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Water and Oil Base Fluid Retention in Low Permeability Porous Media – an Update

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Abstract

Phase trapping refers to the temporary or permanent trapping of oil or water based fluids introduced into a porous media during drilling or completion operations which result in a reduction in the effective permeability to the desired producing or injected phase. This problem has emerged in recent years as a major mechanism of formation damage, most notably in low permeability gas producing formations. This paper reviews the current state of the art with respect to new technology which is being used to identify formations that are particularly susceptible to this mode of formation damage, as well as describing some of the most current technology being used to avoid and remove these problems. This includes the use of various types of new non-alcohol based surface tension reducing agents, foamed fluids and other surfactants, transient wettability modifying agents, oil based fluids, as well as CO_2 *or nitrogen based fracturing technology. The potential advantages of some of these new technologies and where they have the greatest degree of potential application are discussed.*

Introduction

Phase trapping is a common mechanism of formation damage that can occur in a variety of oil, gas or water bearing formations and can create severe reductions in productivity or injectivity. The problem has been documented in numerous publications in the literature (1-12) as well as in previous publications by the authors (13-18). The basic mechanism of a phase trap refers to either the transient (sometimes referred to as a 'phase load') or permanent (phase trap or block) retention of water, oil or sometimes gas based fluids which are generally introduced from an outside source into the formation during drilling and completion operations. There are also situations, such as retrograde condensate gas reservoirs or the depletion of black oil reservoirs, where the creation of potentially permeability reducing near wellbore phase traps may occur through the normal depletion process of the reservoir.

Common Types of Phase Traps

The most common types of phase traps can be summarized as follows;

Gas Producing Formations

- Water based phase trapping (caused by water based drilling, completion or kill fluids)
- Hydrocarbon based phase trapping (caused by hydrocarbon based drilling, completion or kill fluids) or by retrograde condensate liquid dropout in rich gas producing situations

Oil Producing Formations

- Water based phase trapping (caused by water based drilling, completion or kill fluids)
- Gas based phase trapping (caused by gas liberation by sub-bubblepoint production)

Water Producing Formations

- Hydrocarbon based phase trapping (caused by hydrocarbon based drilling, completion or kill fluids)
- Gas based phase trapping (caused by free gas injection)

Gas Injection Wells

- Water based phase trapping (water of condensation)
- Oil based phase trapping (compressor lubricant carryover)

Phase trapping is caused by an interaction of capillary pressure and relative permeability phenomena in porous media. A simplified formulation of the capillary pressure equation in porous media can be expressed as;

$$P_C = \frac{2\sigma\cos\theta}{R_p} \qquad (1)$$

Where:

Rp = Pore radius
Pc = Capillary pressure
σ = Interfacial Tension
θ = Contact angle, degrees

Although phase trapping and retention issues can occur in some situations in high permeability porous media (common in oil wet sandstone and carbonates and also with gas in higher permeability oil bearing formations) the most severe and common occurrence of the problem is confined to lower permeability porous media (generally less than 10 mD in-situ permeability). This paper will concentrate primarily on these lower permeability formations.

Factors Impacting the Severity of Phase Trapping

The literature is replete with laboratory and case studies on the topic of water and hydrocarbon based phase trapping in porous media (5-25). Phase trapping has been found to be related to a number of phenomena, these being;

1. Capillary pressure (as illustrated in the previous equation) and relative permeability, both of which are direct functions of
    a. Pore system geometry
    b. Interfacial tension between the invading 'trapped' fluid and the produced (or injected) reservoir fluid
    c. Wettability
    d. Fluid saturation levels
2. Depth of invading fluid penetration
3. Reservoir pressure, temperature and drawdown potential

The authors presented a correlation, the APT index (14) in 1995 that uses easily measured rock parameters of permeability and initial water saturation to predict the potential for water based phase trapping issues in both oil and gas reservoir applications. This equation has been used extensively in the industry since its development as a screening tool with favorable results.

