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Low Permeability Gas Reservoirs: Problems, Opportunities and Solutions for Drilling, Completion, Stimulation and Production

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Abstract

As the industry seeks to increasingly exploit reserves of natural gas contained in low permeability intercrystalline sandstone and carbonate formations (<20 mD in permeability) many questions have arisen as to the optimum practices to drill and complete horizontal and vertical wells in these systems as well as the best techniques to hydraulic or acid fracture these formations to obtain economic production rates.

This paper provides a summary of recent work which has been conducted in the diagnosis and remediation of problems associated with tight gas reservoirs. Information on the importance of reservoir quality assessment and initial saturation determination is presented as well as a detailed discussion of common damage mechanisms which can affect the productivity of tight gas formations. These include fluid retention problems, adverse rock-fluid and fluid-fluid interactions, counter-current imbibition effects during underbalanced drilling, glazing and mashing, condensate dropout and entrainment from rich gases, fines mobilization and solids precipitation. The impact of these problems during drilling, completion, workover and kill operations is reviewed and suggestions presented for the prevention and potential remediation of these problems.

Specific examples of where these problems have been observed in 23 different common Western Canadian lower permeability gas horizons are presented in a summary format

for informative purposes.

Introduction

Vast reserves of valuable natural gas and associated liquids exist trapped in low permeability intercrystalline and microfractured carbonate and sandstone formations throughout the world. Due to the low inherent viscosity of gas, conditions can be such that these reserves can be recovered from these low permeability strata in situations where the economic recovery of conventional liquid hydrocarbons would be impossible. This paper describes various mechanisms which can influence the effective recovery of gas from low permeability formations and presents a variety of drilling, completion, production and remediation techniques that have proven useful recently in optimizing the recovery of gas from formations of this type.

The definition of a "low" permeability reservoir is somewhat arbitrary, but for the purposes of this paper would be considered to be formations which have a surface routine average air absolute permeability of less than 20 mD. In-situ reservoir condition permeabilities in these types of reservoirs are generally less than 1 mD and can range down into the microDarcy range (10^{-6} D) in many situations.

Although the emphasis in this paper is specifically on low permeability gas reservoirs, much of the information presented is also applicable to higher permeability gas bearing formations.

What is the Challenge?

If we consider what could cause uneconomic production rates from a low permeability gas bearing formation, the options generally will fall into six categories, these being;

1. Poor reservoir quality - period!
2. Adverse initial saturation conditions
3. Damage induced during drilling and completion
4. Damage induced during hydraulic or acid fracturing
5. Damage induced during kill or workover treatments
6. Damage induced during production operations

contemplated. Due to the low permeability nature of the matrix, unless huge losses of clear fluid to the matrix occur, due to poor fluid rheology and high hydrostatic overbalance pressures, the zone of extreme permeability impairment is generally contained in a fairly localized region adjacent to the wellbore. If hydraulic fracturing is the contemplated final completion technique, which is often the case in many low perm vertical gas wells, shallow invasive damage induced by drilling, cementing and perforating may not be significant as a well propagated and placed frac will penetrate far beyond the zone of drilling induced invasion and damage during the fracturing treatment will become the major issue of importance (to be discussed later). Exceptions would include failed or small frac treatments where short fracture half length does not effectively penetrate the zone of drilling induced damage, a high concentration of invaded fines which may subsequently be produced into and plug the high conductivity fracture directly adjacent to the wellbore, or simple mechanical problems initially propagating the frac due to high near wellbore tortuosity induced by formation damage (a problem often addressed with a small pre-frac HCl or HCl/HF acid squeeze to reduce tortuosity).

Drilling induced formation damage becomes more of an issue when open hole non-fractured completions are contemplated. When considering low permeability gas reservoirs, these types of completions are generally only successful if a large surface area of the formation can be accessed, such as in a horizontal well, a large vertical pay zone with a conventional well, or an openhole completion in a shorter but naturally micro/macrofRACTURED zone of the formation.

