MEASUREMENTS OF RESIDUAL GAS SATURATION UNDER AMBIENT CONDITIONS

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ABSTRACT

The value of residual gas saturation to water influx (S_{rg}) is a critical property when estimating recoverable reserves in gas reservoirs overlaying active aquifers, or natural gas storage reservoirs. However, it seems that very little work has actually been done to investigate this value. Early work in the 1950s and 1960s established that S_{rg} was not going to be as low as 10-15% PV, as was commonly expected at the time. Further work at that time also demonstrated that there was a link between S_{rg} and porosity or initial water saturation. However, in the last 25 years, not much has been published on this topic. Our group has conducted extensive experimental work to determine the value of S_{rg} for a variety of reservoir types and conditions. Work was done under different scenarios including primary and spontaneous imbibition, secondary spontaneous imbibition and forced imbibition. The results of 27 core samples were interpreted using all existing published models. It was found that the value of residual gas saturation was sensitive to initial water saturation and to the permeability to porosity ratio. It was also found that this sensitivity does not always follow the same law. Some reservoirs followed Land's model closely, while other reservoirs did not. The true residual gas saturation cannot be determined until after several weeks of constant imbibition. Regardless of this fact, the values of S_{rg} after primary and spontaneous imbibition are very high. Under the current buoyant natural gas price scenario, such reservoirs are worth pursuing, but at lower gas prices many of these reservoirs may become marginal. Our findings are of particular importance in naturally fractured reservoirs that are plagued by early water breakthrough. Estimating the true residual gas saturation may lead to decisions on Enhanced Gas Recovery.

INTRODUCTION

Most of the research related to imbibition in heterogeneous formations deals with the problem of oil recovery from fractured reservoirs. Not much information was found in the literature regarding recovery from gas reservoirs. Crowell *et al.* (1966) discussed the efficiency of gas recovery by water imbibition. It was shown that gas recovery is a strong function of the initial gas saturation and that the maximum recovery is obtained at zero initial water saturation. The experiments were done with Berea sandstone cores. Similar results were obtained for Boise sandstone cores. Free imbibition or forced imbibition at a constant flow rate seemed to have no difference in terms of final recovery of gas in Boise sandstone. A slight increase in gas recovery with a reduction of interfacial tension was observed in Berea slabs. The effect of permeability seemed to be rather convoluted when different sandstones were employed. Finally, for the fluids tested, there was consistent behaviour of the gas recovery efficiencies irrespective of the fluid (water, brine or oil) used.

Katz *et al.* (1966) studied how water displaced gas from porous media. A method of predicting residual gas saturation behind an advancing waterfront was obtained. The use of residual gas measurement on cores and the requirements for calculating saturation distribution were covered. They found that residual gas saturation at the base of a porous bed appeared to be the same as that of gas saturation on a relative permeability curve at zero relative permeability. It was also concluded that only a very general relationship existed between gas saturation and porosity and no relationship was found with permeability.

Agarwal (1967) addressed the relationship between initial and final gas saturation from an empirical perspective based on 320 imbibition experiments and segmented the database to develop curve fits for common rock classifications. The Agarwal's Model was given as:

$$S_{gr} = S_{gi} * 0.1813 + 0.096071$$

Land (1968) noted that available data seemed to fit very well to an empirical functional form given as:

$$S_{gr} = \frac{S_{gi}}{1 + \left(\frac{1}{S_{gr}^{\max}} - 1\right) S_{gi}}$$

In this model, the only free parameter is S_{gr}^{max}, the maximum observable trapped non-wetting phase saturation corresponding to S_{gr} $(S_{gi}=1)$. In the original paper, a normalized gas saturation function is used. The presented version of Land model is proportional to the one presented by Land (1968) if one divides S_{gr} by $(1-S_{win})$. This expression does not predict residual phase saturation, only how residual saturation scales with initial saturation. A modified Land's Model was adopted by Kantzas *et al.* (2000) to match experimental data.

$$S_{grLand's} = aS_{gr\,\exp eriment} + b$$

Beattie and Roberts (1996) treated the problem of water influx in fractured reservoirs as a coning problem. They used computer simulation to identify the factors contributing to water production. They found that water was able to cone significant vertical distance (250 m) with coning exacerbated by a larger aquifer, higher production rates and a smaller vertical distance between perforations and the gas-water contact. However, they found that ultimate gas recovery was not significantly affected. They also concluded that reservoir properties that restrict the degree of invasion of the matrix blocks (e.g., wide fracture spacing) favour a rise of the water level in the fractures toward the well.

