PRJ, Vol. 3 (January 1991); P. 13–20, 5 FIGS, 2 TABLES.

ADVANCED RESERVOIR MANAGEMENT ASPECTS OF ENHANCED OIL RECOVERY

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آثار إدارة المكامن الحديثة على الإسترداد الإضافي

كياريتشي ج. ل.

في هذه الورقة عرض لفلسفة وتقنيات إدارة المكامن الحديثة. والغرض من إدارة المكامن الحديثة الآتي : (أ) الحصول على نموذج فريد ومفصل لمنشأ المكامن (تركيبها الداخلي) من معلومات المسح السطحي والجيولوجيا وسلوك الحقل. (ب) المتابعة الدقيقة لمدى تقدم وإزاحة الموائع في المكامن. (جـ) لإجراء عمليات المعالجة الهندسية وذلك للحصول على الحد الأقصى من إنتاج الزيت بطرق الإنتاج الأولية وبطرق عمليات حقن الموائع (مثل الماء والغاز وغيرها من الموائع المستعملة في الإسترداد الإضافي).

إستخدامات تقنيات إدارة المكامن الحديثة بداية بتطوير وإستغلال الحقول النفطية مروراً بتكوين فريق عمل موحد من الجيولوجيين والجيوفيزيائيين والمهندسين والخبراء في مجال الجيواحصاء تعتبر من أساسيات فلسفة إدارة المكامن الحديثة. تعتبر المعلومات المتحصل عليها من تطبيق تقنيات المكامن الحديثة بالغة الأهمية للمهندسين وكذلك للسيطرة على عمليات الإسترداد الإضافي.

ABSTRACT

The philosophy and techniques of Advanced Reservoir Management (ARM) are described. ARM is aimed (i) at obtaining a unique and detailed model of reservoir architecture (i.e. its internal structure) from seismic, geological and field performance data, (ii) at accurately tracking the progress of the fluid front(s), and (iii) at engineering remedial action in order to maximize oil recovery by primary depletion and fluid (water, gas or EOR fluids) injection. The use of ARM techniques right from the start of field development and exploitation, and the synergetic team work of geologists, geophysicists, engineers and experts in geostatistics are the essential points of ARM philosophy. Information provided by ARM techniques is of vital importance for engineering and controlling EOR processes.

INTRODUCTION

A good pragmatic definition [1] of reservoir management is "maximizing the economic value of a petroleum reservoir by optimizing production rate and hydrocarbons recovery, while minimizing capital investments and operating expenses".

This is evidently not an engineering definition: it is a definition which is based on yardsticks related to market economics. Descriptors such as present worth, rate of return, pay out time and investment efficiency are used to measure the success or failure of the reservoir management techniques practiced in developing and exploiting an oil or gas field. In certain economic environments, different descriptors are used; for instance, acceleration of production and maximization of oil recovery.

The task of the reservoir manager is to maximize (minimize, in the case of investments and operating expenses) the values of the above-mentioned descriptors.

The reservoir manager thus trades off expenditures (which drain present worth) against the chance of increasing present worth by adding reserves and/or increasing production rates. This process is a continuous balancing act, which begins the very moment a field is discovered.

In the world of market economics, enhanced oil recovery (EOR) is a tool (not the only one!) for optimizing reservoir exploitation. Currently, EOR processes are considered as the "last chance" to

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"scrape the barrel" when the conventional improved oil recovery processes (water injection, immiscible gas injection) are reaching the economic limit.

This is only partially corrrect: in fact, advanced reservoir management (ARM) techniques, if applied to an oilfield from the start of its exploitation, can sometimes maximize the economic value of the field without resorting to EOR processes.

In any case, ARM techniques applied to an oilfield throughout its life provide most of the information needed for the sound engineering of EOR processes used in the tertiary mode, thus increasing their probability of success.

In the following pages advanced techniques will be discussed which, if applied to an oil reservoir from the time of its discovery, will increase its economic value and maximize the probability of success of EOR processes, if needed.

RESIDUAL OIL: HOW MUCH IS THERE? AND WHERE IS IT?

As is well known, the average oil recovery factor from oilfields worldwide ranges between 30% and 34%. It should be stressed that this is an *average* value. Peaks as high as 80% have been reached in some cases (like the East Texas field [2], which was developed with extremely closely spaced wells), and throughs as low as a few percent have been experienced in some heavy-oil reservoirs in primary porosity rocks.

