

APPLICATIONS FOR TRACERS IN RESERVOIR CONFORMANCE PREDICTIONS AND INITIAL SATURATION DETERMINATIONS

By

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Abstract

When evaluating a reservoir for optimization potential, an interwell tracer program is a valuable tool to be utilized as a means to better understand the by-passed pay areas of the reservoir that can cause poor conformance. Tracers can be an effective tool also when incorporated into the development of a detailed reservoir model so that the geologist and reservoir engineer have a better understanding of the flow units that exist between wells and of the initial oil, water and gas saturations which may exist in the reservoir.

This paper addresses the benefits that tracers can provide, both on a macroscale and microscale basis, to more effectively determine and model flow units in the reservoir. The paper uses case examples to illustrate the application of tracers to improve production. It shows which tracers provide the best results and gives a better understanding of saturations, sampling and analytical techniques used to obtain quality data.

It also addresses some of the environmental concerns that may cause companies to refrain from using tracers as a viable tool in understanding flow units and quantifying by-passed pay.

Introduction

Although many of the world's reservoirs have reached maturity in relation to oil production (even though OOIP still exceeds 75% in many cases), the question remains, "Is there recovery technology available that will allow more oil to be produced from these reservoirs?". Many technical people answer, "Yes, if we had a better understanding of the reservoir so that we could identify potential unswept zones". The key component to helping us unlock the remaining reserves in mature fields is to have a better understanding of reservoir heterogeneities which significantly affect where the fluids are or are not flowing through the reservoir¹. By applying an integrated reservoir analysis approach (geology,

geophysics, coring, reservoir and production engineering and petrophysics) a more comprehensive understanding of how the fluids are flowing through the porous media will be achieved².

This information is valuable in providing data on how to characterize the reservoir but it is limited to information in the near wellbore region. Application of geostatistical techniques can integrate a variety of data to extrapolate interwell properties, but these still represent non-quantifiable properties in most situations. It is with the additional knowledge of fluid flow between individual wells that a proper understanding of the reservoir can be obtained.

The benefits of tracers are:

1. Improved understanding of how and where injected fluids are or are not flowing between wells.
2. Better identification of the amount of hydrocarbons remaining in individual flow units as a result of poor sweep efficiency. This information is obtained by measuring S_w and/or S_o from preserved core obtained in swept zones, or by using reservoir modelling and material balance techniques to quantify the volume of oil remaining in a by-passed zone based upon the results of the tracer program.

Over the years, two methods have been utilized to obtain interwell fluid flow characteristics - pressure transient analysis and interference tests and interwell tracer programs. Both tests complement each other by providing key information on how the fluids move between wells. Pressure transient analysis tests measure average properties between wells and are good measurement techniques for determining if permeability trends exist. Interference tests can quantify if individual wells exhibit interconnectiveness and some indication of the degree of interconnectiveness. On the other hand, interwell tracer tests provide valuable information about the extensiveness of heterogeneity that exists to clarify the averages measured by the interference tests. Interwell

tracer tests can also provide quantitative information concerning the rate of movement and volume of fluid that is produced at each well. This data provides clues concerning the early breakthrough characteristics of a flood that strongly affect its ultimate recovery. Therefore, pressure transient analysis and interwell tracer studies are complementary, not competitive, tests³. The main objective of this paper is to address how tracers allow one to more effectively:

- characterize interwell fluid flow
- obtain better measurements of S_w and S_o in the reservoir's flow units through improved coring techniques

Through improved knowledge of how and where the fluids are moving between wells and how much by-passed pay remains, technologies can be identified that will be best suited to optimize mature reservoirs.

Using Tracers to Characterize Interwell Fluid Flow

When evaluating the upside potential of a maturing reservoir, a tracer program can provide valuable information with respect to optimizing production. This information includes:

1. **Flow direction** - Where are fluids flowing? What injectors are influencing various producing wells?

Case Examples -

- i) waterflooding
- ii) gas injection (WAG)

- i) **Waterflooding** - Is the waterflood maximizing reservoir sweep efficiency?

