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APPLICATION OF HEAT TREATMENT TO ENHANCE PERMEABILITY IN TIGHT GAS RESERVOIRS

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ABSTRACT

During drilling and completion phases, the primary mechanisms of near-wellbore formation damage can be attributed to the following factors: 1) pore throat constriction caused by clay swelling, deflocculation due to incompatible fluids or clay migration; 2) water blocking resulting in a reduction in relative permeability to hydrocarbons; 3) plugging with drill solids and mud products; and 4) loading of the reservoir with drilling or completion fluids. In tight reservoirs, phase trapping and water-blocking are believed to be the primary causes of near-wellbore formation damage, resulting in very low productivity. Clay swelling and phase trapping in tight gas reservoirs during drilling and completion have long been identified as major problems. Preventive measures have been discussed in literature; however, prevention of clay damage and phase trapping is not always possible or effective and curative measures may then become necessary. Several curative methods have been attempted and presented in literature with mixed success.

A formation heat treatment (FHT) process has been developed in the last four years and initial field test results showed promise. The primary mechanisms of the FHT process are to vaporize blocked water, dehydrate clay-bound water, destroy clay lattices and possibly create microfractures due to thermal induced stresses.

The objective of this laboratory study was to evaluate the feasibility of applying the formation heat treatment process on cores taken from a tight gas reservoir. The results indicate that the FHT stimulation at 650°C resulted in a 210% improvement in permeability from the baseline undamaged value and 675% improvement from the damaged (water-trapped) value. The post FHT waterflooding of the core still showed 50% improvement in permeability from the baseline value and 275% more than the water-trapped value. Laboratory results along with the field logistics will be presented in this paper.

INTRODUCTION

Formation damage can occur at any time during the history of a well - from the initial drilling and completion of the wellbore through to the depletion of the reservoir during production. Operations such as drilling, completion, workovers and stimulation, which expose the formation to a foreign fluid, may cause formation damage because of adverse wellbore-fluid to formation interactions. Such damage is usually severe in horizontal wells, because of the longer exposure of the wellbore to the offending fluids.[1] During the drilling and completion phases, the primary mechanisms of near-wellbore formation damage can be explained by the following factors:

Pore throat constriction, caused either by clay swelling due to incompatible fluids or by clay migration.
Water blocking due to reduction in relative permeability to hydrocarbon.
Plugging with drill solids and mud products.
Loading of the reservoir with drilling or completion fluids.

In tight gas reservoirs, formation damage, due to phase trapping and water blocking, has long been identified as a major problem. Preventive measures against this type of damage is not always possible or effective, and curative measures may then become necessary. Several curative methods have been attempted and presented in the literature.[8-15]

Non-thermal Curative Processes

One approach is to bypass the near wellbore damage using hydraulic fracturing. This technique is very effective in sandstone formations and in vertical wells. However, there are situations where hydraulic fracturing is not desirable (eg. in water or gasflooding situations, zones containing active bottom water or gas caps) or not economical (eg. in some horizontal wells).

Another approach is to stimulate the near wellbore region using acids, which dissolve the surrounding formation rock (HCl and HF acids). Matrix stimulation techniques using acids have been applied to carbonate reservoirs for productivity improvement. In some cases, however, the reaction of HF[9] (or HBF_4)[10-11] acid with feldspars and other minerals can result in various insoluble precipitates. In addition, many acids have a limited effective penetration due to rapid spending when in contact with the formation.[9] In both hydraulic fracturing and acid stimulation techniques, the proper design of the fluid system is very important. When the fluid systems contain fresh water, the chances of further phase trapping and water blocking exist.

Thermal Curative Processes

One of the earliest reports of in-situ thermal treatment was that of Albaugh,[16] on a field test that was carried out in an oil well in California. During the field test, an electrical heater was lowered into a 6.5 in diameter well and positioned close to the formation face. Natural gas was injected to push the oil back into the reservoir and subsequently, the well was heated to 375°C (733°F) for 6 days. After this time, the heating ceased and when the temperature had decreased to 175°C (373°F), the well was put on production. The pre-treatment rate was 21 bbl/day, while the post-treatment oil rate was increased to 37 bbl/day. An incremental production of 16 bbl/day was achieved and maintained for several months.

