

Unconventional Fracturing Fluids : What, Where and Why

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A Wide Range of Fluid Systems

- Water-Based Polymer Systems
- Surfactant Systems
- Energised Systems
- Emulsion Systems
- Non-aqueous Systems
 - Oil-Based
 - Methanol

A Wide Range of Fluid Systems

- Why So Many Fluids?
 - Different Formations
 - Base Lithology
 - Additional Mineral Components
 - Different Formation Fluids
 - Different Objectives
 - Different Pumping Configurations
 - Etc.

Conventional Frac Fluids

- Water Based Polymer Systems
 - Water with Friction Reducer
 - Base Gel
 - Crosslinked Water Based Fluid
 - Borate Crosslinked
 - Zirconium Crosslinked
 - High pH and Low pH Fluids
 - Low Polymer Systems
 - Energized Systems
 - Foams

Water-Based Polymer Systems

- Low Residue
- Base Fluid (Water) Is Inexpensive
- Continuous or Batch Mix
- Excellent Rheological Properties

Why Unconventional Fluids

- Tight Gas Wells
 - Unconventional Wells
 - Shales
 - Coal Beds
- Wells with Adverse Capillary Effects
 - Sub-irreducible Water Saturation
 - Sub-irreducible Hydrocarbon Saturation

Technical papers



SPE 35577

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

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 reservoirs, the techniques discussed are applicable to a wide range of reservoir types.

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ABSTRACT

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Water Sensitive Reservoirs

- Clay expansion - Smectite and mixed-layer clays are water-sensitive (swelling and fines migration).
- Clay dispersion - “water shock,” or “salinity shock.” : the dispersion of poorly-cemented clays, such as some of the more fragile versions of illitic clays or pore-filling kaolinite.

Undersaturated Gas Reservoirs

- Capillary undersaturation:
 - initial water saturation is less than would be expected under capillary equilibrium or irreducible water saturation
 - also called sub-irreducible water saturation