Fluid Retention Effects. The single greatest enemy of tight gas, whether during drilling, completion, fracturing or workover operations, is fluid retention effects. These can consist of the permanent retention of both water or hydrocarbon based fluids or the trapping of hydrocarbon fluids retrograded in the formation during the production of the gas itself. This phenomena is commonly referred to as aqueous or hydrocarbon phase trapping and has been discussed in detail in the literature (Ref. 2&3). Capillary pressure forces which exist in the porous media are the dominating factor behind fluid retention.

Capillary pressure forces, are defined as the difference in pressure between the wetting (generally water in most gas reservoirs) and non-wetting (gas) phases that exist in the porous media. This capillary pressure can be expressed by the following equation:

$$P_i = P_{nw} - P_w \\ = (\text{Interfacial Tension})_{o-g \text{ or } g-w} (1/R_1 + 1/R_2) \quad (1)$$

This mechanism is pictorially illustrated in Fig. 2. Fig. 3 illustrates how this mechanism is operative in low and high quality porous media and why capillary pressure and retention effects are more significant in low vs high permeability formations.

A large number of tight gas bearing formations are susceptible to phase trapping and fluid retention effects due to the fact that many of the economically producible formations would be considered to be "subirreducibly saturated" where the initial water saturation is at some value considerably less than what would be considered to be the "irreducible" liquid saturation. This, in fact, is the major reason why many tight gas reservoirs are exploitation candidates as this subirreducible saturation condition creates significant in-situ reserves and reduces the adverse relative permeability effects present in the system, thereby significantly increasing the productivity of the wells if they can be completed in a non damaging fashion. Most gas reservoirs of this type exhibit high log resistivities, produce no free water (other than fresh water of condensation from the produced gas), are not in direct communication with active aquifers or high water saturation zones and have a distinct propensity to retain the majority of any introduced water based fluid, much like a very large sponge. The basic mechanism of an aqueous phase trap is illustrated in Fig. 4. Fig. 5 illustrates the interplay of invasion depth and pressure with the severity of aqueous phase trapping. Equation 2 (Ref. 3) is used as a predictive tool to provide an estimate of the significance of potential problems associated with aqueous phase trapping:

$$APT_i = 0.25[\log_{10}(k_{air} \text{ in mD})] \\ + 2.2(Sw_{i-\text{initial fraction}}) \dots \quad (2)$$

Fig. 6 provides a pictorial representation of Equation 2. A value of the aqueous phase trap index (APT_i) of greater than 1.0 is generally an indication that significant problems with permanent aqueous phase trapping in the formation should not be apparent [although non permanent invasion and transient permeability impairment or aqueous phase loading (APL) may still occur (Ref. 3)]. Values of APT_i between 0.8 and 1.0 indicate potential sensitivity to aqueous phase trapping, and values less than 0.8 generally indicate significant potential for damage due to permanent fluid retention if water based fluids are displaced or imbibed into the formation. The smaller the value of the APT_i index, the more significant the potential for a serious aqueous phase trapping problem. Examination of Figure 6 indicates that the permeability and initial saturation conditions in which many tight gas reservoirs exist render them prime candidates for aqueous phase trapping.

Countercurrent Imbibition. Underbalanced drilling, while touted as a means of minimizing formation damage (Ref. 4&5), may actually increase the severity of near wellbore aqueous phase trap problems when it is used with water based fluids in horizontal wells which will be completed open hole in tight gas formations. Fig. 7 provides a schematic illustration of the mechanism of countercurrent imbibition which can occur during an underbalanced operation in a subirreducibly water saturated formation. Due to the discrepancy between the "initial" and "irreducible" saturations, one can see that there is a tremendous capillary force that exists between the initial water saturation level and the

during high drawdown cleanup operations, or if the formation produces liquid at rates above the critical migration rate during underbalanced drilling operations.