When considering a reservoir which exhibits the potential for water or hydrocarbon based phase trapping, two general approaches to the problem can be considered;

1. Design a drilling, completion and production program to avoid or minimize the impact of phase trapping (preferred approach).
2. Use conventional drilling, completion and production practices and then attempt to remove induced phase trap damage through subsequent operations (more problematic, but common in the industry given the lack of general understanding in the industry with problems related to phase trap potential).

Prevention of Phase Trapping

Phase trapping can be avoided in many situations by a proper understanding of the original reservoir conditions of fluid saturation, pore geometry and wettability. The following points are generally of interest when attempting to design a drilling or completion fluid with minimal or no phase trap potential;

Fluids that are mutually miscible with the producing/injected reservoir fluid will not have phase trap potential – This is rather obvious – for example, in a strongly oil wet sandstone or carbonate oil reservoir with low initial water saturation, using a compatible (from an asphaltene, sludge and non-wettability altering perspective) hydrocarbon based fluid will result in no external water being introduced into the formation and the fluid saturations and wettability remaining unchanged and eliminating the potential for phase trapping). Several case studies in the literature (14, 15, 19, 20) illustrate the use of oil based fluids in situations such as this to reduce water blocking potential. Comparable examples can be presented for the use of air/foamed based drilling in tight gas reservoirs at low (subirreducible) water saturation conditions (1-6, 9, 12, 13) ,water based fluids for water injection and disposal wells (21, 23) as well as nitrogen, air or carbon dioxide in some gas reservoir applications.

Use of Non-Polar Hydrocarbon Based Fluids for Reducing Water Block Potential in Tight Gas Reservoirs – This approach may seem counterintuitive for a dry gas reservoir in that there is no pre-existing initial liquid hydrocarbon saturation in-situ, and it would be expected that the introduction of an immiscible liquid hydrocarbon drilling or completion fluid would result in the entrapment of an additional third phase in the porous media which would exacerbate formation damage effects. Although a certain amount of hydrocarbon fluid retention does unavoidably occur, it has been found in many cases (13-17) that if non-polar oils can be used which do not have a wetting/spreading affinity for the naturally water wet surface of the reservoir that this, combined with the significantly lower IFT that exists between natural gases and light refined oils vs. water, results in many cases in less total fluid being retained when a hydrocarbon based system is used in contrast to a water based system in the same circumstances. This is schematically illustrated in Figure

1. The presence of oil wetting contaminants or additives in the introduced hydrocarbon phase, or a condition of oil wet natural wettability in the gas reservoir (due to the presence of pyrobitumen or heavy hydrocarbon residual films), in general would contraindicate this approach due to an increased tendency for hydrocarbon based trapping and spreading affinity.

Reducing Invasion Depth – The ability to recover entrapped reservoir fluids is a strong and direct function of the amount of capillary drawdown that can be applied on an instantaneous basis to the area of the reservoir in which the fluid is entrapped. The greater the depth and extent of the fluid retention, the larger the degree of dispersion of the available drawdown gradient, which in turn reduces the effective instantaneous capillary gradient and hence the ability to recover trapped fluid from the formation. Invasion depth during drilling and conventional completion operations can be reduced by reducing overbalance pressure (low density drilling and completion fluids or underbalanced drilling/completion operations) or improving fluid rheology and filter cake building ability to reduce fluid loss potential. Hydraulic and acid fracturing are challenges in this area, as if one does a material balance at closure conditions, the volume of injected fluid required to propagate an acid or hydraulic frac generally exceeds the volume of the closed fracture by about 20 times. This results generally in 95% of the injected frac fluid being introduced into the formation matrix along the walls of the fracture. This results in invasion depth being greater in these applications than would normally be associated with a conventional overbalanced drilling and completion operation.

Increasing Reservoir Drive Energy – In a manner similar to the preceding paragraph concerning invasion depth, instantaneous capillary drawdown gradient is also directly impacted by available reservoir pressure. High pressure formations have the ability to apply larger drawdown gradients over a given zone of invasion. Low pressure or depleted formations have little drive energy to unload and recover trapped fluids. Low reservoir pressure often also generally increases invasion depth due to the fact that higher overbalance pressures are present, resulting in the potential for increased fluid loss and invasion in conventional overbalanced drilling and completion operations in contrast to normally pressured or over pressured formations. In order to combat this effect in low pressure situations when fracturing operations are considered, energized fluid systems, where either nitrogen or dense phase carbon dioxide are entrained in the injected water or oil based fluid are often used. The presence of these gases acts to both reduce the total volume of oil or water phase entering the reservoir as a potentially trapping fluid and provides an area of localized assisted high pressure for flowback, which aids in increasing the capillary gradient and improving the recovery of the introduced fluid from the formation.