Pow *et al.* (1997) also addressed the imbibition of water in fractured gas reservoirs. Field and laboratory information suggested that a large amount of gas could be trapped through fast water imbibition through the fractures and premature water breakthrough. The postulation was made that such gas reservoirs would produce this gas if and when the bypassed gas was allowed to flow to the production intervals under capillary controlled action. The issue was raised on whether the rate of imbibition could enhance the production of this trapped gas. Preliminary experiments with full diameter core pieces showed that the rates of imbibition were extremely slow and that if the different imbibition experiments were performed in full diameter plugs, the duration of the experiments would be prohibitively long. These experiments formulated the experimental strategy presented in the following sections.

Kantzas *et al.* (2000) discussed the effect of core conditioning on residual gas saturation and found that rate of imbibition, wettability and production history seemed to play an important role on the final value of residual gas. They also found that semi-empirical models such as the Land model to be accurate for a limited number of samples.

Li and Firoozabadi (2000) addressed the wettability alteration to preferential gas wetting in the porous media and its effect. A series of experiments were performed on both Berea sandstone and Kansas chalk. The wettability of a gas-water rock can be changed from strong water wetting to intermediate or preferential gas wetting by some chemicals. This can result in better control of production rate and better pressure maintenance for extended production.

EXPERIMENTAL

Core plugs from four reservoirs were selected for the evaluation of the residual gas saturation. They are noted as North Africa sandstone I, North Africa sandstone II, North America Sandstone and Carbonate reservoir, respectively. A total of 27 core plugs of 3.81 cm or 2.54 cm in diameter and approximately 5.0 cm in length were chosen.

Preparation of core plugs and brine

All core plugs were cleaned in the Dean Stark apparatus prior to any testing. Plugs were placed in the Dean Stark apparatus and were cleaned under toluene for 24 hours and under an equal volume mixture of methanol/acetone for another 24 hours. All plugs were cleaned in the Dean Stark apparatus between imbibition tests as well, using same method as above.

The pore volume was measured using the Archimedes principle. The plugs were saturated in synthetic brine that mimics the corresponding formation brine. The process of saturating consists of exposing the dry core plugs in water vapor under vacuum in special containers. Then the water vapor saturated plugs are immersed in the brine under vacuum. This approach was found to be the best method of saturating cores and eliminating jammed gas droplets. The pore volume was then calculated by measuring the weight change of the core and the weight and volume of the liquid that the core displaces when immersed in formation brine. Subsequently porosity was calculated. The density of the brine was measured by using both a pycnometer and a Brookfield densitometer. The results obtained are summarized in Table 1. Spot checks of the porosity measurements against helium porosity were done with excellent reproducibility of the results. Different synthetic formation brines were made for different reservoirs. The corresponding synthetic brine densities are summarized in Table 2.

Measurements of air permeability and brine permeability were also performed prior to the secondary spontaneous imbibition tests. For most reservoirs, except for the West Canada Carbonate, air permeability tests were preformed with backpressure in order to avoid turbulent flow effects. Plugs of West Canada Carbonate contained micro fractures while plugs of West Canada Sandstone contained considerable amount of clays that swelled during the brine permeability measurement.

For primary imbibition experiments the dry core was tested after the completion of Dean Stark cleanup. For the secondary spontaneous imbibition tests the initial water saturation varied. The initial water saturation in the secondary spontaneous imbibition tests was obtained from gas drainage experiments of water-saturated plugs in the centrifuge. The plugs with 100% water saturation were put in the centrifuge and spun under 6000RPM (approximately 1000 kPa end-face capillary pressure) for at least 4 hours. The residual gas saturation values that correspond to each experiment are shown in Table 3.

Imbibition experiments

All imbibition air/brine experiments include spontaneous imbibition steps and forced imbibition steps. The spontaneous imbibition steps include primary spontaneous imbibition tests and secondary spontaneous imbibition tests, i.e. water imbibing into plugs without or with initial water saturation respectively. Imbibition was monitored by measuring the change of weight of the core plugs as a function of imbibition time. An automatic weight measurement method was developed for recording the change of weight with time continuously and accurately. The schematic of the automated imbibition measurement apparatus is shown in Figure 1. A core plug was suspended by a line in a beaker containing the brine. The beaker containing the core and brine was balanced against a fixed weight metal cylinder. This cylinder was resting on an electronic balance that was in turn connected to a computer. As water imbibed in the core, its weight increased thus reducing the weight of the cylinder on the balance. The time step for data recording and the change in weight of the core suspended in the brine was recorded automatically. A thin layer mineral oil was put above brine to prevent water evaporation affection.

