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


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
Each of these categories will now be reviewed in more detail.

1. **Poor Reservoir Quality - Period!** The saying "You cannot make a silk purse out of a sow's ear" has definite applicability to the field of tight gas exploitation. Through the use of appropriate drilling, completion and in some cases large scale fracturing techniques, some operators have been amazingly successful in obtaining economic production rates from formations exhibiting in-situ matrix permeabilities of as low as $10^{-6}$ D. Some reservoir applications, however, are doomed to failure by the simple virtue of the fact that, no matter how successful and low damaging our drilling and completion operations, sufficient in-situ permeability, pressure, reserves or all of the above are not present to obtain economically viable wells. The prime objective of this paper is to identify candidates of this type, in comparison to those where the judicious application of the appropriate technology can obtain economic wells. In general, no documented evidence exists of economic production from formations having an interconnective matrix permeability of less than $10^{-6}$ D (even in the presence of successful large scale fracturing treatments). If an extensive micro or macrofracture system exists and the well can be completed without impairing the conductivity of the natural fractures, then documented cases exist where viable production has been obtained from source matrix of lower permeability values than $10^{-6}$ D. Penetration of a less extensive microfracture system by a conventional hydraulic or acid fracturing treatment, to augment inflow, has also been successful in some super micro-Darcy reservoir applications. Well successes in these situations have been highly dependent on geological control and being able to effectively predict the location of and penetrate the pre-existing natural fractures with the wells or fracture treatments. Where such penetration has not occurred, the wells have generally been non viable.

2. **Adverse initial saturation conditions.** In many cases, gas exists in low permeability formations of "acceptable" permeability according to the previous criterion, but, due to adverse capillary forces, high in-situ saturations of trapped water, and in some cases, liquid hydrocarbons are present. If these saturations are too high, economic production of gas from the zone is often difficult due to:
   - Limited reserves available for production due to the majority of the pore space being occupied by an immobile trapped fluid.
   - Adverse relative permeability effects caused by the presence of high immobile fluid saturations rendering economic production rates impossible.
   - One of the first steps in ascertaining if gas is economically producible from a low permeability formation is the accurate determination of initial fluid saturations. This process is often difficult due to the fact that:
     - Water saturations calculated from logs are often inaccurate due to limited availability of accurate "a", "m" and "n" electrical property data to calibrate field resistivity logs.
     - Accurate $R_w$ data is often unavailable for these formations as, due to high capillary trapping effects, many of these zones do not produce mobile free water to facilitate accurate compositional and $R_w$ measurements.
   - Water saturations evaluated from cores drilled with water based fluids are often elevated due to core flushing and spontaneous imbibition effects. Water saturations obtained using air or nitrogen as coring fluids are often lower than true in-situ values due to localized heating during the coring process and core desiccation. Oil-based coring fluids can result in good water saturation determinations, but flushing can affect the accuracy of the measurement of the magnitude of any trapped initial liquid hydrocarbon saturation which may be present in the reservoir.
   - A variety of techniques are available to measure in-situ water and oil saturations, the best and most reliable being speciality coring programs in the producing zone of interest. In zones containing only an initial water saturation, radioactively traced (deuterium or tritium) coring fluids can provide an accurate evaluation of initial water saturation when coupled with low invasion coring technology (Ref. 1). When both an initial oil and water saturation are present and we desire to evaluate the true magnitude of the "free" gas saturation available for reserves evaluation and recovery, sponge coring, when coupled with a radioactively traced water based coring system and a low invasion coring tool can give good results, as illustrated in Fig. 1. It can been seen from Fig. 1 that with this data (when the oil volume is adjusted for gas solubility and swelling effects) one can accurately evaluate the free gas saturation and determine if sufficient reserves and relative permeability exist to obtain a viable and exploitable play. These techniques have been used in the past to ascertain initial saturations in formations such as the Montney, Gething, Rock Creek, Ostracod, Viking, Cardium and Jean Marie in Canada and in a number of low permeability Permian Basin gas fields in the United States. Although highly related to reservoir quality, if a free gas saturation of lower than 25-30% exists in the media this reduces both reserves and effective gas permeability below what would typically be quantified as economically producible values.