Let us remember that the oil recovery factor, E_R, is the product of two quantities, that is:

$$E_R = E_D \cdot E_V \tag{1}$$

where:

E_D = microscopic displacement efficiency (fraction of oil displaced from the pores in those parts of the reservoir rock which have come into contact with the displacing fluid), and

E_V = volumetric efficiency (fractional coverage of the reservoir rock volume by the displacing fluid).

As a consequence, at any time in the life of a field the volume of the residual oil in a reservoir whose original oil in place was Nm^3 at stock-tank conditions, can be split as follows:

$$N_{r,v} = N(1 - E_v) \tag{2}$$

m^3 of stock-tank oil remaining in the reservoir rock volume not yet contacted by the displacing fluid, and:

$$N_{r,D} = NE_v(1 - E_D) \tag{3}$$

m^3 of residual oil remaining in the reservoir rock volume which has come into contact with the displacing fluid.

Before considering any EOR project in a field, one of the main questions to be answered is: "how much oil still remains in the reservoir, and how much of it could be recovered?"

Usually, standard numerical model simulations "matched" on reservoir past history are used to answer these questions.

Only in the last few years, after many post-mortem analyses of pilot and fieldwide EOR projects which had technically failed, has another question been raised: "*where* is the residual oil? How is it split between oil remaining in the reservoir rock streaks not swept by the displacing fluid ($N_{r,v}$, Eq. 2), and residual oil in the pores of those parts of the reservoir rock which did come into contact with the displacing fluid ($N_{r,D}$, Eq. 3)?".

This is not an academic question: it is one of the most important questions to be answered before one may even consider an EOR process for a field.

In fact, if most of the residual oil is of the $N_{r,v}$ type (poor E_v), there is no point in considering a miscible process with a gas, or a micellar/polymer flooding. These fluids will preferentially flow along the same paths as the water or gas) which displaced the oil before, and only a small amount of the oil left in the pores will be displaced. In these conditions a miscible or surfactant flooding is bound to be a failure.

On the other end, if most of the residual oil is of the $N_{r,D}$ type (poor E_D), there is no point in considering a process designed for increasing the rock conformance factor, such as polymer flooding.

To obtain reliable information on the split of the residual oil between $N_{r,v}$ and $N_{r,D}$ and to gather the basic data needed before starting to engineer an EOR process, the following steps should be taken:

1. build a reliable *geological* model of the reservoir based on all "static" information gathered during the exploration and development of the field (3D seismic data, well logs, core studies, reservoir rock outcrops, if any);
2. validate (and, if necessary, modify) the geological model by embedding all "dynamic" information gathered during the exploitation of the field. Special tests, which will be discussed in a following chapter, must be run for this purpose;
3. periodically run numerical model simulations in a "feedback" mode (Fig. 1) and, at each step, validate the dynamic model against actual reservoir behavior. To this end, probabilistic numerical models are preferable;
4. before engineering the EOR process, check again the spatial distribution of the residual oil, and its split between $N_{r,v}$ and $N_{r,D}$ by running cased-hole logs [3] specially designed for this purpose.

