Re-establishing Reservoir Performance by Revaporization of Condensate in the Nubian Sandstone Reservoir

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Abstract:

The Nubian formation, which is a significant hydrocarbon reservoir in the NC 98 Concession of Libya, consists of a low to medium permeability, fine grained, sandstone. Reservoir fluids in the Nubian tend to be either very rich retrograde condensate gas or volatile oil. In either case, the reservoir pressure is at or slightly above the saturation pressure. Because the gas containing reservoirs are very rich in condensate, small decreases in pressure often result in high volumes of condensate accumulation. Similarly for the volatile oil case, small decreases in pressure result in large fractions of the volatile oil turning into the vapour phase. Both of these phenomena can result in adverse relative permeability effects which can reduce the permeability to the primary hydrocarbon being exploited.

Laboratory experiments were conducted to characterize the phase behavior of the reservoir fluids. Conventional core analysis provided good coverage of the petrophysical description of the reservoir rock. Subsequent core flow experiments determined base line flow to reservoir gas followed by the impairment to permeability at a series of pressure decrements. The pressures modeled in the laboratory were chosen to closely approximate anticipated field conditions. Laboratory results indicate a moderate to severe effect on permeability, caused primarily by the high critical saturation of condensate necessary for flow of condensate to be established. To mitigate the effect of condensate on permeability, laboratory experiments were constructed to determine the viability of condensate removal through revaporization by gas injection.

Introduction

The NC 98 concession, operated by Waha Oil Company, consists of low to medium permeability sandstone. The reservoir fluids occupying the pores of the rock tend to be volatile oils or very rich condensate bearing gas. In either case, the pressure drawdown required to cause economic production of gas or oil would result in the flowing bottom hole pressure to be below the fluid saturation pressure. When the flowing bottom hole pressure drops below the dew point of the gas, large quantities of condensate will form in the pores affected by the pressure drop. The resultant condensate will not flow through the rock until critical condensate saturation is established. The critical condensate saturation is controlled by pore geometry and to a lesser extent reservoir wettability (fluid distribution in the porosity). Similarly, as the flowing bottom hole pressure drops below the bubble point of the volatile oil, large quantities of gas will form; the gas will not flow until critical gas saturation is established. In both cases, the formation of separate phases causes flow restrictions (relative permeability effect) that can be a severe detriment to economics and ultimate recovery of the primary resource. Laboratory experiments were designed to evaluate and quantify the effect of flow impairment to the primary phase and to evaluate the remedial course of action required to regain flow to gas in the subject reservoir.

The objective of this paper is to illustrate the effect of pressure on the impairment of permeability as a result of liquid accumulation from a gas-bearing reservoir. Following the establishment of a given pore volume condensate saturation, dry gas was injected to determine the mass transfer into the gas phase and subsequent enhancement of permeability. Core samples were assembled into multiple plug stacks at reservoir conditions of saturation, pressure and temperature model the reservoir; live reservoir gas models the fluid dynamics.

Geology

The NC 98 concession currently consists of 4 distinct pools that have somewhat different reservoir character. The pools; A, F, C and B are listed in order of current and anticipated economic importance. The A pool is rich gas condensate bearing while the three others contain volatile oil. The A pool will be the focus of this paper.

The pool is comprised of the Nubian Formation - fine grained, well-cemented, occasionally shaley sandstone. The Nubian itself is constructed of 3 members: upper Nubian, Middle Shale and Lower Nubian. Refer to **Figure 1** for a thin section that illustrates the average rock quality of the Upper Nubian. Structurally, the unit is a Grabben and about 600 feet thick. Most of the pay is gas overlying water. Average gas / water contact is 14,670 feet while the reservoir pressure is in the range of 7,100 psig and temperature is 318 F. Initial estimates of the reserves are 3.4 trillion cubic feet (tcf) and 550 million barrels (mmbbl).

Reservoir fluid character

A series of bottom hole samples were collected from the A pool. The bottom hole samples were supported by separator samples of gas and condensate that were subsequently recombined to reservoir parameters in the laboratory. Comparisons of the samples resulted in three bottom hole samples chosen to represent the reservoir. **Table 1** is a compositional analysis of the reservoir gas from Well A3, DST 4. Due to the large volume of live reservoir gas necessary for the core flood experiments, the recombination of separator fluids was used. Common bottom hole cylinder volumes contain approximately 600 cc of fluid for use in lab testing versus the use of separator fluid recombinations to yield “unlimited” amounts of live reservoir gas. Bottom hole sample volumes are also limited due to cost while separator fluid recombinations are relatively inexpensive.

Rich gas condensate systems result in high accumulations of liquid drop out over small pressure ranges. This effect is typical of fluids where conditions are near the critical point on the phase diagram. **Figure 2** shows the conditions of pressure and temperature of the well A3 bottom hole sample relative to the critical point. The phase envelope was calculated using the Peng Robinson equation of state and was tuned by laboratory data.

The laboratory exercise known as the constant volume depletion (CVD) experiment results in a close approximation of the dynamics of gas / condensate equilibrium during pressure depletion and subsequent production. The lab data describes the almost instantaneous formation of condensate (to 15% pore volume) when the pressure drops from 6,597 psig (dew point) to 6,000 psig. Maximum condensate accumulation occurs at 3,900 psig after which further pressure drop results in the more volatile components of the condensate revaporizing back into the gas phase. **Figure 3** graphically illustrates the rates of condensate formation and revaporization.

Petrophysical properties of the reservoir rock

Initial petrophysical description of the reservoir rock was a function of statistical sampling. At intervals of approximately 1 foot, 1.5 inch diameter plug samples were cut from the full diameter core. Every 10th sample was cut as a full diameter size so as to develop the relationship between the two horizontal direction permeability values and the vertical permeability. Rock homogeneity was ultimately not a concern; permeability porosity cross plots of full diameter were indistinguishable from the small plug data plots.

The cross plot of permeability to air versus porosity is illustrated in **Figure 4**. Application of net overburden stress and Klinkenberg corrections to permeability resulted in a tighter grouping of the permeability porosity data. Final sample selections for the lengthy and more expensive special core experiments were based on the stressed and Klinkenberg corrected measurements. In addition to the measured rock properties, extensive rock characterization was done by petrology. Thin section interpretation, x-ray diffraction and scanning electron microscopy aided in understanding rock types, reservoir layers and reservoir quality and participated in the methodology of choosing acceptable special core analysis samples.