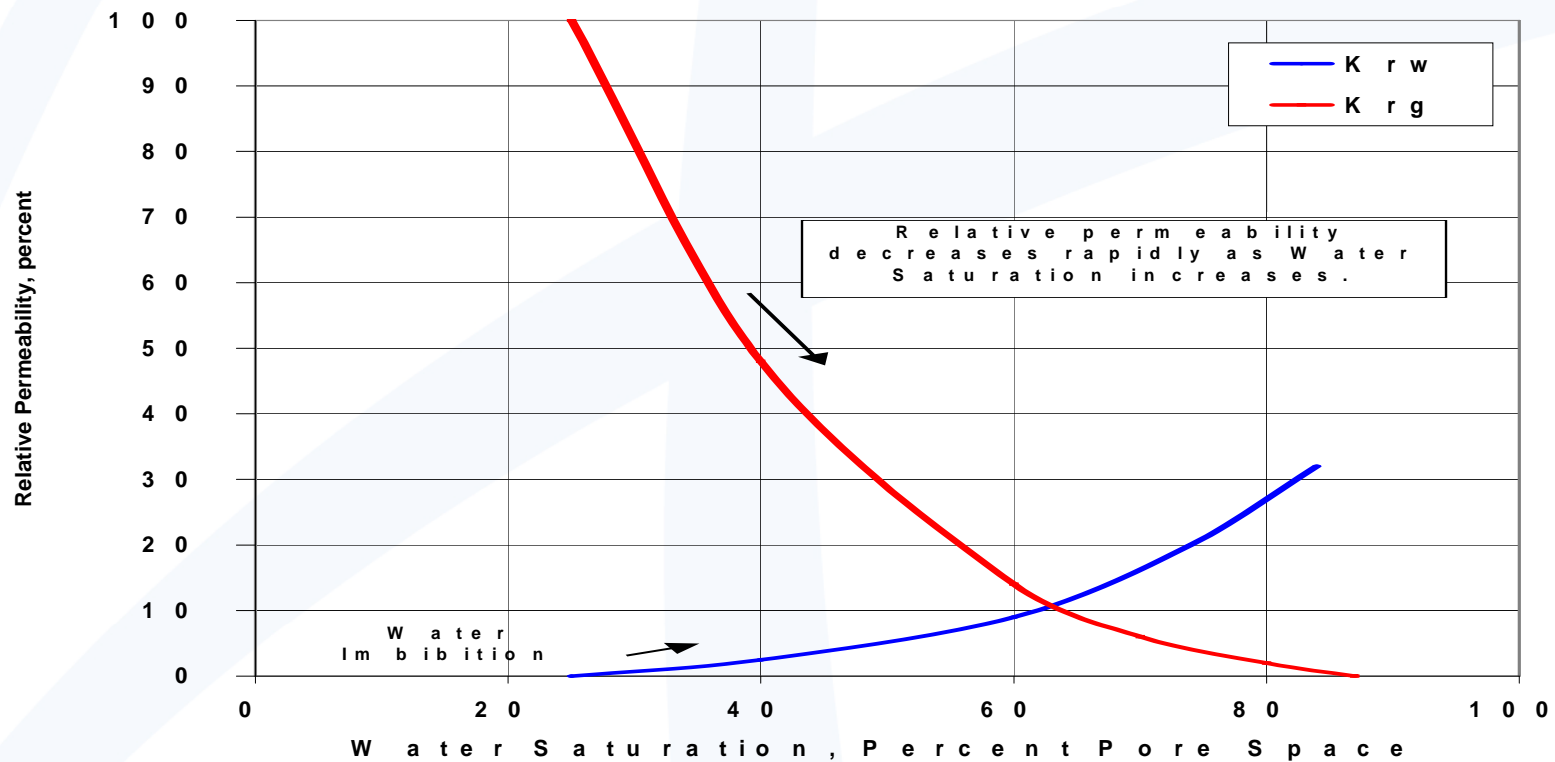
Tight Gas Reservoirs

- Aqueous Phase Trapping - Hydrocarbon permeability is frequently reduced due to imbibition of aqueous treatment fluids during well operations. This imbibition effect has been observed as a particularly severe problem in reservoirs where a sub-irreducible water saturation exists.

Aqueous Phase Trapping

- Understanding aqueous phase trapping is important due to it being the driving force behind many low-permeability stimulation decisions.
- Diagnostic tools can be used in evaluating sensitivity to aqueous phase trapping.

Relative Permeability Decreases Due to Water Imbibition



Remediation or Prevention Techniques

- Adding methanol to water-based treatments to reduce water content, lower interfacial tension, and enhance the evaporation of the water-based filtrate during reservoir cleanup
- Use of non-aqueous fluids (methanol-based, oil-based, or gas-based) to eliminate water injected into the formation

Unconventional Frac Fluids

- Polymer Systems
 - Aqueous Methanol Based
 - Non-Aqueous Methanol Based
- Non Polymer Systems
 - Surfactant Gels (VES)
 - VES Foams
 - Hydrocarbon Based
 - Liquid CO₂ Based

Liquid CO₂ Based Emulsion

- Minimize Water In Formation
 - 25% gelled fluid
 - 40% Methanol
- Low Residue
- Rapid Clean Up

Gelled Methanol Systems

- 100% Gelled Methanol
 - Good for water-sensitive formations
- Low Surface Tension - Better Flowback
- Vapor Density
- New Gelling / Crosslinking Systems
 - Easier to break
 - CO₂ compatible
 - Wide temperature range
 - Less damaging than earlier systems

Crosslinked Non-Aqueous Methanol

- Water Sensitive Formations
- Dry Gas Wells
- Wells Damaged with Water

Surfactant Systems

- Cationic + Salt
- Amphoteric + Salt
- Cationic + Anionic
- Anionic

VES System

- Two Surfactant System
 - Cationic + Anionic
- Simple
 - Two fluids added on-the-fly
- Formation Benign
 - No residue, no formation damage
- Low Surface Tension
 - No additional flow-back surfactant is needed