Since then, many other curative thermal processes have been described for a variety of purposes including the removal of wax[17] or asphaltene[18] buildups, thermal fracturing of the formation,[19] and the consolidation of unconsolidated formations.[20] More specifically related to phase trapping and water blocking damage are methods aimed at removing water by evaporation at high temperatures.

It is a well known fact[25] that the lattice structure of almost all clay minerals responds to thermal shock and that the degree of change in the lattice structure of various minerals depends on the temperature level. It is believed that these mechanisms of the FHT process would be beneficial to gas production improvement and thus a new matrix stimulation concept was designed and tested in the laboratory. The process involves the application of heat for the treatment of near wellbore damage. Bench scale heating tests were carried out on cores taken from a tight gas-bearing formation to determine the effect of heat on permeability, fluid saturation, and mineralogy (i.e. degradation of in-situ minerals). The experimental stimulation results are presented in this paper.

FORMATION HEAT TREATMENT (FHT) CONCEPT

The concept of applying intense heat for the treatment of near wellbore formation damage was evaluated. The process[26] consists of exposing the formation to an elevated temperature to cause:

Vaporization of blocked water
Dehydration of the clay structure

Partial destruction of the clay minerals
Possible microfracturing of the formation in the near wellbore area due to thermal induced stresses

The dehydration and vaporization of bound and blocked water occur at temperatures higher than the saturation temperature corresponding to the reservoir pressure. The extent of clay destruction also depends on the heating temperature.

We based the selection of our experimental temperature conditions on X-ray diffraction (XRD) results from isolated kaolinite and smectite samples in the laboratory published earlier[27]. The spectra from a kaolinite sample treated at five different temperatures were presented[27]. One can see that heating to 107°C and 300°C produces no change in the XRD spectrum, compared to that of the air dried sample. This indicates that heat treatment up to these temperatures does not affect the kaolinite structure. However, at 550°C, it is observed that all the kaolinite peaks disappear, indicating complete destruction of the kaolinite structure at this temperature. The Al-hydroxyl bonds become dehydrated, and the well ordered crystalline form degenerates into an amorphous arrangement. The only remaining peak is at 3.52 Å, which corresponds to anatase, a TiO_2 phase that was present in the original sample.

Similarly, six XRD spectra from a smectite sample were also presented[27]. The top spectrum was that of the wet sample. The peak at 19.09 Å corresponded to the swelled state of smectite, in which each Ca^+ ion on the clay surface was surrounded by four layers of water. As the sample was heated up to 300°C, this peak shifts progressively to the right, indicating progressive vaporization of the water. No major change in the XRD spectrum was observed between the 300°C and 550°C treatments, revealing that the interlayer dewatering process is complete after heating to 300°C. At 800°C, the peak intensities decreased significantly. As with kaolinite, the crystallinity of smectite was destroyed, resulting in an amorphous structure that does not generate any strong XRD peak.

Based on the above results and the literature data, various temperatures (i.e. 120, 315, 480 and 650°C) were selected to evaluate the effect of intense heating on the permeability of the two test cores discussed next.

RESERVOIR DESCRIPTION AND FORMATION EVALUATION

Two core samples were selected to conduct FHT stimulation based on their initial permeability and porosity (Table 1). Petrographic studies were carried out to characterize the core samples. X-ray diffractometry (XRD), and scanning electron microscopy (SEM) were used in these characterization studies. Pre- and post- FHT XRD and SEM analyses were conducted on Sample A. Pre- and post-FHT XRD analyses were conducted on Core Sample B. A brief description of the results is presented below.