This being said, there are particular advantages to each gas type in certain situations. Generally nitrogen is used as an energizing fluid in high pressure environments where bottomhole drawdown pressures will still remain high enough on the flowback phase (generally in excess of 10,000 kPa) that carbon dioxide would remain as a relatively incompressible dense fluid and provide limited expansion to assist in the recovery of the trapped filtrate. The highly compressible nature of nitrogen allows it to retain the ability to provide compressible drive energy under pressure reduction conditions at even very high pressures.

In comparison to nitrogen, carbon dioxide has greater water carrying capacity, higher solubility in oil and water and lower interfacial tension. The volumetric transition from dense phase to gas phase for CO_2 , if low enough flowback pressures in the area of the fracture face can be obtained is large in contrast to nitrogen, which can result in significant drive energy. From this perspective, CO_2 has some advantages over nitrogen as long as flowback pressure will allow this phase transition and expansion to occur. For both gases, relatively rapid flowback after the fracture treatment is essential to prevent the entrained, low viscosity gas from dispersing from the area surrounding the fracture face into the bulk formation. From this perspective CO_2 once again has some advantages over nitrogen as its higher density and viscosity and great solubility in the fracture fluid at lower pressures will generally allow it to be preferentially retained adjacent to the fracture for a longer period than nitrogen.

Reducing Interfacial Tension – Capillary pressure, which creates the potential for phase trapping, is a direct linear function of interfacial tension (see equation #1). Reducing the IFT between the trapped fluid and the producing/injected reservoir fluid reduces the capillary pressure and makes the recovery of the trapped fluid at a given level of reservoir pressure/drawdown easier. The greater the reduction in IFT, the more favorable the effect as illustrated in Figure 2. The ideal situation would be to create a condition of close to miscibility (near zero IFT) between the two fluids. This can be accomplished in some cases between water and oil with the proper blend of surfactants, but effective contact, adsorption and emulsion issues can sometimes render this problematic. The technique is more often applied in gas reservoir situations with water and hydrocarbon based phase traps using some of the following IFT reducing agents;

1. Light alcohols (methanol) for dry gas situations – methanol is not recommended for reservoir situations where oil or condensate liquids are present as it tends to be immiscible with these materials and often creates significant sludge and emulsion problems.
2. Heavier alcohols (propanol, butanol) for reservoir applications containing both gas, water and liquid hydrocarbons.
3. Various glycol solutions.
4. Liquid phase carbon dioxide as an additive to the fluid of interest to reduce both water and hydrocarbon phase trapping potential.
5. Various surface tension reducers (water based) to reduce water-gas surface tension for gas reservoir applications. Several additives are available that can generate surface tensions of less than 25 mN.m (comparable to or less than observed between the same gas and alcohol systems without the flash point and potential reservoir compatibility concerns).

Transient Wettability Modifiers

Capillary pressure can also be reduced by changing the preferential wettability of the rock surface in the reservoir (on either a temporary or permanent basis). The cosine of the contact angle is a term in the numerator of the capillary pressure evaluation equation (see equation #1). In both strongly water wet and oil wet porous media (contact angles of near zero or 180 degrees respectively) strong capillary pressure effects are created which can result in an increase in fluid trapping propensity. As wettability moves to a more neutral condition, where there is less spreading tendency for either water or oil on the surface of the formation, the cosine of the contact angle approaches zero and hence also the effective capillary pressure. Transient wettability modifiers represent a group of common commercial chemicals known as water soluble oil wetting agents which have been used extensively for years in industry as sheeting agents (common applications are in car washes and dishwashers). These materials temporarily alter the surface chemistry of the water wet surface of the solid to a more neutral wet condition which facilitates the sheeting/filming of the water off the surface. Similar effects can be obtained using these materials in reservoir applications. Although extensive use of these materials to date has not been widespread in the industry, considerable potential exists for their use as a low concentration, low cost, environmentally friendly alternative to some of the materials and techniques previously mentioned.

