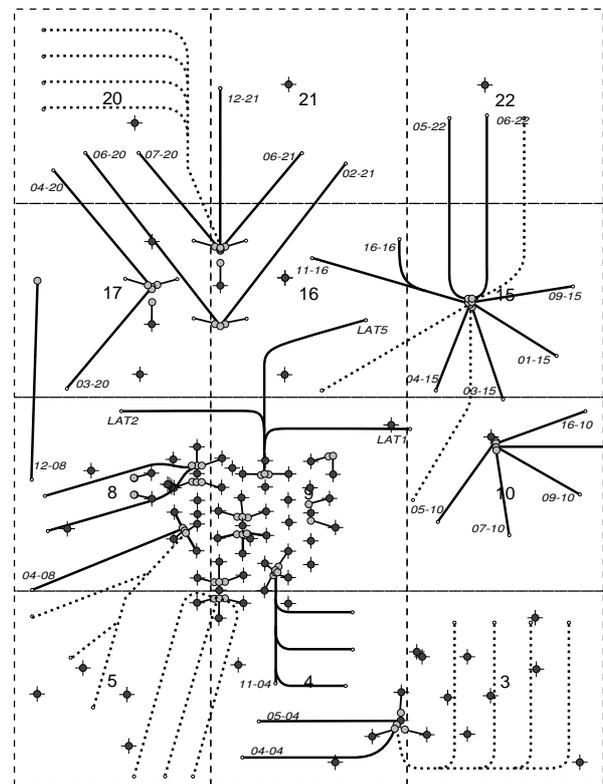


Fig. 3. Pelican Lake field area

Over the period of 1988 to 1996, CS Resources drilled 36 horizontal wells in the Wabiskaw formation (Fig. 3) 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™) 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 2,800 metres of the formation opened for production. The last multilateral well (1B3 - Fig. 3, right bottom corner) has a total length of 5340 m with laterals of 1064, 1048, 1200 and 826 m respectively.

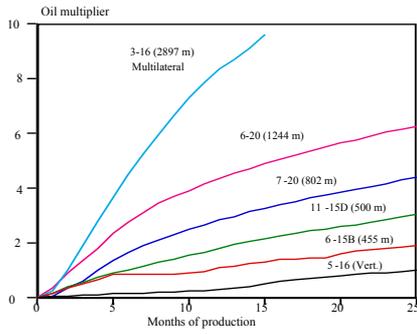


Fig. 4. Pelican Lake - Horiz. wells performance (Oil production multiplier over vertical wells)

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 (Fig. 4), the higher the productivity and reserves with equivalent interwell spacing and drainage areas.

Figure 5 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.

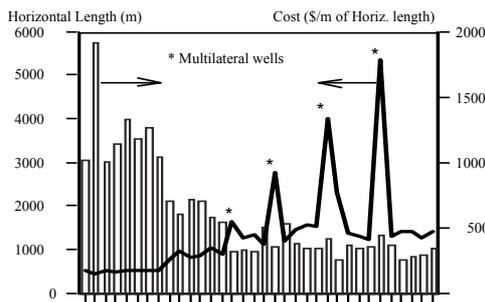


Fig. 5. Pelican Lake - Capital expenditure per horizontal length

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. 3). 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.

*In coning situations*, such as production of heavy oil reservoirs with a bottom aquifer, 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. This is illustrated considering the development of a basic area of width  $a$  and length  $L$ . Using a multilateral well (Fig. 6) placed at the top of the pay zone will require a total drilled length equal to  $L(1+a/d) + \delta$ ,  $\delta$  being the length drilled to reach the reservoir.

If the same basic area is produced from  $n$  equidistant parallel horizontal wells (Fig. 7), the total drilled length will be  $n(L+\delta)$ . To get an equivalent drilled length from both patterns implies a replacement ratio  $n$ :

$n = \text{Erreur !}$

The deeper the reservoir, the lowest the replacement ratio.

