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Reservoir Drill-In Fluid and Formation Damage of Tight Gas Reservoirs

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Abstract

Tight gas reservoirs present challenges to the design of reservoir drill-in fluids (RDF). These challenges include fluid-loss control, fines migration, and mud solids invasion into formation. This paper presents the laboratory methods for formation damage studies of tight gas reservoir.

Our studies indicate that the pre-test core sample preparation is essential for the tight gas reservoir rocks. The ultrafine material created during core plug preparation could lead to artificial fines migration. Strict pre-test cleaning procedures minimize the artificial damage. A centrifuging process of the pre-test core plugs greatly shortens the time of achieving steady permeability and also best reflects the effects of drilling fluid on formation permeability. Formation damage tests consistently indicate that fluid loss is an important damage mechanism for tight gas reservoir.

Fluid loss control is a critical element in designing fluids. A high emphasis is placed on optimizing the bridging particle distribution to control fluid loss and limit the solids invasion into pores, especially into fractures which are important fluid-flow channels in tight gas reservoirs.

Introduction

One of the main issues in drilling tight gas reservoirs is formation damage. Formation damage is a process that causes a reduction of permeability in gas or oil producing formations. This reduction in permeability also brings about a loss in production or the inability to access potential reserves. Among some of the main contributing factors of formation damage is fluid invasion into the reservoir rock, blocking of pores and fractures with clays and other solids materials, and water saturation changes. Sources of solids materials include fines particles, drilling solids, bridging material or polymers from the reservoir drill-in fluid (RDF).

Tight gas reservoirs have low permeability usually less than 0.50 mD in-situ permeability to gas.[1] Porosity is low and pores are usually poorly connected (Fig. 1). They are highly sensitive to water saturation. In fact, most tight gas reservoirs have low or near irreducible water saturations near the wellbore.[2,3] Because the permeability of tight gas reservoirs is so low, even a small drop in permeability can have significant effects on production. For example, if a tight gas reservoir suffers a reduction of permeability of only 0.35 mD, but its initial permeability was 0.5 mD, it has effectively lost 60% of its original permeability. Consequently, due to the high water sensitivity, small changes in water saturation affect permeability, which can greatly reduce production. This paper will present data that supports the highly water-sensitive nature of tight gas reservoirs and highlights the importance of maintaining good fluid loss control as well as the laboratory applications and techniques implemented in pre-test core preparation to avoid artificial damage.

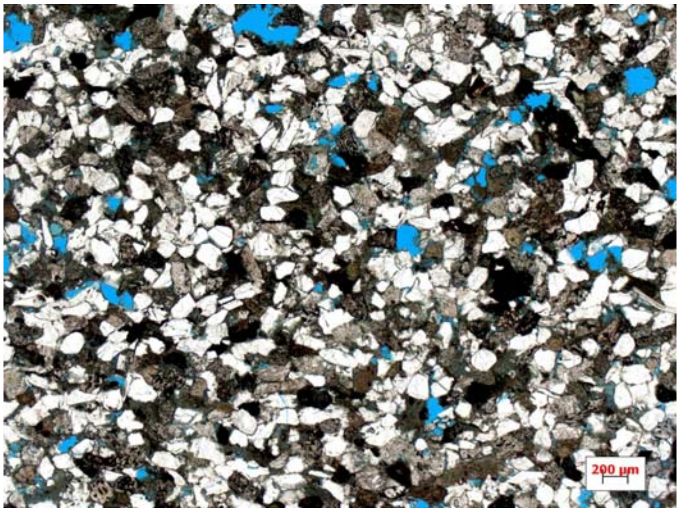

Fig. 1 – Thin-section photomicrography of a tight gas reservoir rock. Both interparticle pores and oversized pores exist. Pores are poorly connected (pores are in blue color).

Formation Rock Study and Fluid Design

To design drilling fluids that would minimize formation damage potential, one must first understand or evaluate reservoir rocks including rock composition, structure, pore system and deformation. This study can be conducted by observation through a petrographic microscope, XRD analysis, SEM analysis etc.