XRD results indicate that both Samples A and B contained 6.3% and 5.8% total clays, respectively. These clays are mostly comprised of kaolinite and illite:

Sample A: illite 64.2%, kaolinite 35.8%
Sample B: illite 68.4% and kaolinite 31.6%

Trace amounts of chlorite materials were also seen in both samples. The illite component loses its hygroscopic water after one hour of heating at temperatures of 125 - 250°C. The kaolinite group is replaced by amorphous meta-kaolin after one hour of heating at temperatures of 575 - 625°C.

The post-FHT XRD analyses on Sample A indicate that the total clay content decreases from 6.2% to 1.5%. The total clay content decreases from 5.8% to 2.7% in Sample B after FHT stimulation at 649°C. It appears that in Sample A, kaolinite clays are either completely destroyed or converted to meta-kaolin after FHT stimulation at 649°C. On the other hand, illite materials appear to be reduced from 68.4% to 37.2% after FHT stimulation at 649°C. These results are presented in Table 2.

EXPERIMENTAL EQUIPMENT AND PROCEDURE

A conventional apparatus was used to measure the effective permeability of the core samples. The samples were then mounted in a tri-axial core holder and confined at a nominal overburden pressure. The portions of the core holder directly adjacent to the injection and production ends of the core were equipped with radial distribution plates to ensure evenly distributed nitrogen flow into and out of the core specimen. Pressure, temperature, and velocity of the nitrogen flow through the core were measured using a nitrogen permeameter. Rotameter-style flow meters were used to facilitate the flow measurements. All permeability measurements were carried out using this procedure. Permeabilities were measured at three rates for Klinkenberg corrections.

Heat cycling was conducted by placing the respective core samples into an Inconel reactor and heating the reactor in a high temperature oven. A schematic diagram of the apparatus used during the heat cycling is presented in Figure 1. A constant pressure of 51 MPa was maintained inside the reactor using a regulated nitrogen source and a backpressure regulator. Temperature was monitored with a thermocouple that displayed the internal reactor temperature. The testing procedure was as follows:

Subject pre-FHT samples to XRD and SEM analyses.
Fix Swi with 2% KCl fluid.
Measure gas permeability to humidified nitrogen at room temperature and full reservoir net overburden pressure at three rates.
Flush core with 2 pore volumes of fresh water (to simulate drilling and completion induced damage)
Desaturate sample by nitrogen flooding to irreducible fluid saturation; measure gas permeability.
Heat core sample to specified temperature at constant pressure (51 MPa) inside Inconel reactor, kept at temperature for four hours, depending on desired temperature level, while circulating nitrogen slowly through reactor.
Cool reactor to room temperature prior to removing sample.
Measure humidified nitrogen permeability.
Flush sample again with fresh water.
Desaturate sample to irreducible fluid saturation prior to measuring gas permeability.
Subject samples to post-FHT X-ray diffraction (XRD) and scanning electron microscopy (SEM) analyses.

A multiple temperature heating cycle was carried out with both core samples.

EXPERIMENTAL RESULTS

The following is a summary of results from the FHT tests on Samples A and B. Permeability values were measured three times at each step. The measured values were corrected for Klinkenberg effects. The Klinkenberg corrections were made by plotting the measured permeability values versus the inverse of mean pressures in atmospheric units. Subsequently, the Klinkenberg corrected permeability values are read as the permeability at zero inverse of mean pressure.

Results of the FHT Stimulation on Sample A

Sequential permeability changes in Core Sample A during the laboratory procedure are presented in Table 3 and the values are graphically presented in Figures 2 and 3. As seen in Table 3, the initial water saturation was determined to be 21.3%. The corresponding effective nitrogen permeability was 0.02 mD. Subsequently, we flooded the core with fresh water and desaturated the core using nitrogen flow to a saturation of 28.2%. The effective nitrogen permeability at 28.2% water saturation was 0.008 mD. This corresponds to a permeability reduction of 60%. This permeability reduction is the result of added water trapping in the core.