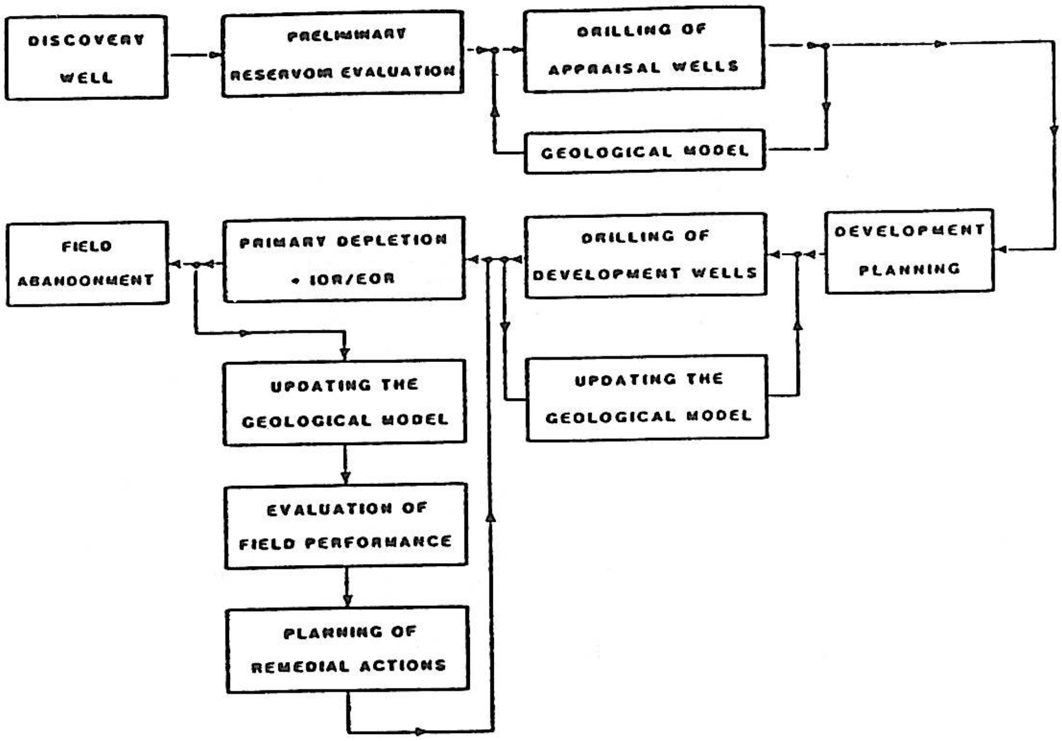

FIG. 1. Reservoir management: the iterative (or "feedback") system.

The above steps are typical of Advanced Reservoir Management (ARM) [4], where "advanced" does not only apply to the techniques used, but also to the attitude of top managements towards reservoir geology and engineering problems.

Time and money should be spent freely to provide the information needed, a complete team of specialists should be available in-house, access should be provided to last-generation probabilistic reservoir models.

All this costs money but, after all, it is certainly much cheaper than an EOR project failure.

THE "STATIC" GEOLOGICAL MODEL

The first step in every reservoir study consists in building a detailed and reliable geological model of the reservoir.

To this end the following information, collected in the exploration, field appraisal and development stages is used:

- 3D seismic surveys interpreted in stratigraphic mode [1, 5],
- sedimenthological, petrophysical and petrographical studies on cores;
- sedimenthological studies at basin scale,
- well logs interpreted in terms of lithology, porosity and water saturation,
- drill-stem and production test results.

The problem which always confronts the reservoir geologist is "how do we extrapolate to the inter-well areas, rock parameter values which are (and can only be) measured at the wells?".

For instance, let us consider permeability values measured on cores and confirmed, as an average value for the pay zone, by well tests.

At the well the picture looks like Fig. 2A. But what about the lateral extent of each streak with different permeability? Are they continuous layers (Fig. 2B), or is it a randomly heterogeneous (sometimes also called "homogeneously heterogeneous") sedimentary unit (Fig. 2C), or is it made up of intercommunicating lenses of different size (Fig. 2D) and, in this case, what is the average size of these lenses and the standard deviation from the average?

And what about the interbedded shale streaks (which are so common in sand/shale sequences deposited in high-energy environments) and their influence in reducing vertical permeability?

All the above factors affect the E_v value in a displacement process.

An insight into the situation can be provided by a sedimentological approach. The well known Weber diagram [6] (Fig. 3) shows how the statistical distribution of interbedded shale layers depends on the environment where they have been deposited: a similar approach can be considered for sand layers.

In a heterogeneous reservoir, the problem immediately arises of the continuity (or "connectivity") between injection and production wells.