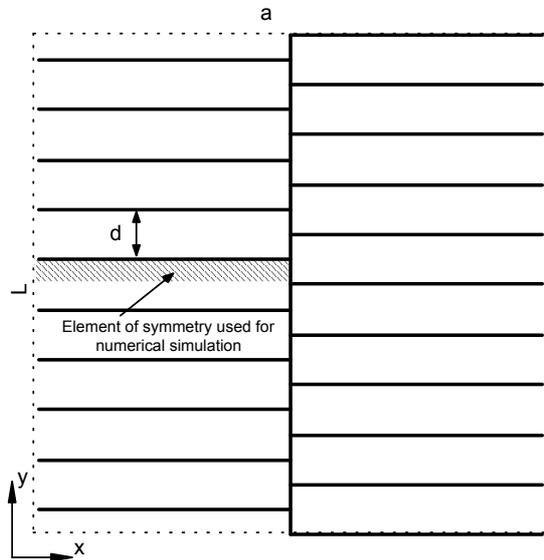


Fig. 6. Multilateral well pattern

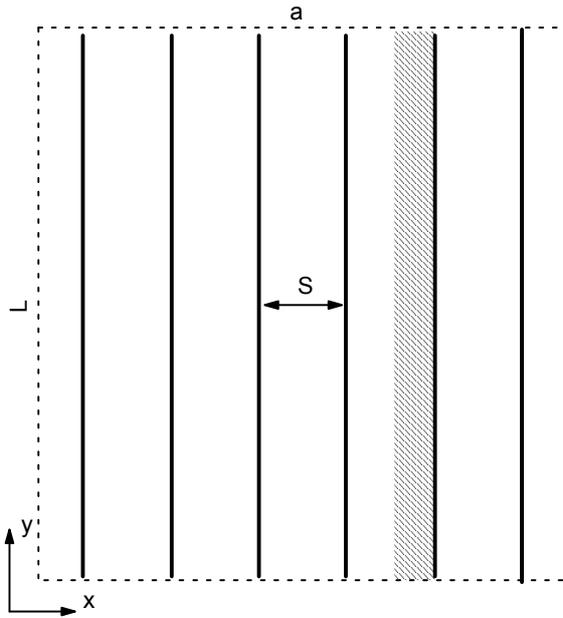


Fig. 7. Parallel horizontal wells pattern

For instance, assuming  $a = L = 1000$  m,  $d = 100$  m, replacement ratios of 6 and 3 are obtained for drilled length  $\delta$ , from surface to reservoir, equal to 1000 and 4000 m respectively. Numerical simulations have been performed with these data and total identical production rates, for both basic patterns, as a theoretical case. Runs were stopped for a 0.95 maximum watercut. Other data are  $h_o = 20$  m,  $h_w = 30$  m,  $\mu_o = 600$  mPa.s,  $k = 3$  Darcy. Results for total production rates of  $2000 \text{ m}^3/\text{d}$  for each pattern are shown in figure 8. For a reservoir depth of 1000 m, oil recovery with the multilateral is twice the recovery obtained with the six parallel horizontal wells pattern having the same total drilled length. The oil recovery increases four times assuming a 4000 m deep reservoir.

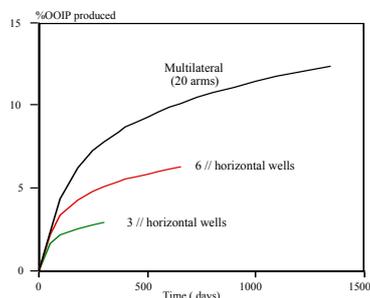


Fig. 8. Multilateral vs horizontal wells production in reservoir with a bottom aquifer

An important result of the simulations is that the interferences between the laterals and the main bore are very small and negligible even with as low as 100 m spacing between the laterals. Moreover, the oil recovery is significantly improved by increasing the number of lateral arms or reducing the drawdown applied to the reservoir. The reduction of coning is therefore very important with less produced water and lowered treatment cost.

**Viscous flooding**, more specifically polymer flooding, is mainly well suited for layered, heterogeneous reservoirs saturated with a viscous oil. One of the main operational difficulties that can be encountered with polymer flooding with 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** 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 [18], 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 [19].

The new technology of Insulated Concentric Coiled Tubing (ICCT) jointly developed by Newsco and Elan Energy [20] indicates that, in a near future, injection of hot fluid would be efficiently performed in deep reservoirs. As a matter of fact, ICCT has a lower thermal conductivity than insulated tubing. Thus it allows the transport of heat on longer distances with limited heat losses to the surrounding formations. Combined with the advantages of advanced wells, this technology is supposed to extend steamflooding application in heavy oil reservoirs with depth ranging between 1000 and 1500 m if steam injectivity through the ICCT can be large enough.