3. **Formation Damage During Drilling and Completion.** Tight gas reservoirs are very susceptible to formation damage. This is due to the generally unforgiving nature of low permeability rock in that we can tolerate only a minimal amount of damage, due to the already inherently low permeability, and to the fact that low permeability formations generally experience much more severe damage than their higher permeability counterparts due to a high degree of sensitivity to capillary retentive effects, rock-fluid and fluid-fluid compatibility concerns.
   - In general, the degree of significance of formation damage associated with a tight gas reservoir during the drilling process will be related to the nature of the final completion
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/macrorfractured 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:

\[ P_t = P_{nw} - P_w \]
\[ = (\text{Interfacial Tension})_{g-w} \left( \frac{1}{R1} + \frac{1}{R2} \right) \]  \hspace{1cm} (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 subreducible 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:

\[ A_{PT} = 0.25[\log_{10}(k_w \text{ in mD})] + 2.2(S_{wi-in} \text{ initial fraction}) \hspace{1cm} (2) \]

Fig. 6 provides a pictorial representation of Equation 2. A
value of the aqueous phase trap index \( A_{PT} \) 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 \( A_{PT} \), 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 \( A_{PT} \) 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
irreducible saturation level (where the capillary pressure curve becomes vertically asymptotic). In a properly designed overbalanced operation the use of appropriate bridging and filter cake building agents can establish a near zero permeability filter cake on the face of the formation which may impede spontaneous imbibition effects. In an underbalanced drilling operation, if any free water saturation is present in the circulating fluid system, this is similar to establishing a gas-water contact directly adjacent to the wellbore face and continuous countercurrent imbibition effects into the formation can occur, even when a continuously underbalanced condition is maintained. The problem with aqueous invasion is attenuated if the underbalanced condition is lost or periodically compromised, or if a well drilled underbalanced is hydrostatically killed for completion, due to the fact that there is no protective filter cake to impede the large scale invasion of fluids into the formation in an overbalanced condition. Laboratory studies describing this phenomena are presented in detail in Ref. 4.

**Mud Solids Invasion.** The physical invasion of natural and artificial solids may occur during drilling, completion, workover or kill treatments if operating in hydrostatically overbalanced conditions. Due to the very small pore throats normally associated with low permeability gas reservoirs, any significant depth of invasion of mud solids into the rock is not normally observed (unless fractures or extremely small solids, which can sometimes be generated by PDC bits, are present). Once again, this is usually only a concern in situations where open hole completions are contemplated due to the shallow nature of the damage.

**Glazing.** Glazing, mashing or wellbore polishing can be a problem in some open hole tight gas completions, particularly if pure gas is used as the drilling media. Due to the extremely poor heat transfer capacity of gases, if no fluid is present in the circulating drilling media, extremely high rock-bit temperatures can be generated. This can result, when combined with connate water and rock dust generated from the drilling process in conjunction with high temperatures and the polishing action of the bit, in the formation of a thin but very low permeability ceramic pottery like glaze on the face of the formation. This phenomena can be observed on the face of sidewall cores cut in such situations and on the face of air drilled core. Like mud solids invasion, due to it’s extremely localized depth, glazing tends to be problematic specifically in open hole completion scenarios. Mashing, caused by poorly centralized strings and tripping, refers to mechanical damage caused by friction and motion of the string and centralizers, collars etc., against the formation face and results in the intrusion of a paste like layer of fines and drill solids into the formation face directly adjacent to the wellbore. Once again, a localized form of damage usually problematic only in open hole completions.