Forced imbibition experiments followed the spontaneous imbibition tests. In these tests, brine flooding occurred at a constant flow rate of 2 cm^3/hr. The injected brine volumes and pressure drops across the core plugs were recorded during all the experiments. The weight change of each plug was measured and the residual gas saturation was estimated. Recovery from brine flooding was further estimated on most plugs.

EXPERIMENTAL RESULTS AND DISCUSSION

The experimental program was conducted over a period of three years. Some experimental procedures were modified for different reservoirs. Only primary and secondary spontaneous imbibition tests were conducted using North Africa Sandstone I. Five sets of primary and secondary spontaneous imbibition tests, based on different initial conditions, plus two sets of forced imbibition tests were conducted using North Africa sandstone II. Only part of experiment results of this reservoir was presented here. Primary and secondary spontaneous imbibition tests and followed forced imbibition experiments were performed on the West Canada Sandstone. Primary and secondary spontaneous imbibition tests were performed on the West Canada Carbonate as well, but forced imbibition tests only followed the secondary spontaneous imbibition tests. Some correlations were obtained using all experimental information. Table 1 also includes the initial water saturation of the secondary spontaneous imbibition test for each plug.

Figure 2 shows a rough correlation between residual gas saturation with core properties. From this graph, it can be seen that core plug properties do affect the residual gas saturation. For our four reservoirs, the tendency of change of residual gas saturation with core properties is the same.

Figure 3 shows the relationship of residual gas saturation with imbibition rate. The imbibition rate was calculated from the initial period of each imbibition test. It is calculated from the slope before the first plateau of the gas production volume curve with time. The initial period of time varies from 10 to 60 minutes depending on the plug properties. The residual gas saturation decreased with initial imbibition rate. It was observed that the initial stages of imbibition could be attributed to the different invasion mechanisms at the early stages of the imbibition process.

Figure 4 shows the relationship of residual gas saturation with Amott Index to water after primary spontaneous imbibition for the sandstone plugs. In this work, Amott Index to water is defined as a ratio of gas produced from spontaneous imbibition to gas produced from both spontaneous imbibition and forced imbibition. It was observed that the residual gas saturation after the long spontaneous imbibition test decreases with increasing water-wetness, whereas it increases after brine flooding with increasing water-wetness.

Figure 5 shows the relationship of recovery factor with Amott Index to water for the same plugs as in Figure 4. The recovery factor is defined as the ratio of gas produced to initial gas in place. The recovery factors after spontaneous and forced imbibition tests were calculated separately. It was observed that gas recovery from spontaneous imbibition tests increase with increasing water-wetness and gas recovery from brine flooding decreases with increasing water-wetness. When the value of Amott Index to water is 1, the maximum gas was recovered from the spontaneous imbibition tests. When the value of Amott Index to water is a number of 0.3 to 0.4, only half of total recoverable gas was recovered from the spontaneous imbibition test and the other half amount was produced from brine flooding. This is in agreement with the results of Figure 4.

Figure 6 is the same graph as Figure 5, but the recovery factor is the sum of the recoveries from both spontaneous imbibition tests and brine flooding together. It was observed that the total recovery after both experiments did not seem to vary much with water wettability. Most gas was recovered from the spontaneous imbibition tests under strong water conditions, whereas the brine flooding experiments could make up the gas recovery for weakly water conditions.

Figure 7 also shows the relationship of gas recovery with Amott Index to water after both primary and/or secondary spontaneous imbibition tests for three reservoirs. The data group of North Africa Sandstone II presents the recovery from both primary and secondary spontaneous imbibition tests. The group of West Canada Sandstone presents the recovery from primary spontaneous imbibition tests and the data for West Canada Carbonate presents the gas recovery from secondary spontaneous imbibition test. It was observed that the gas recovery from spontaneous imbibition tests increased with water wettability increasing. This is in agreement with the results presented in Figure 5.