Removal of Existing Phase Traps

With most phase trapping problems, prevention is generally far more effective in the long term from an economic perspective than remediation. Obtaining effective contact with trapped filtrates, particularly if large fluid volumes of greater than 10 m^3 of retained fluid or complex trapped fluid geometry (long horizontal wells or large fracture treatments) are present is a challenge. Two potential approaches are available in situations where it is felt that the primary mechanism of reduced productivity or injectivity can be associated with phase trapping;

1. Direct mechanical penetration of the damaged zone (in a non-damaging fashion) to access undamaged reservoir.
2. Removal or displacement of the trapped fluid saturation from around the wellbore or frac face to increase the effective permeability to the producing or injected phase.

Direct Mechanical Penetration of the Phase Trapped Zone – Is sometimes the only viable consideration if considerable volumes of fluid are trapped in place. These techniques primarily would center about fracture stimulation (with non-damaging fluids) to penetrate beyond the zone of damage induced by drilling, completion or a previous poorly executed fracturing operation. Another alternative could be short multi-lateral wells, once again drilled and completed to minimize previous phase trap damage effects, to access undamaged reservoir.

Trapped Filtrate Removal or Displacement Techniques – There are a large number of possible techniques in this area that may be worthy of consideration if the volume of trapped fluid is relatively small and localized to the immediate vicinity of the wellbore/frac face area. The challenge in most of these applications, as mentioned previously, is effective contact with the trapped fluid in a heterogeneous environment. Potential options include;

1. High drawdown pressures (water and hydrocarbon phase traps)
2. Static repressurization (hydrocarbon phase traps)
3. Extended flow (water based phase traps)
4. Static shut in/imbibition (primarily for water based phase traps)
5. Dry gas injection (water based phase traps)
6. Formation heat treatment (water based phase traps)
7. Lean gas injection (hydrocarbon based phase traps)
8. Rich gas injection (hydrocarbon phase traps)
9. In-situ combustion (hydrocarbon phase traps)
10. Water displacement (hydrocarbon phase traps)
11. Carbon dioxide injection (water and hydrocarbon phase traps)
12. Mutual solvent injection (water and hydrocarbon phase traps)
13. Surface tension agent reducer injection (water and hydrocarbon phase traps)
14. Acid injection (water and hydrocarbon based phase traps)
15. Wettability modification (water based phase traps)

Brief comments on each of these potential phase trap remediation options follow;

High drawdown pressure - Increased drawdown pressure increases capillary gradient and ease of recovery of trapped fluid. In general, the higher the drawdown pressure that can be applied, the lower the trapped fluid saturation that will be generated for a water block. For condensate phase traps from retrograde gases this obviously would not be a technique to consider, as increased drawdown pressures would only tend to increase the volume of liquid retrograding from the gas phase in the near wellbore region and exacerbate the hydrocarbon phase trap problem. In low permeability formations, particularly in subnormally saturated tight gas reservoirs, this method may not be that effective as the capillary pressure becomes very high at relatively high water saturations and there is generally inadequate drawdown to fully mobilize the water saturation value back to the original subnormal value. This is illustrated in Figure 3.

Static Repressurization – Is a technique sometimes considered for removal of condensate liquid traps in the near wellbore region in high drawdown producers in rich gas reservoirs. The idea is that shutting the well in temporarily will result in repressurization of the reservoir to above the original dew point pressure of the gas and subsequent re-vaporization of the condensate. In reality, since the vaporization process is mass transfer limited and the condensate present in the near wellbore region has retrograded out of a large volume of flowing gas phase and now is in static contact with only a very limited gas volume, the process has little veracity.