Fluid-Fluid Interactions. Problems with fluid-fluid incompatibilities would include the formation of insoluble scales or precipitates caused by adverse chemical reaction of invaded drilling or completion fluid filtrates and in-situ water. The potential for stable emulsion formation also exists if hydrocarbon drilling and completion fluids are used, or if water based fluids are used in formations which contain an initial irreducible liquid hydrocarbon saturation. Acid compatibility issues may also be apparent if acid is used in the presence of an immobile liquid hydrocarbon saturation.

4. Formation Damage During Fracturing of Tight Gas Formations. The majority of tight gas formations, by their nature, require hydraulic or acid fracturing in order to obtain economically viable production rates. Although it has been suggested by various authors that fracture faces can tolerate a huge amount of damage and that the productivity of the treatment is still limited by the amount of fracture conductivity present, there is significant lab and field evidence present to indicate that formation damage occurring during fracturing treatments is still a major issue. If we consider factors which may impair the productivity of a fracture treatment, these would include;

- Physical mechanical problems with the fracture treatment
- Formation damage to the high conductivity fracture itself
- Formation damage to the fracture face

Physical problems with the fracture treatment. These would include such problems as poor mechanical propagation of the frac, sandoffs, fracturing out of zone or channelling behind casing, etc.

Formation damage to the high conductivity fracture itself. No matter how large the treatment, if a very high conductivity fracture channel is not maintained, particularly if permeability is lost in the portion of the fracture directly adjacent to the well, the benefit of hydraulic fracturing is severely compromised. A variety of mechanisms can result in impairment of the permeability of fractures in propped or acid fracture treatments, including

- improper breaking of linear or crosslinked gels
- polymer adsorption and entrapment
- entrapment of produced formation fines/solids in the fractures
- emulsion blocks in the fractures
- compaction of the fracture and embedment affects associated with plastic formations and increasing overburden pressures during the depletion process
- physical production of proppant from the high conductivity fracture causing a loss in fracture conductivity

A common misconception is that fracture treatments are impervious to formation damage on the fracture face itself during the fracture treatment and it is only the fracture conductivity which must be maintained. Mathematical

modelling, plus considerable field experience, has indicated that this is not the case in many reservoir situations. The smaller the size and effective cross sectional area of the fracture treatment, the more significant the damage occurring on the frac face in impairing the ultimate productivity of the frac treatment. Large, (100-200 tonne for example) fracs, can tolerate a significant amount of permeability impairment on the fracture face, perhaps in excess of 95%, without appreciably reducing the productivity of the frac. A permeability reduction of 100%, however, cannot be tolerated. Some of the damage mechanisms mentioned previously, particularly fluid retention, are capable of causing 100% permeability reductions in tight gas formations and have been the result of significant reductions in well productivity. Companion tight gas well fracs of identical size (150 tonnes) have been placed in tight formations in the Permian basin in identical quality pay with the only variable being the break time and rheology of the cross linked water based fracture fluid used. When the crosslink was preserved to propagate the frac, followed by subsequent breaking, lab tests indicated a fracture face invasion depth into this 0.01 mD, 12% Sw_i formation of less than 2 mm with over 80% fluid recovery in the field and 7,000,000 scf/day flow rates. Wells in which premature breaking of the frac fluid occurred exhibited over 6 cm of invasion in the lab, less than 10% fluid recoveries in the field and uneconomic post frac flow rates of less than 50,000 scf/day.

For this reason, fracture fluid compatibility, from both a potential invasion depth and retention point of view, as well as from a chemical and mechanical point of view must be carefully considered to ensure that, not only can a viable frac be propagated, but that invasion into the formation at the high differential pressure gradients occurring during all frac treatments, particularly in pressure depleted formations, is minimized. If invasion does occur to a limited extent care must be taken that the invading fluids are compatible with the formation and designed with maximum ease of recovery in mind.