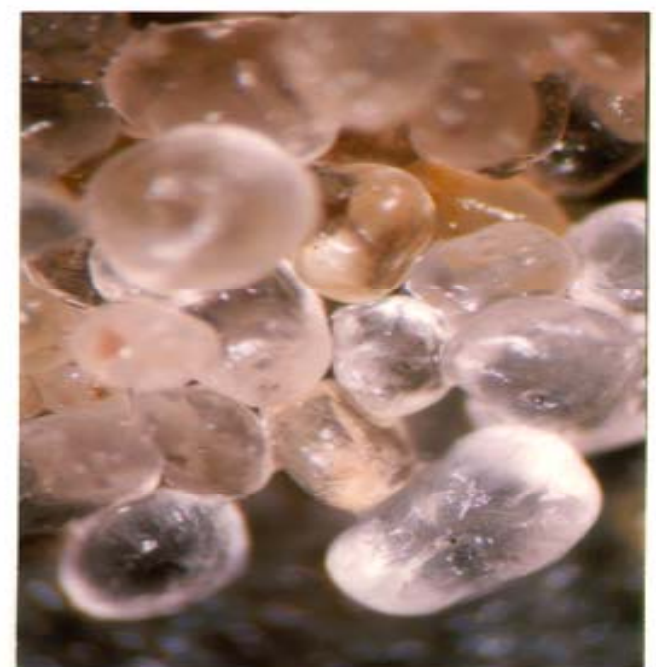
VES System

- The System does not require
 - Biocide or Clay Control Agent
 - Buffer
- Insensitive to salinity
- Flowback fluid can be reused
- Compatible with N₂ and CO₂

VES System

- Shallow Gas Projects
- Tight Formations
- Maximize Fracture Conductivity

Figure 4.3



Proppant
Pack
Clean up of
VES Fluid
System
Showing No
Damage

Foamed VES System

- Two Surfactant System
- No Residue
- Strong Self-Foaming Ability
 - No additional foamer needed
- Cost Effective
- Foam Viscosity: Same as Conventional Foams and also adjustable
- High Quality Foams (>85 Quality) with Light Weight Proppants

Foamed VES System

- Medium to High Temperature
- Under Pressured Gas Wells
- High Permeability Wells
- Wells with Complex Fracture Issues
- Coal Bed Methane Wells
- High Quality Foams for Shales

CO₂ Systems

- Liquid CO₂
- CO₂ / N₂
- Unconventional CO₂ Foam

Liquid CO₂

- Pure Liquid CO₂
- No Other Additives
- Clean System
- Requires CO₂ Blender
- Limited Treatment Size

Liquid CO₂

- Very Low Pressure Gas Reservoirs
- Low & High Permeability Formations
- Cleanest System
- Evaluation Fracs

Unconventional CO₂ Foam

- Liquid CO₂ continuous phase
- Nitrogen as discontinuous phase (internal)
- Proppant forms part of internal phase
- Internal phase quality (Mitchell) : Approx. 70 %
- Stabilized by CO₂-soluble surfactant

Unconventional CO₂ Foam

- Dry Gas Reservoirs
- Under Pressured
- Under Saturated
- Fluid Sensitive Formation
- Evaluation of Reservoir Potential is Critical
- Coal Bed Methane Wells
- Project Basis

Gelled Liquefied Petroleum Gas

- Chemistry similar to oil gels
- Non Damaging
- Potential Safety Issues
- Fast Clean Up
- Phase trapping eliminated
- Direct Flowback to pipeline
- No Flaring required

New Trends

- High Temperature Surfactant Gels
- Associative Polymer Systems
- Produced Water Based Frac Fluids

Reference Papers

- SPE 90170 - Diagnostic Tools
- SPE 37359 - VES Fluid
- SPE 97211 - Foamed VES Fluid
- SPE 106304 - Poly CO₂ Fluid
- SPE 95061 - Crosslinked Hydrocarbon / CO₂ Fluid
- SPE 40016 - Liquid CO₂
- SPE 84119 - Unconventional CO₂ Foam
- SPE 37229 - Non-Aqueous Methanol Fluid
- SPE 84579 - Non-Aqueous Methanol / CO₂ Fluid

Questions?