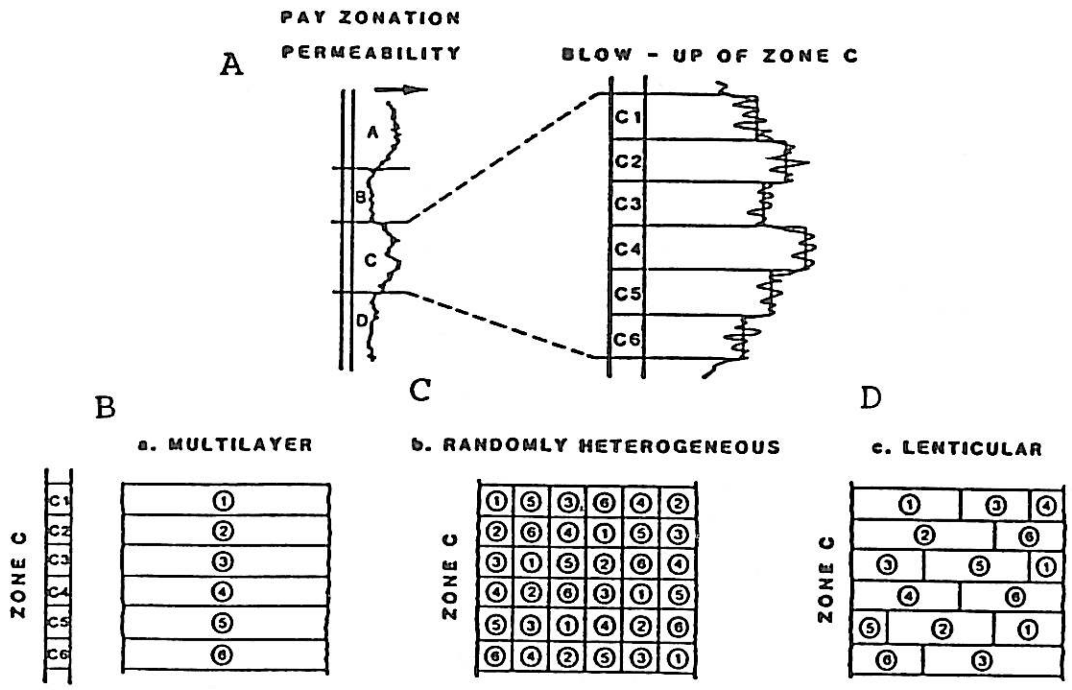

FIG. 2. Permeability variations within a reservoir zone, as shown by core analysis; (a)–(c) different geological models to explain and extrapolate them to the well drainage area.

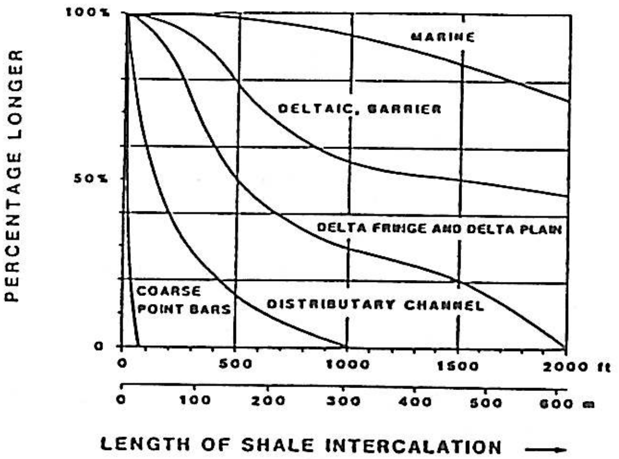

FIG. 3. Statistical distribution of the size of shale intercalations as a function of the depositional environment. (From Ref. 6).

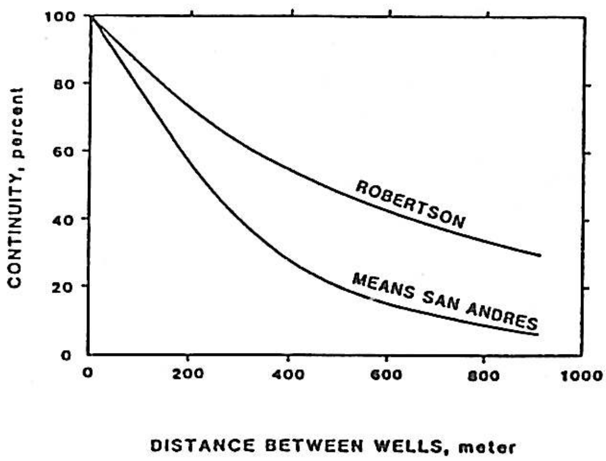

FIG. 4. Pay continuity between wells versus interwell distance, Means San Andres and Robertson Clkearfork units, TX. (From Ref. 4).

Obviously, in order to displace (and produce) the oil from a reservoir layer, at least one injection and one production well must be drilled in it.

For a given numbers of wells drilled in a field, the percentage of oil-bearing rock with which the injected fluid comes into contact (that is, E_v) is a function of the average areal extention of the permeable streaks, and of the standard deviation of the extention.

Viceversa, in a heterogeneous reservoir rock the connectivity between injection and production wells is a function of well spacing: the closer the spacing, the higher the connectivity (and, therefore, the higher the E_v and the oil recovery).

