PRJ, Vol. 4. (January 1992); P. 22–32, 15. FIGS, 6 TABLES.

CONSTRAINTS ON ENHANCED OIL RECOVERY DEVELOPMENT

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القيود المتحكمة في تطوير عمليات الإسترداد الإضافي النفطي

ت . سيماندو وأ . فالنتين

تغطي التقنيات المختلفة لعمليات الإسترداد الإضافي النفطي مجالات تطبيقية واسعة بالنسبة للنفط الخفيف والثقيل. وقد وصل إنتاج الإسترداد النفطي في عام 1988م إلى 1.5 مليون برميل يومياً ، ويمثل هذا حوالي 3 % من جملة إنتاج النفط في العالم.
وتمثل العمليات الحرارية والحقن الغازي على التوالي 55 % و43 % من الطرق المستخدمة في إنتاج الإسترداد النفطي. ومن وجهة النظر الفنية ، تعتبر الأبحاث التي تنفذها شركات النفط والمتعلقة بإنتاج الإسترداد النفطي من أكثر المشاريع تعقيداً.
فعمليات الإسترداد الإضافي تتطلب أوقات ومصاريف كثيرة من أجل القيام بالأبحاث والتطوير المطلوب. وقد تطورت هذه العمليات تقنياً في السنوات الأخيرة ، غير أن التدهور الحاد في أسعار النفط الخام عام 1986 أكد مرة أخرى على التأثير الحاسم لتكاليف تلك الطرق عند تنفيذها.
تناقش هذه الدراسة السبل المختلفة للتقليل من المخاطر الفنية والإقتصادية لطرق الإسترداد الإضافي النفطي بواسطة التحكم في العوامل الرئيسية المؤثرة في هذه الطرق.

ABSTRACT

The different techniques of enhanced oil recovery (EOR) cover a wide range of applications from light to heavy crudes. In 1988, EOR production reached 1.5 million bbl/d, representing about 3% of the total amount of oil produced in the world. North America is the main actor in this domain, ensuring half of the total EOR production. Thermal processes and gas injection represent respectively 55% and 43% of EOR production by the various processes that are widely used in the world.

From a technical point of view, research on EOR processes is among the most complex projects carried out by the oil industry. Process tailoring itself requires long lead times to do the necessary research and development. All the processes have evolved technically in recent years and steady progress has been made, but the sharp drop in the price of crude oil in 1986 again emphasized the crucial influence of the cost of these methods on their implementation.

This paper discusses the different ways of decreasing the technical and economic risks of EOR methods by mastering the main parameters of the processes thanks to extensive research and development in laboratories, by improving reservoir characterization or their performance to be predicted with some degree of confidence, and lastly by searching for synergy with new technologies that have emerged in the meantime, such as horizontal drainholes.

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PRESENT STATUS

The different techniques of EOR cover a wide range of applications from light to heavy crudes. They are widely used around the world, but some processes are better suited to the general characteristics of specific fields, depending on where they are located.

Out of pure necessity, North America was and still is the proving ground of the various EOR concepts. Its large oil demand and declining oil fields have forced the United States and Canada to search for new ways to more efficiently recover the oil that was being left behind. In 1974, tertiary oil recovery (nearly all thermal) accounted for 3% of total oil production. Today, it accounts for 8%. The trend is inexorably toward secondary and tertiary oil production, because oil fields in North America are aging, new discoveries are much smaller in size and increased reliance is being put on low productivity "stripper" wells. The 1980's saw a very rapid growth of both oil production and the number of active EOR projects in North America (Fig. 1). In 1988, the USA and Canada produced 637,000 bbl/d and 145,000 bbl/d respectively by EOR. The popularity of EOR techniques in the United States and Canada differs significantly (Fig. 2).

In the former USSR, about 95% of domestic oil production was coming from oil fields developed with artificial waterflooding. However, recent years have been characterized by an increase in applications of enhanced oil recovery techniques (Table 1).

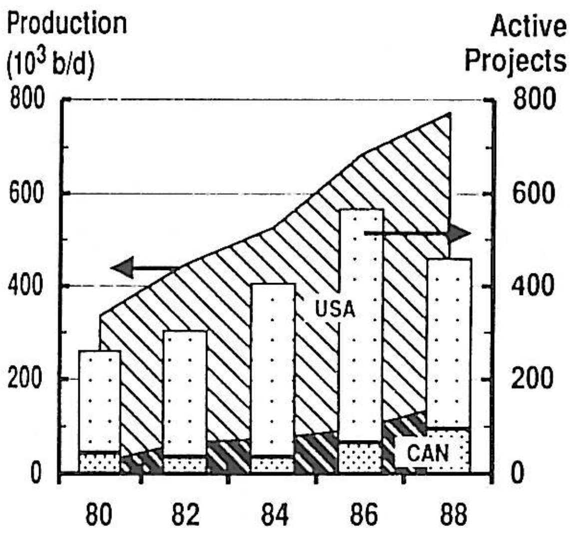


FIG. 1. EOR trends in North America.

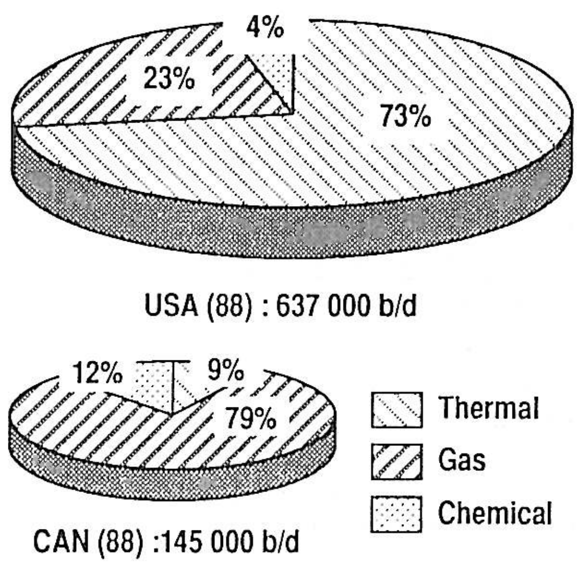


FIG. 2. Breakdown of EOR production in N. A.