While instituting a multi-tracer program, in a sandstone reservoir in Alberta, to optimize an existing waterflood (direction, rate and continuity), it was discovered, upon injection of four different tracers (Cobalt 60, Nickel 63, Cesium 137 and Tritiated HO) into separate injection wells, that the tritiated HO (HTO) broke through at a production well within six months (three months

before any of the other tracers began appearing at the production wells). Following its initial sweep through the reservoir, the HTO then completed a second, more extensive, sweep evidenced by a much higher concentration of HTO at the respective production wells. This double sweep indicates that there was a high permeability sand lense, which provided greater definition of the size and conductivity of the high permeability streak within the geological model. This improved model could then help reduce the risk in developing a water shut-off strategy on the high permeability sand lense in selected wells so that reservoir conformance to water injection could be improved. (Figure 1)

- ii) **Gasflooding (WAG)** - Is the water following the solvent to maximize sweep efficiency?

An area of interest over the years has been the application of gas injection technology in enhanced oil recovery. Specifically, those gases classified as "miscible" have been applied in the field and, in some cases, the results have been somewhat less than expected. There are a number of technical reasons why so-called "miscible" floods have performed inadequately⁴, but such discussion is, for the most part, beyond the scope of this presentation. Some of the more recent work⁵ has indicated that depending upon the testing used to evaluate the process, the extent of the interfacial tension reduction actually can pre-dispose a gas injection project to success or failure.

The basis for this is shown in Figure 2 where one observes a typical cross-section of a reservoir. In this figure, the geology indicates that there are approximately six separate flow units present. Figure 3 illustrates the microscale geology associated with two of these flow units. In Figure 3A, a pore size distribution is observed where the bulk of the porous features exhibit a characteristic diameter greater than 20 microns, whereas in Figure 3B, over 90% of the porous features are exhibited at a characteristic diameter of less than 20 microns. In such a case, the flow characteristics of gas and oil, and for that matter, water and oil, in these various flow units, can be very different. The following equations show the

relationships of concern when coupling micro-scale geology with the phase behaviors.

$$\Delta P = \geq \Delta P_{CAP} \propto \frac{\sigma}{D} \quad (1)$$

$$fg = \frac{1}{1 + \frac{1}{M}} M < \frac{\mu_o}{\mu_g} \quad (2)$$

$$\frac{Surface\ Area}{Volume} \propto \frac{1}{D} \quad (3)$$

Equation (1) provides the capillary pressure equation, which simply states that the capillary pressure which is holding the oil in the porous media is proportional to the interfacial tension between the displaced and displacing fluid provided by the diameter of the porous feature in which the two-phase system is present. Equation (2) shows the standard fractional flow equation where the mobility ratio "M" is proportional to the viscosity ratio, and Equation (3) shows the standard proportionality between surface area and volume.

The way in which a gas will displace an oil depends upon the compromise reached between these three relationships. Coupling these three relationships in the context of the macroscale and microscale geology leads to the identification of whether a system will be mobility- or interfacial tension-dominated. There are a series of lab tests that can be used to identify the extent of mobility vs interfacial tension domination, but sometimes floods have been implemented in the field on the basis of testing which is less than sufficient. For example, Figure 4 illustrates the standard plot which is used many times for evaluating an appropriate gas design. The plot shown in Figure 4 describes the conditions in terms of the C₂₊ percentage as well as the C₂₊ molecular weight which define a

specific interfacial tension value. In the past, interfacial tension has been viewed by some as a sufficient condition for gas design and, consequently, once the relationship in Figure 4 had been identified, the design was completed. However, from more recent experience, we know that because the efficacy of a gas is going to be dependent upon the compromise between the interfacial tension and mobility, this balance is not indicated in Figure 4. For example, in some enriched gas displacements in the field, those gases which have a low molecular weight of C_2^+ often exhibit a bias towards mobility domination; whereas those solvents which have a higher C_2^+ molecular weight tend to be more associated with an IFT domination. Moreover, in some cases, the higher C_2^+ percentage at low molecular weight have a disadvantage from a gravity stabilization standpoint and, therefore, an increased pressure must be applied so that even though the potential IFT is the same, the expected sweep is going to be comparable also. These are some of the indicators that can be scoped in the lab, but which are often omitted.

This brings us to the benefit of applying tracers to the field. For example, Figure 4 shows the irregular patterns of gas breakthrough when compared to the path which the water follows. Because of different interfacial tensions between the gas and the water in the presence of oil, the accessibility, from a microscale perspective and in light of Equation (1), will predispose a gas to flowing in a direction different than that of the water as illustrated in Figure 5 from a gas injection (WAG) project in Alberta.

2. Reservoir Continuity - The information received about which injector influences which producer in terms of rate (breakthrough times) and what percentage of fluid (volume) is going into each well can provide abundant information about reservoir continuity⁶ (high permeability streaks, unswept zones, shale barriers and permeability and porosity lenses).