Specific attention is given to the pore and fracture systems including the relationship of pore to pore, pore to fracture, and fracture to fracture. These pores and fractures are the flow channels through which the gas must travel between the reservoir and the wellbore. It is important to study the connectivity of these open channels, the pore sizes and the fracture widths because small materials such as clays, fines or mud solids can block the flow channels. If the pores or fractures become blocked, the number of pathways for the gas to flow decreases and permeability is reduced.

Additions of bridging materials in conjunction with fluid loss control agents are also examined in order to reduce fluid loss. The proper distribution of the sized carbonates for bridging pore spaces is a critical step to prevent mud solids and filtrate from invading the reservoir.[4,5] Bridging particle sizes should be optimized according to pore-size distribution and fracture width. Table 1 and Figure 2 show an example of particle size distribution for a formation with the largest pore size measured at 100 microns. Figure 3 shows an example which has no significant solid invasion from the RDF due to appropriate bridging particle blend.

Table 1 – Bridging Particle Size Distribution

% Distributions	Sized Bridging Particles in Select Blend (Largest Pore size = 100 µ)
D10	1.4µ
D50	25 µ
D90	110 µ

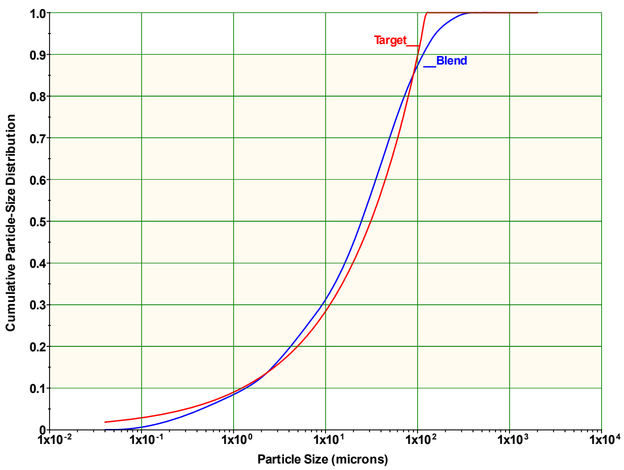

Fig. 2 – Optimum bridging particle blend showing the target blend which is related to pore size distribution and optimized blend of sized calcium carbonate.

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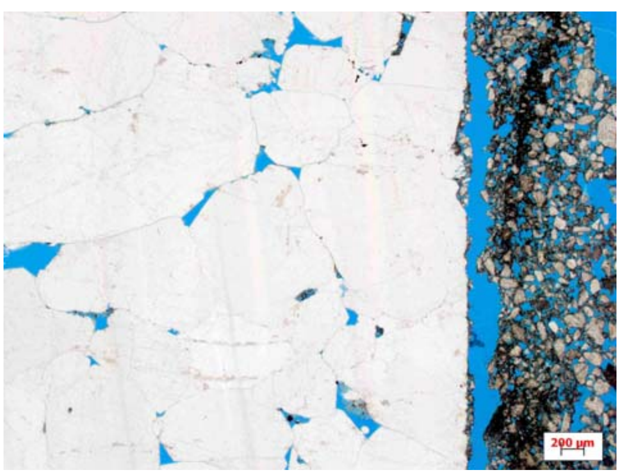

Fig. 3 – Thin-section photomicrography of a post-test rock sample. The brown material on the right side is the filter cake.

Some tight gas reservoirs can have fairly large pores that can be as large as 300 microns or greater (Table 2). The low permeability suggests that these large pores are not well connected. The permeability may be limited by the abundance and width of the fractures that connect the pores to other pores or fractures.[6] When optimizing the bridging particle sizes, pore connection is an important factor.