Core flood experiments

Prior to the construction of the core stacks from the chosen core plugs, the question of reservoir wettability was addressed. Traditionally, oil-bearing formations have a variety of wettability conditions ranging from strongly water wet to strongly oil wet. Wettability controls include water chemistry, oil composition, reservoir rock composition and pore geometry. Gas reservoirs typically are water wet; gas being the non-wetting phase. Given the high condensate concentration, possibility of pyrobitumen types of pore lining material and rapid condensate drop out due to pressure depletion, the core samples were allowed to come to equilibrium with the reservoir water and gas according to the Anderson method for oil water systems as described in the literature. Synthesized reservoir brine and live (from recombination of separator fluids) gas were the core filling fluids. The core restoration was conducted at reservoir conditions with the duration being 4 weeks. The results of the restoration indicated that the reservoir is a water wet system at reservoir conditions.

In order to model the impairment of permeability to live gas as caused by condensate drop out over a reasonable depth of investigation, core stacks rather than core plugs was used. Calculations of volume and pressure versus depth suggested 10 to 12 inch core stacks would not cause unreasonable pressure differentials while allowing good volumetric control. Four core plugs of very similar porosity / permeability were assembled for each core stack. Permeability to live reservoir gas was measured at reservoir conditions (ie pressure above dew point) and at reservoir initial saturations (ie pores saturated with live gas and with irreducible water). This initial permeability served as the base line permeability.

At least six pressure decrements were believed to be sufficient to model the production pressure response around the well bore and a short distance into the reservoir. Most damage or impairment to production occurs in the near well bore region so given the stack length and pressure ranges, we believe the lab model to be a reasonable and reliable indicator of field performance. Following each pressure decrement, the stack was allowed to come to equilibrium by flowing live gas stripped of the condensate to the same pressure as the stack. This allows the condensate at each decrement to accumulate in the porosity without additional condensate accumulation from "upstream" portions of the reservoir.

During field production, upstream gas will be stripped of some condensate in the near well bore region as affected by the pressure transient from initial reservoir pressure deep in the reservoir to the flowing draw down pressure in the well bore. Accumulation of condensate will occur until the condensate saturation eventually reaches a critical and thereafter moveable saturation. Careful data gathering in the field will yield evidence of this effect when gas liquid ratio (GLR) is plotted versus time: GLR will increase as the condensate accumulates in the pores while the leaner stripped gas is produced. Upon establishment of critical condensate saturation, the condensate becomes mobile and any further condensate will be produced with the gas stream resulting in a decrease in the GLR to some steady GLR rate at that specific production rate.

In order to control the impairment of permeability due to condensate formation in the pores and to determine the magnitude of the critical condensate saturation, decline pressure equilibrium gas was injected into the core stack.

Eight core stacks were used to model the permeability impairment as a function of pore pressure (resulting in condensate drop out). Follow up experiments were designed to evaluate the mitigation of the condensate caused impairment by dry gas injection.

To ensure adequate volumes existed in the core for the sensitive revaporization experiments, full diameter core stacks were assembled – by much the same technique as for the core plugs. Two stacks were prepared – one to model low permeability (5 mD) rock and the other to model medium quality rock (50 mD). After establishing equilibrium condensate saturation, methane gas was reinjected for five pore volumes through the core stack. Methane gas will be the least efficient hydrocarbon based gas that would be considered for revaporization; separator A Pool gas would be the most likely "dry" gas that might be used in the field. If methane were to be successful then A Pool separator gas would be even more so due to the heavier component concentration typical of the gas produced out of the high stage separator relative to pure methane. Again, test conditions were at reservoir pressure and temperature. The composition of the effluent gas as well as gas liquid ratio were measured and added much value to the resulting permeability measurements across the core stack.

Results and discussions

The severity of the impairment of permeability due to condensate formation is illustrated in **Tables 2A & 2B**. Rock of medium-low quality is described in Table 2A while a better quality rock is the content of Table 2B. Permeability reduction was severe in both cases ie from the initial 6500 psi start point where permeability was 55 md to single phase gas at irreducible water and net overburden stress down to 1 mD at a pore pressure of 100 psig for the better quality rock. The lower quality rock had initial permeability to live gas as almost 4 mD at the start condition of 6500 psi pore pressure with impairment down to 0.09 mD at a pore pressure of 100 psig. The cause of the impairment magnitude is the very high critical volume of condensate required prior to the flow of the condensate through the pore throats and the low relative permeability to gas. Though a critical condensate saturation experiment was beyond the scope of the original lab study design, anecdotal observations of the volume of condensate exiting the core suggest a very high retained condensate volume in the rock pores hence impairing the flow of gas. Mobility and fluid dispersion in the pore environment is much more favourable towards gas rather than condensate.

Figures 5A & 5B illustrate the relationship between permeability to live reservoir gas at reservoir conditions as a function of pore pressure for the high and low perm quality core stacks. In both high and lower quality rock, permeability declines rapidly as pressure decreases. This can be attributed to both the large volume of condensate available for drop out at pressures a little below saturation pressure and the pore geometry ie little evidence of high permeability streaks and appearance of a homogeneous pore network with small pore throats.

Figure 6 is a plot of cumulative condensate production versus the cumulative volume of methane gas injection as a percentage of initial condensate in place for the low permeability stack (3 md) at pressures of 6320 and 5700 psig. The results indicate that methane breaks through of the core stack at about one pore volume injection. At the higher pressure, most of the condensate is recovered by one pore volume injection of the dry gas. At the lower pressure, the production of the condensate continues for another two pore volumes of methane injection by which time 80% of the condensate in place is recovered. The cumulative recovery of the condensate for both pressure runs is very high ie above 80 percent which is a result of two mechanisms: displacement by gas flood and vaporization of the heavier hydrocarbon components by contact with methane gas.

Figure 7 shows the molecular weight of the produced condensate liquid as a function of methane injection. The data show two different effects:

1 at high pressure, gas cycling appears to displace the condensate in a piston like manner ie very little change of the mole weight versus gas injection but a lower mole weight of displaced condensate than that as exists in the live gas. There remain some heavier ends in the core stack.