Unconventional Fracturing Fluids

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Baker Hughes

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Abstract

Many tight gas formations are water-wet and under-saturated where the initial water saturation in the reservoir is less than the capillary equilibrium irreducible water saturation. The use of water-based conventional fracturing fluids causes water to be trapped in the near-wellbore region, thereby significantly impairing the ability of gas to flow. Formations with sub-irreducible water saturation can be stimulated with fluids that minimize the interfacial tension (such as surfactant gels), minimize the amount of water used in the fluid (such as energized or foamed fluids), dehydrate the formation (such as alcohol-based fluids) or completely eliminate water (such as hydrocarbon-based or liquid carbon dioxide-based fluids). Since the rheology and proppant-carrying properties of these fluids vary, the uses of these fluids are different and will be discussed in detail in the paper. The paper will also present guidelines, based on formation properties, to indicate the need for considering unconventional fluids. Some of the new trends in the development of unconventional fluids are also presented.

Introduction

As the industry moves to extracting gas from tighter and tighter formations, particularly formations such as shales or coalbeds where production is controlled by desorption of the gas rather than matrix flow, fluids that are non-damaging to the proppant pack and formation are becoming increasingly important. Wells with adverse capillary effects due to sub-irreducible water or hydrocarbon saturation also require different fluids to minimize those effects or mitigate effects caused by drilling with the wrong fluid. Several unconventional fluids have been developed and successfully used for these unconventional formations in the last decade.

Adverse saturation in the formation can contribute to productivity impairment. Production has been successfully achieved in formations with matrix permeability as low as 10^{-3} millidarcies (mD). However, adverse capillary forces, which result in high *in situ* saturation of trapped water or liquid hydrocarbons even in very low-permeability formations, make economic production difficult. Low-permeability formations are typically tolerant of only minimal saturation damage due to the sensitivity to capillary retention effects, and rock-to-fluid and fluid-to-fluid compatibility issues. In these wells, the damage from drilling and completion can be overcome by a properly designed frac treatment, which can penetrate beyond the zone of induced invasion and damage.

Fluid Retention

The major cause of productivity impairment in gas wells during drilling, completion and fracturing or workover operations is fluid retention effects. These can include the permanent retention of water or hydrocarbon based fluids or the trapping of hydrocarbon condensate fluids retrograded in the formation during gas production. Bennion and his collaborators have labeled these phenomena aqueous and hydrocarbon phase trapping (Bennion *et al.*, 1994, 1996). Capillary forces in the formation are the reason for fluid retention. Capillary pressure forces are the difference in pressure between the wetting (typically water in gas reservoirs) and non-wetting (gas) phases in the matrix. The imbibition effect has been observed as a particularly severe problem in reservoirs where sub-irreducible water saturation exists. Sub-irreducible water saturation may have been created by a combination of factors, including dehydration, desiccation, compaction, mixed wettability, significant height above the free water level in oil reservoirs due to drainage, and diagenetic effects occurring during geologic time. Laboratory capillary pressure measurements supply good approximations of the irreducible water saturation that would normally be expected, but actual reservoir water saturation can be substantially lower, i.e., a sub-irreducible level. The high capillary pressure associated with low-permeability microporous reservoirs is illustrated in Figure 1. Measured capillary pressure values for four rocks with permeability from 0.001 to 1.0 mD are presented to illustrate the greater imbibition effects of water in lower-permeability formations. The capillary pressure of the 0.001-mD core at 40% water saturation is 325 psi greater than that of the 0.01-mD core at initial saturation. This illustrates the higher capillary pressure available in tighter reservoirs to imbibe and trap aqueous liquids due to capillary imbibition. Injecting water-based fracturing fluids into a high-capillarity reservoir results in the creation of a zone of high water saturation in the near-wellbore or near-fracture face area. The relative permeability curves in Figure 2 show how increasing water saturation above the irreducible water saturation results in a dramatic decrease in gas relative permeability.

Gas production results in the affected zone reverting to the irreducible water saturation dictated by the capillary effects of the system and not the sub-irreducible saturation that existed before. The net effect is that the critical producing area of the well retains the increased water saturation, a lowered relative permeability to gas and therefore lower productivity. Several diagnostic techniques are available to estimate these effects (Gupta, 2009). These correlations can be used to estimate compatibility of the formation to water-based fracturing fluids. These are just guidelines, and exceptions abound, particularly for over-pressured reservoirs where the capillary imbibition effects can be overcome in a relatively short time frame (Bennion *et al.*, 1996).