After the FHT stimulation at 121°C, the permeability did not change significantly (0.01 mD). This was due to the inability to vaporize the blocked water at the test temperature. Permeability did increase significantly after heating to temperatures of 315 and 482°C. The FHT stimulation at 482°C increased the core permeability to 0.035 mD and this is a permeability improvement of 75% from the base line value of 0.02 mD. As seen in Table 3, FHT stimulation at 482°C also vaporized all the water from the core. Subsequent saturation and de-saturation with water resulted in a water saturation of 15.3% and the corresponding nitrogen permeability was 0.02 mD. This corresponds to the baseline permeability at an initial water saturation of 21.3%. However, this permeability is a 150% improvement over the water-trapped permeability of 0.008 mD at a water saturation of 28.2%. Subsequent FHT stimulation to 649°C resulted in a significant improvement in permeability (0.062 mD). This improvement corresponds to 210% from the baseline permeability (0.02 mD) and 675% from the water-trapped permeability (0.008 mD). After water flush, the regain saturation was 5.2% and the corresponding permeability (0.03 mD) is 50% more than the baseline permeability (0.02 mD) and 275% more than the water-trapped permeability (0.008 mD).

Results of the FHT Stimulation on Sample B

Sequential permeability changes in Core Sample B during the laboratory procedure are presented in Table 4 and the values are graphically presented in Figures 4 and 5. As seen in Table 4, similar results were also obtained in Core Sample B. A reduction of 56% in nitrogen permeability was obtained in this core sample due to water trapping. However, in this sample the initial water saturation was 19.2%, giving an effective nitrogen permeability value of 0.016 mD. After water flooding and desaturation, the water saturation was 24.5%. At this water saturation, the corresponding effective nitrogen permeability was 0.07 mD. The FHT stimulation at 315°C increases the core permeability to 0.025 mD. This is a permeability improvement of 56% from the baseline value of 0.016 mD. Subsequent stimulation at 482°C resulted in an improvement in permeability of 87% from the baseline permeability of 0.016 mD. As seen in the table, FHT stimulation at 315 and 482°C also vaporized all water from the core. Subsequent saturation and desaturation with water resulted in a water saturation of 15.5% and the corresponding permeability was 0.02 mD. This is a 25% improvement over the baseline permeability of 0.016 mD at a water saturation of 19.2%. However, this is still a 185% improvement over the water-trapped permeability of 0.007 mD.

Similar to Core Sample A, FHT stimulation at 649°C resulted in a significant improvement in permeability of 0.047 mD. This improvement corresponds to 194% from the baseline permeability (0.016 mD) and 571% from the water-trapped permeability (0.007 mD). Following the water flush, the regain saturation was 10.5% and the corresponding permeability (0.022 mD) is 37% more than the baseline permeability (0.016 mD) and 214% more than the water-trapped permeability (0.007 mD).

Discussion

At this point, it is appropriate to summarize the various mechanisms which have affected the effective permeability of these cores upon intense heating. The foremost effect of heat was to vaporize the trapped water. Secondly, the hygroscopic water of the clay materials were also vaporized. Finally, it was evident from the petrographic studies that various clay minerals were degraded at very high temperatures, and that this effect contributed to the drastic increase in effective permeability observed after the high temperature treatments.

Besides water vaporization and clay degradation, the application of heat may also have generated substantial thermal stresses in the rock. Such high temperatures may have been sufficient to exceed the yield strength of the constitutive grains or cementing material, which in turn would have introduced microfractures into the system. These microfractures would allow increased fluid flow and thus serve as a secondary mechanism of permeability enhancement. However, this microfracture mechanism was not apparent from the petrographic studies on the heat treated samples.

If the in-situ results are comparable to those obtained to date in the laboratory, the FHT process would be most suitable in situations where conventional treatment methods are not effective (i.e. horizontal wells) or not desirable (i.e., hydraulic fractures in vertical wells with active bottom water). The process would be applicable in sandstone formations with moderate permeability, to ensure proper nitrogen injectivity, with high reservoir potential, and containing swellable clays and shales. Reservoirs where fluid blocking is a common phenomenon would also be suitable candidates for the FHT process.