5. Formation Damage During Kill/Workover Treatments. Mechanisms of damage to perforated, open hole or fractured wells that can occur during hydrostatically overbalanced kill or workover treatments are similar to those described previously for drilling and completion. Damage and invasion may be more severe in these cases as, similar to an underbalanced drilling operation, these formations lack any type of protective or sealing filter cake to prevent wholesale invasion of the water or oil based kill/workover fluid, so a significant amount of fluid invasion and damage may be incurred before a hydrostatic kill condition is achieved.

6. Formation Damage During Production Operations. Potential damage which could occur during normal production operations of tight gas formations include;

- Physical fines migration
- Retrograde condensate dropout phenomena (rich gas systems)

and production. This section attempts to identify drilling and completion practices which may be useful in tight gas scenarios, as well as remediation techniques for wells with existing damage.

Fluid trapping/retention problems. This is a major mechanism of damage in many tight gas reservoirs. If we consider methods of minimizing the impact of this type of damage, they would include:

Avoid the introduction of water based fluids into the formation during the drilling and completion operation in totality. This would include straight gas drilling or the use of hydrocarbon based drilling and completion fluids. Oil based fluids may also phase trap to a certain extent in the formation and reduce permeability, but due to the fact that the liquid hydrocarbon will generally be the non-wetting phase in most gas reservoirs, where no pre-existing liquid hydrocarbon saturation is present, the physical amount of trapping of the hydrocarbon phase may be significantly less than would be encountered if water was used in an equivalent situation and a large increase in gas phase relative permeability may be apparent. This phenomena is illustrated in Fig. 9. If a pre-existing liquid hydrocarbon phase saturation is contained initially within the porous media (as is common in many Montney, Rock Creek, Ostracod, Gething, Viking and Cardium formations) it is possible that the formation may be partially or totally wetted by the hydrocarbon phase, or the small pre-existing hydrocarbon phase saturation may act as a spontaneous adhesion site to trap additional hydrocarbons. In these types of reservoirs, oil based fluids may not be advantageous over water based systems as they may have equal or more trapping and damage potential. The use of straight CO₂ or highly CO₂ energized hydrocarbons has been successful as a frac fluid medium in some reservoirs of this type as an alternative to water. Alcohol fracs (i.e. gelled methanol) have been used with success in some situations. Care must be taken with the use of alcohol in very low (<0.1 mD) formations as adverse capillary pressure effects can also physically trap the alcohol. Low molecular weight alcohols, such as methanol, have a very low degree of miscibility with liquid hydrocarbons and can often suffer from incompatibility problems with respect to sludge formation with many crude oils. For these reason, their use should be avoided in most situations where a liquid hydrocarbon saturation is known to exist in the reservoir in favour of higher molecular weight mutual solvents (i.e. - IPA, EGMBE) which exhibit significantly greater miscibility with liquid hydrocarbons and fewer compatibility problems.

If water based fluids must be considered for technical or economic reasons, invasion depth should be minimized to the maximum extent possible to avoid significant aqueous phase retention problems. For drilling fluids this would include minimization of overbalance pressure, if possible, and rheology and bridging agents, if appropriate, to establish a protective filter cake to act as a barrier for significant fluid loss into the formation. Kill or workover fluids should be designed with

appropriate fluid additives to prevent losses to the formation under hydrostatic overbalance conditions. The use of cross-linked fracture fluids with appropriate breaker packages and as rapid recovery times as possible after fracturing, foamed systems or poly-emulsions should be considered if water based frac fluids are considered.

Remediation of fluid retention problems. A number of basic approaches can be taken to removing existing phase traps, these would include:

1. Increasing capillary drawdown. Trapped saturation is a direct function of applied capillary gradient, the higher the available capillary gradient, the lower the obtainable water saturation. Therefore, in the absence of fines migration problems, water coning potential or retrograde condensate dropout potential (rich gas systems) the higher the drawdown pressure which can be applied across the phase trapped zone, the lower the water saturation which will be able to be obtained. In a practical application, unless the invasion depth of the infiltrated aqueous phase is very shallow, or the reservoir pressure is extremely high, due to the vertically asymptotic nature of most gas-liquid capillary pressure curves near the irreducible saturation, extreme drawdown gradients, which cannot be realized in most normal field applications, are required to obtain an effective reduction in the trapped liquid saturation. For this reason this method does not tend to be of great efficacy in most situations.