Fracturing Fluids

Conventional fracturing fluids include water-based and polymer-containing fluids, hydrocarbon-based fluids, energized fluids and foams. These are not covered in this paper. Unconventional fracturing fluids include non-polymer-containing fluids such as viscoelastic surfactant fluids, methanol-containing fluids, liquid CO₂-based fluids and liquefied petroleum gas-based fluids. The most cost-effective solution is to fracture the formation with the simplest of fluids. Low-

viscosity water or hydrocarbon with the fewest additives would be the simplest fluids. However, these have very low proppant transport properties, very little leak-off control and, if pumped at high rates, will result in unacceptable friction. Various additives can control friction, but if the formation has adverse saturation effects, even in tight gas formations with very little leak-off, desired stimulation may not be achieved. Using salts in the fluids can control compatibility with clay containing formations. Depending on pumping conditions, i.e., the shear regime the fluid would experience, there may be need for shear-tolerant or shear-recoverable fluids. For higher-temperature applications, these can be achieved by the use of organometallic or borate crosslinked water-based fluids and crosslinked oil-based fluids. If the gas formations are under-pressured, the fluids can be energized with N₂ or CO₂ or foamed with N₂ or CO₂ or a combination of the two. The foam fluids also provide good leak-off control. If compatibility with water may be an issue due to wetting issues, the use of viscoelastic surfactant fluids can be considered. They also do not damage the proppant pack and can also be energized or foamed. If incompatibility is due to capillary and unloading issues, methanol-containing fluid can be considered. If the incompatibility is severe, then crosslinked methanol-based fluid, liquid CO₂-based fluid or LPG may be the answer.

Viscoelastic Surfactant Fluids

Viscoelastic surfactant (VES) gel systems have been described in the patent literature for friction reduction and as well treatment fluids (Teot, 1981). Its use in everyday life has been around for some time. Its use in fracturing fluids is relatively a new phenomenon, but the patent literature has exploded in this area in the last few years.

Principally, these fluids use surfactants in combination with inorganic salts or other surfactants to create ordered structures, which result in increased viscosity and elasticity. These fluids have very high zero-shear viscosity without undue increase in high-shear viscosity. Thus, they tend to be shear-degradable fluids. As explained by Asadi *et al.* (2002), zero-shear viscosity has been found to be an essential parameter in evaluating proppant transport. Therefore, these fluids can transport proppant with lower loading and without the comparable viscosity requirements of conventional fluids.

The technology of VES systems can be broken down into several categories based on the structure the system creates: worm-like micelles, lamellar structures or vesicles.

As the concentration of surfactant increases in water, micelles start to form. Further increasing the concentration exceeds the critical micelle concentration (CMC) for the surfactant in water; these molecules start interacting with each other. These interactions are based on ionic forces and can be amplified by adding electrolytes (salts) or other ionic surfactants. Depending on the ionic charges and the size and shapes of the surfactants and these counter ions, ordered structures start to form, which increases viscosity and elasticity. The reverse mechanism is true for breaking these systems. The structures can be disrupted by adding other surfactants, ionic additives and hydrocarbons (from the formation or mutual solvents or other solvents) or can be diluted by additional formation water. The most common commercial systems use cationic surfactants with inorganic salts (Teot *et al.*, 1988) or with anionic surfactants (Zhang, 2002).

Anionic surfactants with inorganic salts are also common (di Lullo *et al.*, 2002). Zwitterionic and amphoteric surfactants in combination with inorganic salts have been used (Dahanayake *et al.*, 2004).

The common VES fluids have a temperature limit in the range of 160 to 200 °F without foaming. High-temperature stabilizers have been known to increase the temperature limit to 250 °F. Not all of these fluids are compatible with CO₂. They have been shown to be economical replacements for conventional borate fluids for tight gas applications (Rieb, 2007). At least with one of these fluids, the flowback water from these treatments can be recycled (Gupta and Tudor, 2005, Gupta and Hlidek, 2009). This particular fluid uses a cationic surfactant neutralized with an anionic surfactant. The flowback water, in gas wells, tends to return some of the cationic surfactant and most of the anionic surfactant. The flowback water is typically collected for 24 hours into a tank. Initially, the fluid was filtered to remove any formation fines. Based on experience, it was found that allowing the fines to settle was sufficient to remove the fines. After settling, the middle 75% of the flowback water was transferred to a frac tank and the rest of the required water for the fracturing treatment was made up with fresh water. Using analytical or viscoelastic measurements, additional surfactants were used to reconstitute the fluid. Russell (2001) reported the procedure and well production results from using the recycled fluid in field study in Canada showing no effect of recycling on well production.