TENTATIVE FIELD SCHEME

The field implementation of the FHT process would involve the placement of a tubing- or wireline-conveyed heating device across the perforations or the producing sand face, and the injection of an inert gas (eg. nitrogen) into the wellbore, through or around the heating device. The heating device can be made of an electrical resistance heating element or any other device that can generate heat downhole. This downhole heater raises the temperature of the injection gas, which in turn heats up the formation.

This heating process could be designed for both cased and open holes, vertical and horizontal wells, as long as the formation and the casing are able to sustain the thermal stresses generated by the heat source. In the case of tubing-conveyed heaters, reduction of wellbore heat losses can be achieved by injecting cool gas through the annular space.

CONCLUSIONS

Experimental results obtained to date in the laboratory indicate that the application of intense heat vaporizes bound and blocked water, destroys clay lattices, and ultimately increases the permeability of clay-rich formations. A significant increase in permeability can be achieved in cores exposed to 649°C. This intense heating process can be used to increase the permeability of cores taken from light gas reservoirs.

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TABLE 1
FHT FEASIBILITY STUDY
PERMEABILITY AND POROSITY DATA

Sample ID	Permeability (mD)	Porosity (%)
A	0.28	8.70
B	0.31	8.30

TABLE 2
FHT FEASIBILITY STUDY
XRD RESULTS

Clay Components	Sample A		Sample B	
	Pre-FHT	Post-FHT	Pre-FHT	Post-FHT
Quartz	90	98.1	90.9	95.7
K-Fledspar	0.7	0.4	0.8	0.5
Na-Feldspar	0.7	-	0.8	-
Pyrite	1.4	-	1.7	1.1
Kaolinite	2.7	0.4	2.5	1.1
Illite	4.5	1.1	3.3	1.6
Chlorite	Trace	Trace	Trace	Trace
Total Clays	**6.3**	**1.5**	**5.8**	**2.7**

TABLE 3
FHT FEASIBILITY STUDY
SUMMARY OF PERMEABILITY VALUES ON CORES - SAMPLE A

Tests	Water Saturation (%)	Klinkenberg Corrected Perm (mD)	% Change in Perm From Baseline	% Change in Perm From Water Trapped
Initial Water Saturation	21.3	0.02	0	--
Post Water Flush	28.2	0.008	-60	--
FHT @ 121°C	26.5	0.01	-50	25
FHT @ 315°C	0.0	0.025	25	212
FHT @ 482°C	0.0	0.035	75	337
Water Flush	15.3	0.02	0	150
FHT @ 649°C	0.0	0.062	210	675
Water Flush	5.2	0.03	50	275

TABLE 4
FHT FEASIBILITY STUDY
SUMMARY OF PERMEABILITY VALUES ON CORES - SAMPLE B

Items	Water Saturation (%)	Klinkenberg Corrected Perm (mD)	% Change in Perm From Baseline	% Change in Perm From Water Trapped
Initial Water Saturation	19.2	0.016	0	--
Post Water Flush	24.5	0.007	-56	--
FHT @ 315°C	0.0	0.025	56	257
FHT @ 482°C	0.0	0.03	87	328
Water Flush	15.5	0.02	25	185
FHT @ 649°C	0.0	0.047	194	571
Water Flush	10.5	0.022	37	214

FIGURE 1
FHT FEASIBILITY STUDY
HIGH TEMPERATURE COREFLOW APPARATUS SCHEMATIC

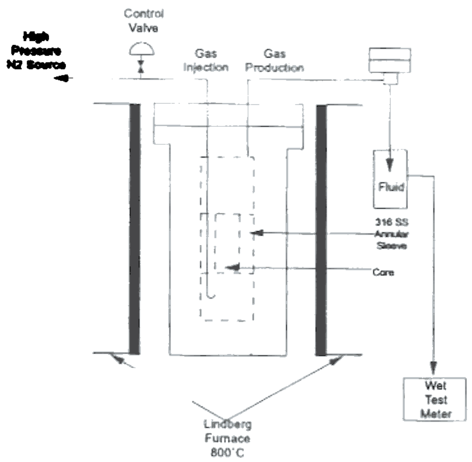


FIGURE 2
FHT FEASIBILITY STUDY - SAMPLE A
(Base Permeability = 0.02 mD)