2 at low pressure, an increasing trend in the molecular weight of the produced condensate liquid which is a good indication of vaporization of the heavy hydrocarbon components by multi contact miscibility with the methane gas.

After breakthrough both the rate of condensate production and the molecular weight of the produced liquid stabilize very quickly.

Figure 8 is a plot of the cumulative production of the retrograde condensate liquid as a function of methane gas injection in terms of percentage of condensate in place using a stack of relatively high permeability (i.e.50 md). These results show that breakthrough of the injected methane gas occurs after about 1/2 pore volume of methane injection while significant amount of condensate continues to be produced after breakthrough. The overall recovery of the condensate is not as efficient as that in the low permeability stack ie (about 70%) probably due to the higher permeability of the core (50 md) which causes early breakthrough and the resulting poorer sweep efficiency.

Figure 9 illustrates the relationship between the mole weight of the produced condensate versus pore volumes of dry gas injection. The mole weights for both pressure regimes are somewhat similar; vaporization of heavier ends after gas breakthrough occurs more for the lower pressure injection than for the higher pressure. As with the low permeability stack, the composition of the condensate changes due to the pressure at which the condensate is created hence the composition of the swept condensate reflects this phenomenon.

Another set of tests was conducted to investigate the regain in permeability due to condensate revaporization by dry gas injection. Starting at the same two pressures ie 6320 psi and 5700 psi (as a separate test), dry gas was injected and permeability was measured as a function of pore volumes injected of dry gas. **Figure 10** shows the regain in permeability during the vaporization of condensate tests using methane injection for the low permeability stack with **Figure 11** illustrating the high permeability stack behaviour. The results show that as methane gas is injected the effective permeability to gas increases from about 6 percent before the start of methane injection to about 50 percent after 3 pore volumes of methane gas has been injected for the high permeability stack. The regain permeability never returns to near original rates for the low permeability stack. In our experience this phenomenon may be caused by the effect of very small pore throats clogged by even small amounts of condensate.

Conclusions

(1) Reservoir performance in terms of flow to gas is very dependant on flowing bottom hole pressure. Formation of condensate at flowing bottom hole pressures below dew point will significantly impede the flow of gas. Both low and medium quality rock types will be affected significantly.

(2) Investigation of the vaporization of condensate by methane gas at pressures below the dew point pressure was conducted by displacement testing of the gas and the retrograde condensate in the presence of connate water in horizontal core stacks. All of the testing was conducted at reservoir temperature, at net overburden stress and at a variety of pore pressures.

The recovery of the gas condensate by laboratory displacement test with methane gas varies from about 50 to 80 percent of the original condensate in place depending on the rock permeability and the resulting sweep efficiency. Theoretically, a high percentage of the condensate should be expected to be vaporised by the methane gas given the high pressure and temperature of the system and light nature of the pore filling liquid. In practice, the recovery by the laboratory displacement test would be lower than the theoretical recovery due to poor sweep efficiency.

The displacement of gas condensate by methane gas is characterised by poor mobility ratio and viscous fingering resulting in early breakthrough of the injected methane gas and very high gas/oil ratios during the test. The volume of methane gas injection required to completely recover the condensate liquid in the core is a function of temperature, pressure, composition of the gas and especially the permeability of the core sample. For the reservoir conditions investigated in this study (i.e. 7082 psig and 315 ^{o}F), the methane gas requirement varies from 3 to 4 pore volumes at a permeability of 5 md but will increase significantly at higher permeabilities (e.g. 50 md) due to early breakthrough and poor sweep efficiencies.

(3) It is evident from the laboratory data that heavy hydrocarbon components from condensate can be vaporised by multi contact miscibility with methane gas (as evidenced by the mole weight behaviour of the produced condensate) which is believed to be the major factor in providing such high recovery of the condensate liquids from certain kinds of pore systems

(4) Re-establishing permeability to reservoir gas by dry gas injection appears to be a function of the rock quality. Poor quality rock – though well suited to high condensate recovery – appears significantly impaired and does not respond well to dry gas injection. An interpretation of the persistence of the impairment is that even small quantities of condensate cause large relative permeability – liquid blocking effects. High quality rock seems well suited for permeability regain after dry gas injection.

A future exercise will compare field data with the laboratory derived model. The comparison will be presented as a case study.

We wish to thank Waha Oil Company of Libya and Hycal Energy Research Labs for the support necessary for writing this paper.

Tables and Figures:

Figure 1 - Thin Section Description of Nubian Sandstone From Waha NC98

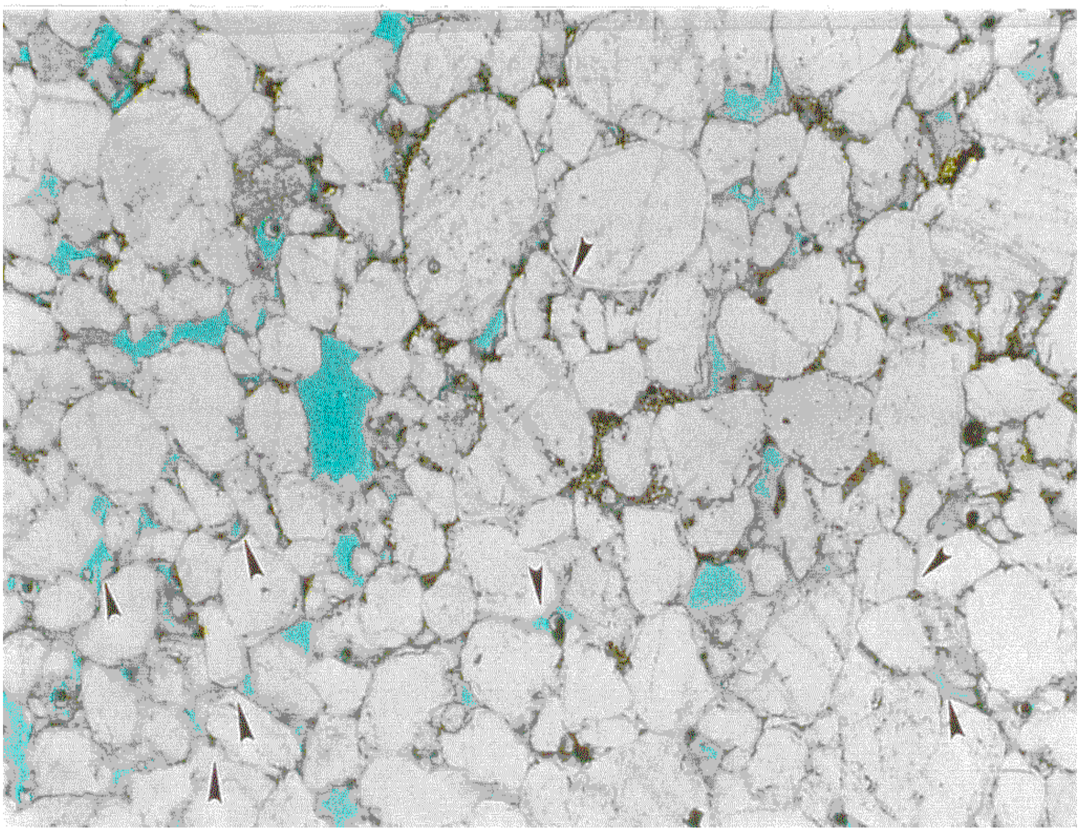


Table 1 Waha NC98 PVT Routine and Special Core Study Vaporization of Condensate by Dry Gas at Pressure Below Dew Point Recombined Composition For Surface Separator Samples From "A" Reservoir	
Composition (mole %)	**Well A3 DST#4 Sample #8B Gas bottle #147 Liquid bottle #862**
N2	1.24
CO2	5.25
H2S	0.00
C1	72.34
C2	7.85
C3	2.46
IC4	0.65
C4	1.10
IC5	0.46
C5	0.45
C6	0.72
C7+	7.48
TOTAL	100.00
GOR	6030 SCF/bbl
Dew Point Pressure (psia)	6597

Figure 2 - Phase Envelope of Recombined Composition for Waha A3 DST#4 Sample 8B

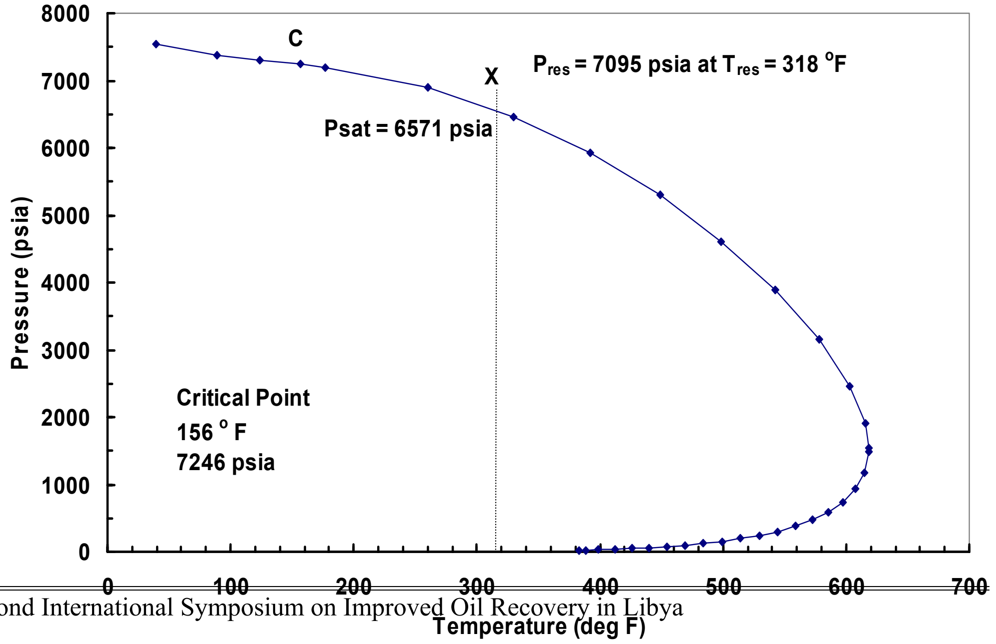


Figure 3 - Retrograde Liquid Volume Percent During Constant Volume Depletion.