3. Reservoir Anomalies - Are there areas of the reservoir that tracers have not swept thereby allowing valuable information to be gained as to macroscale heterogeneities (tight zones, lenses of porosity and permeability, faults,

fractures, etc.). As illustrated by Figure 6, from a waterflooded sandstone reservoir in Alberta, in the centre of the pool, none of the four tracers (HTO, Ni63, Co60, Cs137) injected swept this section of the reservoir. The conclusion was made that there was a tight streak surrounding this well. From this information the water injection pattern was altered to eliminate this tight zone.

Water-Based Tracers

For water soluble tracers which are added to injection water, over the last few years most of the interwell tracer studies have been conducted using radioactive isotopes versus chemical-based tracers as isotopes are more reliable and accurate. Chemical tracers have been largely abandoned due to numerous problems including adsorption of the chemical onto the rock system, destruction of the tracer (oxidization, bacteria or precipitated out of solution), natural interference or contamination which make analysis difficult (ie. fluorescent compounds), and the large volumes and expense required for accurate detection (ie. alcohol ~ several thousand litres vs HTO 5 ml).

Due to advances made in radioisotope technology many safe radioisotopes can be used although tritium is, by choice, more widely used because it is the safest beta-emitter. Tritiated water emits electrons which cannot pass through paper or skin, versus gamma-emitters which emit gamma rays which can pass through most materials. Greater expense is involved in a tracer program utilizing gamma tracers (Cobalt 60, Cesium 137, Cesium 134) because of safety requirements generally imposed by the regulatory agencies. Transportation of gamma tracers, particularly to foreign or remote sites, can also be problematic. Table 1 provides a list of various types of water-based radioisotope tracers and concentrations to consider for field use.)

Gas Tracers

When designing a gas tracer program, it is important to determine gas tracer partitioning into the oil phase because the greater the

partitioning, the longer the tracer will lag behind the injection front. Since the use of a gas tracer helps to identify solvent breakthrough in gas injection projects, it is important to select gas tracers with low partitioning coefficients. When using gas tracers with a low gas-oil partitioning coefficient, the tracer will be predominately in the gas, not oil, phase, thus making the collection of pressurized oil samples unnecessary⁷. In a multi-well program, a variety of tracers are usually used to quantify individual well performance. Once again, tritiated hydrocarbons are often used due to detection limits. A knowledge of gas solubility effects, however, is crucial to dissociated produced solution gas from breakthrough gas to adequately characterize true amount of breakthrough gas.

Sampling and Analytical Techniques To Ensure Quality Data From a Field Tracer Program

1. Sampling

- a) Always sample water from producing wellheads where possible.
- b) If analyzing a gas-gated tracer, ensure that the solvent comes from a test separator and that the well can be isolated to that separator. Allow sufficient time to purge previous well tests from the separator. Sample apparatus must be thoroughly purged before sampling.
- c) It is necessary to have a higher sample frequency at the beginning of the program to enable identification of any unusual formation characteristics (lenses, fractures, faults) or anomalies as these features may contribute to very rapid tracer breakthrough. Many of these samples are not analyzed unless anomalies occur but it is important to collect and store these early samples.
- d) Match dosage and sampling frequency to the performance of the tracers - it is important to consider the time period that will be utilized to characterize the reservoir (ie. month versus year). This will be a function of injection rates, net pay, porosity, saturations, heterogeneity and well spacing and must be individually considered for each particular application.

2. Analytical Techniques

Beta-Emitter vs Chemical - Beta-emitters are counted in liquid scintillation counters which measure atomic disintegrations. Chemical tracers are measured by wet-chemistry, colorimetric or gas chromatography (ie. technician skills and interpretation for repeatability). By comparison, nuclear counting would accurately measure one part per trillion, where most chemicals would require several parts per million for accurate detection. This illustrates the utility of radioactive tracers in comparison to chemical tracers.

Using Tracers to Determine In-situ Saturations From Preserved Core

Recent Advances in Core Bit Technology

Over the last three to five years, coring technology has advanced considerably in the ability to retrieve core in a non-invaded state due to the development of low invasion core bits. This low invasion coring technology^{8,9} gives companies a clearer picture of in-situ saturations when used in conjunction with a traced mud system and, in some cases, a sponge core barrel.