Figure 4 shows an example [4] of how interwell connectivity is influenced by well spacing in two oilfields in Texas. It must be noted that in the San Andreas reservoir the connectivity (and therefore, to stress this once again, E_v and oil recovery) increased by 50% when the spacing was reduced from 40 to 20 acres/well(!).

It should be noted that the influence of well spacing on oil recovery was recognised as early as in the 1920s, on an empirical basis (Cutler's rule [7]). This concept was then rejected when reservoir engineering "science" was forced to forget about heterogeneity, due to the difficulties it caused in the calculation of

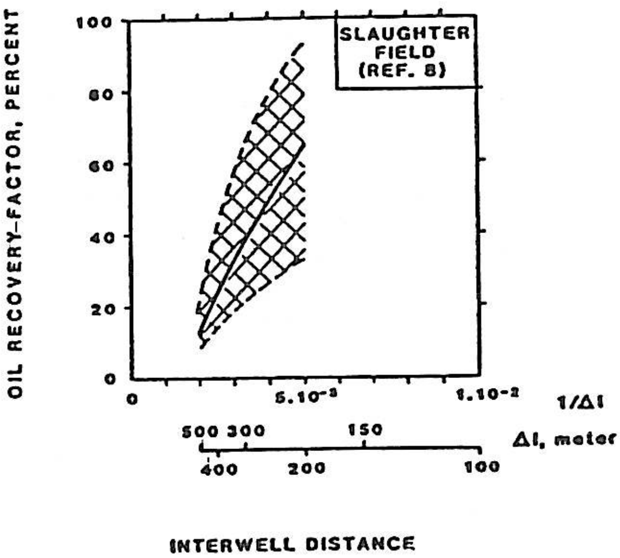

FIG. 5. Oil recovery versus interwell distance, Slaughter field, TX. (Data from Ref. 8).

reservoir behaviour. Figure 5, based on data presented in a classical paper [8], shows how Cutler's rule holds good for a real oilfield.

If outcrops of the producing formation are known to exist, they must be studied in very great detail, as they are the only source of direct (even if only qualitative) information on facies distribution, permeability trends, presence of impermeable barriers, etc. The statistical treatment of such data can result in information of the utmost importance in understanding the "architecture" of the reservoir.

It must be noted that the study of outcrops as an aid to evaluate reservoir architecture was carried out for the first time some 27 years ago [9], but it is only recently that this technique has become common practice both in the U.S.A. and Europe [10].

Crosswell seismics [11], and its interpretation in tomographic mode, is still in its infancy. This technique shows excellent potential for describing interwell characteristics of the reservoir rock: it is hoped that it will soon grow to the stage when it becomes a routine tool for reservoir description.

It should be borne in mind that only the data from cores and outcrops are *direct* measurements of reservoir rock properties. All the other information and data mentioned above are *indirect* evaluations of these properties. In order to merge all direct and indirect data to build the most reliable geological model(s) of the reservoir, and in particular in order to extrapolate the information to interwell areas, statistical techniques must be used (cluster analysis [12], fractal distribution [13], etc.). A very efficient technique for describing the statistical distribution of shale lenses within the reservoir rock has been proposed by Haldorsen [14].

The interpretation and evaluation of reservoir architecture calls for the *joint* effort of specialists from many disciplines: sedimentology, petrography, petrophysics, regional geology, log analysis, geochemistry, seismics, reservoir engineering, and geostatistics. *Only team work can provide the synergy needed* to build the more realistic and probable geological model of the reservoir. And sometimes a number of geological models show the same probability of representing the actual architecture of the reservoir, being equally consistent with the basic data and information available.

"DYNAMIC" DATA FROM RESERVOIR PERFORMANCE

When the field starts producing a lot of information on its dynamic behaviour can (and *must*) be gathered.

Data on well performance (oil, gas and water production rates, shut-in and flowing bottom-hole pressures, standard pressure drawdown, buildup and production logging tools, PLT surveys) as routinely measured and collected in the data-base are very valuable, but they provide only a partial picture of reservoir behaviour.

The other very important part is provided by the following non-routine tests and data:

- inter-well connectivities and transmissibilities,
- vertical communication between zones in layered reservoirs, with the measurement (or evaluation) of vertical permeability,
- advance in time of the displacing fluid front(s).

In standard petroleum engineering practice these measurements are seldom taken.