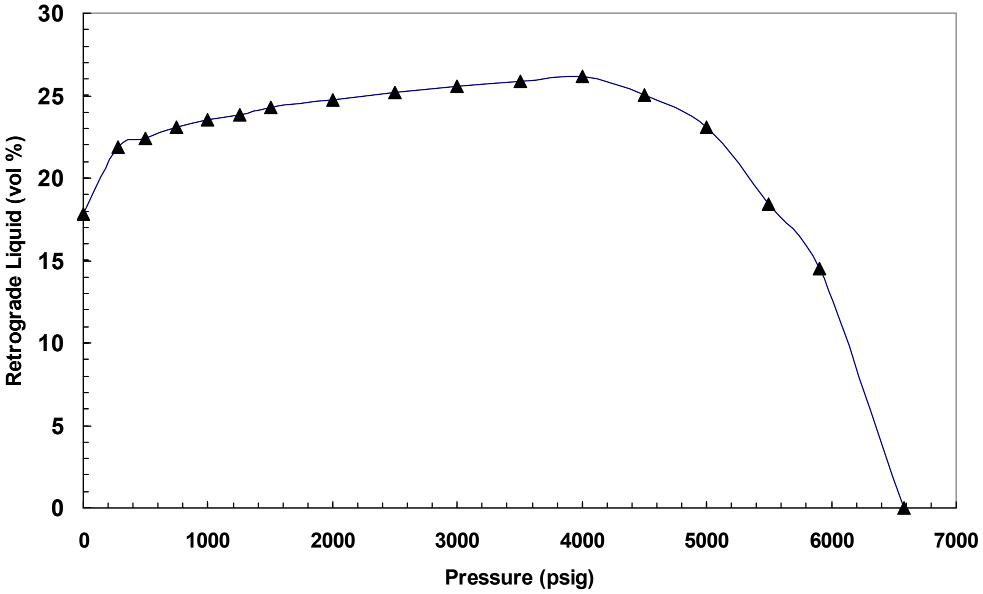


Figure 4: Well A1 - NC98 K / Phi XPlot

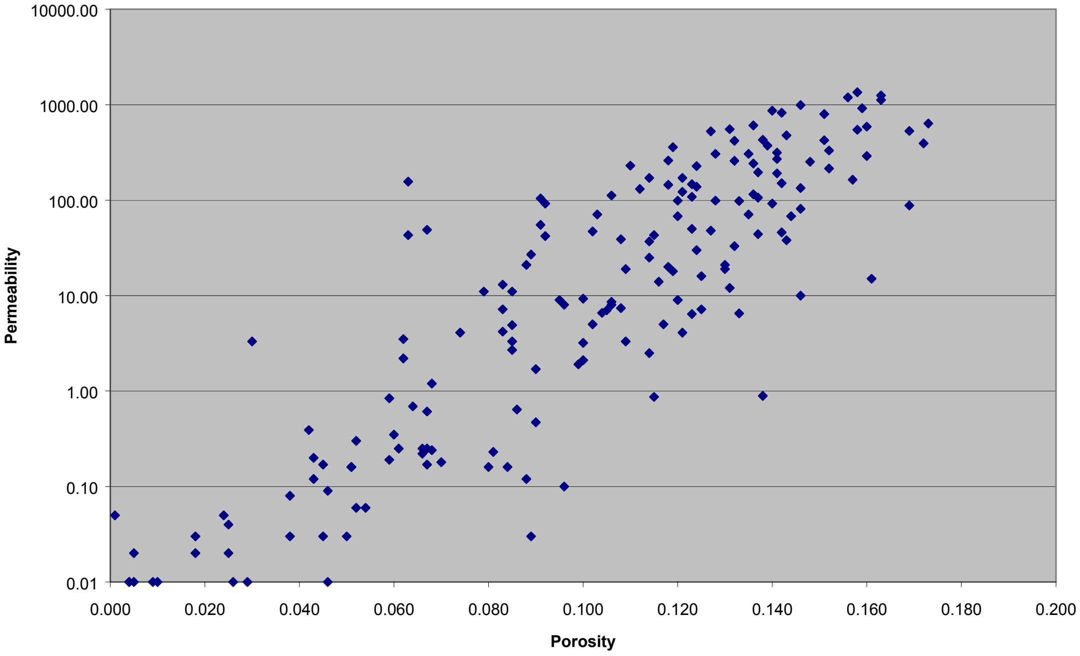


TABLE 2 A

PERMEABILITY REDUCTION AS A FUNCTION OF PORE PRESSURE

Test Parameters	
Core stack I.D.:	Stack #5
Formation:	Upper Nubian
Well I.D.:	A3
Core stack configuration (from inlet):	227, 192, 52, 117
Average reservoir depth (ft):	14392.75 ft
Core stack average porosity (%):	12.5 %
Core stack average permeability(mD):	5.65 mD
Test temperature (°F):	315
Net overburden pressure (psig):	4850

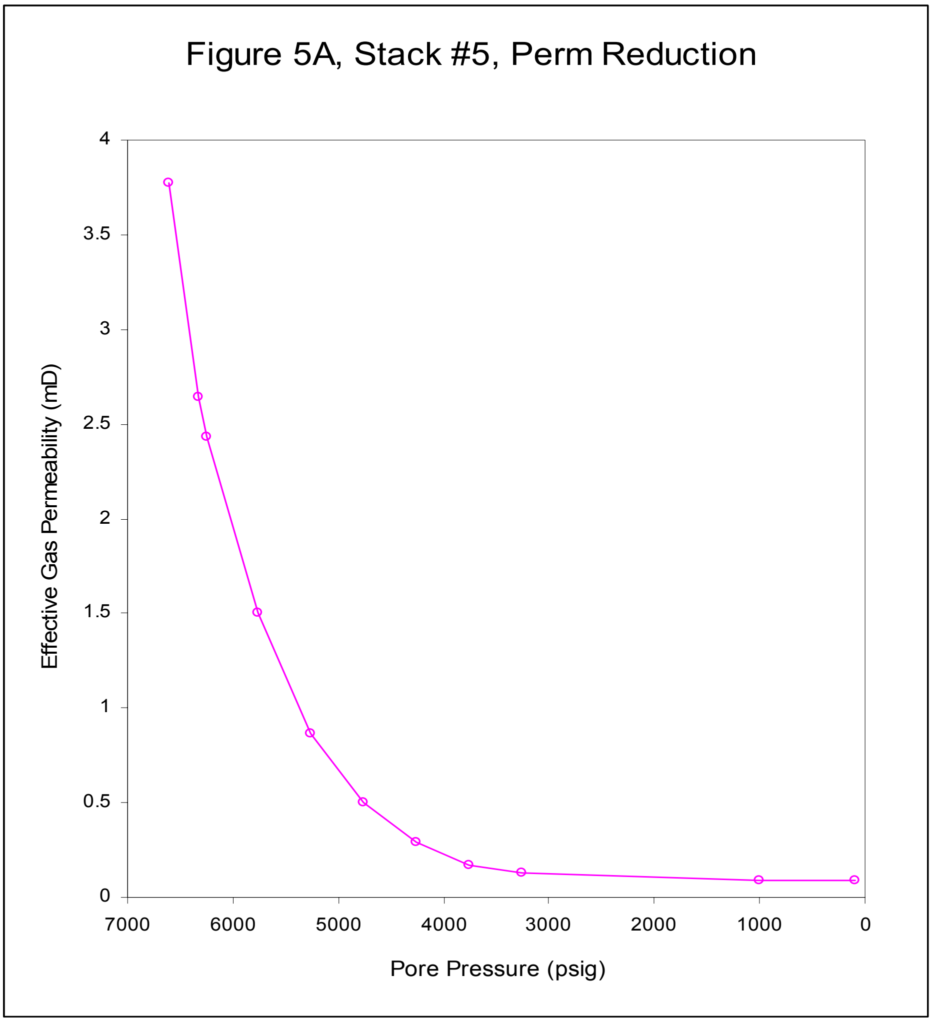


Figure 5A, Stack #5, Perm Reduction

TABLE 2 B
PERMEABILITY REDUCTION AS A FUNCTION OF PORE PRESSURE

Test Parameters	
Core stack I.D.:	Stack #8
Formation:	Upper Nubian
Well I.D.:	A1
Core stack configuration (from inlet):	17, 69, 41, 38
Average reservoir depth (ft):	14433.3 ft
Core stack average porosity (%):	12.8 %
Core stack average permeability(mD):	99.5 mD
Test temperature (°F):	315
Net overburden pressure (psig):	4850