2. Reduced IFT between the water-gas or oil-gas system. Capillary pressure, which is the prime mechanism for the entrapment of the oil or water based fluid within the pore system, is a direct linear function of the interfacial tension (IFT) between the trapped phase and the gas in the bulk of the pore space (Equation 1). If some means can be found to reduce the IFT between the gas and liquid phase, then at the available reservoir drawdown it may become easier to mobilise and produce a portion or all of the entrapped fluid. A variety of treatments are available to reduce the IFT in situations such as this:

- a) Chemical surfactants have been used in some cases, but due to the disparate molecular nature of gas and liquids, it is difficult to find liquid soluble chemical surfactants which are effective in obtaining the multiple orders of magnitude reduction in IFT (from say 70 to 0.1 dyne/cm) required in order to effectively mobilize a significant amount of trapped fluid from the system.
- b) Mutual solvents, such as methanol or higher molecular weight alcohols or materials such as EGMBE can significantly reduce IFT between gas and liquid and are mutually miscible in the trapped liquid phase and tend to reduce viscosity and increase volatility and vapour pressure extractive effects to remove a portion of the trapped liquid. As mentioned previously, careful selection of a mutual solvent is important to ensure miscibility and compatibility if a liquid hydrocarbon saturation is present within the porous media.
- c) Liquid carbon dioxide has been used for aqueous phase traps

nitrogen, injected down the CT string, to very high temperatures which is then subsequently injected directly into the formation. If downhole temperatures can be elevated above 500°C, supercritical volatilization of water, regardless of the reservoir pressure, occurs as well as partial or total thermal decomposition and desensitization of reactive clays. In lab tests the technique has resulted in over 10 fold improvements in permeability in damaged zones. The technique has particular application to relatively shallow tight gas reservoirs where vertical wells penetrate thin, highly damaged sand layers. Treatment area is generally approximately two metres in length by 1 to 2 metres in radius in a single application. The most common application is potentially stimulating secondary target gas zones which were badly damaged using conventional water based fluids when targeting deeper primary zones. Fig. 11 provides an illustrative schematic of the FHT process.

c) Localized Combustion. This has been a method suggested to remove hydrocarbon phase traps in tight gas. The technique involves short term air injection. If downhole temperature is sufficient, spontaneous ignition will occur, combusting the condensate saturation while simultaneously generating localized heat which may also vaporize a portion of the trapped connate water saturation and thermally decompose reactive clays. Wellbore flashback effects and extreme potential corrosion concerns are potential problems associated with the use of this method.

d) Time. Nature abhors a steep capillary gradient. Thus, when a zone of high water saturation is induced into a water-wet formation, natural capillary action will tend to have a dispersing effect in gradually imbibing a portion of the water saturation away from the wellbore or fracture face. This phenomena is illustrated in Fig. 12. Due to the limitations of the capillary imbibition, the water saturation in the flushed zone will only be able to imbibe down to the irreducible saturation dictated by the capillary geometry of the system, therefore a significant residual aqueous phase trapping effect may still be apparent. This phenomena has been observed in many cases where tight gas wells have been drilled, tested and subsequently shut in or abandoned. After an extended period of time some of these wells have been retested and produced at order of magnitude or more greater rates that observed initially. Production of the well obviously counteracts, to an extent, this phenomena and may slow the speed of this process.