Table 1. EOR Projects in the former USSR

EOR Techniques	1976 Total	1976 Active	1987 Total	1987 Active
Thermal	19	16	52	40
Gas	6	5	20	12
Chemical	56	56	165	128
Total	81	77	237	180

EOR techniques are used in various regions of the former Soviet Union. Mostly these techniques are widely used in Kazakhstan, representing 46% of the total oil in place, Tataria (23%) and West Siberia (11%). Thermal methods are applied mainly in Kazakhstan, chemical ones in Tartaria, gas and chemical methods in West Siberia. In 1988, the production was 160,000 bbl/d of oil by EOR application. The oil production in time for thermal, gas and chemical methods is shown in Fig. 3.

Venezuela is the second largest EOR producer with a production of 215,000 bbl/d in 1988, achieved essentially with the aid of thermal processes. Among other thermal producers, China, Indonezia, Romania, and Trinidad can be mentioned. Thermal production in China is achieved essentially through huff-and-puff steam injection in 3 oil-bearing areas: Liaohe, Xinjiang and Shengli. EOR in Indonezia is essentially provided by steam flooding. It should also be noted that the major producers include Algeria and

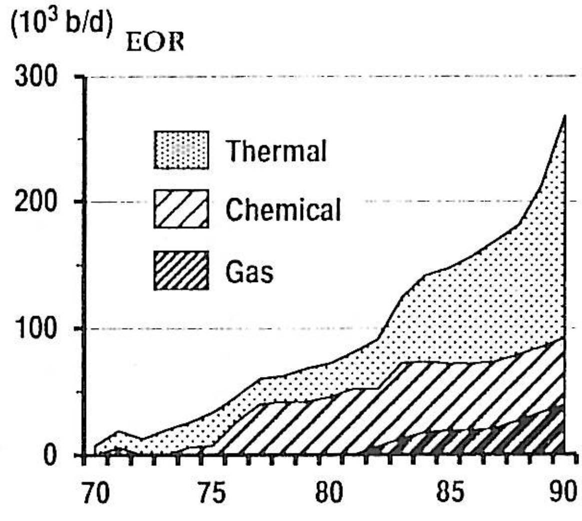


FIG. 3. EOR production in the former USSR.

Libya, due to the importance of the miscible gas operations on their respective Hassi-Messaoud and Intisar fields.

The overall EOR production worldwide can thus be evaluated at about 1.5 Mbbl/d of which thermal processes represent 55% and gas flooding 43% (Table 2).

Commercial applications of different EOR processes evolve at various rates and depend strongly on local conditions such as the suitability of reservoirs to a particular technology (steam flooding in California), the availability of injectants (natural gas in Alberta, carbon dioxide in the Permian Basin, Texas) local market conditions, and economic incentives.

Table 2. World Oil Production by EOR Methods

(10^3 b/d)

	Thermal	Gas	Chemical	Total
USA	465	150	22.5	637.5
Canada	13	115	17.5	145.5
Venezuela	207	9	-	216
USSR	20	90	50	160
Other (estimated)	107	280 (*)	1.5	388.5
Total	812	644	91.5	1547.5

* Mainly Hassi-Messaoud (Algeria) and Inlisar (Libya) IFP/Economics Department/89

Table 3. Criteria for Selecting EOR Processes

CRITERIA	THERMAL STEAM	THERMAL IN SITU COMBUSTION	MISCIBLE GAS	CHEMICAL POLYMER	CHEMICAL SURFACTANT
LITHOLOGY	N.C.	SANDSTONE	N.C.	SANDSTONE	SANDSTONE
FRACTURING	N.C.	NUL or WEAK	NUL or WEAK	NUL or WEAK	NUL or WEAK
TRANSMISSIBILITY (KH/μ)	>100	>20	N.C.	N.C.	N.C.
MOBILITY (K/μ)	N.C.	N.C.	N.C.	>25	>25
VISCOSITY (cp)	N.C.	N.C.	<10	<40	<20
DEPTH (m)	300-1500	<1500	>700	N.C.	N.C.
SALINITY (g/l)	N.C.	N.C.	N.C.	N.C.	<50
TEMPERATURE (°C)	N.C.	N.C.	N.C.	<100	<80

N.C.: Non Critical

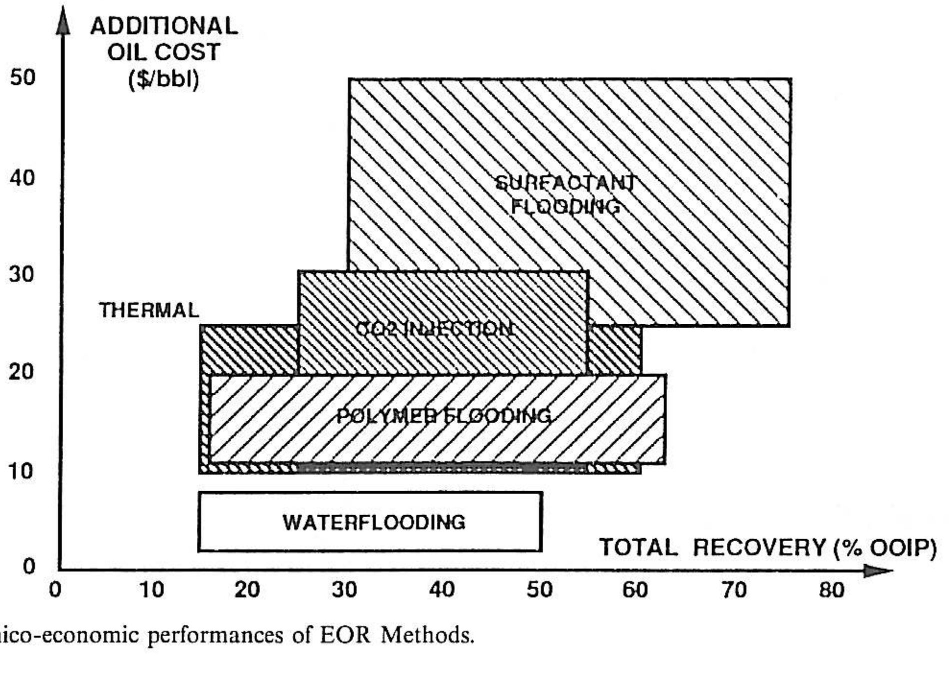


FIG. 4. Technico-economic performances of EOR Methods.