**Rock-Fluid Interactions.**

**Clays.** The low permeability associated with many tight gas formations is generally caused by small grain size in sandstones or limited intercrystalline porosity development in carbonates, but in some formations, predominantly clastics, the permeability is also reduced by significant concentrations of clay. A variety of different types of clay can be present. Highly fresh water sensitive expandable clays such as smectite or mixed layer clays can occur in shallower tight gas formations. Examples include the Viking, Basal Colorado, Belly River and Milk River formations in Western Canada. When contacted by fresh or low salinity water these clays expand in size due to substitution of water into the clay lattice (Ref. 6). The physical expansion of the clay (up to 500% depending on the type of clay under consideration) can result in near total permeability impairment. Other types of clay, such as kaolinite are susceptible to electrostatic deflocculation (Ref. 6), where abrupt changes in salinity and pH can cause the clay to disperse and migrate to pore throat locations where it bridges, blocks and can cause permanent reductions in permeability (Cardium, Belly River, Glauconite, Halfway, Bluesky, Basal Quartz, Gething, Ostracod, Viking, Rock Creek and Montney are some formation types in Western Canada where this phenomena has been observed). Since filtrate invasion can extend a significant distance into the formation if fluid losses are appreciable, this type of damage may be of sufficient radius of penetration to partially impair the productivity of limited scale subsequent fracture treatments in certain situations. If fresh water sensitive or reactive clays are present, care should obviously be taken to use inhibitive fluids or low fluid loss systems to minimize the depth of invasion. **Chemical Adsorption.** Physical adsorption of high molecular weight polymers or oil wetting surfactants can reduce permeability significantly in low quality formations or preferentially elevate permeability to water if a free water saturation is present in the formation. The relative size of the large polymer chains, when adsorbed on the surface of the porous media, is significant in comparison to the relative diameter of the pore throats allowing gas to flow from the media. Thus a film of adsorbed polymer, which may only moderately reduce the permeability in a higher quality formation, can totally occlude available permeability in a lower quality zone. Once again, this is a wellbore localized phenomena. Adsorbed polymer can often be removed using oxidizing agents, but care should be taken to ensure that invasion of the oxidizing agent, and subsequent entrapment, does not occur when the sealing effect of the polymer filter cake is degraded by oxidant contact.

**Fines Migration.** Fines tend to move preferentially in the wetting phase and hence when only gas is flowing migration of particulates in the porous media should be minimized. Problems can occur when fluid invasion occurs due to relatively high spurt losses potentially encountered during the drilling or fracturing process, due to motion of invaded fluids
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 entrainment
- entrainment 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 crosslinked 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, 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)
- Paraffin deposition problems (waxy rich gas systems)
- Diamondoid and hydrate plugging problems
- Elemental sulphur precipitation (high H₂S concentration systems)

**Fines Migration.** Considerable research (Ref. 7) has indicated that fines generally tend to preferentially migrate in the wetting phase. For most gas reservoir systems this would be water (the exception being sub-dewpoint rich gas systems or gas reservoirs containing an initial immobile conventional or heavy oil saturation in which case the liquid hydrocarbon phase may partially or totally wet the surface of the formation) and significant problems with fines migration do not occur during normal production operations unless the interstitial shear rate caused by extreme gas flow rates causes mobilization of the connate water. Water coning, caused by excessive production rates, or the high rate cleanup of invaded water based drilling, completion, stimulation or workover fluids from the formation, may result in a condition of mobile water saturation and hence movement of the wetting phase. This results in conditions where, if loosely attached particulate matter is present in the pore system and the critical rate for migration is exceeded, that mobilization of the fines and damage may occur. Many examples of this phenomena are present where wells produce at high gas rates until the first sign of water breakthrough. At this point massive reductions in gas rate, which cannot be solely attributed to relative permeability effects, can occur, including, in some cases, physical sand production and formation collapse (some higher quality Gulf Coast formations in the USA exhibit this phenomena).

**Retrograde Condensation Phenomena.** Fig. 8 provides a schematic illustration of a pressure-temperature diagram for a hydrocarbon system. A "dry" gas formation (typically a gas having a liquid yield of less than about 10 to 15 bbl condensate per MMscf of gas) follows the depletion path A to B. It can be seen that this depletion path never intersects the two phase envelope and hence this type of system is not prone to problems associated with downhole condensate dropout effects. These systems of reservoirs may still produce liquid condensate at surface as the depletion path through the production tubing often follows the path A to C with the separator temperature being sufficiently low that production at surface conditions is well within the two phase envelope.

"Rich" gas systems, being those with liquid yields of greater than approx 15 bbl of condensate per MMscf, fall more to the left on the P-T diagram (Figure 8), and it can be seen at reservoir temperature conditions that during the depletion operation (path D to E) these systems will pass through the dewpoint line and liquid hydrocarbon condensate, which often may represent the most valuable fraction of the reservoir gas, condenses out of solution in the gas. In a manner analogous to an aqueous phase trap, because these tight gas formations do not generally contain a pre-existing hydrocarbon saturation, a sufficient hydrocarbon saturation to build a continuous liquid film to allow flow of the liquid condensate to the wellbore must occur. This is commonly called the critical condensate saturation and the value is very dependant on reservoir lithology, wettability, condensate composition and drawdown pressure and can vary from a very small value (less than 2%) to very large values in excess of 40%. Tight gas systems, due to adverse capillary effects, often tend to exhibit higher critical condensate saturations than their higher permeability counterparts making them more susceptible to this particular mechanism of damage. The presence of the trapped condensate saturation has a blocking effect, identical to that described previously for the aqueous phase trap, and can substantially reduce near wellbore gas permeability.