Countercurrent Imbibition. Countercurrent imbibition problems during underbalanced drilling operations can be minimized by increasing the magnitude of the apparent underbalance pressure to act as a greater deterrent to imbibition. If a significant difference exists between the initial and irreducible water saturations, however, such as in the case of many tight gas reservoirs, this technique is generally insufficient to counteract the extremely adverse capillary pressure gradients present in the porous media if a water based fluid is used. Better results are obtained in situations such as this by avoiding the use of water based fluids through either

straight gas drilling, or using a hydrocarbon based fluid as the drilling fluid medium (if the formation is water-wet). Since hydrocarbon is the non-wetting phase, no impetus will be present for spontaneous imbibition to occur. If the underbalance pressure condition is compromised, invasion and trapping of the hydrocarbon based fluid could still occur and be problematic.

Mud Solids Invasion. As mentioned previously, this is generally only a significant problem if an non-stimulated open hole completion is contemplated for the well under consideration. If this is the case, care must be taken in the design of the drilling fluid to ensure that significant invasion of solids into the formation does not occur. In general solids larger than about 30% of the median pore throat size will not invade a significant depth into the formation. Due to the small pore throat size associated with most tight gas reservoirs, natural exclusion of the majority of artificial (barite, bentonite, bridging agents, natural drill solids, etc.) occurs. Pore size distribution data (and fracture aperture sizing if fractures are present) should be obtained in this type of situation to allow mud engineers to ensure that the expected size distribution of solids present in the fluid system are appropriate to avoid invasion.

Due to the very small pore throat size, normal mud solids are too large to form a low permeability sealing filter cake in most low permeability gas reservoirs. This results in the solids being retained from invading into the formation, but because the filter cake is relatively coarse (in comparison to the small pore throats the cake is attempting to block) a considerable amount of fluid seepage into the pore system can still occur which can initiate a damaging phase trap or other fluid-fluid incompatibility problems. Proper sizing of the suspended particulate matter can generate a much lower permeability filter cake than would be obtained using naturally occurring solids and can act as an efficient barrier to damaging filtrate invasion. Sizing criteria vary depending on the system, but would range from 10-40% of the pore throat size for matrix systems and 10-100% of fracture aperture for fractured reservoirs. Specific size distribution for a fluid bridging agent can generally only be quantified after a detailed evaluation of the system under consideration.

Underbalanced drilling may also be considered as a technique to prevent this type of damage if a heterogenous formation exists where formulation of a single fluid system with effective bridging characteristics is impractical.

Glazing. Classic glazing is generally motivated by heat associated with pure gas drilling operations in open hole completions in uniform, low permeability clastics or carbonates. Glazing can generally be avoided by the inclusion of a small amount of compatible fluid (i.e. mist drilling) in the system to increase lubricity and heat transfer from the bit.

applications in Canada.

Nomenclature

- CCI = Countercurrent imbibition
 FFI = Fluid-Fluid Interactions (precipitates, scales, emulsions, acid incompatibility)
 FM = Fines Migration
 GL = Glazing
 MI = Mud Solids Invasion
 RFI = Rock-Fluid Interactions (reactive clays)
 OR = Oil Retention
 PP = Production Problems (Condensate dropout, solids precipitation)
 WR = Water Retention

Formation Name and Potential Damage Mechanism Susceptibility

Bakken -	WR, GL, CCI
Baldonnel -	WR, OR, MI, CCI, FFI
Basal Colorado	WR, OR, MI, GL, RFI, FM
Basal Quartz -	WR, OR, MI, GL, RFI, FM, PP
Belly River -	WR, MI, GL, CCI, RFI, FM
Bluesky -	WR, MI, GL, CCI, RFI, FM
Cadomin -	WR, MI, GL, CCI, RFI, FM
Cadotte -	WR, MI, GL, CCI, RFI, FM
Cardium -	WR, OR, GL, CCI, RFI, FM
Doig -	WR, GL, CCI, RFI, FM
Gething -	WR, OR, GL, CCI, RFI, FM
Glauconite -	WR, GL, CCI, RFI, FM
Halfway -	WR, OR, GL, CCI, RFI, FM, PP
Jean Marie -	WR, GL, CCI, RFI, FFI
Medicine Hat -	WR, GL, CCI, RFI, FM, PP
Milk River -	WR, GL, CCI, RFI, FM, PP
Montney -	WR, OR, GL, CCI, RFI, FM, PP
Ostracod -	WR, OR, GL, CCI, RFI, FM, PP
Paddy -	WR, CCI, RFI
Rock Creek -	WR, OR, MI, GL, CCI, RFI, FM, PP
Taber -	WR, GL, CCI, RFI, FM
Viking -	WR, OR, GL, CCI, RFI, FM, PP
White Specks -	WR, OR, GL, CCI, RFI