In ARM they must be taken at regular intervals *from the start of production.*

Only by so doing a detailed picture of how oil moves in the reservoir, and where "pockets" of rock not flooded by the displacing fluid(s) are located, can be obtained.

Long-duration interference tests [15], pulse tests between groups of wells [16], and between layers in the same well [17], "coloured" tracer tests between injection and production wells [18], if properly interpreted by means of *ad hoc* numerical models, can provide valuable information on interwell connectivity and transmissibility, as well as on vertical communication between layers and vertical permeability.

The progress of the displacing fluid front(s), and the spatial distribution of rock "pockets" which have been by-passed by the displacing fluid(s) can be located by means of cased-hole logs.

Pulsed neutron capture (PNC), pulsed neutron spectral (PNS) or induced gamma-ray spectral

(IGRS) logs [3], as well as nuclear magnetism logs [19] (NML) are the most suitable tools for this purpose. For locating gas fronts the routine neutron+density logs (CNL+FDC) combination can give good results.

When the wells are completed in open-hole, standard focused resistivity logs can be used to locate the displacing water (or water-bearing fluid) front.

When ARM techniques are used, the most suitable combination of the above-mentioned tests and logs must be engineered for each reservoir and displacing fluid considered.

This combination of tools must be run at regular intervals during the life of the field. In addition, special campaigns must be arranged when something "unexpected" happens (an early breakthrough of water or gas in a well, an abnormal pressure drop in an area of the reservoir, etc.).

NUMERICAL MODELS AS AN ADVANCED RESERVOIR MANAGEMENT TOOL

In the early stage of field development, numerical models based on the initial geological model are used for locating wells and defining drilling schedules. A stochastic approach [20] should be used in order to provide a scenario of the various possible reservoir architectures which show an equal probability of representing the actual reservoir structure.

This calls for a lot of Central Processing Unit (CPU) time. The use of parallel computers, when it becomes standard practice, will drastically reduce this time.

As soon as dynamic data from reservoir performance are available, they should be embedded into the geological model(s), so as to validate them against the actual reaction of the field to the production history. In this way the number of models which match reservoir performance is progressively reduced, until such time as only a few models show the same probability of describing the actual reservoir architecture.

It is of the utmost importance that each modification to the model be based only on data gathered from well and field tests [21]. The current "garbage in, garbage out" approach of modifying reservoir parameters (mainly vertical permeabilities and relperms) with the only aim of matching well behaviour, without being consistent with the geological model, must be avoided.

The trial-and-error approach of matching model results to actual reservoir performance should be repeated at sufficient intervals during reservoir life.

Every time, the information gathered from the model on the position of the displacing fluid front(s), and the presence and location of reservoir rock "pockets" which have not been swept, should be used to engineer remedial action aimed at improving the conformance factor, E_v, of the reservoir.

Well workovers and recompletions, drilling of infill wells [22], changing the production/injection well pattern should be planned according to the results of model simulations. And field reaction to the planned remedial action should be evaluated on the model before being carried out in the field.

Infill wells aimed at improving interwell connectivity may be very efficient in enhancing oil recovery. A recent study [23] shows (Table 1) how some 73% of oil reserve additions in Texas from 1973 to 1982 was provided by infill drilling, against a mere 21% resulting from new field and new pool discoveries.

Table 1. Composition of Oil Reserve Additions in Texas from 1973 to 1982 (from Ref. 23)

	Volume (10^6 m^3)	% of Total
– New-field wildcat discovery, with appreciation	103.4	11
– New-pool discovery	95.4	10
– Infill and extension drilling	696.4	73
– Tertiary projects	38.8	4
– Delayed abandonment	22.3	2
	956.3	100

The same study [23] estimates at 12.7 billion m^3 the amount of *movable* oil in place in U.S. oilfields which is not swept by the current well patterns, and could be recovered by infill wells (Table 2).

Table 2. U.S. Oil Distribution (from Ref. 23)

	Volume (10^9 m^3)	% of Total
– *Recoverable oil by primary depletion and waterflooding*		
• produced	21.6	27.8
• remaining	4.5	5.8
– *Recoverable oil after waterflooding*	26.1	33.6
• recoverable by currently implemented EOR processes, with an oil price up to 30 \$/bbl	2.6	3.3
• mobile oil in unswept zones (target for infill drilling)	12.7	16.3
	15.3	19.6
– *Immobile Oil*	36.4	46.8
TOTAL	77.8	100.0

Accordingly, conventional water-flooding with infill drilling could raise to 50% the average oil recovery from U.S. fields, against the currently estimated value of 33.6%.