In many rich gas systems, gas cycling schemes are implemented as a mechanism to recover the majority of the condensate liquids from the formation. In these systems condensate dropout, although mitigated in the bulk of the reservoir volume due to a properly executed cycling operation, can still significantly impair the productivity of the production wells as in many tight rich gas systems, even with large frac treatments in place, drawdown below the dewpoint pressure of the gas in the near wellbore region is require to obtain economic production rates.

**Solids Precipitation Problems (Paraffins, Hydrates, Diamondoids, Elemental Sulphur).** A detailed discussion of these phenomena is complex and beyond the scope of this paper, but is discussed in the literature (Ref. 8 & 9). The formation of all of these solid precipitates are generally initiated by reductions in temperature, and are also in some cases weaker functions of reductions in pressure. In most situations this results in the generation of these elemental solids being more of a production problem in tubing and surface equipment, rather than directly in the formation itself. Near wellbore problems are encountered in some waxy condensate systems which are producing at high rates due to a significant Joule-Thompson effect occurring at the perforations or in the fractures. The rapid expansion of gas in these zones, due to high drawdown effects, results in a significant localized temperature drop which can aggravate problems with solids precipitation. Diamondoids are granular solids, similar to their oil reservoir counterparts, asphaltenes, which are directly precipitated from natural gases (generally rich gases). These hard granular solids can result in erosion and plugging problems, most often in surface equipment. Elemental solid sulphur production can also occur downhole and in production equipment under certain temperature and pressure conditions in very sour gas systems which can result in both corrosion and plugging problems.

**Techniques to Avoid Damage and Remediate Existing Damage to Low Permeability Gas Reservoirs**

Many of the types of damage described previously can be avoided or their effect greatly reduced if a proper understanding of the reservoir and the types of problems which may be encountered is obtained prior to drilling, completion
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, Ostracid, 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 reasons, their use should be avoided in most situations where a liquid hydrocarbon saturation is known to exist in the reservoir in favor 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
due to its ability to reduce IFT, dissolve in the trapped liquid phase, physically extract a portion of the trapped water as a desiccant and provide a zone of localized high reservoir energy to obtain a high instantaneous capillary gradient on blowdown which might not normally be present in the formation (particularly in low pressure zones).

d) Liquid CO₂, LPG, Liquid ethane and dry gas have all been used as techniques to remove hydrocarbon traps in porous media. Depending in the available treatment pressure, temperature and gravity of the trapped hydrocarbons, one or more of these liquids will often be miscible with the entrapped hydrocarbons. The treatment is designed to either miscibly displace the trapped hydrocarbon a sufficient distance into the formation so that cross sectional flow area is increased to the extent that the zone of trapped fluid does not substantially reduce productivity, or produce the hydrocarbon saturated liquid back out of the formation at sufficient backpressure to keep the extracted hydrocarbons in solution to physically "scrub" a portion of the formation adjacent to the wellbore or fracture face clean of entrapped hydrocarbon. High treatment pressures are required for this treatment to be effective with conventional dry gas (natural gas or nitrogen) injection, generally in excess of 35 MPa. The treatment may be effective at much lower pressures (8 - 20 MPa) with gases such as liquid CO₂ or ethane, and at very low pressure (3 - 5 MPa) with very rich low vapour pressure gases such as LPG. In the case of a retrograde condensate trap, the treatment may be of only temporary utility as, if the well is continued to be produced in a high drawdown condition, further entrapment will occur as additional condensate is retrograded as the gas continues to be produced from the well.