Conclusions

1. Significant reserves of natural gas and condensate liquids exist in low permeability formations throughout the world. Good engineering and evaluation is required in order to understand the initial reservoir quality and saturation conditions and accurately assess, at the current level of technology, if reserves exist and if those reserves are economically recoverable.

2. With advanced technology gas has been effectively and economically produced from many tight gas formations with permeabilities of less than 0.1 mD.

3. Tight gas formations are very susceptible to formation damage. Fluid retention is a major mechanism of damage in many of these situations. Means of minimizing damage effects

include understanding the wettability and initial saturation conditions of the reservoir and then minimizing invasion through the use of gas or gas energized fluids, ultra low fluid loss conventional systems or underbalanced drilling and completion techniques.

4. Significant damage can occur during fracturing treatments in tight gas due to improper fluid selection or mechanical problems with the frac. Fluid retention near the frac faces and fracture permeability impairment are major damage mechanisms in these cases. The smaller the fracture treatment, the more significant the effect of frac face damage on productivity. In some cases oil based, gas energized oil or pure CO₂ fracs have proven useful in minimizing damage. Success has also been achieved with very low fluid loss cross linked water based gel systems in some very low permeability formations which were highly susceptible to fluid retention effects.

5. Reducing drawdown rate can result in minimizing problems with retrograde condensation, water coning, fines migration and a variety of solids precipitation problems. This can be accomplished by reducing production rate, or more commonly by increasing cross sectional flow area by open hole completions, horizontal drilling or fracturing.

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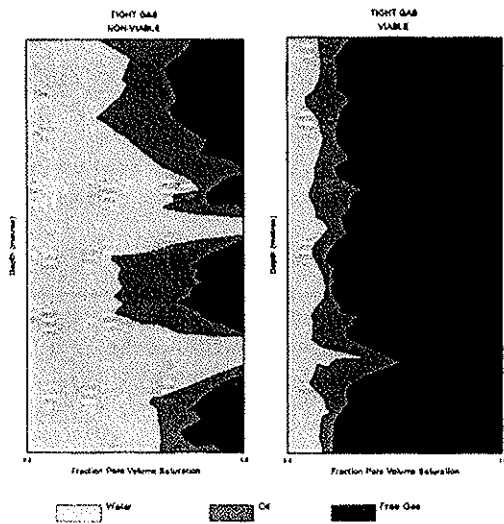