Table 2 – Pore Size and Porosity for Tight Gas Reservoir

Permeability (mD)	Avg. Pore Size (µm)	Max. Pore Size (µm)	Porosity (%)
0.038	10-25	30	8.8
0.051	10-20	20	8.2
0.024	20-30	50	5
0.019	70	120	5-8
0.020	50-80	250	15-20
0.091	50-80	300	17.3

A more natural mechanism for pore blocking/fracture blocking is introduced by the presence of abundant clay or fines material. Clays can block flow channels by two ways: through displacement or by chemical reaction to water such as swelling. Clay inhibitors or oil-base fluids can be used to help minimize the effects of clay interaction.

Test Sample Preparation

Artificial formation damage can be attributed to the core preparation process. Previously it was introduced that water saturation plays an important role in permeability. When preparing a core plug for a gas return permeability test, careful attention is given to the initial water saturation of the core, which is vacuum saturated in a synthetic or connate brine solution and centrifuged at high rpm to near irreducible water saturation. This process helps reduce error in test result interpretation due to high initial water saturation. In contrast, if the initial water saturation is high, subsequent permeability measurements will take longer to reach a steady state of permeability. This is an artifact of water saturation decreasing as the test progresses and excess water is 'pushed out'. Beginning the test at near irreducible water saturation provides a more stable permeability measurement.

Figure 4 shows an initial permeability curve of a core plug that was saturated in brine but not centrifuged to irreducible water saturation. The permeability did not begin to stabilize until approximately 275 minutes.

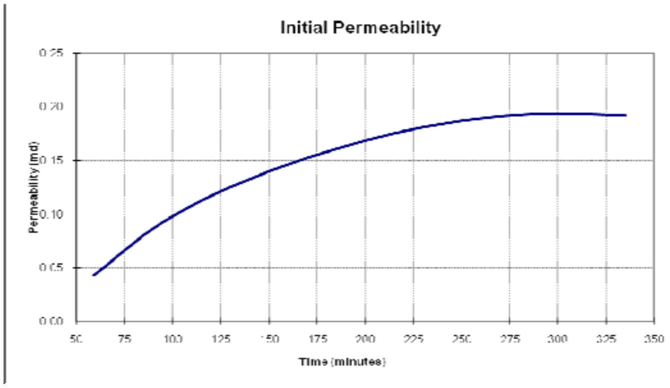

Fig. 4 – Non-centrifuged core plug

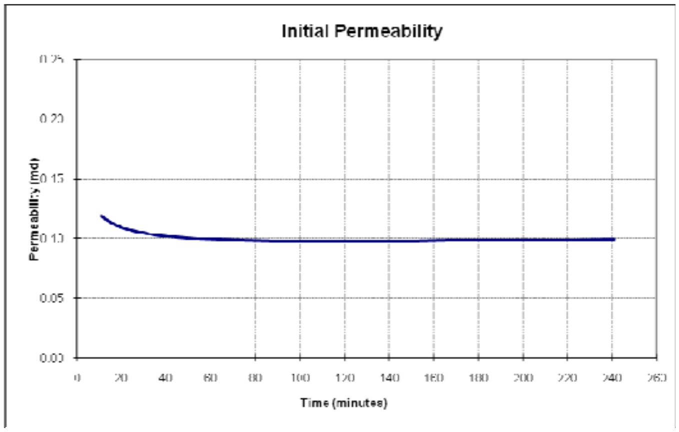

Fig. 5 – Centrifuged core plug.

Figure 5 depicts the initial permeability curve of another core plug that was saturated in brine but then centrifuged to irreducible water saturation. The permeability stabilized at approximately 40 minutes, which is significantly earlier than the non-centrifuged sample.