The theory behind low invasion coring technology is as follows:

1. The design of the core bit hydraulics has been altered so that the flow ports that are flowing mud out of the core head are now perpendicular to the axis of the hole. With the flow ports perpendicular to the formation, a vortex flow is created at the bit face which improves the removal of the drilled cuttings from the face of the bit. With this vortex flow removing drilled cuttings from the face of the bit, the bit now continuously cuts virgin core which increases the rate of penetration (ROP) and reduces contact time during drilling. (See Figure 7 for an illustration of a LIC core bit.)
2. The vortex flow creates a positive pressure on the core and a negative pressure on the outside of the core barrel thereby

minimizing invasion tendencies on the core by drawing the circulating mud system away from the core face.

3. The placement of an inner barrel very close to the cutting surface of the bit enhances the ability to minimize fluid invasion as the core enters the inner barrel immediately after being cut by the bit.

Fluid System Design to Obtain Preserved Core

In order to obtain a preserved core to evaluate not only in-situ saturations but other properties such as wettability, capillary pressure or relative permeability, using the low invasion core (LIC) technology, further refinements need to be made to the mud system so that the LIC bit can perform effectively. This is due to the fact that some mud invasion may still occur, particularly in higher permeability formations or with high compressibility (gas) reservoirs. The mud system refinements to maintain native state wettability include:

1. Neutral pH
2. No chemical additives (surfactants, lignosulphonates, corrosion inhibitors, polar mud additives, mud thinner caustics and acidic additives).
3. Radioactive tracers to quantify the amount of invasion due to drilling to determine the initial water saturation through a material balance calculation. If a sponge core inner barrel is used vs an aluminum or fibreglass tube then initial oil and gas saturations may also be quantified if the core is obtained in a non-flushed or minimally flushed state.

Types of Tracers

From experience, radioactive and stable isotope (HTO and D₂O) tracers are preferred because chemical tracers have the tendency to be adsorbed into microporous clays or readily decompose and be subject to contamination issues. If the water saturation in the core is too low to be removed for analysis by non-destructive means (ie. centrifugation) then crushing and

extraction must be used which can result in errors due to commutation effects. Preferred tracers are:

- Tritium* (HTO) - radioactive (Beta-emitter)
- Deuterium (D₂O) - non-radioactive (heavy water)

* Tritium has some advantages in that it is considerably less expensive than deuterium, does not naturally exist in formation waters and has much lower detection limits than deuterium.

Case I

Objective for Coring: To determine initial water saturation and oil in place to evaluate waterflood feasibility.

- Sunburst sand
 - Oil reservoir
 - Average permeability - 100-200 mD
 - Average porosity - 25%
- conventional core and logs calculate 45% water saturation
 - drilled preserved core using a low invasion coring technology and a water-based mud with a resin system for fluid loss
 - preserved core measures 30%, an increase of 27% OOIP
 - preserved core, logs and build-up analysis show negligible skin indicating minimal formation damage

Results - An addition of 3 million barrels of recoverable oil by optimizing the existing waterflood.

Case II

Objective for Coring: To determine water saturation and optimize fracturing program to investigate concerns with phase trapping of water-based fracture fluids.

- Gething sand
- Gas reservoir
- Average permeability - 1-10 mD
- Average porosity - 7-8%

- conventional coring indicated insitu water saturation was 40% and correlates with logs
- drilled preserved core with an oil-based mud
- preserved core logs indicated insitu water saturation is 15-20%

Results - Increased production by optimizing frac jobs, switched to oil-based fracs.

Case III

Objective for Coring: To determine insitu water saturations for completion strategy

- Glauconite sand
 - Gas reservoir
 - Average permeability - 1-5 mD
 - Average porosity - 11%
- conventional coring with water-based mud and logs. Produced gas, but was difficult to calculate an accurate water saturation from logs.
 - preserved core with oil-based mud with low invasion core bit, water saturation 25-30% and verified with air-mercury capillary pressure which calculates irreducible water saturation - it was determined that this reservoir was not undersaturated but damaged due to swelling clays.

Results - Used to optimize the drilling and completion program.

Sampling and Analytical Techniques to Determine In-Situ Saturations With a Tracer

1. Sampling and Preparation of Mud

Once a specified volume of tracer is added to the mud tank and 1-2 complete mud circulations have been achieved to ensure an evenly distributed tracer concentration, coring can begin. After coring begins, a standard practice is to collect mud samples in 1 litre containers every metre of depth so that a profile of tracer baseline concentration in the mud system vs core depth can be determined.

