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AN INVESTIGATION OF LOW-INVASION CORING FLUIDS

Annual Report, October 1, 1978—September 30, 1979

Work Performed for the Department of Energy
Under Contract No. DE-AT19-78BC00015

Date Published—October 1980

Sandia Laboratories
Albuquerque, New Mexico

DEPARTMENT OF ENERGY UNITED STATES OF AMERICA

U. S. DEPARTMENT OF ENERGY

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AN INVESTIGATION OF LOW–INVASION CORING FLUIDS

Annual Report
For the Period
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U.S. DEPARTMENT OF ENERGY

FOREWORD

The work described in the following pages was performed by Sandia Laboratories under a contract with the Department of Energy and was sanctioned by personnel at the Bartlesville Energy Technology Center (BETC) in Bartlesville, Oklahoma. The contract resulted from a proposal submitted by personnel in the Drilling Technology Division at Sandia which proposed to identify, evaluate, and develop a fluid or fluids suitable for use in pressure coring operations and which would reduce or eliminate mud filtrate invasion and flushing of the core. Contract work began October 1, 1978 and was scheduled to end September 30, 1979, but the contract has been extended for another year with completion anticipated by September 30, 1980.

Enhanced oil recovery operations require an enormous investment and, as such, any decision concerning this investment needs to be based on the most accurate information on important reservoir parameters as is available. BETC personnel have been engaged in field projects and laboratory studies to define weaknesses in and to improve the accuracies of techniques used to measure these reservoir parameters. Pressure-retaining core barrels provide core samples at reservoir pressure, but they do not eliminate flushing or filtrate invasion of the core during coring. This contract is directed at producing a low-invasion coring fluid which will drastically reduce flushing and mud-filtrate invasion of the core.

At present, the coring fluid developed exhibits good properties as a coring fluid and has demonstrated unique temperature characteristics that will significantly reduce the time required for sample preparation and analysis. Additional testing and development is currently underway to further reduce mud-filtrate invasion and flushing of the core.

R. Mike Ray
Technical Project Officer
BETC

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AN INVESTIGATION OF LOW-INVASION FLUIDS FOR PRESSURE CORING*

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ABSTRACT

A new pressure coring system has been developed which could significantly improve the measurement of in-situ oil and gas saturations in hydrocarbon reservoirs. This improved system incorporates a low-invasion fluid that is stored in the core retriever and is extruded to seal and protect the core. The low-invasion fluid consists of an extremely viscous, brine-based polymer system with sized calcium carbonate bridging particles to minimize invasion. This special coring fluid has been selected from several candidates that were laboratory tested at simulated downhole conditions. Both static and dynamic filtration characteristics were considered. Other important properties of this low-invasion pressure coring fluid are discussed, including freezing point, formation damage, clay stabilization, wettability changes, and pressure buildup in the core barrel. Preliminary results from actual coring operation are also presented.

Objective

The primary objective of this program is to identify fluids that are suitable for use in a pressure coring system, and that allow a minimum invasion of drilling fluid into the core. In order to obtain accurate reservoir saturation data from cores, invasion of drilling fluids into the core must be minimized. The low-invasion coring fluid is stored in the inner core barrel and is extruded as the core is cut to seal and protect the core from invasion by drilling fluids.

Background

Cores are taken to determine the rock properties and fluid content that exist in subsurface formations. Each oil or gas reservoir has unique characteristics that make examination of unaltered cores desirable in designing optimum recovery techniques. Pressure coring has become a valuable tool for obtaining saturation and relative permeability data for enhanced recovery projects. At this time, the primary limitation of pressure coring is fluid invasion of the drilling mud into the

*This work is supported by the U. S. Department of Energy, Bartlesville Energy Technology Center, under Contract No. DE-AT-19-78BC00015.

core. This invasion can significantly reduce the oil and gas saturations in the core and can also cause formation damage and relative permeability changes.[1,2,3,4]

A great deal of study has been devoted to drilling fluids, including those used in coring. Unfortunately, the coring fluids currently in use are of necessity a compromise between low invasion, good drilling properties, and expense.[5] For example, to minimize invasion into the core, a very viscous mud with a high solids content is desirable. This type of mud would cause high bottom-hole pressures, low penetration rates, and high costs. In effect, a good drilling fluid is a poor coring fluid, while a good coring fluid may be completely unacceptable as a drilling fluid.