Each of these EOR processes has a specific range of application depending on the main parameters of the field (Table 3).

The technical and economic performances of the main EOR techniques, that have been scaled up to the industrial level, are shown in Fig. 4. These assessments were made in the economic conditions of early 1986 in Western Europe.

The lessons gleaned from past experience lead to the following conclusions that illustrate the actual constraints on EOR development:

(1) in most cases, the cost of the additional oil recovered through the use of any EOR method is above $ 10/bbl;

(2) thermal processes are the only EOR processes whose use is sometimes obligatory to recover a high viscosity oil. In all other cases, the use of EOR processes is restricted to fields where they can be implemented under good economic conditions, and where it is assumed that they will lead to a significant increase in the final oil recovery compared to conventional techniques such as waterflooding. In addition this increase in recovery must be achieved at the same time and the risk of failure must be reduced.

As a consequence the development of EOR techniques implies that risk and cost must be fully mastered during their implementation. The experience gained in the past now makes it possible to understand the different ways of attaining this goal.

UNDERSTANDING THE MAIN PARAMETERS OF EOR PROCESSES

From a technical point of view, research on EOR processes is among the most complex projects carried out by the oil industry. For each process both the reservoir parameters and operating parameters must be fully understood in order to reduce financial risks.

For thermal methods, the most important and often poorly understood variable is the displaceable-oil content (Fig. 5). Another source of uncertainty, especially for in-situ combustion, is linked to the understanding of the heterogeneities of the reservoir. Regarding the operating parameters and especially for steam injection, well spacing has the greatest impact on oil recovery and hence on production costs (Fig. 6).

For surfactant processes, most of the reservoir parameters and operating parameters have a strong influence. This is certainly one of the major difficulties in the designing of such a project. The imperfect chemical stability and the uncertainty as to how much product will be consumed by retention are what introduce the greatest errors in estimating

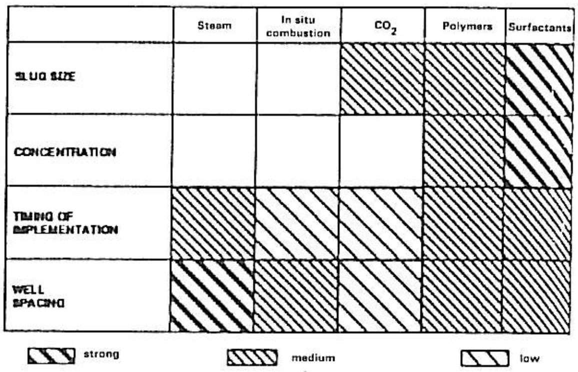


FIG. 5. Influence of operating parameters.

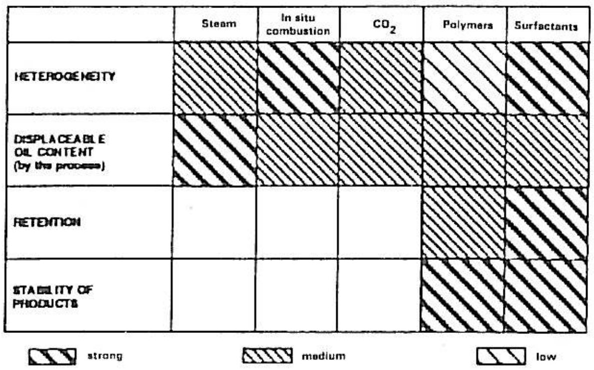


FIG. 6. Influence of operating parameters.

recovery and cost for surfactant flooding. However, uncertainties as to the residual oil saturation and the heterogeneity of the reservoir may also be of major importance.

Taking into account Libyan field characteristics, special attention must be paid to gas injection, for instance CO_2, and polymer flooding.

The following analysis was made specifically for Western European economic conditions. But the tendencies are general and can be extrapolated to other areas.

CO_2 Flooding

At economic optimum, additional recovery (Fig. 7) varies between 5 and 15% for specific CO_2 consumptions of 1 to 10 t of CO_2/t. The most sensitive parameters are heterogeneity and oil saturation at the start of the project.

Fig. 8 shows the marginal cost of the additional oil for different costs of CO_2, as a function of CO_2 requirements expressed in relation to the tons of CO_2 injected per ton of oil recovered. It can be seen that, in a first approximation, the cost of the oil is an increasing linear function of the CO_2 requirements. The scattering of the results around this straight line is slight. This can be explained by the fact that the cost of CO_2 supplies makes up the principal item in the production cost of the oil (50 to 70% of the technical production cost).

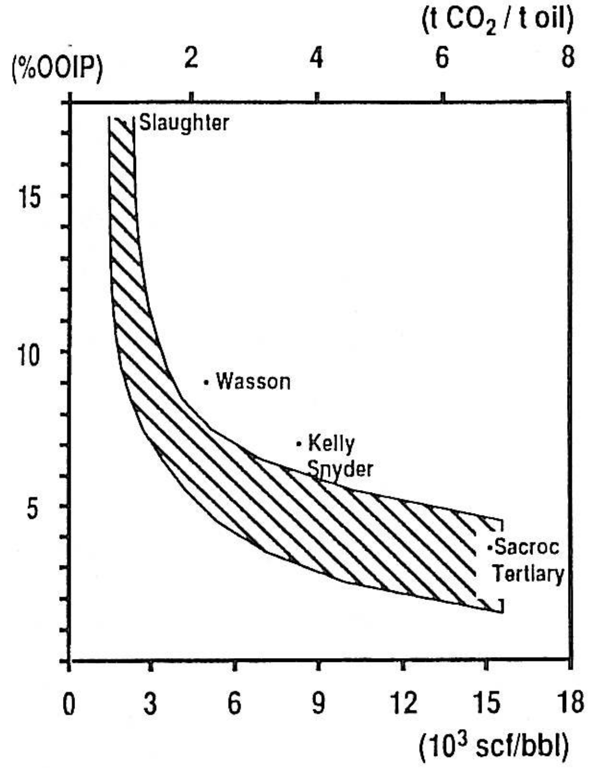


FIG. 7. Oil recovery versus CO_2 efficiency.