Extended Reservoir Flow – The water carrying capacity of natural gases increases with reductions in pressure. Several authors have postulated, based on lab studies where 10,000 to 100,000 PV of gas have been flowed through samples, that this long term evaporative effect will remove trapped water and improve permeability. Although observable in the lab in a controlled environment, if one considers the volume of gas that would need to be displaced on a field basis the stimulative effect is generally minor unless gas flow rates are extremely high (which generally implies high permeability porous media in which phase trapping problems are not significant in any event). Consider, for example, the isothermal flow of methane gas at 60^oC in a near wellbore region with pressure dropping from 10000 to 5000 kPa over the phase trap impacted region. To remove 20 m^3 of trapped water, solely due to the increased water carrying capacity of the flowing natural gas, would require a produced gas volume of over 11 million cubic meters (almost 0.4 Bcf) of gas, so it can be seen that cleanup of a tight gas well flowing at an average rate of 150 MMscf/day would require over 7 years for any substantive cleanup.

Static Shut in - If the trapped phase is the same as the preferential wetting phase that exists in the reservoir, imbibition effects will gradually 'wick' the water away from the near wellbore region and disperse the fluid deeper into the formation, reducing high near wellbore saturations that may be impeding flow. This is illustrated in Figure 4. The speed of this process is highly dependant on formation permeability and degree of preferential wetness and, in very low permeability situations, can require several years to have an appreciable effect. Experience suggests that rock of matrix permeability in the range of 0.5 to 2 mD is the most favorable for this type of treatment – exhibiting permeability low enough that phase trapping can still be a significant issue, but high enough to allow imbibition to proceed at reasonable rates where cleanup may be observed in weeks to months timeframe rather than years. In general static shut in provides the best performance in this situation as, if the well is flowing, the natural pressure gradient imposed by the drawdown counteracts and slows the rate of imbibition of the trapped fluid back into the bulk formation.

Dry Gas Injection – Is a technique useful for the removal of relatively small volume water blocks. In this case dehydrated methane or nitrogen gas is injected into the wellbore for a period of time to both displace mobile water and dehydrate trapped water. Due to the relatively modest evaporative capacity of natural gas, only limited (less than 2 m^3) volumes of water are generally practical to extract in this fashion. One must also be cautious in applying this technology in situations where the trapped water phase is highly saline (over 100,000 ppm) as the evaporation process can result in supersaturation and potential plugging of the pore system with precipitated salts.

Formation Heat Treatment – The use of electrically powered downhole heating tools has been discussed in the literature (26) as a means of increasing temperature to speed the rate of evaporative drying by gas injection, as well as to permanently decompose reactive clays in the near wellbore region. Field tests have indicated only moderate success with this treatment method due, in part, to a very limited radius of effective treatment.

Lean Gas Injection – Has been used for many years in gas cycling operations where compression and a ready source of lean (methane) gas is available as a means of miscibly vaporizing/displacing trapped condensate or other light hydrocarbon liquids from near wellbore or frac face regions. High contact pressures (35-40 MPa) are generally required in order for this process to be successful. Nitrogen has also been used in some situations at higher (45-50 MPa) pressures for light hydrocarbon miscible displacement and extraction.

Rich Gas Injection – Injection of CO_2, ethane, propane and butane have been documented in the literature (27) as a means of miscible displacement and extraction of light to mid-gravity hydrocarbon/condensate phase traps at moderate to low pressures. Care must be taken with this approach to ensure that the injected solvent is chemically compatible with the trapped hydrocarbon liquid and does not cause deasphalting which may result in the formation of plugging precipitates.

In-Situ Combustion – Injection of air or enriched air to result in auto ignition of trapped light hydrocarbon/condensate saturations in the near wellbore region has been pilot tested in some non-published applications. The motivation is to use limited near wellbore combustion to 'burn' the trapped fluid out of the formation. Problems with control, effective propagation and non-stoichometric uptake of the injected oxygen resulting in the potential for downhole explosions on return flow have, to date, limited the application of this technology.

Water Displacement – In high permeability formations (1000 mD plus) water injection has been used, followed by dry gas (generally nitrogen injection to re-establish a zone of connective gas saturation) to displace condensate traps from near wellbore regions in prolific, but depleted, gas condensate production wells. Use of this technique in lower permeability media has been found to be less successful due to the potential for water based phase trapping issues due to relative permeability and capillary pressure hysteresis effects.