2. Analytical Techniques To Determine S_w from Core

To obtain quality S_w data from the core, priority should be given to ensure that the time period for the core to reach surface until it is in the lab is no more than 24 hours. After 24 hours various factors may come into play (such as condensation and imbibition of water-based filtrate) if a water-based mud is used, reducing the ability to measure accurate S_w . When the core is shipped to the lab (if consolidated), do not allow it to freeze as this will affect the fabric of the rock and alter the rock's wettability. Once the core arrives in the laboratory and the plugs have been cut in a non-damaging fluid, the water saturation can be determined by extracting the fluids using a Dean Stark technique with toluene as an oil-dissolving solvent. The water from the extraction process will then be measured to determine tracer concentrations. The following methods are used to determine tracer concentrations:

Tracer		Accuracy Level
Tritium (HTO) - Liquid scintillation counter	Atomic disintegration	pptrillion
Deuterium (D ₂ O) - Mass spectrometer	Differences in abundance between H ₂ and HD isotopes	ppthousand

3. Analytical Techniques to Determine S_o from Core

To determine in-situ oil saturations accurately, a sponge core barrel must be utilized in conjunction with a traced water-based system and LIC technology in order to account for oil expelled from the core by degassing due to the high gas solubility of hydrocarbons in comparison to water.

See^{10, 11, 12} for further details on techniques utilized to measure in-situ saturations from core.

Environmental and Safety Concerns

Injection (highly concentrated material of HTO or gamma emitters) - The radioisotopes are

produced in such infinitesimal quantities that only sophisticated equipment can detect them. Therefore, there are no health or environmental hazards whatsoever when sampling, storing or transporting the samples (ie. for HTO a few pci/ml in a typical reservoir water vs drinking water standard of 1000 pci/ml).

The only area in which environmental and health hazards may exist is with the injection of radioisotopes. For this reason, injection is conducted by a team of highly trained personnel. This group ensures that no trace of the tracer remains and that all of the material has been injected below surface. Naturally the use of soft beta tracers have further improved the safety of the injections.

CONCLUSIONS

1. An interwell tracer program is an effective tool for identifying areas of by-passed pay due to poor reservoir conformance.
2. An interwell tracer program provides valuable information concerning flow direction, reservoir continuity and reservoir anomalies.
3. Beta-emitter radioisotopes are becoming more widely used due to low health and environmental concerns and accurate, reliable measurements (HTO, Ni63, Tc99, tritiated isopropyl alcohol).
4. Radioisotope and stable isotope tracers (HTO and D₂O) are a valuable tool when used with low invasion coring (LIC) to determine S_w and S_o.

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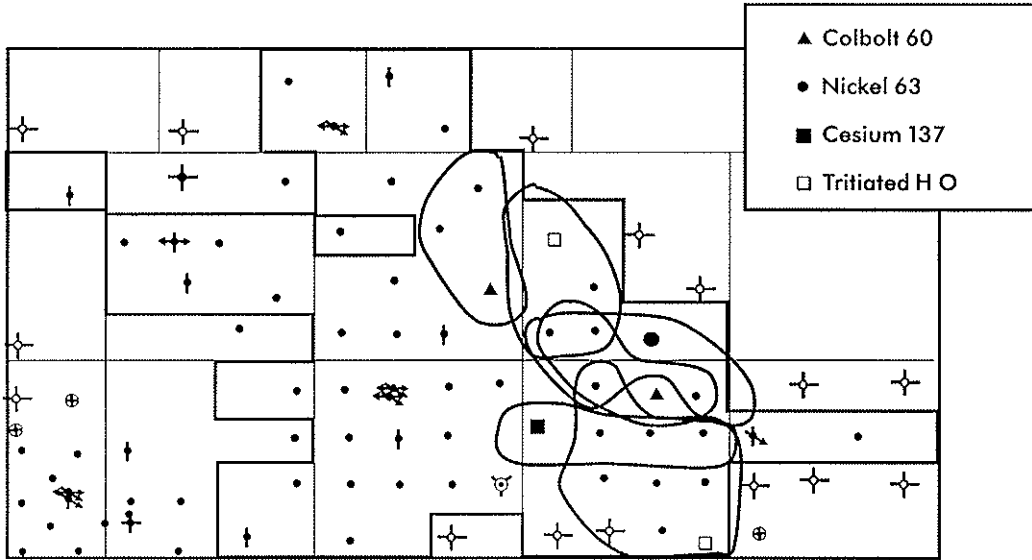
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TABLE 1