Figure 8 shows the predictions of the Land model as they are compared to the experimental data from Crowell and the data from the four tested reservoirs. The residual gas saturation corresponds to secondary spontaneous imbibition tests with initial water saturation as shown in Table 1. The residual gas saturation from Land's model was calculated. The Crowell data fit Land's model very well. The data from our four reservoirs do not fit Land's model as well, although the trends are very similar. The data for each reservoir was fit to a linear transform of the Land's model.

Figure 9 shows the predictions of Agarwal model as they compared to experimental data from Crowell's data and our four reservoirs. In both cases, there is a poor fit with Agarwal's model.

The common knowledge regarding gas/water systems is that water is the wetting phase and gas is the non-wetting phase. As a result, the spontaneous imbibition test should provide the true residual gas saturation even if the rate of imbibition becomes slow and the test needs to be extended for several weeks. According to this assumption, any additional recovery of gas through flooding must be attributed to the mobilisation of residual gas blobs. According to Chatzis and Morrow (1984), such mobilization in oil/water systems will occur when the capillary number N_{ca} exceeds a critical value that is approximately 10^{-5}. Our brine flooding capillary numbers were calculated to be in the order of 10^{-9}. Thus, according to capillary number analysis, we are well within a capillary controlled flow regime. If this argument is correct, then the issue of wettability becomes more important. Based on the calculated capillary numbers, all displacement experiments are done under capillary forces; thus, the Amott Index to water approach is correct and several plugs show non-water-wet characteristics. This argument (that still needs further verification) has profound implications for the management of natural gas reserves. In a strongly water-wet reservoir, all bypassed gas will be the residual gas. In a weakly water-wet or neutral reservoir, the true residual gas saturation will be substantially lower than the apparent bypassed gas saturation in place. Understanding which phenomenon actually takes place will dictate the strategy for recovering additional gas.

CONCLUSIONS

The following conclusions can be obtained from this work:

- The data was recorded from an automated imbibition apparatus continuously; therefore, the results are more accurate compared the results from a manual method.
- Residual gas saturation from four reservoirs fit a modified Land's model even if a different slope was obtained for different reservoirs.
- Wettability does affect the gas recovery obtained from spontaneous imbibition. When forced imbibition tests followed the spontaneous imbibition tests, total gas recovery from both experiments is not dependent on wettability for sandstone plugs. Forced imbibition is very important to achieve high gas recovery for weakly water-wet sandstone gas reservoirs.
- Initial imbibition rates and physical properties of core plugs also seem to affect residual gas saturation.

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Figure 1: Schematic of automated imbibition measurement apparatus