Another source of artificial formation damage is the introduction of ultrafine material that is created during the core plug preparation process, which may include cutting, facing with an abrasive wheel, etc. Figure 6 shows the wellbore face of a core plug before it was cleaned. The pore spaces and grains are covered and coated with a layer of white dust generated from sawing. The coverage of fine dust makes it difficult to see the pores in Figure 6. This type of ultrafine material can be forced into pore spaces at overbalance pressures causing artificial formation damage by blocking pore channels. This is especially of concern in reservoir rock of extremely low permeability. In order to remove the ultrafine dust before a test, core plugs are first carefully vacuumed to remove the fine dust particles and in some cases lightly brushed and vacuumed. An additional step of flushing the core gently with a mild solvent in both directions also helps to mechanically remove any residual artificial fines material deposited at either end of the core plug. Figure 7 shows the same core plug that was vacuumed after cutting. The pore spaces and grains are clean and free of most of the dust introduced from sawing.

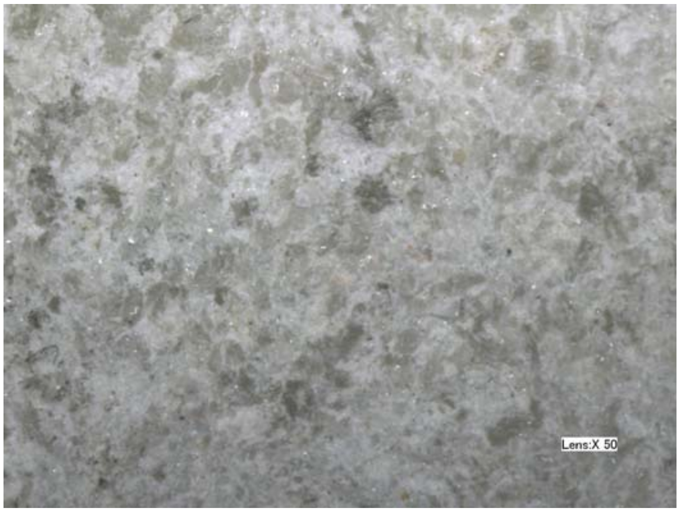

Fig. 6 – Before vacuuming core plug – pores are filled with white dust. Individual grains are difficult to distinguish.

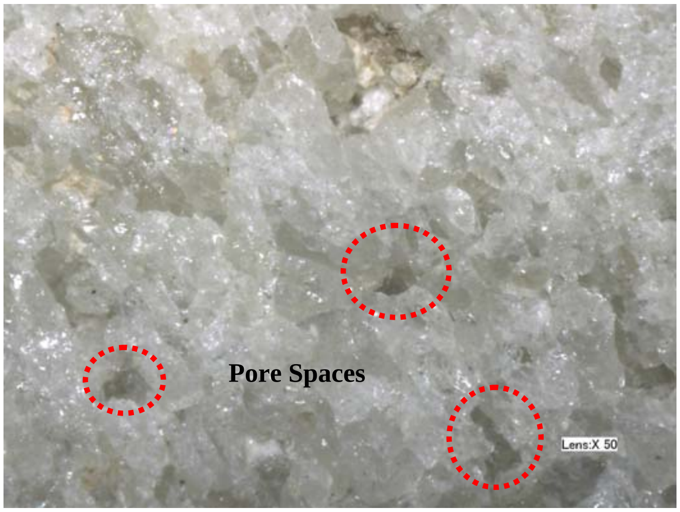

Fig. 7 – After vacuuming core plug – pores are more visible and mostly clean of dust. Individual grains are clearly seen.

Test Procedure

Once a core plug has been properly cleaned and centrifuged, the sample is then loaded into a permeameter for testing. Humidified nitrogen is flowed through the core plug in the production direction at reservoir temperature and raised pressures in order to establish a baseline permeability. A filter cake is then formed on the wellbore end of the core plug and overbalance pressure is applied for determined period of time. During this time, filtration data is also collected and recorded. Following the test fluid exposure phase, permeability is then re-established in the same manner as the initial permeability phase. The reduction in permeability is reported as a percentage of the original baseline permeability that was measured in the beginning of the test.