ARM techniques as described in this paper are already in use in some oilfields. The case of the Stratfjord field in the Norwegian sector of the North Sea has recently been described in technical literature [24], and it is known that the same technique is being applied to the Oseberg oilfield, in the same area. An earlier case where an ARM approach was used [25] is the Bu Attifel field, GSPLAJ.

The use of numerical models for ARM calls for a number of improvements in simulation techniques. For instance, it is known that standard numerical models almost always indicate little or no sensitivity of the ultimate oil recovery to production rates [26]. This is one of the areas which deserves further investigation.

EOR OR NO EOR FOR THIS FIELD?

As already discussed, when the decision is made to explore the feasibility of a suitable EOR process in a field, the first questions needing an answer are:

- is a reliable and detailed description of reservoir architecture available?
- how much residual oil remains in the reservoir at this stage of the game?
- how is the residual oil split between:
  - residual oil in the pores of the rock volume swept by the displacing fluid(s)
  - oil in the reservoir rock "pockets" which have not come into contact with the displacing fluid(s)?

If ARM techniques have been used in developing and exploiting the field, the information which has been collected provides reliable answers to the above questions.

Moreover, a good connectivity between injection and production wells should already exist, and a good volumetric efficiency, E_v, should have been attained.

And, it ought to be stressed here, a good connectivity is *the* prerequisite for the success of any EOR process, as it assures a good coverage of the reservoir by any kind of injected fluid.

This is a very valuable by-product of ARM techniques used in the primary and waterflooding (or gas injection) phases of reservoir exploitation.

It may be that, due to the high E_v, the oil recovery factor attained thus far is very high, so the amount of oil left in, the reservoir does not warrant any EOR process.

This is good news, as EOR processes are usually very expensive, require front-end investments and, so far, do not guarantee a success.

If ARM techniques have not been used, a lot of work remains to be done along the lines sketched in the previous pages. But the information that could have been provided by monitoring reservoir peformance is lost for ever.

Based on the foregoing considerations it appears that the use of ARM techniques right from the beginning of the life of an oilfield represents the most efficient (and cost-effective) way of optimizing, throughout its life, the exploitation of an oilfield, including the "scraping" phase of EOR.

Obviously, the same ARM techniques must then be used in order to monitor and control field performance in the EOR production phase.

CONCLUSIONS

The Advanced Reservoir Management (ARM) techniques described in this paper provide the vital information needed to:

- determine the internal structure (or "architecture") of the reservoir, so as to build a realistic and unique geological model,
- track the advance of the displacing fluid front(s) and define the volume and location of reservoir rock "pockets" not swept by the displacing fluid(s),
- properly engineer remedial action (well recompletions and workovers, changes in the injection/production pattern, drilling of infill wells, etc.) in order to maximize reservoir coverage by the displacing fluid(s),
- provide basic data for the selection of the most cost-efficient EOR process
- monitor and control progress of the EOR process.

ARM techniques should be used from the start of the development and exploitation of the oilfield.

If properly and continuously used, ARM techniques may result in oil recovery by primary depletion plus waterflooding (or immiscible gas injection) which make recourse to EOR processes no longer necessary.

A complete and efficient team of specialists (geologists, geophysicists, engineers and experts in geostatistics), and their synergetic team work is needed to apply ARM techniques to a field.

Moreover, a lot of well and interwell tests, as described in this paper, must be run throughout the life of the field to provide basic data on its internal structure and dynamic performance.

Obviously, the ARM approach calls for additional costs. Top managements of the oil companies should be made aware that the extra time and money spent to run special tests in the field, and to process them by teams of specialists, is not a waste of time and money.

Afterall, a mere 1% increase in oil recovery from a field with 1 billion barrels (159 million m^3) of *oil in place* means, in present worth, some 100 million dollars of additional income for the oil company.

NOMENCLATURE

E_D = microscopic displacement efficiency, fraction
E_R = oil recovery factor, fraction
E_v = volumetric efficiency, or conformance factor, fraction
N = initial oil in place, m^3 STO
$N_{r,D}$ = oil remaining in the reservoir rock volume which has come into contact with the displacing fluid, m^3 STO
$N_{r,v}$ = oil remaining in the reservoir rock volume which has not yet come into contact with the displacing fluid, m^3 STO

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