TRACERS USED TO CHARACTERIZE INTERWELL FLUID FLOW

Tritiated Water Tracer (Beta Materials)				
	Typical Distance Traced (Yards)			
	100 - 500	500 - 1000	1000 - 2000	2000 - 6000
Tritiated H ₂ O (HTO)	1 - 5 ci	5 - 20 ci	20 - 50 ci	50 - 100 ci
Nickel 63 (Ni63)	10 - 100 mci	100 - 200 mci	200 - 400 mci	400 - 1000 mci
Technician 99 (TC99)	10 - 100 mci	100 - 200 mci	200 - 400 mci	400 - 1000 mci
Tritiated Isopropyl Alcohol	0.5 - 2 ci	2 - 5 ci	5 - 8 ci	8 - 20 ci
Optional Water Tracers (Gamma Materials)				
Cs134	10 - 100 mci	100 - 200 mci	200 - 400 mci	400 - 1000 mci
Cs137	"	"	"	"
Co60	"	"	"	"
Co57	"	"	"	"
Gas Tracers				
Krypton 85	0.5 - 2 ci	2 - 3 ci	3 - 5 ci	5 - 10 ci
Tritiated Hydrocarbons C ₁ , C ₂ , C ₃ , C ₄	1 - 5 ci	5 - 8 ci	8 - 20 ci	20 - 50 ci