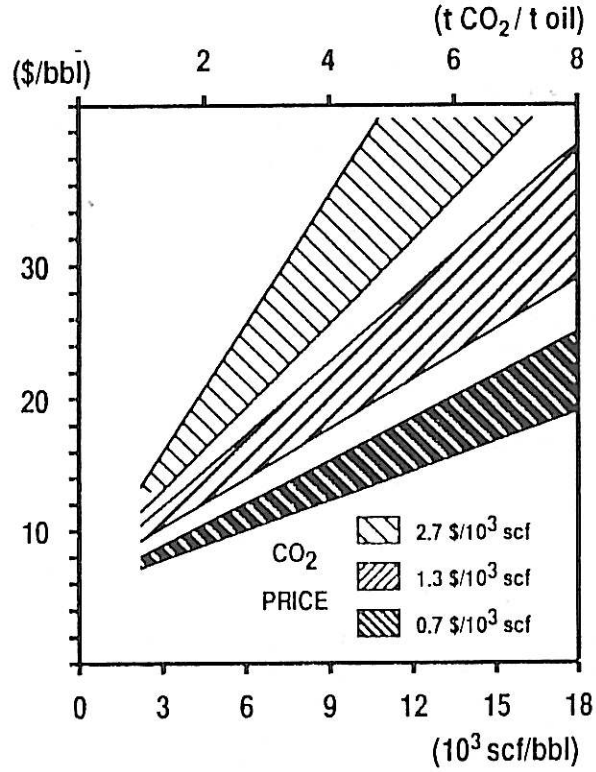


FIG. 8. Price per barrel versus CO_2 efficiency.

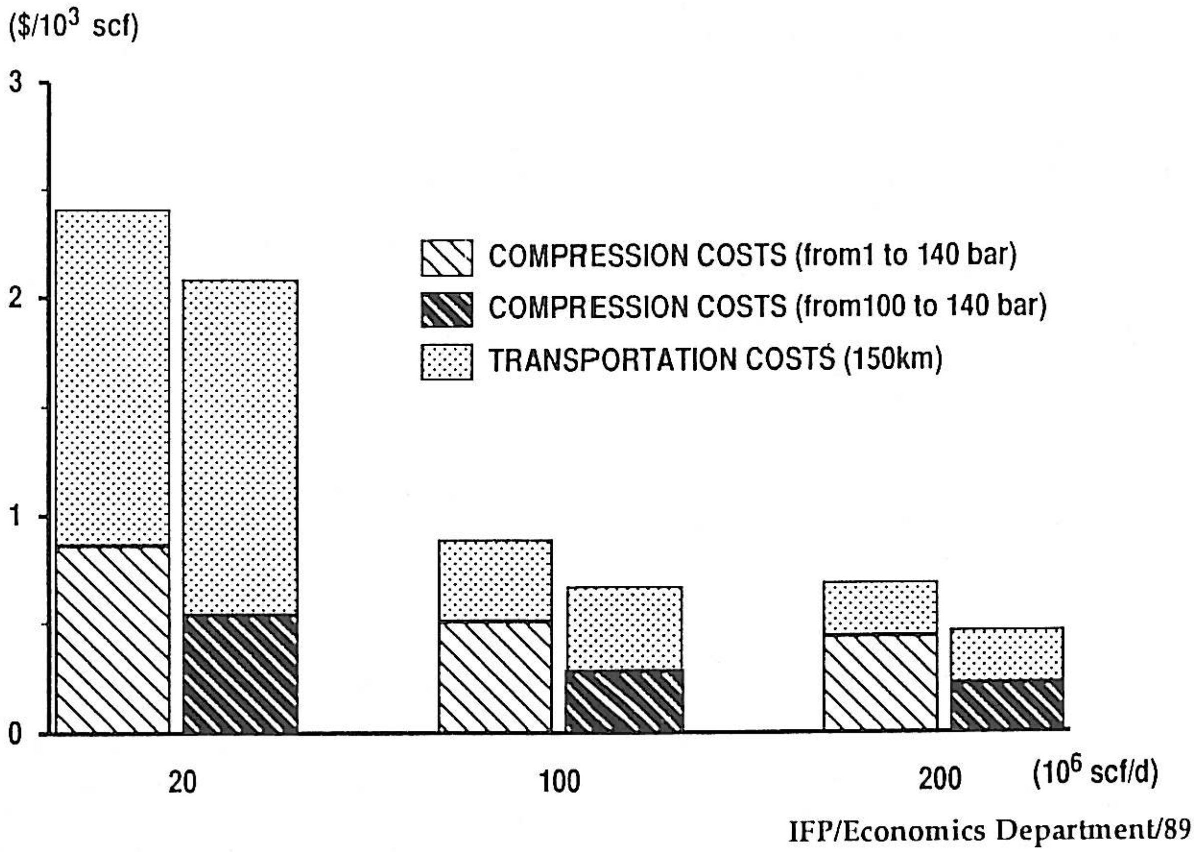


FIG. 9. Cost of CO_2 from natural deposits.

Values of \$ 1.3 and 2.7/10^3 scf, considering the recycling of produced gas (economically advantageous), respectively represent the case of a source rich in CO_2 (natural deposit or ammonia plant) or poor in CO_2 (power-plant fumes in particular).

These Western European economic conditions could be adapted to the specific case of Libya. As a matter of fact, the figures can be very different if large amounts of CO_2 from natural deposits can be injected at a very low cost, depending on the plant capacity and on the initial pressure of CO_2 (Fig. 9).

When the mobility of the CO_2 is reduced by alternating water and gas flooding or by the addition of foaming agents, production increases in quite appreciable proportions, whereas the specific cost of this operation is slight when compared to the additional oil produced in relation to CO_2 flooding alone. Therefore, the higher the cost of the additional oil recovered by CO_2 flooding, the more advantageous it will be from the economic standpoint to use foaming agents. Indeed, for all the additional oil produced, the effect of foaming agents will be all the greater as drainage efficiency by CO_2 is low. Presently the use of foaming agents is limited by the poor technical behavior of available chemicals.