FIGURE 1
ILLUSTRATION OF TRACED
SPONGE CORING PROGRAM TO DETERMINE S_{wi} , S_{ol} , S_{gi}

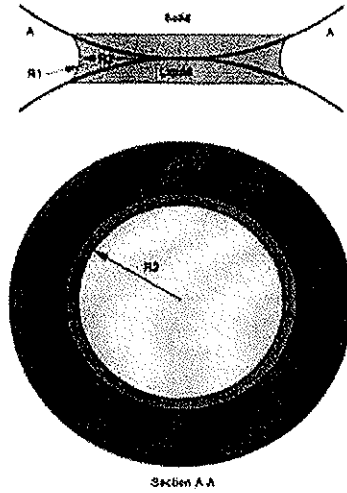


FIGURE 2
RADIUS OF CURVATURE
IN POROUS MEDIA

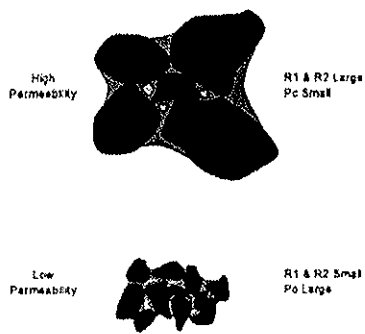


FIGURE 3
ILLUSTRATION OF CAPILLARY EFFECTS IN POROUS MEDIA

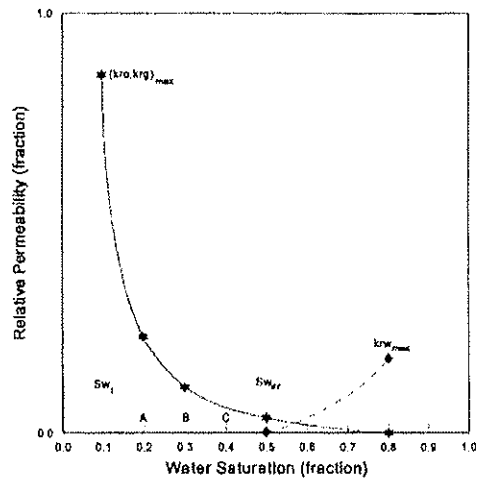


FIGURE 4
AQUEOUS PHASE TRAPPING IN A LOW PERMEABILITY GAS RESERVOIR
RELATIVE PERMEABILITY RELATIONS

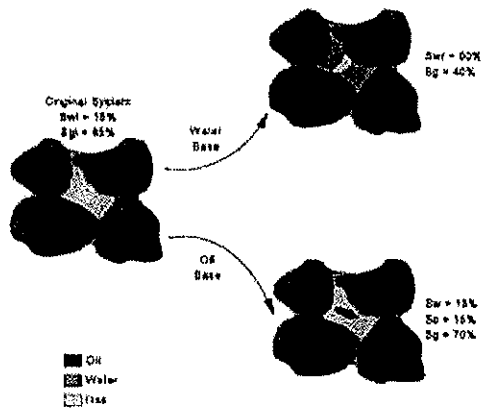


FIGURE 9
 WATER vs OIL-BASED FLUID
 TRAPPING IN A WATER-WET SYSTEM

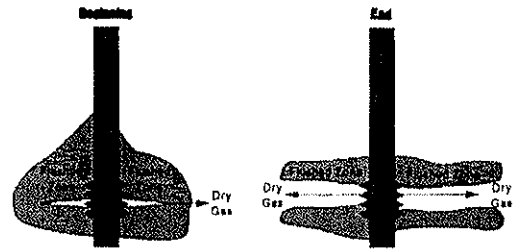


FIGURE 10
 DRY GAS
 INJECTION PROCEDURE

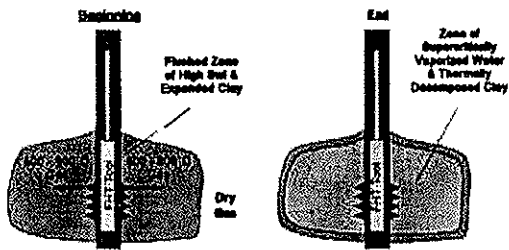


FIGURE 11
 FORMATION HEAT TREATMENT PROCEDURE (FHT)

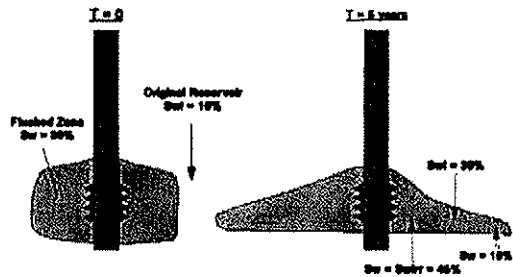


FIGURE 12
 ILLUSTRATION OF CAPILLARY IMBIBITION vs TIME