**Fig.1 : Roseray Formation-Sandstone Reservoir
Water Flood**



**FIGURE 2
CROSS-SECTION SHOWING ROCK TYPE DISTRIBUTION**

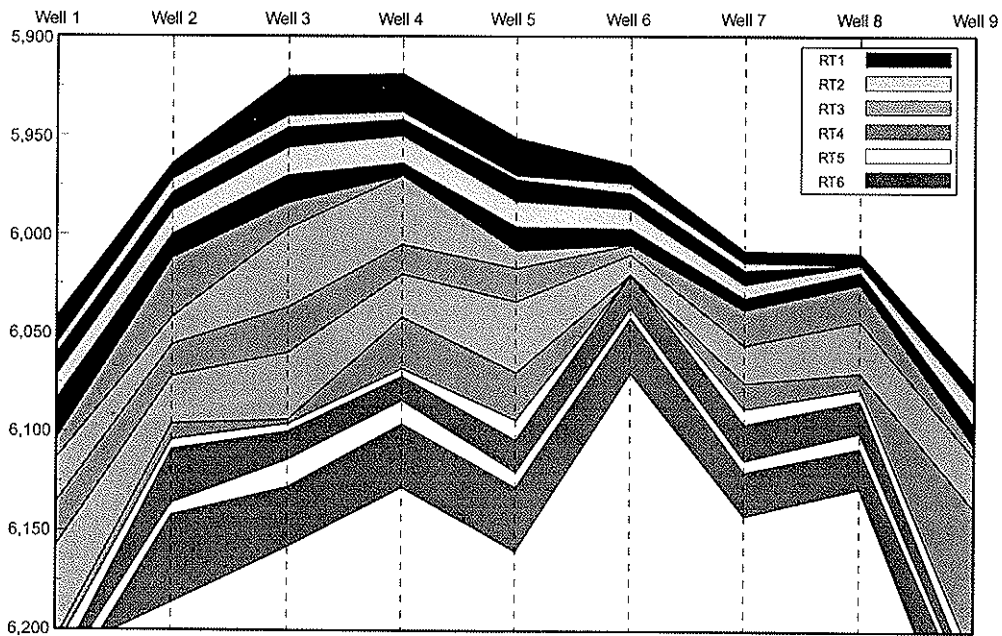


FIGURE 3A
RELATIVE PORE SIZE DISTRIBUTION

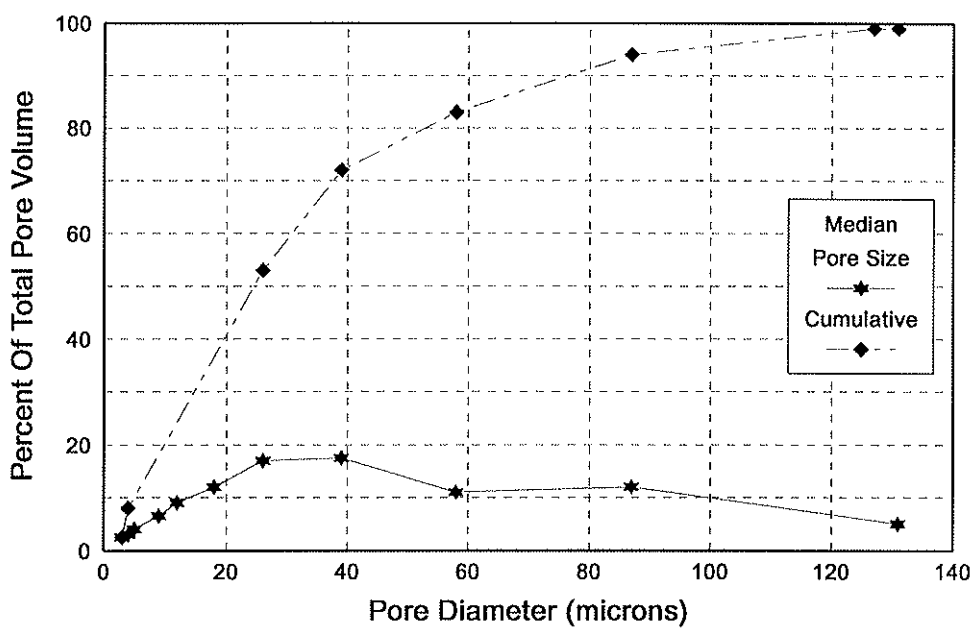


FIGURE 3B
RELATIVE PORE SIZE DISTRIBUTION

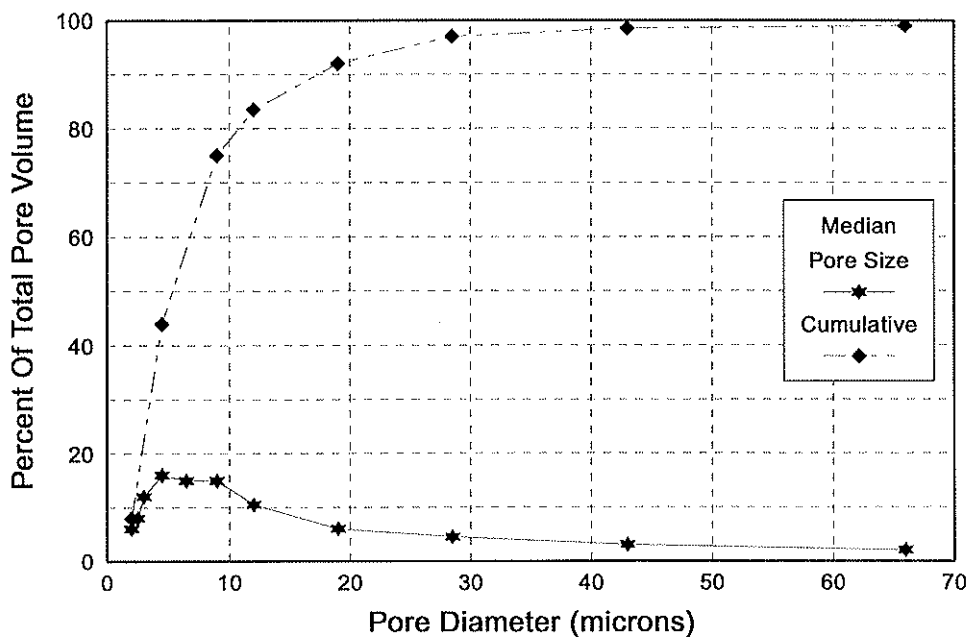
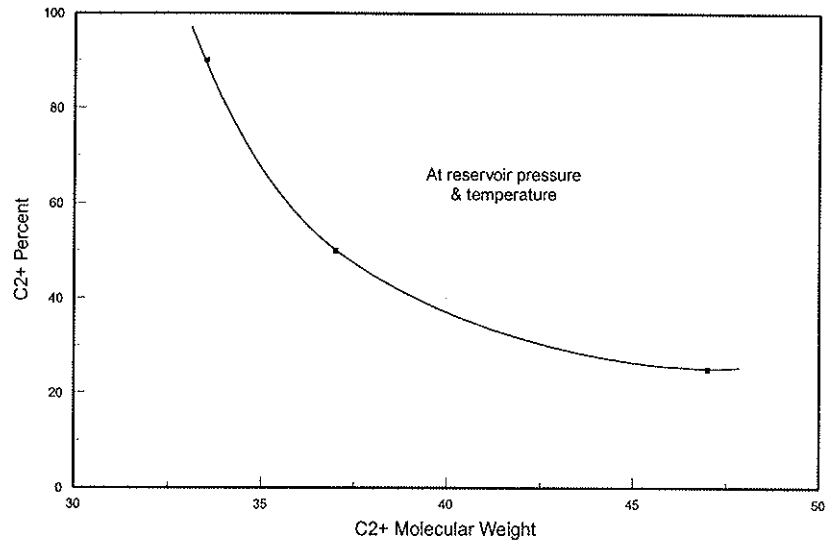