Flow initiation pressure refers to the pressure required to initiate flow of gas (or the flow fluid) through the reservoir rock after exposure to the RDF. Flow initiation pressure, which is calculated by subtracting the stable pressure from the maximum pressure when determining the final permeability, is recorded and can give an indication of damage. Often times, significant reductions in regained permeability are associated with higher flow initiation pressures. Filtration values can also give a good indication of the amount of damage since higher fluid loss is often associated with lower regained permeability in tight gas reservoirs. All test results contribute to the overall interpretation of formation damage, but the most telling clue is the percent of regained permeability.

Case Study

Table 3 shows test examples in which higher filtration resulted in significantly lowered regained permeability. In Case #1 the core plugs had high filtration (12.8 mL, 204% pore volume) that corresponded with greater reduction in permeability (19.6% regained perm). Cases #2-#4 have much lower filtration and high return permeability. In Cases #3 and #4, the return permeability values that are >100% are most likely an artifact of reduced water saturations in the latter stages of the test. This is particularly true in tests that are conducted at very high temperature in which the core is more likely to 'dry out'. This effect is smaller in cores that have been centrifuged. Figure 8 demonstrates the drying effects of a core that was not centrifuged.

Table 3 Results of formation damage tests

Case#	Initial Perm (mD)	Filtration Vol/ % Pore Vol.	Return Perm (mD)	Return Perm (%)
1	1.39	12.8 mL/204%	0.27	19.6
2	2.1	0.4 mL/8%	2.0	90
3	0.01	*0.0 mL/0%	0.02	114
4	0.90	*0.0 mL/0%	0.11	116

*no measureable filtration recorded

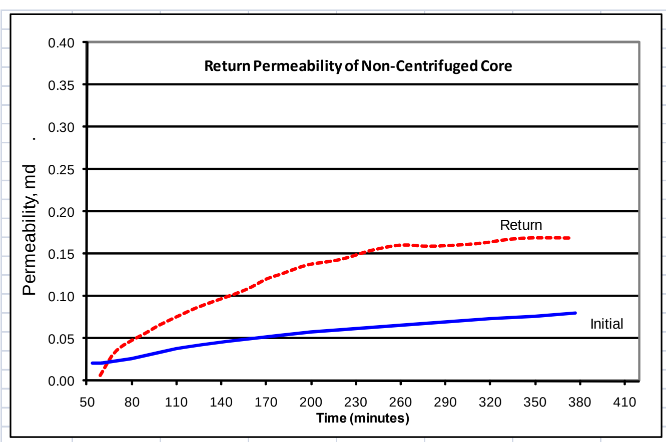

Fig. 8 – A test conducted at 300°F on a non-centrifuged core plug features an initial permeability curve that is artificially low due to excess water saturation. The initial permeability appears to be still increasing or approaching a steady state.

Fluid invasion is a dominant damage mechanism. The tight fracture spaces and pore spaces that become more saturated with water develop strong capillary forces that cannot be easily overcome. Situations such as this result in phase trapping. In many cases, the reservoir becomes permanently damaged with fluid invasion into the wellbore face.[7]

Conclusions

Due to the high sensitivity of gas permeability to water saturation, it is essential to minimize fluid loss into the formation. This can be achieved by optimizing the bridging particle sizes and incorporating FLC agents that will minimize filtration for better fluid loss control. For tight gas reservoirs, clay reaction and fines migration are detrimental damage mechanisms; therefore, clay inhibitors can be incorporated in the fluids to minimize clay reactions.

For formation damage test preparation, it is important to clean the core by removing the fine dust material that is introduced from sawing the core. The removal of fine dust material helps prevent artificial introduction of fines into the core plug and allows the test results to more closely represent the particle sensitive nature of the downhole formation. It is also essential to centrifuge the core plug to near irreducible water saturation in order to minimize the effect of residual water on permeability. Formation damage tests indicate that fluid loss is an important damage mechanism for tight gas reservoirs.

Acknowledgments

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Nomenclature

RDF = *Reservoir Drill-In Fluid*
OBM = *Oil Based Mud*
SBM = *Synthetic Based Mud*
WBM = *Water Based Mud*
FLC = *Fluid Loss Control*

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