3. Physical changes in the pore geometry. Since capillary pressure is also a direct function of the radii of curvature of the immiscible interfaces which are present in the porous media (Eq. 1), which are forced by the geometry of the confining porous media (Fig. 3), if the radii of curvature can be increased, by making the pore spaces less constrictive, capillary pressure will be reduced and it may become possible to mobilize the trapped fluid. While generally difficult to accomplish in clastic formations, unless HF acid is considered, this can be accomplished in some cases in tight carbonates with appropriate acid treatments. These stimulation treatments, however, are in some respects the proverbial "two edged sword" in that when the acid spends we simply have more water in the formation. If the spent acid is squeezed past the zone of effective reaction, it may become entrapped like any other invaded aqueous fluid and, in some cases, aggravate the production problem it was intended to cure. This is evident in many acid squeeze treatments in tight gas reservoirs where acid recoveries have been exceptionally poor and well productivity has often been further impaired, rather than improved, by the acid treatment. The use of nitrified or foamed acids has been useful in some situations of this type as the total volume of liquid introduced into the formation is reduced and localized charge energy to recover the acid is introduced into the formation by the gaseous agent (often CO₂) used to foam the acid. Caution is required in implementing this procedure to reduce a hydrocarbon trap, as many acids are incompatible with hydrocarbons and de-asphalting or the formation of stable emulsions, particularly in the presence of high concentrations of unsequestered iron, could occur.

4. Direct physical removal of the trapped water or hydrocarbon saturation. This encompasses a rather wide range of potential techniques which include:

a) Dry gas injection. A common misconception is that merely flowing the reservoir gas for an extended period of time will result in evaporation and removal of a portion of the trapped water or hydrocarbon saturation. Since the produced reservoir gas is saturated with both water vapour (in all cases) and heavy hydrocarbons (for a rich gas reservoir) at reservoir temperature and pressure conditions as it passes by the trapped liquid, it can be seen that no additional water or hydrocarbon could be effectively absorbed into the gas phase. If pressure can be elevated significantly, some hydrocarbon liquid may revaporize, but this is obviously much easier accomplished in an injection rather than a production scenario. Dry, dehydrated, pipeline spec gas injection will result in the gradual desiccation of a portion of the reservoir directly adjacent to the injection zone, a phenomena well known in many gas storage wells. The objective of a dry gas injection technique is to inject dry gas for a short period of time (3 to 10 days at 1 to 3 MMscf/day typically) to attempt to dehydrate some of the higher conductivity channels in the reservoir and establish a conductive flow path to the bulk of the undamaged reservoir. The technique is relatively easy to apply and has particular application in damaged horizontal wells where large exposed pay zones may render other types of penetrating treatments impractical. Dry gas injection has been successfully combined, in some situations, with mutual solvents such as methanol to increase the potential extractive power of the treatment. Variations of the procedure would include the use of alternative dry gases such as nitrogen, oxygen content reduced air, dehydrated flue gas or carbon dioxide. Figure 10 provides a schematic illustration of the dry gas injection process. If highly saline brine is the trapped phase (i.e. - weighted drilling, completion or kill fluids or spent acid) laboratory investigation of this technique is often warranted as precipitation of the soluble salts from solution as evaporation occurs in the pore system can result in significant residual permeability impairment which may counteract the benefit of the removal of the trapped water saturation.

b) Formation heat treatment. This is a relatively new experimental treatment which has been specifically designed to remove both aqueous phase traps as well as thermally decomposing potentially reactive swelling or deflocculatable clays (Ref. 10). The treatment is applied using a specially designed coiled tubing conveyed downhole treating tool. Electrical heaters in the downhole tool are used to heat
temperatures which is then subsequently injected directly into 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, combust 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, natural 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 in 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.
Rock-Fluid and Fluid-Fluid Interactions. Initial analysis of the formation to investigate the presence of any potentially reactive clays (smectite, mixed layer clays, mobile kaolinite), is essential in tight gas reservoirs. This is generally conducted using a combination of thin section, XRD and SEM analyses. If reactive clays are present, this should act as a warning flag for the use of fresh or low salinity water in most situations. Detailed compatibility testing should be conducted, if water based fluids are to be used, to quantify inhibitors (i.e. - KCl, CaCl₂, etc.) which may stabilize reactive clays if invasion does occur. Chemical stabilizers (i.e. - high molecular weight polymers), while potentially efficient at stabilizing reactive and mobile clays, often may cause more damage due to physical adsorption of the polymer on the rock surface which may occlude the minuscule area available for flow in tight gas formations and hence should only be used after detailed laboratory evaluation has been conducted to ascertain their usefulness and degree of damage that they may cause.