FIGURE 4
ENRICHMENT CORRELATION
FOR CASE HISTORY 2



**Fig.5 : Beaverhill Lake Formation-Carbonate Reservoir
Miscible Flood (Alternating Solvent and Water) - Comparison**

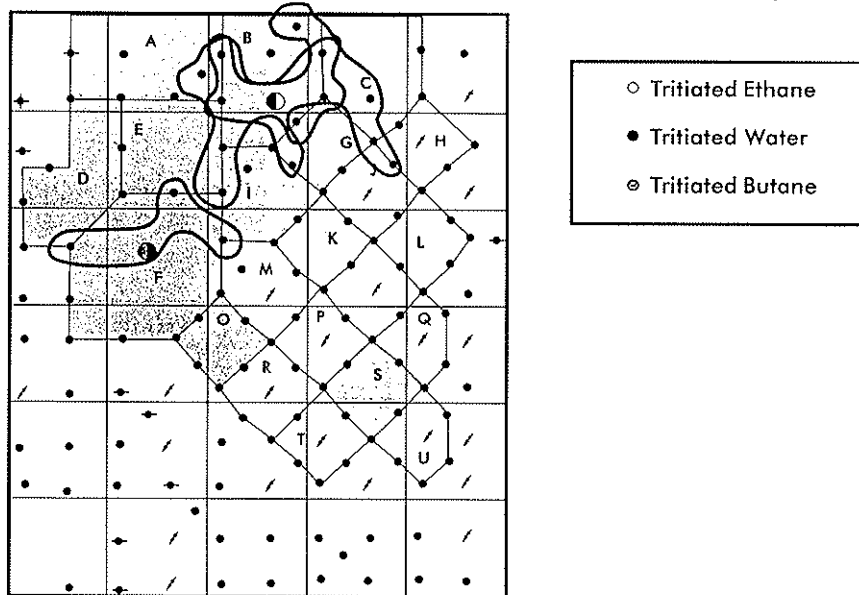


Fig.6 : Viking Formation-Sandstone Reservoir
Water Flood - Multi Well Tracer Program

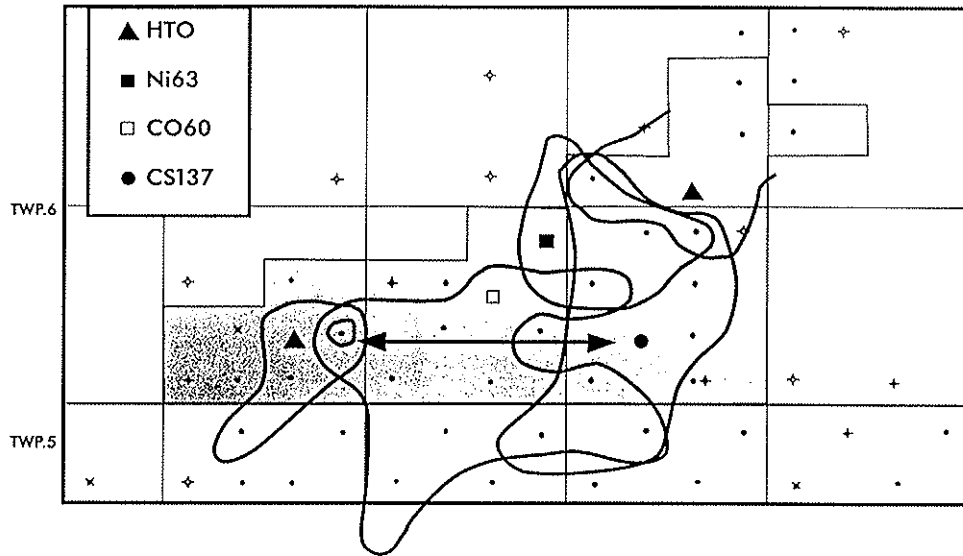


FIGURE 7
Low Invasion Core Bit Design