Dense Phase CO_2 Injection – Carbon Dioxide has high solubility in both water and hydrocarbons and can generate low gas-brine IFT (28) and, at sufficient pressures, zero or near zero gas-oil IFT. This has made CO_2 a very effective solvent for the displacement and removal of both water and hydrocarbon based phase traps. Challenges of this method center about effective contact and conformance of the CO_2 treatment and incompatibility between CO_2 and some hydrocarbon liquids from the asphaltene precipitation perspective.

Mutual Solvent Displacement – The use of mutual solvents (light and heavy alcohols, glycols, etc) has been extensively documented in the literature (29) as a method for reducing IFT and increasing volatility of trapped water and hydrocarbon phases. These solvents are often combined with CO_2 to increase their effectiveness. Once again, effective contact and potential compatibility issues between light alcohols, such as methanol, and many liquid hydrocarbons are the major challenges to the application of this technology.

Surfactant Treatments – Surface tension reducing agents spotted in water or hydrocarbon based injection fluids have been used in some situations to remove both hydrocarbon and water based phase traps. Various authors in the literature (30) have illustrated how, particularly for removal of hydrocarbon traps in water wet water injection zones (water injection and disposal wells), this technique can have application.

Acid Treatments – Acid treatments in a soluble (carbonate) formation can reduce capillary pressure in a phase trapped zone by dissolution of the matrix resulting in an increase in the effective pore throat radius and geometry which reduces capillary pressure and hence the potential for phase trapping (see equation #1). This method has many potential pitfalls, including the further trapping of the spent acid phase if the acid is allowed to spend in the formation and is subsequently displaced into non acid enhanced matrix permeability and potential sludges, emulsion and precipitates that may occur between the insitu fluids and active/spent acid which may impair permeability. Proper acid screening and design must be conducted to eliminate these issues and to ensure that the reaction rate of the acid is retarded to the extent that the acid can be recovered while still in a partially active state.

Wettability Modification – Transient wettability modifiers, as discussed previously in the paper, can also be used as stimulation fluids to temporarily change wettability to a more neutral wet condition to reduce capillary pressure and increase the ability of the formation release trapped water based fluids. Effective contact of the phase trapped zone is generally the biggest challenge in the application of a treatment of this type.

Conclusions

This paper has reviewed many of the recent technologies being used to prevent and remediate water based and hydrocarbon based phase trapping in a variety of oil and gas production well and water and gas disposal/injection well situations. Although a variety of remediation techniques are available, experience suggests that effective contact of the phase trapped zone, particularly if it is of large volumetric or complex geometric extent, represents the greatest challenge in the remediation of a phase trap. In general prevention of the problem before it occurs with appropriate drilling, completion and production practices results in better net present value in almost any situation where the potential for phase trapping induced formation damage exists.