Figure 5 B Perm Reduction Stack #8

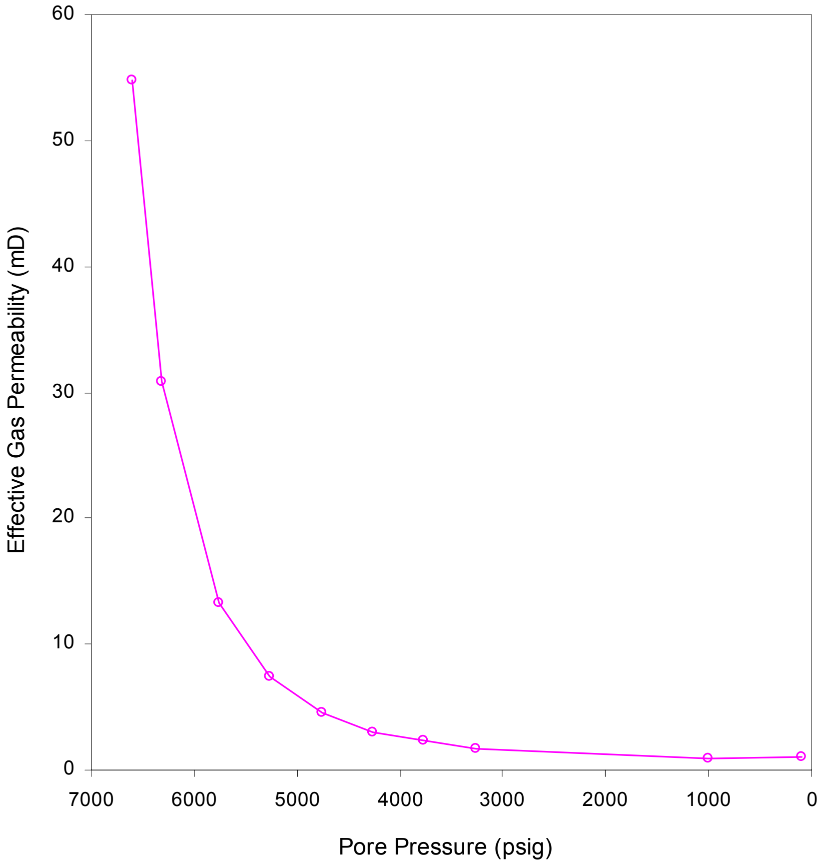
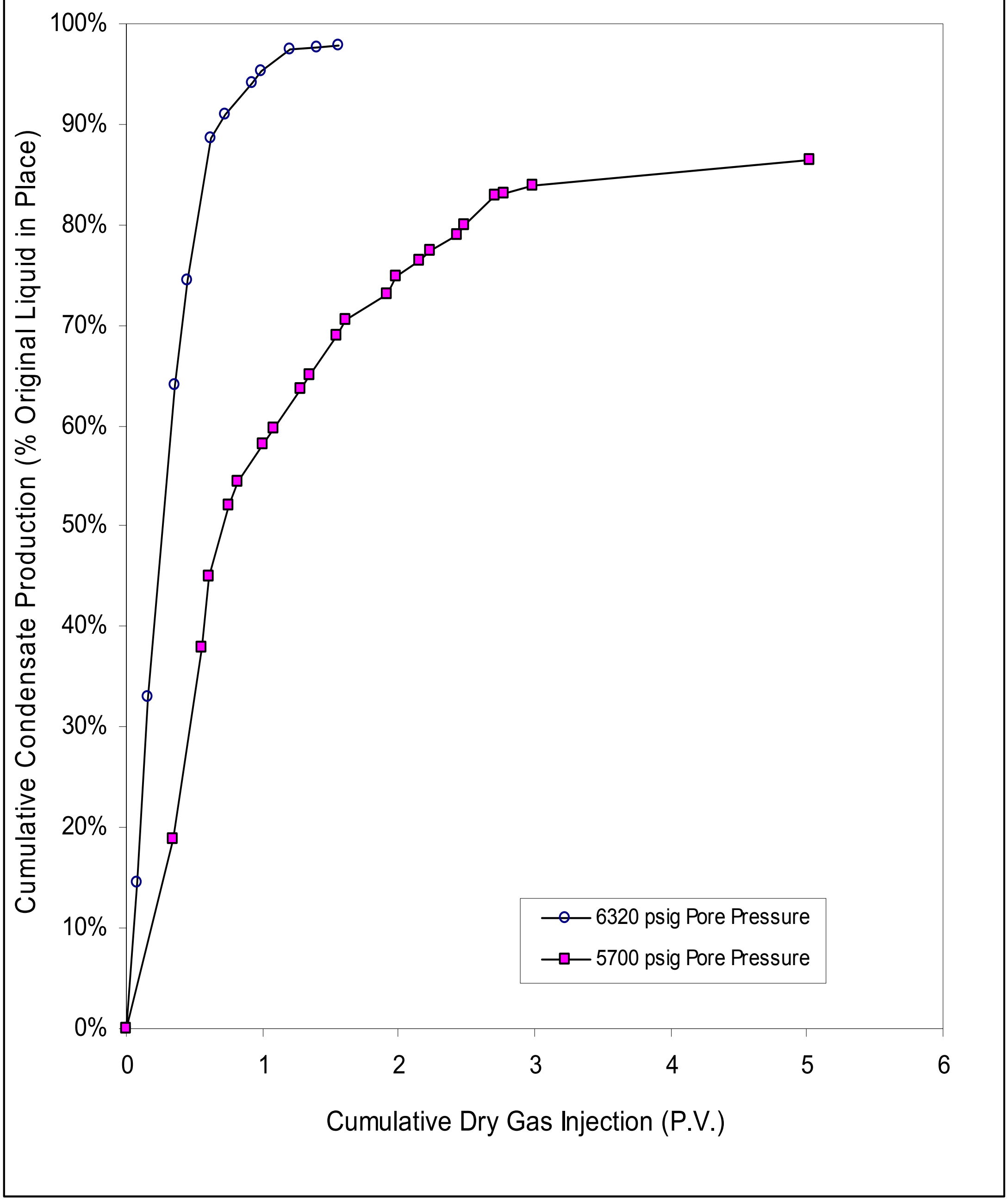