These VES fluids are operationally very simple as only one or two additives are added on the fly without any need to hydrate polymers. They do not require any biocides because they do not contain any biopolymers. They do not require additional flowback surfactants because they have inherently low surface and interfacial tension. No additional clay control additives are needed: They contain either salts or cationic surfactants, which have properties similar to KCl substitutes. The surfactants have molecular weights of hundreds, as opposed to the guar polymer with millions.

Viscosity is broken by altering the surfactant properties, by adding other hydrocarbons or by altering the salinity or pH. The regain permeability with these types of systems approaches 100%. Because of the wetting tendencies of the surfactants in some of the VES systems, they are useful even in formations with sub-irreducible water saturation and liquid-trapping issues, despite being aqueous-based.

Viscoelastic Surfactant Foams

A natural extension of VES fluid technology is the VES foams (Zhang, *et al.*, 2002). These foams can be formed with N₂ or CO₂. As mentioned before, not all VES systems are compatible with CO₂. No additional foamers are needed with these systems. The foam viscosity can be adjusted by adjusting foam quality and the viscosity of the base VES system. They have been successfully used in gas formations to 250 °F (Gupta and Leshchyshyn, 2005a). In formations with potential to form water blocks, these fluids are particularly suited because the leak-off fluid still contains the surfactants, which reduce surface tension in the matrix, overcoming capillary forces and helping in recovery of the fluid. These fluids have been shown to be suited for fracturing

coalbed methane wells that contain water because the foams control leak-off into the cleats without damage from polymer residue.

With the advent of ultra-lightweight proppants (ULWP), an extension of this technology has been very successful in under-pressured tight gas fields. A liquid suspension of the ULWP in a viscoelastic gel can be added to a stream of nitrogen or CO₂ in the field to form a very high quality (> 85 quality or volume percent) mist as a fracturing fluid, resulting in a partial monolayer frac treatment. This technology has been utilized very successfully in dry, low-pressure, tight formations in shales and coalbed methane wells in the US and Canada.

Emulsion of Carbon Dioxide with Aqueous Methanol Base Fluid

Certain formations have potential to retain even limited water used in foams and VES foams of over 70 quality. These fluids may damage these sensitive formations because of sub-irreducible water saturation and liquid trapping. In these formations, replacing 40% of the water phase used in conventional CO₂ foams (emulsions) with methanol can minimize the amount of water. Gupta *et al.* (2007) showed that a 40% methanol aqueous system yielded the highest viscosity of aqueous methanol mixtures, has a freeze point close to -40 °C (the lowest operating limit for fracturing equipment in the field) and surface tension around 30 dynes/cm. These emulsions use surfactants, which are methanol-compatible foamers, in the place of conventional foamers. Typical CO₂ quality approaches 85, which has resulted in high regained permeability and rapid clean up and production results in several Canadian gas formations (Gupta *et al.*, 2007).

Non-Aqueous Methanol Fluids

In formations with severe liquid (aqueous and hydrocarbon) trapping problems, non-aqueous methanol fluid may be a solution. Over the years, several authors have identified the advantages of alcohol-based fluids (McLeod and Coulter, 1966; Smith, 1973; Tiner *et al.*, 1974; Thompson *et al.*, 1992; Hossaini *et al.*, 1989; and Hernandez, *et al.*, 1994). These advantages include, but are not limited to, low freezing point, low surface tension, high water solubility, high vapor pressure and formation compatibility. Methanol is also the fluid of choice for formations with irreducible water and/or hydrocarbon saturation (Bennion *et al.*, 1994, 1996b). Three concerns with methanol all relate to safety: low flash point, high vapor density and flame invisibility. With special precautions, as previous authors have identified (Thompson *et al.*, 1992; and Hernandez *et al.*, 1994), methanol can be safely used in the field.