Similar tests should be conducted between potential invading filtrates and formation fluids to ensure that they are compatible with respect to scale, precipitate or emulsion formation with in-situ water and liquid hydrocarbons which may be present in the porous media. If acid treatments are to be used in reservoirs which contain a trapped liquid hydrocarbon saturation, compatibility tests to ensure that asphaltenes, sludges and emulsions do not form between the acid and the in-situ oil should be conducted. Rock solubility tests should also be conducted in this case to ensure that a large concentration of insoluble fines (i.e. - quartzose rock fragments, pyrobitumen, anhydrite, etc.) are not released by acidization and allowed to subsequently be squeezed deeper into the formation where they may reduce permeability.

Fracturing Operations. Detailed modelling and geomechanical measurements can be undertaken to attempt to ensure that the mechanical propagation of hydraulic and acid fracturing treatments are acceptably achieved. Fluid retention, particularly water retention, is a significant problem in many tight gas fracturing operations. A variety of techniques have been utilized to attempt to reduce fluid losses to the formation in situations where water trapping is problematic including the use of pure oil fracturing, CO₂ energized oil fracturing, croslinked water based fracturing fluids, poly-emulsion fluids and water based foam fracturing fluids. The selection of the appropriate fluid will be highly dependant on the size of the frac, formation characteristics and phase trapping potential and available drawdown pressure.

In formations which contain a pre-existing oil saturation and which may (or may not be) oil-wet, oil based fluids may react as adversely or worse than water. Pure CO₂ fracturing has been used successfully in some formations of this type (i.e. - Rock Creek, Ostracod, Gething, Montney), but obvious limitations exist with respect to the size of frac which can be effectively propagated (generally less than 20 tonnes with current technology) and depth constraints (generally less than 2000 metres, depending on tubing/casing size)

Kill/Workover Treatments. Many wells have been drilled with great care paid to formation damage, only, at some later date, to have poorly conceived kill jobs conducted which were very effective in achieving not a only temporary but permanent well control results. Water-based kill fluids generally react poorly in most tight gas situations and significant invasion generally occurs due to the unprotected nature of the fracture faces or open hole wellbore after production has been occurring for some period of time. Oil-based fluids with appropriate bridging agents may be a better choice for kill agents in some situations. Careful care with respect the composition, rheology, bridging character, filter cake building potential and removability should be taken in kill fluid design in a manner similar to designing a drilling fluid. In many cases the use of CT or snubbing equipment may be viable and the workover or recompletion can be conducted with the well in a live mode, underbalanced, to avoid significant additional damage effects.

Production Problems. A large majority of production problems with tight gas reservoirs, including fines migration, retrograde condensate dropout and solids precipitation are all associated with large pressure drops or rates associated with the low permeability nature of the reservoir. Means of reducing rate or pressure drop, including physical rate reduction or an increase in flow area by horizontal drilling, open hole completions or fracturing are the best techniques to counteract these problems.

Dual completions using downhole ESP's to pump off water in wet zones can prevent the premature coning of water in some gas reservoir situations, which may have adverse relative permeability and fines migration effects.

Solids precipitation problems are difficult to prevent, being inherent to the nature of the produced gas itself. But can often be minimized by judicious selection of the correct downhole operating temperature and pressure and the selective use of a variety of chemical inhibitors or treating agents (solids precipitation inhibitors, organic solvents, crystal modifiers, etc.). Detailed work has also been conducted recently in insulated and heat traced tubing, coupled with detailed numerical wellbore heat loss models for paraffin deposition, to optimize the production of deep waxy retrograde condensate gas reservoirs.

Canadian Formations Susceptible to Various Tight Gas Damage Mechanisms. This section provides an incomplete summary of a number of low permeability formations in Canada that have been investigated recently for tight gas damage mechanisms in the lab and the field. The results are site specific and can, of course, vary regionally with reservoir quality and saturation conditions, but provide some idea of the type and scope of this problem in some common field
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 |
| Glaucnite  | 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, OR, 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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**References**


SI Metric Conversion Factors

1 m = 0.3048 ft.

1 MPa = psi
FIGURE 1
ILLUSTRATION OF TRACED SPONGE CORING PROGRAM TO DETERMINE Swi, Sal, Sgl

FIGURE 2
RADI Al 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-MAT SYSTEM

FIGURE 10
DRY GAS INJECTION PROCEDURE

FIGURE 11
FORMATION HEAT TREATMENT PROCEDURE (FHT)

FIGURE 12
ILLUSTRATION OF CAPILLARY IMBIBITION vs TIME