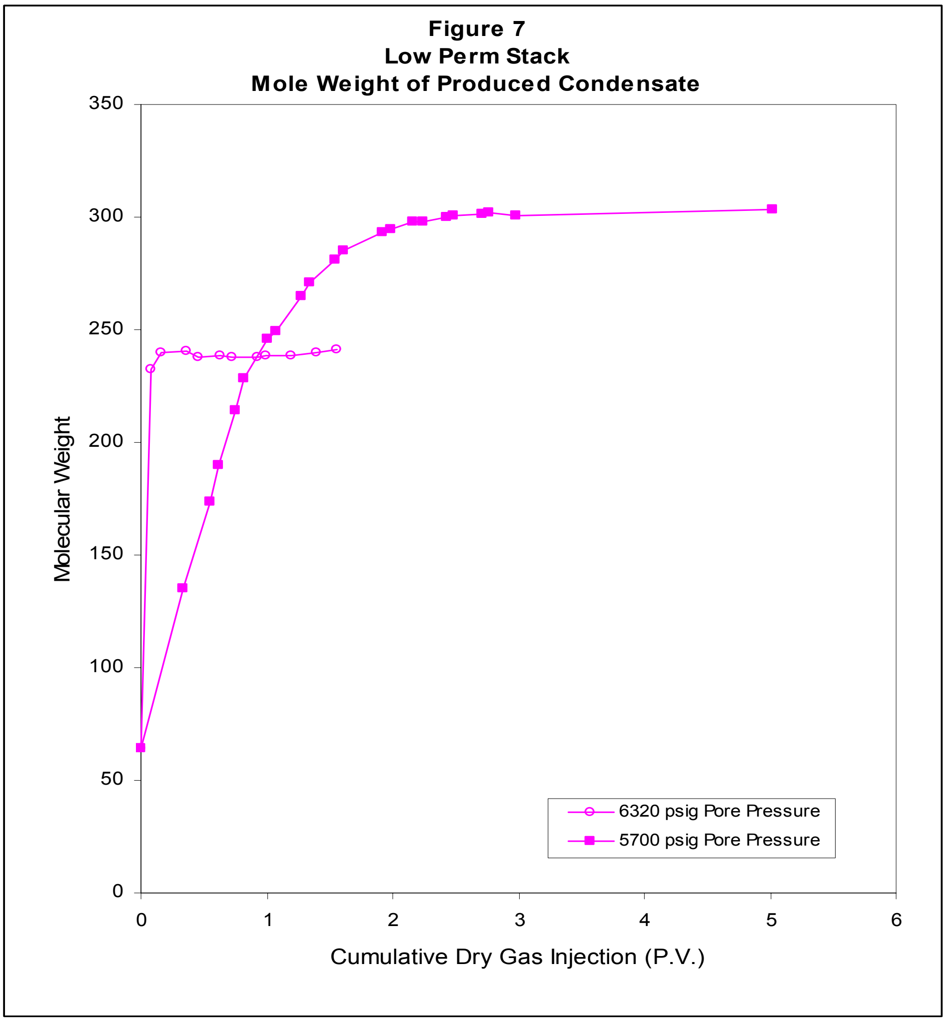
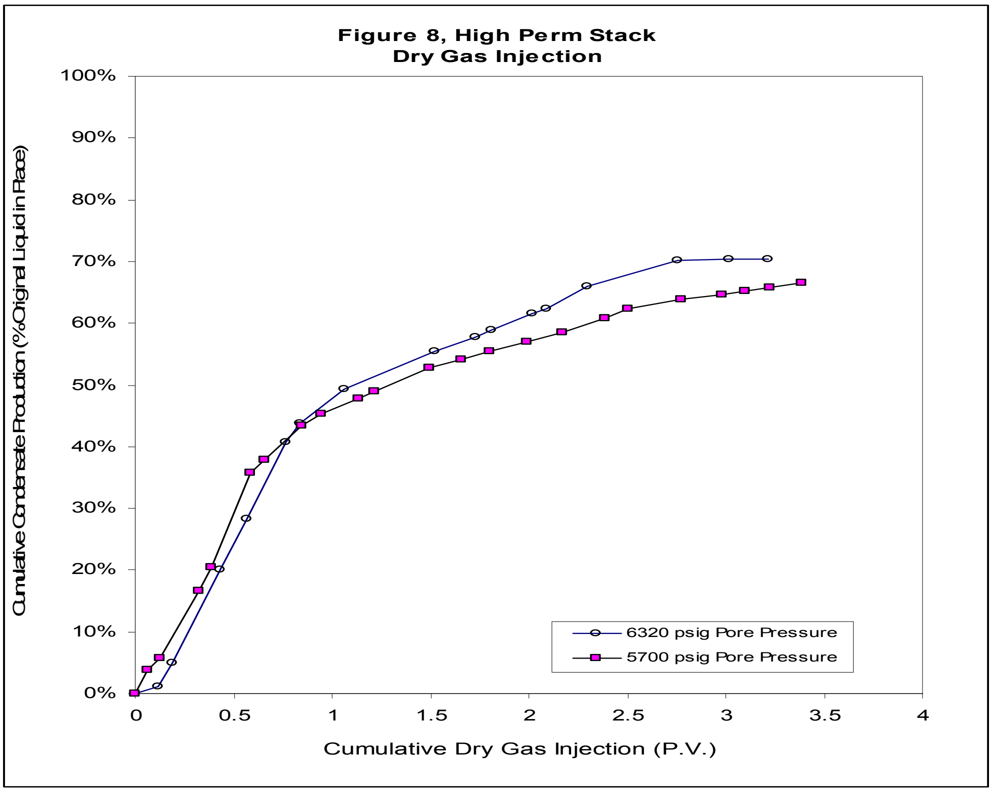