Several approaches to increasing the viscosity of methanol have been described in the literature (Thompson *et al.*, 1992; Hossaini *et al.*, 1989; Boothe and Martin, 1977; Crema and Alm, 1985; and Gupta *et al.*, 1997). These range from foaming methanol to gelling with synthetic polymers (e.g., polyacrylamide and polyethylene oxide) and modified guar. Attempts were also made to crosslink gelled methanol with metal crosslinkers. However, Ely (1994) described limitations that restrict the use of gelled non-aqueous methanol: solubility of these polymers in both aqueous and non-aqueous methanol, ability to crosslink, ability to break the polymer, and temperature limit.

The most recent development (Gupta, *et al.*, 1997; and Mzik, 1993 and 1994) describes a modified guar dissolved in anhydrous methanol crosslinked with a borate complexer and broken by an oxidizing breaker. This system has been successfully used in the field. In under-pressured wells, it has been energized with N₂. There has been an interest in a CO₂-energized methanol fluid for similar formations with severely under-pressured wells. Hence a new polymer that is soluble in non-aqueous methanol and compatible with carbon dioxide was identified. These non-aqueous base gels can be crosslinked with borate at pseudo-high pH (non-aqueous fluids do not have pH) or with zirconium crosslinker at pseudo-low pH for CO₂ compatibility. The special version of this HPG can hydrate in 100% methanol to give viscosity to the base gel and is also compatible with CO₂ without precipitation (Gupta *et al.*, 2003).

These fluids can be completely broken with special breakers, resulting in very high regained permeability in the proppant pack and in very sensitive formations. These fluids should be selectively used in gas formations with special safety considerations due to flammability of methanol. These new-generation fluids also do not require any water for hydration or for breaking.

Liquid CO₂-Based Fluids

Fluids based on liquid CO₂ are the real unconventional fluids. The concept and applications of these fluids require outside-the-box thinking. These fluids have been very successfully used in tight gas applications in Canada and several US formations. Their chemistry and physics have been extensively published, as summarized in a paper by Gupta and Bobier (1998) and described in brief here. The family of these fluids consists of pure liquid CO₂ and a binary fluid consisting of a mixture of liquid CO₂ and N₂ to reduce costs.

Conventional fracturing fluids rely on viscoelastic properties to inhibit leak-off from the fracture into the reservoir. Filter cake deposition from long-chain polymers or high filtrate viscosity in oil gel systems provides fluid loss control to establish adequate fracture width. Sufficient fracture width is required to allow proppant placement in the fracture. Liquid CO₂ has very low viscosity (Gupta and Bobier, 1998) and thus does not have the viscosity or filter cake properties to establish fracture widths when pumped at typical rates (i.e., 20 BPM).

Low-viscosity, low-temperature fluids have higher leak-off rates than conventional fluids, but this characteristic has an upper limit that is dependent on reservoir parameters. The use of a gas or liquefied gas makes the fluid compressible. Pumped at high pressure and low temperature, the fluid volumetrically expands when exposed to lower pressure and higher temperature in the formation. The fluid is not in steady state, and thus positive transient effects occur. This thermal expansion effect inhibits leak-off near the fracture face and promotes the development of fracture width. A combination of thermal expansion, relative permeability effects and possible turbulence through small reservoir pore throats curtails leak-off of liquid CO₂ from the fracture into the reservoir.

Several papers have described the unique nature of liquid CO₂ and liquid CO₂/N₂ mixtures as fracturing fluids (Lillies, 1982; Tudor *et al.*, 1994; Mazza, 1997; and Gupta and Bobier, 1998). In

these systems, the proppant is placed in the formation without causing damage of any kind, and without adding any other carrier fluid, viscosifier or other chemicals. As was described previously, “the use of a reservoir friendly substance like liquid CO₂” (and inert N₂) “offers unique advantages through the elimination of capillary fluid retention and clay swelling” (Mazza, 1997).

These low-viscosity fluids are not an obvious choice of fracturing fluid. However, a large number of jobs have been successfully performed with them (Gupta and Bobier, 1998). One of the major limitations of this technology has been their high treatment cost. Although stimulation treatments using the low-viscosity liquid CO₂ system have been successful, the high rates required to place these jobs and the associated frictional losses raised horsepower requirements.