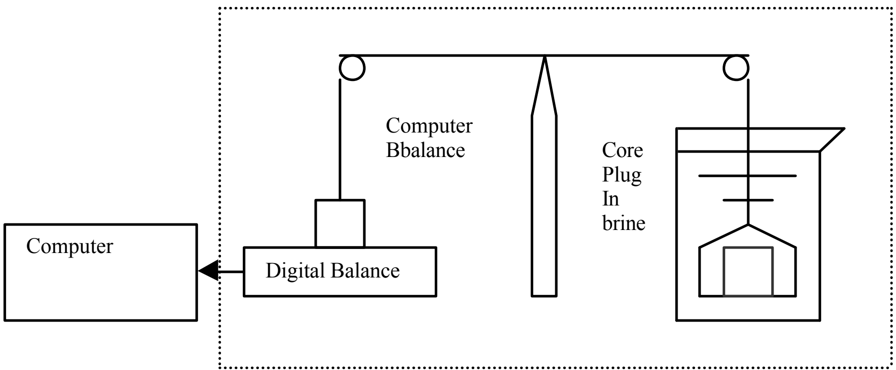

Table 1: Routine Core Properties

Core plug ID	Diameter (cm)	Length (cm)	Porosity (Fraction)	Air permeability (mD)	Brine permeability (mD)	Swir (fraction)
North Africa Sandstone I						
1	3.66	3.675	0.186	20	17	0.064
2	3.68	4.05	0.141	100	52	0.080
3	3.66	4.01	0.139	442	118	0.082
4	3.655	4.02	0.123	183	154	0.064
5	3.675	4.15	0.147	578	105	0.215
6	3.64	4.05	0.310	149	21	0.201
7	3.655	3.93	0.267	372	221	0.559
North Africa Sandstone II						
1	2.485	4.015	0.139	490	290	0.07
2	2.495	4.585	0.087	26	33	0.207
3	2.49	3.865	0.104	252	54	0.379
4	2.50	3.53	0.152	674	271	0.311
5	2.495	3.65	0.164	820	640	0.328
6	2.495	4.045	0.133	643	421	0.063
7	2.495	3.425	0.140	507	268	0.046
8	2.485	3.915	0.158	1283	925	0.057
9	2.485	3.385	0.176	984	793	0.171
West Canada Carbonate						
1	3.78	5.09	0.072	0.11	0.038	0.22
2	3.78	4.21	0.045	0.134	0.038	0.28
3	3.78	4.6	0.034	0.111	0.034	0.48
4	3.78	4.9	0.037	0.127	0.046	0.45
5	3.79	4.92	0.0129	0.44	0.097	0.64
6	3.78	4.95	0.0125	0.187	0.049	0.54
West Canada Sandstone						
1	3.84	5.065	0.159	609	71	0.093
2	3.87	5.065	0.0897	138	14	0.073
3	3.86	5.01	0.0536	46	12	0.186
4	3.84	5.07	0.0979	378	86	0.146
5	3.86	5	0.0709	133	26	0.086

Table 2: Densities of synthetic brine

Reservoir	Density (g/cm^3)
North Africa sandstone I	1.0306
North Africa sandstone II	1.0306
West Canada carbonate	1.0224
West Canada sandstone	1.019

Table 3: Residual gas saturation at different conditions

Core plug ID	Primary Imbibition Swi	Sgr after Primary imbibition (fraction)	Secondary Imbibition Swir (fraction)	Sgr after secondary imbibition (fraction)
North Africa Sandstone I				
1			0.064	0.569
2			0.080	0.365
3			0.082	0.313
4			0.064	0.304
5			0.215	0.671
6			0.201	0.674
7			0.559	0.284
North Africa Sandstone II				
1	0	0.615	0.07	0.296
2	0	0.612	0.207	0.411
3	0	0.459	0.379	0.270
4	0	0.609	0.311	0.030
5	0	0.649	0.328	0.068
6	0	0.641	0.063	0.334
7	0	0.552	0.046	0.352
8	0	0.492	0.057	0.360
9	0	0.404	0.171	0.185
West Canada Carbonate				
1	0	0.56	0.22	0.495
2	0	0.129	0.28	0.0138
3	0	0.204	0.48	0.005
4	0	0.523	0.45	0.341
5	0	0.241	0.64	0.068
6	0	0.553	0.54	0.121
West Canada Sandstone				
1	0	0.641	0.093	0.36
2	0	0.790	0.073	0.428
3	0	0.729	0.186	0.368
4	0	0.525	0.146	0.313
5	0	0.722	0.086	0.479