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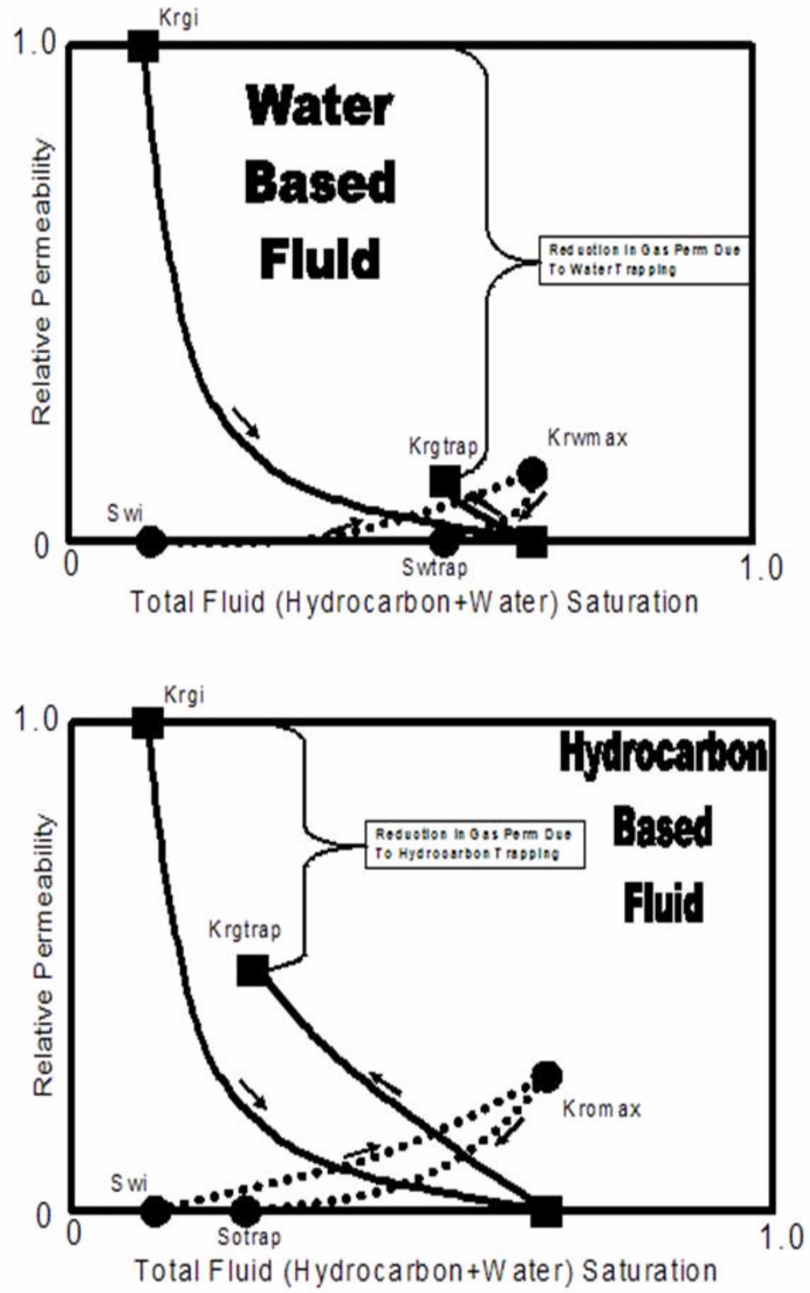

Figure 1 - Illustration of Reduction of Phase Trap Damage Effect Between Water and Hydrocarbon Based Fluids in Low Permeability Subnormally Water Saturated Gas Reservoirs

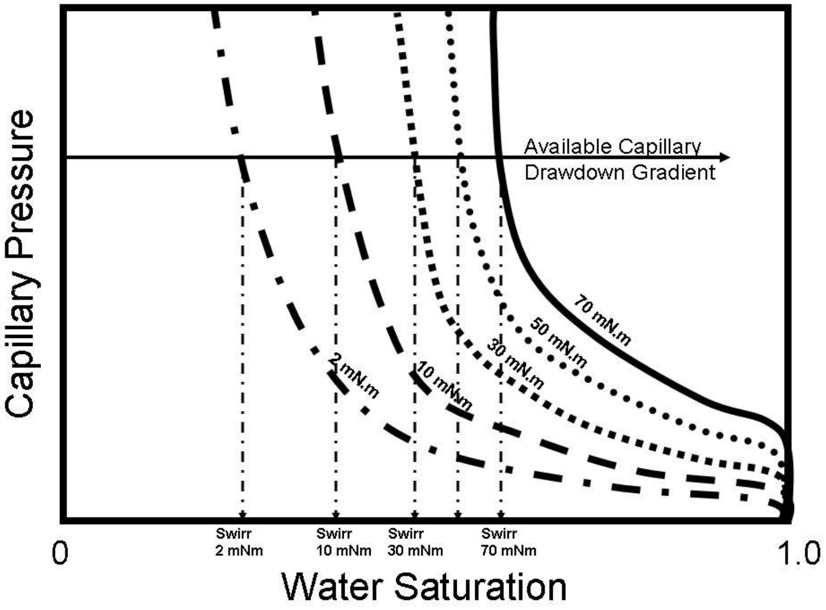

Figure 2 - Effect of Gas-Brine Interfacial Tension on Capillary Pressure and Resulting Irreducible (trapped) water saturation at a given drawdown pressure gradient