In the case of hydrocarbon gases, the results are also greatly influenced by the local value of the gas. They could be very similar if this gas is close enough to a gas market, with a price in the range of \$2 to 4/10^3 scf similar to the high level mentioned for CO_2 cost. If not, the cost of the gas is the production cost which can be very low. In this specific case the cost of the additional oil produced is much less sensitive to the hydrocarbon gas requirement.

Polymer Flooding

Additional oil recovery due to polymer flooding amounts to about +5 to +20% of the oil in place at the start of chemical flooding, and the cost is fairly stable, between \$10 to 20/bbl. With regard to the breakdown of the technical cost, it can be seen that the product item still represents 40 to 50% of the end cost of production. This process is particularly suitable for heterogeneous reservoirs or ones having an unfavorable water/oil mobility ratio. Under optimized conditions, the greatest improvement in the recovery corresponds to a high mobility ratio and medium heterogeneity.

An increase in polymer retention reduces the increase in recovery. This decrease is always fairly low as long as retention is no greater than about 100 to 200 ug/g, but increases rapidly above these values. In addition, the stability of the polymer solution under the reservoir conditions obviously has a strong influence on the oil recovery and the production cost.

The operating parameters generally have a moderate influence. It can be emphasized that the optimum situation corresponds to large size slugs with a high polymer concentration.

If compared to the main pilot operations carried out, this situation of economic optimum corresponds to the injection of a large amount of polymers. Despite higher specific polymer consumption, this results in considerably greater recovery, with approximately the same cost per barrel of oil.

SEARCHING FOR POTENTIAL IMPROVEMENTS FROM RESEARCH AND DEVELOPMENT

For thermal processes, improvement of sweep efficiency using surfactant additives to generate foam and reduce fingering of steam is required. Research must be carried out to find agents consistant with temperatures as high as 300°C.

For gas injection, improvement of sweep efficiency through WAG (Water Alternating Gas) or foaming agents is necessary since many reservoirs have only a low dip that is insufficient for gas oil gravity stabilization.

Looking towards ideal viscous flooding, additional research on polymer flooding should aim at:

(1) Improving the control of polymer adsorption and retention, particularly in reservoirs containing a high proportion of clay and carbonates;

(2) ensuring polymer stability especially in high temperature and salinity reservoirs.

For micellar polymer processes, the quantity of surfactants per cubic meter of oil recovered must be optimized by reducing losses due to retention together with preserving the efficiency of the micellar slug. One method consists in preflushing the reservoir with alkaline agents. An alternative solution consists in injecting a desorbing agent together with chase water behind the micellar slug.

The resulting improvement in the economics could reach 25 to 30% of the technical cost of the processes as shown in Table 4.

IMPROVING RESERVOIR CHARACTERIZATION

The experience accumulated about the application of EOR processes, especially when implementing pilots, has shown the extreme importance of reservoir heterogeneity on the technical and economic results.

In practice, if the external geometry of the reservoir must be determined accurately, above all, its internal architecture must be described quantitatively in terms of porosities, permeabilities and saturations so that this description can be integrated into reservoir simu-

Table 4. Reduction of EOR Costs

Methods	Mean costs ($/bbl)	Optimized costs ($/bbl)	Action
Thermal	15	11	- Optimizing drilling - Optimizing sweep efficiency - Improving energy balance
CO_2	20	13	- Optimizing cost and amount of CO_2 - Improving sweep efficiency
Polymers	17	12	- Optimizing products - Controlling retention
Surfactants	30	15	- Reducing the share of product in the technical cost (at present 65 to 80%) - Reducing adsorption

lators. The dynamic behavior of the field during its production life has to be followed up.

Traditional reservoir engineering techniques for data acquisition (tests and well logging) are continuing to evolve and to improve. Nevertheless, a satisfactory answer to the above problem can come only from a multidisciplinary approach that is progressively implemented by associating reservoir engineers with geologists and geophysicists, whose knowledge and know-how have made considerable progress in their disciplines.

One of the difficulties is the scale factor between the size of heterogeneities (tens of meters) and the spacing between wells (hundreds of meters or more).

Today, developments aim is interpolating between wells or extrapolating around one well. Among the different possible tools, geostatistics appears very promising. Even though the quantitative data on