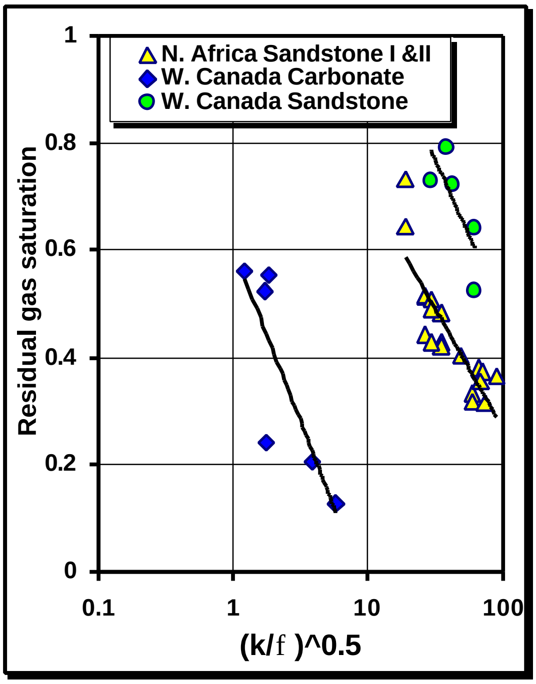

Figure 2: Residual gas saturation as a function of core properties

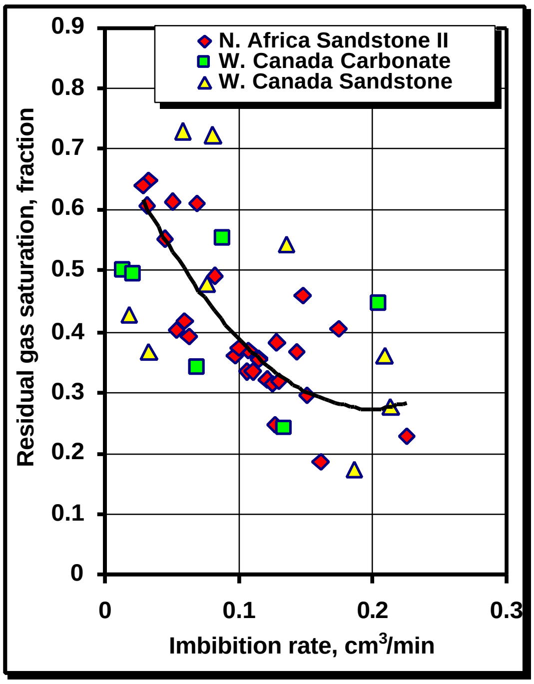

Figure 3: Residual gas saturation as a function of initial rate of imbibition

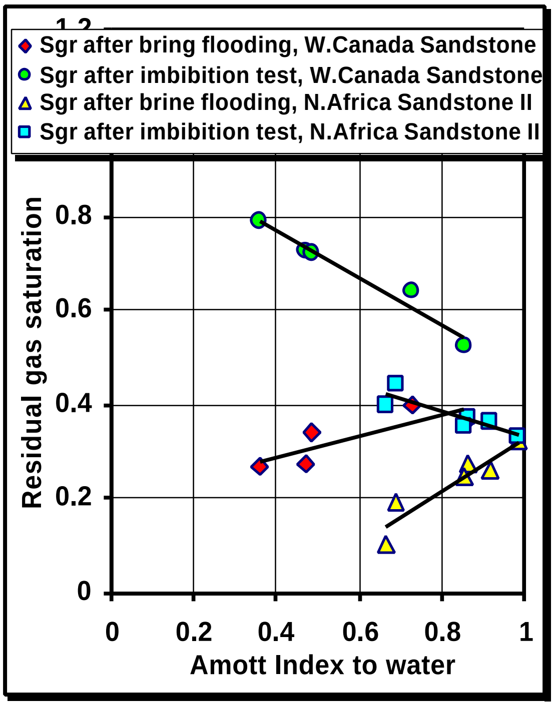

Figure 4: Relationship between residual gas saturation and wettability for sandstone plugs