**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. However, its use to unlock bitumen reserves to profitable recovery was not so obvious. The concept of AGD was first suggested and studied by Butler as a special form of steamflooding [21]. 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 the only means of 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. Butler developed the gravity drainage theory that predicts the rate at which the process will occur and confirmed the viability of the concept by lab experiments. Afterwards, the successful application of the SAGD process at the UTF site [22] convinced operators of the huge potential of the process.

The unique features of SAGD [23-24] are:

- Use of gravity as the primary motive force for moving oil.
- Surprisingly large production rates obtainable with gravity using horizontal wells.
- Flow of the heated oil directly to the production well without having to displace uncontacted oil.

- Almost immediate oil production response.
- High recovery efficiency.
- Low Cumulative Steam Oil Ratio due to the large potential injection/production rates limiting the burdens heat losses.
- Very low sensitivity to heterogeneities except extensive shale intervals.

They make it easier to predict and control than a conventional drive scheme.

SAGD is at the present time of primary interest to Canadian operators. Table II summarizes current or planned applications in Canada [25].

Screening criteria for the application of steam injection in heavy oil reservoirs using horizontal wells have been derived recently from a numerical study [26]. 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 pay thickness  $h_o$ , sand permeability  $k$ , oil viscosity  $\mu_o$ . Possible presence of a bottom aquifer of thickness  $h_w$  was accounted for.

Table II: Current or planned SAGD applications in Canada

Company	Field	Expected prod.
Alberta Energy Co.	Foster Creek	1000 b/d
Amoco	Wolf Lake	
CS Resources	East Senlac	5000 b/d
Elan Energy*	Cactus Lake	-
	Cold Lake	4500 b/d
	Wolf Lake	4500 b/d
Gibson Petroleum	UTF (Ft Mc Murray)	4500 b/d
Gulf Canada	Surmont	3000 b/d
Japan Canada Oil Sands	Hangingstone	-
Shell Canada	Peace River	-
Suncor	Burnt Lake	-

\*Single Well SAGD

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 can not 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 has to be noted that a final screening study in 3D should be performed to appropriately choose between steam flooding and SAGD.

In the conventional SAGD process, two horizontal wells, one injector and one producer, are drilled quite parallel in the same vertical plane. In special cases, for instance reservoirs with an active bottom aquifer, the adjunction of lateral arms to the horizontal producer could improve the recovery of oil that would otherwise be displaced into the aquifer.

Recently, Elan Energy [27] proposed the Single Well (SW-) SAGD process to reduce the investment cost of the conventional SAGD using the ICCT technology and only one horizontal well, both to inject steam and produce recovered oil. Implemented in the Cactus Lake field, SW-SAGD showed a rapid increase in heavy oil production, doubling average production rates compared to primary [27]. Other applications of the process are planned by Elan in its Cold Lake and Wolf Lake fields (Table II). In spite of its attractiveness, it is too early to ascertain that the SW-SAGD has the potential to effectively replace conventional SAGD. Numerical modelling of the strong coupled interaction between the well and the reservoir has to be performed to clearly indicate how the steam chamber develops in the reservoir before steam reaches the heel of the well.

**Miscible flooding** of heavy 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 [28] 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 [29]. 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.

#### RISKS ASSOCIATED WITH ADVANCED WELLS

Advanced wells by their complex trajectories present higher risks than more conventional or even horizontal wells. It is not only a problem of drilling and completion but also of production during the whole life of the wells, as already outlined. The potential of this new technology and its successful implementation by many companies already now give evidence that it has a promising future. Routine applications will necessitate a strong and efficient multidisciplinary approach.

#### CONCLUSIONS

In the area of horizontal and multilateral wells, there is no question that extraordinary progress has been made within the last few years. This technology is improving the world's reserves levels, especially by opening the economical production to heavy oil reserves. At the same time, this technology is not a panacea. Using multilateral wells introduces an element of risk which needs to be reduced by a good reservoir characterization, good well modelling and added experience.

#### NOMENCLATURE

- a Width of basic area
- n Replacement ratio
- L Length of basic area
- d Distance between two parallel laterals

$h_w$  Aquifer thickness  
 $h_o$  Pay thickness  
 $k$  Sand permeability  
 $\mu_o$  Oil viscosity  
 $S$  Distance between parallel horizontal wells  
 $\delta$  Reservoir depth

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