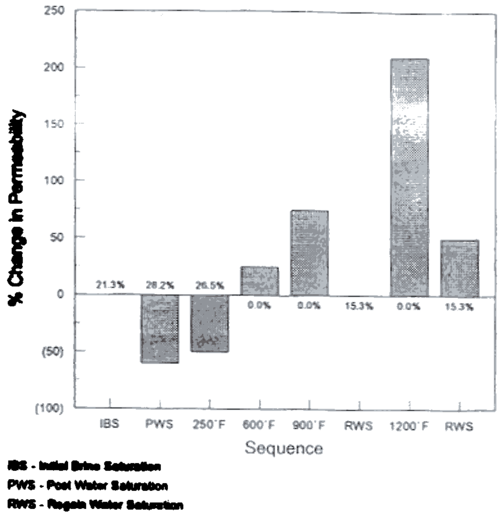


FIGURE 3
FHT FEASIBILITY STUDY - SAMPLE A
(Base Permeability = 0.008 mD - Water Trapped)

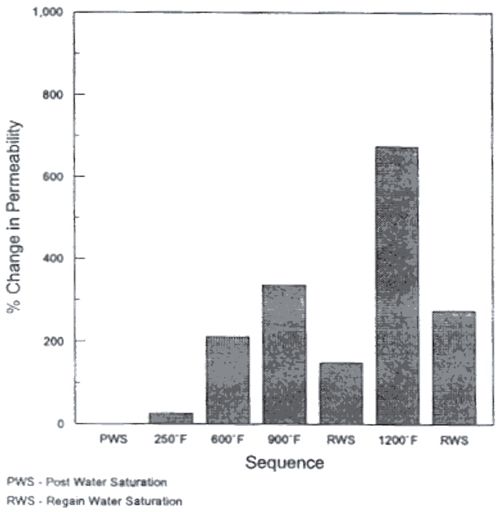


FIGURE 4
FHT FEASIBILITY STUDY - SAMPLE B
(Base Permeability = 0.016 mD)

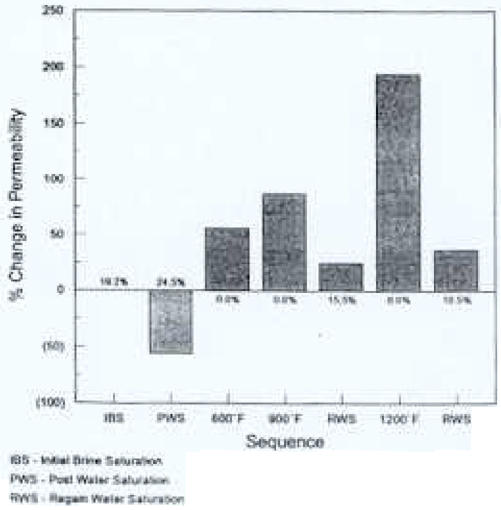
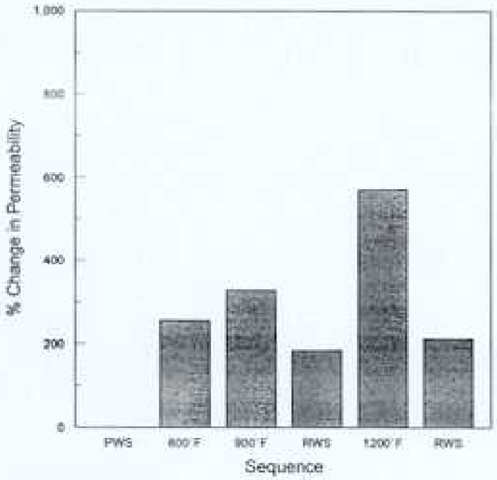


FIGURE 5
FHT FEASIBILITY STUDY - SAMPLE B
(Base Permeability = 0.007 mD - Water Trapped)



PWS - Post Water Saturation
RWS - Regain Water Saturation