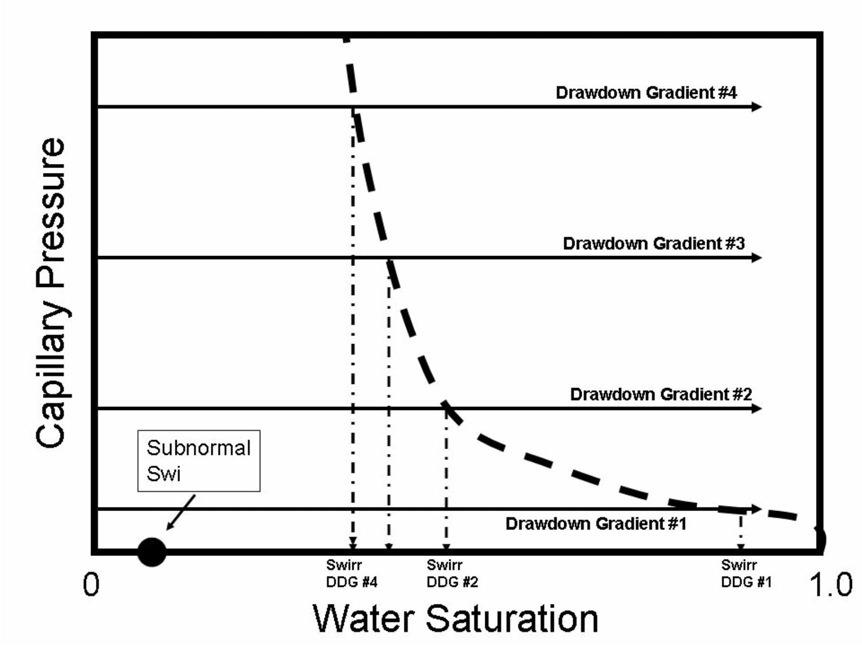

Figure 3 - Effect of Capillary Drawdown Gradient on Irreducible (trapped) Water Saturation

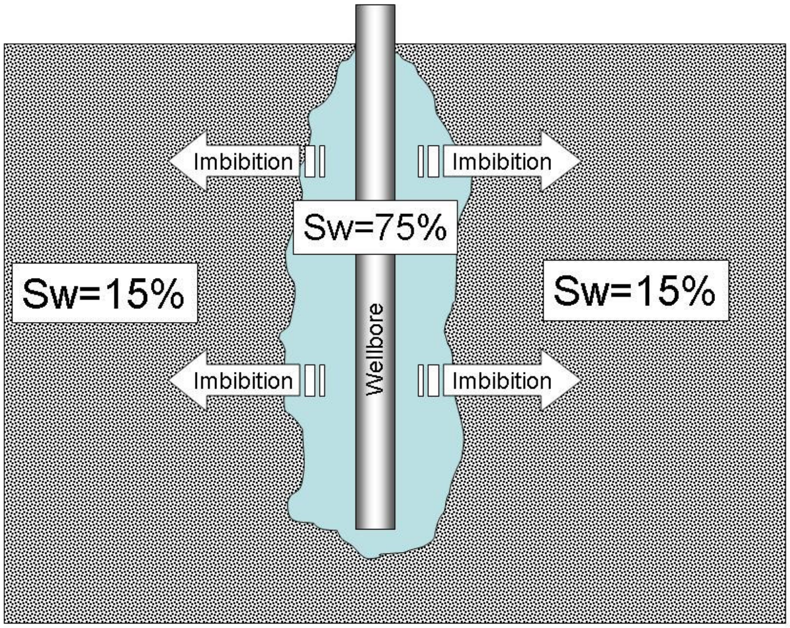

Figure 4 - Countercurrent Imbibition Effects in Reducing High Near Wellbore Water Saturations in Subnormally Saturated Low Permeability Water Wet Gas Reservoirs