Liquid CO₂-Based Foam Fluid

Several attempts have been made to increase the viscosity of CO₂-based fluids while trying to maintain the conductivity and formation compatibility of these fluids — with very little operational success (Bullen *et al.*, 1987). The liquid CO₂-based foam fluid consists of a foam of N₂ gas in liquid CO₂ as the external phase stabilized by a special foamer soluble in liquid or supercritical CO₂ (Gupta, 2003). The main advantage of this fluid is the additional viscosity gained by the foam over liquid CO₂. The use of 75 volume percent of N₂ also makes the fluid very cost-effective and applicable to project frac applications where multiple jobs can be performed in a single day. The fluid has also found niche application in coalbed fracturing in Canada on dry coalbeds where any water introduced into the formation damages the cleats.

Gelled Liquefied Petroleum Gas

Recently, Liquefied Petroleum Gas (LPG) has been discussed in a patent application as a hydraulic fracturing fluid (Loree and Mesher, 2007). The application proposes that LPG can be viscosified and proppant added to the fluid much like conventional fracturing fluid. The application further describes a unique and novel process that safely handles LPG and meters proppant into the gelled LPG stream for fracturing treatments. LPG gases are a mixture of petroleum and natural gases existing in a liquid state at ambient temperatures and moderate pressure (less than 200 psi). Unlike conventional hydrocarbon-based fracturing fluids, the common LPG gases, propane and butane, are tightly fractionated products with over 90% purity. There are many advantages in using liquefied petroleum gases for hydraulic fracturing if it can be done safely. The properties of density, viscosity and surface tension with complete solubility in formation hydrocarbons are very beneficial. Recovery of the LPG very nearly approaches 100%, clean up is very rapid (often within 24 hours), phase trapping is virtually eliminated, and LPG properties allow for extended shut-in times without detriment. Additionally, direct flowback to an available pipeline can be readily achieved. The result is a potential cost-effective stimulation with effective fracture lengths, excellent post-treatment production and the potential for zero flare clean-up.

New Developments

New developments in the area of unconventional fluids have been in increasing the temperature of use of viscoelastic fluids, the use of associative polymers that associate with surfactants that can be used as straight fluid or foams (Gupta and Carman, 2011) and fluids based on produced water that are also based on associative polymers.

Conclusions

Several unconventional fracturing fluids are described in this paper to minimize or eliminate phase trapping issues associated with stimulation of tight gas wells. Proper selection of the fluid depends on the severity of the issues and economics.

Acknowledgement

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Figure 1. Effect of capillarity on water saturation (after Holditch, 1979)

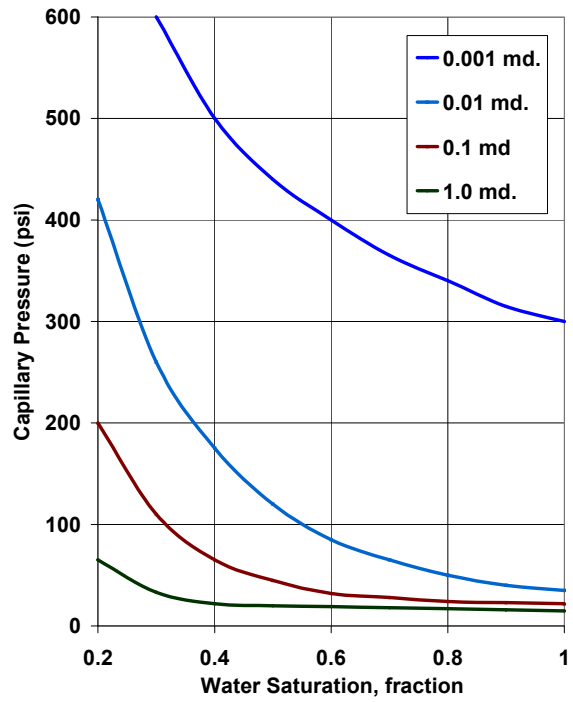


Figure 2. Effect of water imbibition on relative permeability changes (after Keelan, 1975)