Figure 6, Low Perm Stack,
Dry Gas Injection

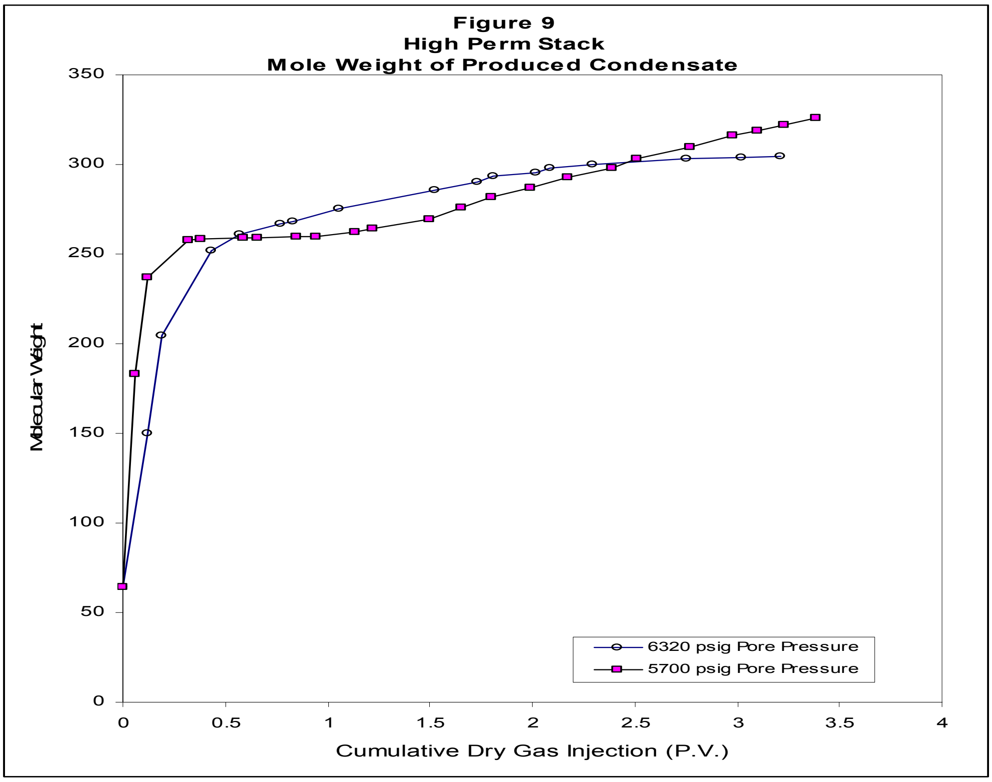


Core stack I.D.	Stack #2	Average core depth:	14462 ft
Formation:	Upper Nubian	Average core perm:	2.8 mD
Well I.D.:	A1, A2	Average core porosity:	9.56%





Core stack I.D.:	Stack #1	Average core depth :	14462 ft
Formation:	Upper Nubian	Average core perm:	49.5 mD
Well I.D.:	A1, A2	Average core porosity:	12.1 %



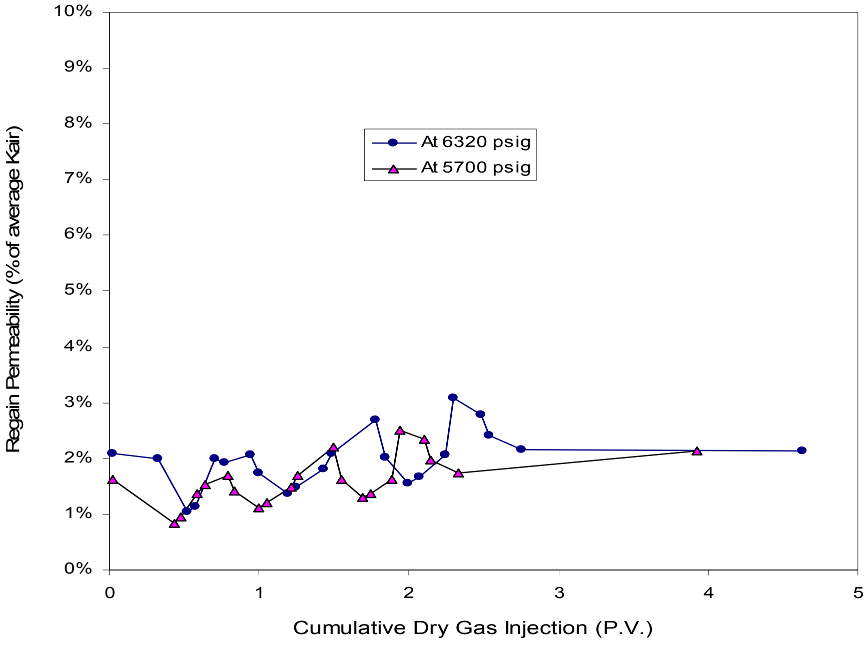


Figure 10, Low Pem Stack,
Regain Permeability

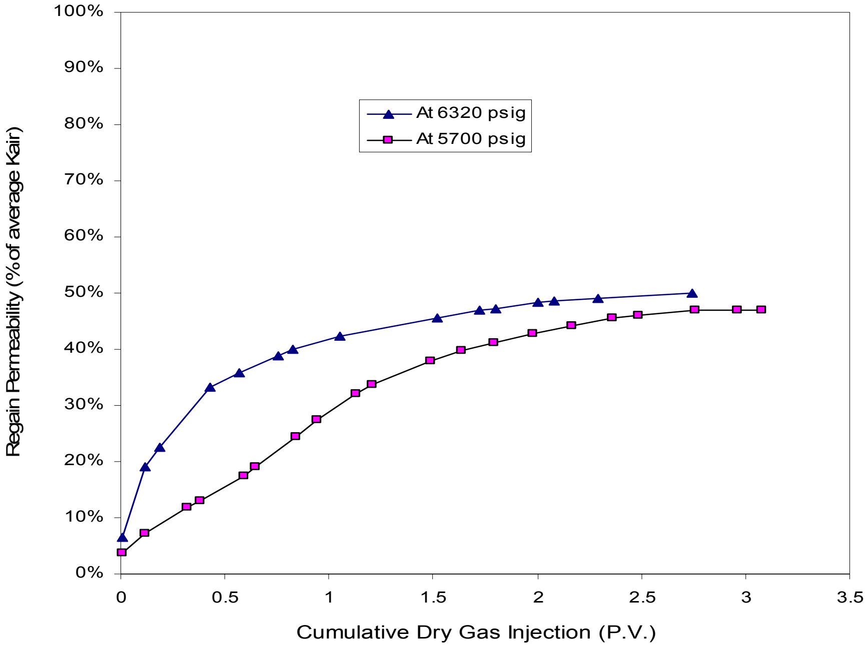


Figure 11, High Perm Stack,
Regain Permeability