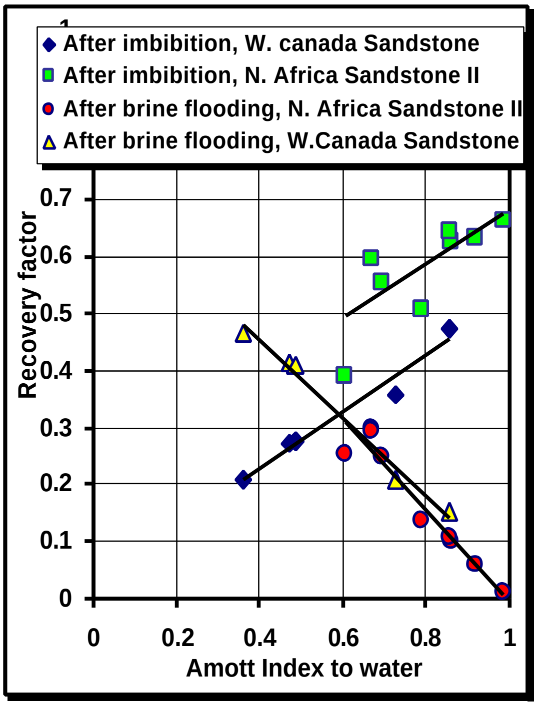

Figure 5: Relationship between gas recovery and wettability for sandstone plugs

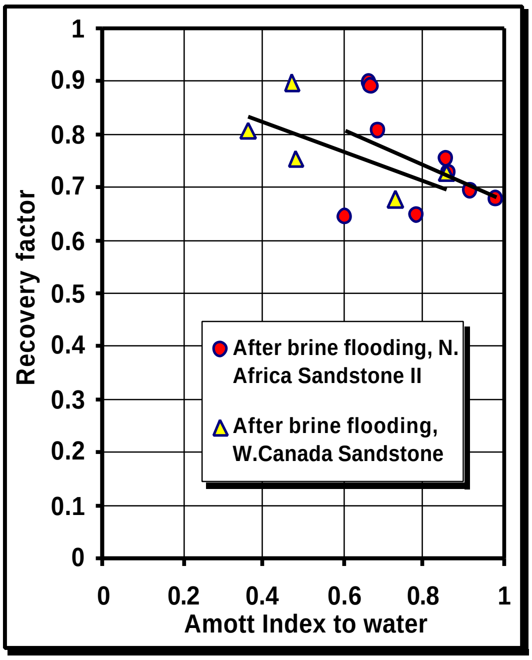

Figure 6: Relationship of total gas recovery factor with wettability

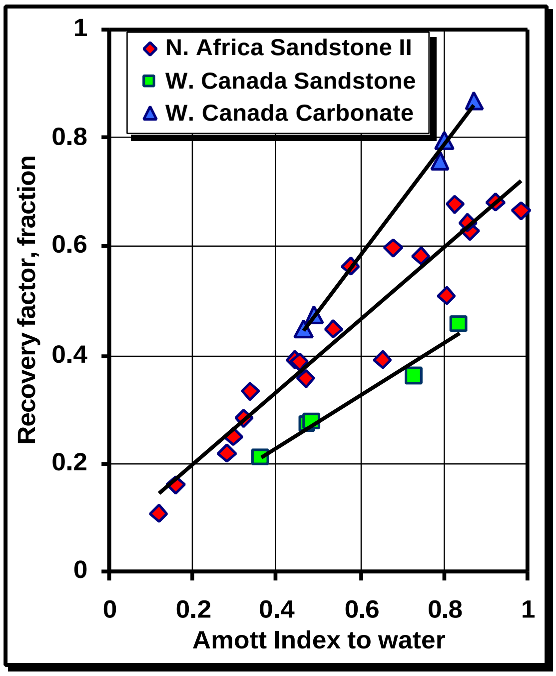

Figure 7: Recovery factor from spontaneous imbibition test with wettability

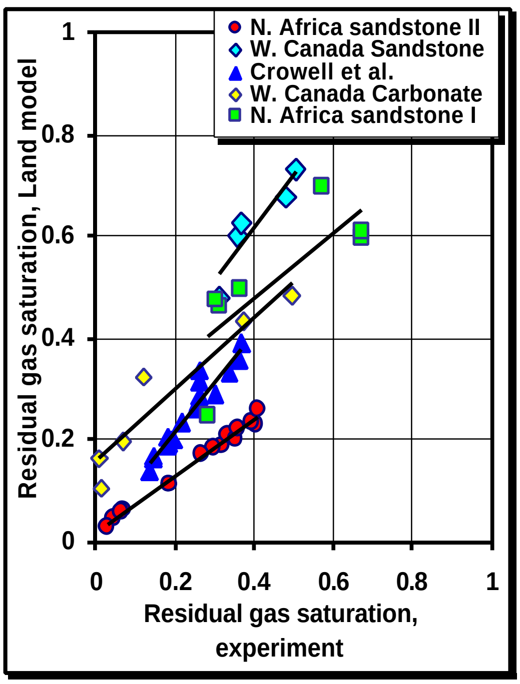

Figure 8: Comparison of experimental data to Land's model

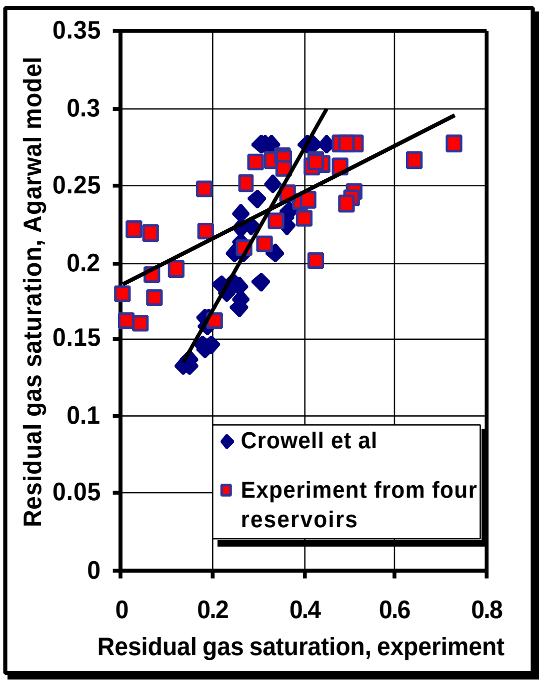

Figure 9: Comparison of experimental data to Agarwal's model

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