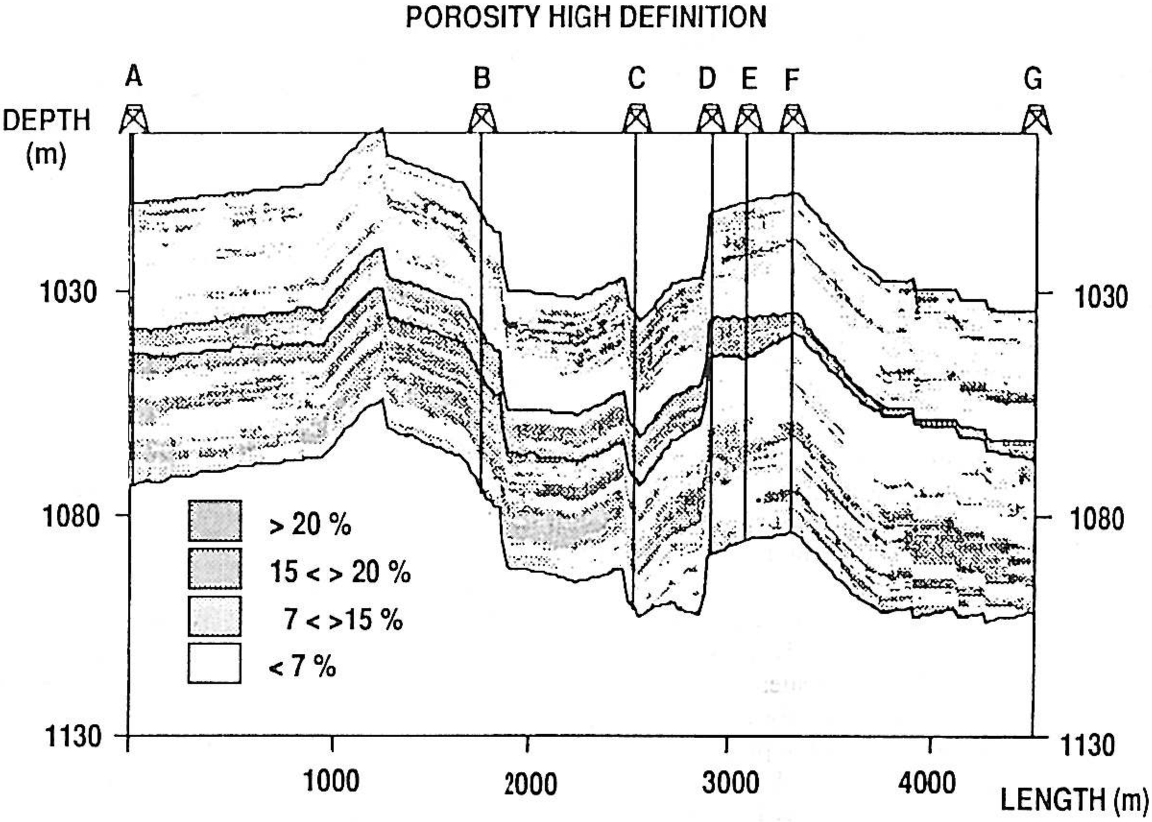


FIG. 10. Geostatistical interpretation with HERESIM®.

heterogeneities are of a statistical nature, their spatial distribution is not completely random, and the understanding of the depositional environments can be very useful. In the method, rather than defining sedimentary bodies having a given geometry, the goal is to incorporate information about "sequences". These sequences are characterized by variograms deduced from field observations of the same type of depositional environment.

The method of geostatistical interpretation can then be used to generate a series of equiprobable models. These models are progressively constrained by well data as well as by additional constraints such as seismic data, dynamic data or any other pertinent data. The resulting reservoir images are supplied to the geologist, who can select the models that are most likely to represent reality (Fig. 10). The models selected are then at the disposal of the reservoir engineer, giving him a quantitative description of the heterogeneities. His task is then to transfer this quantitative geological model to the typical grid-block model for reservoir calculation.

SEARCHING FOR SYNERGISM WITH NEW TECHNOLOGIES

Horizontal Drainholes

The technology of horizontal drilling, for which the principle is not new, was taken up again in the late 1970s by Elf Aquitaine/IFP to substantially boost production from the Rospo Mare field in the Adriatic Sea (Fig. 11). This field consists of a fractured and vuggy limestone reservoir containing a very heavy oil located above an active aquifer.

The problem was first to demonstrate the feasibility of drilling drainholes several hundred meters long horizontally in the reservoir. The results exceeded anticipations, because productivity rose by a factor of more than 10 with production over a long period of more than four times that from vertical and slanted wells close to it.

However, horizontal well costs are about 1.4 to 2 times those of a vertical well. Depending on the method selected, completion costs could also increase the differential. Do enhanced production, more efficient drainage, and ultimate recovery compensate for the added drilling, completion, and operating expenses of going horizontal? The answer lies in a cost-benefit analysis that must be performed on a case-by-case basis.

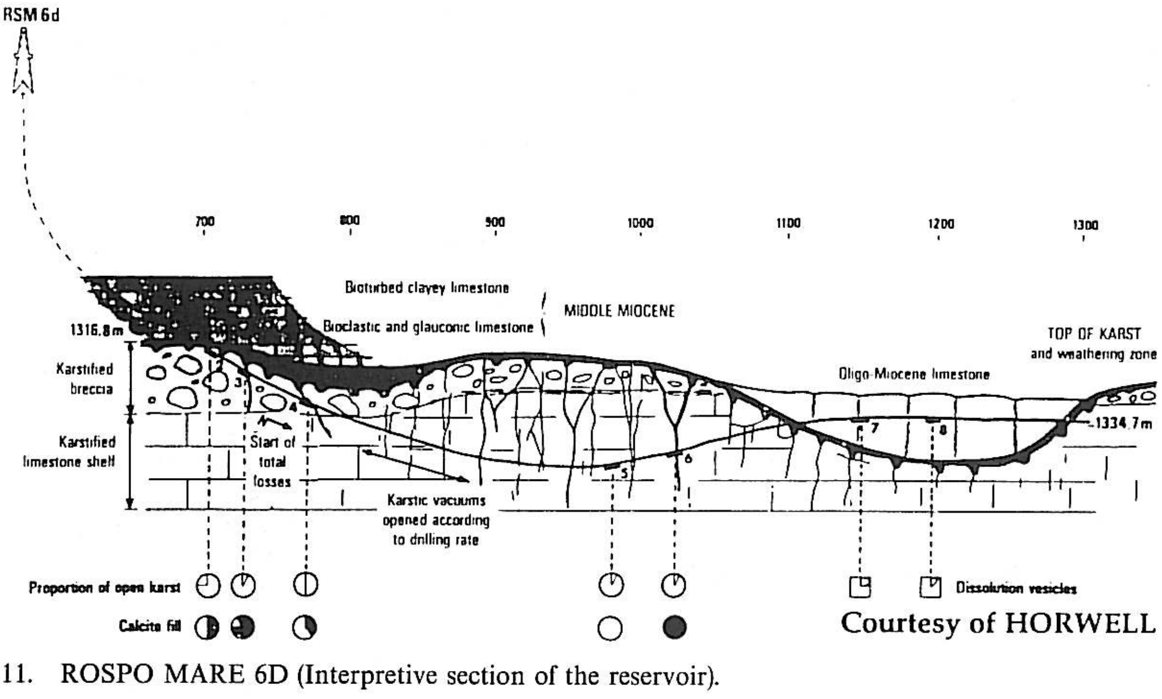
Horizontal economics is most compelling in: (1) thin formations, (2) relatively isotropic (homogeneous) reservoirs, (3) naturally fractured reservoirs, (4) formations with gas or water coning problems (Fig. 12).

In a thick pay zone, the incremental benefit from drilling horizontally through the formations is reduced.

Concerning drilling technology, two main technologies have emerged:

(1) a lung turning radius: This is the most spread out technique using conventional drillstring rotation and standard equipment;

(2) a short turning radius: This method requires the rotating of the drillstring and the use of articulated drill collars in the deviated section. So far the drain length is limited to 1000 ft.



Courtesy of HORWELL

FIG. 11. ROSPO MARE 6D (Interpretive section of the reservoir).

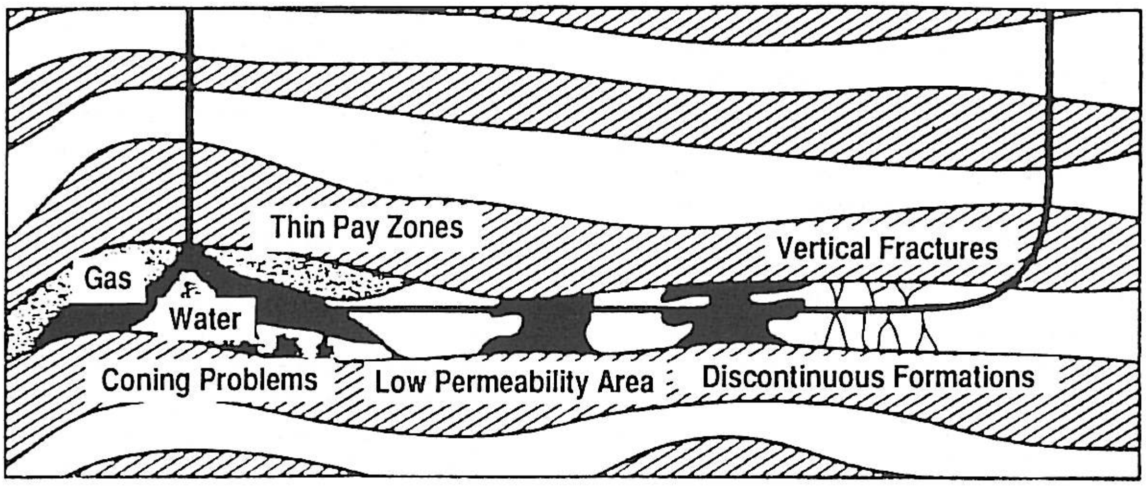


FIG. 12. Horizontal drainholes applications.

The first technique is more advantageous for improving recovery. Several dozen wells of this type have been drilled in recent years in a wide variety of fields (Fig. 13). They have generally demonstrated gains in productivity over vertical wells by a factor of 2 to 5 (Fig. 14), to the point where this technique must now be considered as a general technique for improving production. Even more importantly, horizontal wells appear to be a new technique for production, as achieved for the first time at Rospo Mare, where a complete zone has been developed at Elf Aquitaine exclusively with horizontal wells drilled from a rig. Offshore situations such as this one are very attractive, because horizontal wells reduce the number of wells needed, thus drastically reducing the size of the platform, or allowing some slots to be kept for future wells such as infill wells or injection wells.

Drainholes measuring 1500 to 3000 ft long can be drilled today at any depth, under most conditions. Core samples can be taken and any type of well log plotted. Completion can be achieved including cementing, which is certainly a delicate technique with this geometry.

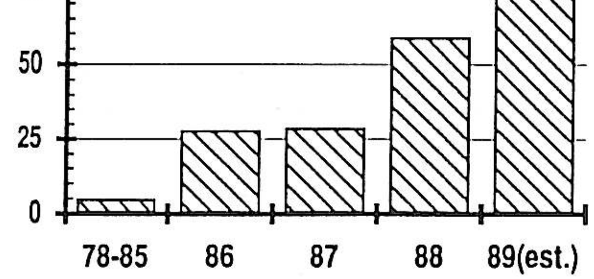


FIG. 13. Horizontal drilling activity (Drainholes longer than 1000 ft).

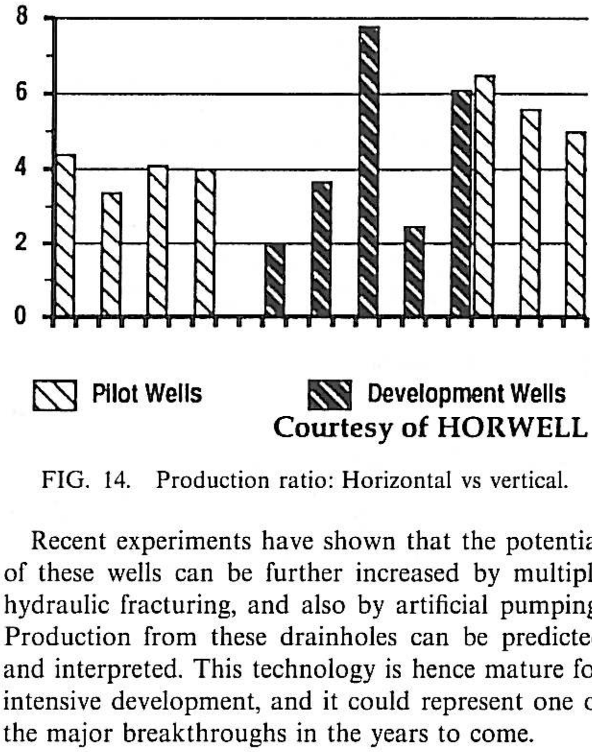


FIG. 14. Production ratio: Horizontal vs vertical.

Recent experiments have shown that the potential of these wells can be further increased by multiple hydraulic fracturing, and also by artificial pumping. Production from these drainholes can be predicted and interpreted. This technology is hence mature for intensive development, and it could represent one of the major breakthroughs in the years to come.

Synergy of EOR Processes with Horizontal Drainholes

Horizontal wells and polymer flooding

The example considered is the case of a typical oil reservoir 2000 ft deep, lying in a sandy channel system with widely contrasting permeabilities (Fig. 15). Two development schemes were considered, one having vertical wells drilled in different zones of the reservoir, and the other horizontal wells.

The simulations made for these two configurations take different types of recovery into consideration, in particular waterflooding and enhanced recovery by polymer flooding, all of which are assumed to be implemented at the start of production. Waterflooding using horizontal drainholes instead of vertical

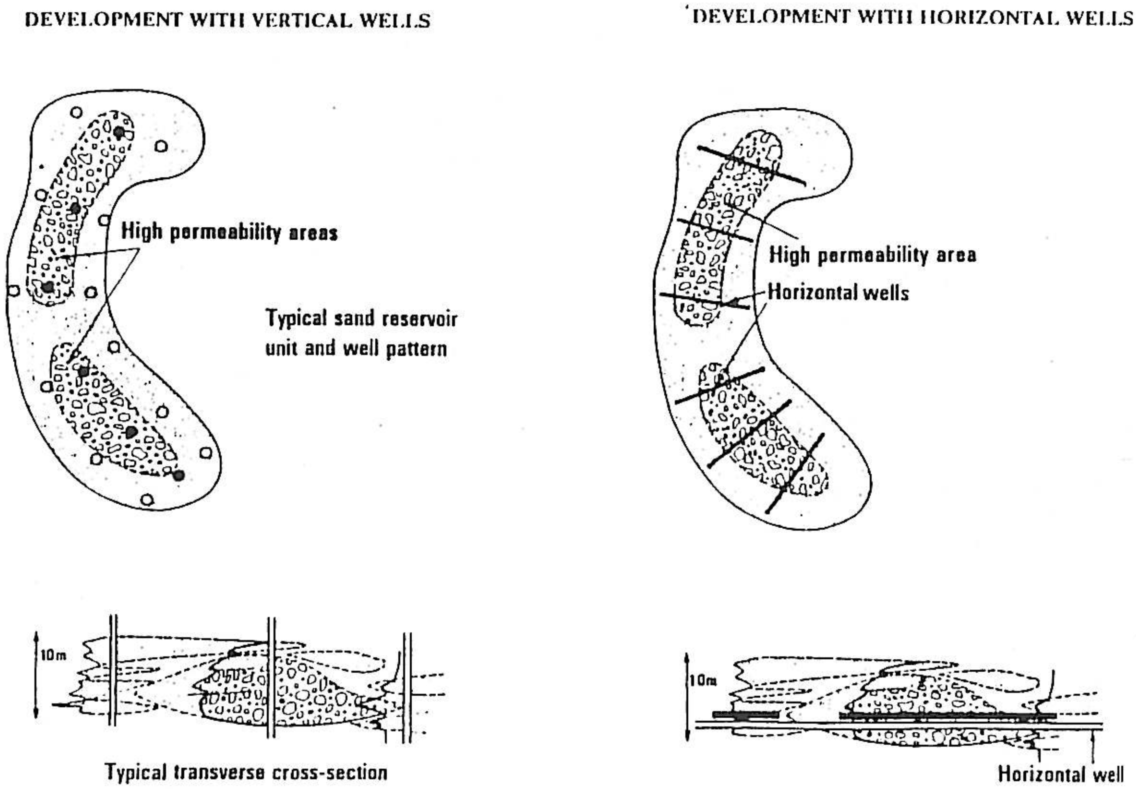


FIG. 15. Development with vertical wells versus development with horizontal wells (Case Study).

wells leads to an additional oil recovery of 0.7 Mbbl at the very low cost of $ 2.5/bbl. Moreover, combining horizontal wells with polymer flooding instead of waterflooding makes it possible to double the addtional recovery compared to the results of the vertical-well scheme, with a cost of $ 6.7/bbl for the additional oil (Table 5). Therefore, the synergy between the two approaches leads to an increase of 50% from total recovery and at the same time a decrease of 20% for the average cost of the oil recovered.

Table 5. Synergy between Horizontal Wells and Polymer Flooding

Development scheme	Oil recov. after 20 y (Mbbl)	Average oil cost ($/bbl)	Addit. oil recov. (Mbbl)	Cost of addit. oil ($/bbl)*
Waterflooding				
vertical wells	2.9	13.2	-	-
horizontal wells	3.6	11.1	0.7	2.5
Polymer flooding				
horizontal wells	4.4	11	1.5	6.7

* by reference to waterflooding in vertical wells

Horizontal wells and steam injection

Two types of well configurations have been considered for the development of a 1300 ft deep reservoir: parallel horizontal-wells lines used alternately for injection and production, or five-spot patterns with vertical wells. With 300 ft spacing, the use of horizontal wells leads to an oil recovery of 25 Mbbl in 5 years, i.e. half of the time needed to reach the same amount of oil by using vertical wells (Table 6). Moreover, the optimal unit cost per barrel is 30% lower. With larger spacing (450 ft), the project life is doubled by comparison to 300 ft spacing. The unit cost in this case is only 20% lower, but the decrease remains significant.

Table 6. Synergy between Horizontal Wells and Steam Injection

Development scheme	Spacing (ft)	Project life (year)	Oil recov. (Mbbl)	Unit cost ($/bbl)
Vertical wells	300	10	25.3	9.6
Horizontal wells	300	6	25.0	7.0
Vertical wells	450	21	20.3	8.8
Horizontal wells	450	11	19.8	7.1

From these two specific examples, it appears that horizontal wells, as a means of boosting productivity and a new method of production, should show close synergy with enhanced recovery, by favoring the propagation of the injected fluids and the drainage of the oil mobilized.

CONCLUSION

The different technique of EOR rely on a wide variety of physical principles and cover a wide field of applications from light crudes to heavy crudes. Their implementation differs from one continent to another depending on the average characteristics of the fields and on economic factors such as the availability of low cost gases to inject.

All the processes have evolved technically in recent years, and steady progress has been made, but the sharp drop in the price of crude oil in 1986 again emphasized the crucial importance of the cost of these methods. The experience gained in the past now enables us to choose different ways for the necessary reduction of the technical and economic risks of EOR methods:

(1) by the mastery of the main parameters of the processes thanks to extensive research in laboratories and to pilot applications;

(2) by better reservoir characterization aiming essentially at determining its internal architecture in terms of porosities, permeabilities and saturations;

(3) by systematically searching for synergism with promising technology such as horizontal drainholes.

In the economic environment prevailing now, these ways of investigation appear to be the best ones that could ensure the necessary development of EOR applications in the world.

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