To overcome these problems, the Department of Energy has contracted to Sandia Laboratories to develop an improved pressure coring system. (See Figure 1.)[6] This new system incorporates a low-invasion fluid which is stored in the inner core barrel and extruded to seal and protect the core. As the core is pushed up into the inner core barrel, it displaces the low-invasion fluid down the outside of the core and around the pilot bit. Conventional drilling mud is pumped down the drill pipe for chip removal and cooling, but the core itself is drilled with the pilot bit and is contacted only by the low-invasion coring fluid.

The major objective of the program is to develop and evaluate a suitable low-invasion coring fluid to be used with the improved pressure coring system. The coring fluid, being completely separate from the drilling fluid, is no longer under the severe constraints of viscosity, solids content, chemical composition, and expense that limit the choice of drilling muds. Because of this great flexibility, a wide variety of fluid types were considered. Criteria for a low-invasion fluid compatible with the improved pressure coring system were established, and all fluid candidates were evaluated on that basis. Those fluids that appeared promising were then laboratory tested to select the best low-invasion fluid. Laboratory testing included static filtration at simulated downhole conditions and static invasion testing in high-permeability and medium-permeability sandstones. The best coring fluid was then evaluated in freezing tests, laboratory drilling tests, and actual coring operations. The low-invasion coring fluid appears to be working very well at this time. However, further testing and evaluation is required to optimize the coring fluid and to better understand the overall invasion process.

Coring Fluid Requirements

To take full advantage of the improved pressure coring system, the following criteria were established for selection of the low-invasion coring fluid:

(1) Minimum invasion of filtrate into the core to obtain accurate saturation data,

(2) Non-reactive with reservoir rocks and fluids to obtain accurate permeability and wettability data,

(3) Good drilling properties for removing cuttings and cooling the pilot bit at the very low flow rates encountered while coring,

(4) Stable at the high temperatures anticipated near the bit,

(5) Low freezing point to allow removal of the frozen core from the inner core barrel, and

(6) Moderate viscosity to limit pressure buildup in the core barrel as the core extrudes the low-invasion fluid.

Of the criteria listed, minimizing fluid invasion into the core is clearly the most important. The coring fluid should also be stable at fairly high temperatures, since less than three gallons of low-invasion fluid will cool the pilot bit while cutting a 10 foot long core. The most severe environment for invasion is at the bit face, where heat generation and continuous removal of surface filter cake will occur.

The viscosity of the coring fluid is limited by the pressure buildup which occurs as the low-invasion fluid is extruded by the core. Since an increase in coring fluid pressure will increase the fluid invasion into the core, this pressure buildup should be kept small.

Fluid Types Examined

A wide variety of fluid types were examined before a brine-based polymer system was chosen. The first fluid to be tested was dimethyl siloxane, a readily available silicone fluid used in damping and insulating electronic instruments. At a viscosity of 62,000 centipoise, this fluid showed low invasion and good chip removal, and was non-freezing to -42°F. Unfortunately, dimethyl siloxane is soluble in toluene and would therefore appear as increased oil saturation in a Dean Stark core analysis. Silicone fluids also have undesirable surfactant properties that would alter the wettability of the core.

Several patents have been granted in which a liquid metal is used to prevent flushing of the core. A liquid metal coring fluid would be non-reactive, temperature stable, and easily distinguished from both oil and water, so this possibility was examined. Gallium/tin based alloys were considered because they have low melting points, are non-toxic, and are relatively inexpensive. However, mercury injection data on the 1550-millidarcy Brown sandstone showed that the mercury invaded almost 70 percent of the pore space with only 6 psi differential pressure. Similar invasion data from other sources eliminated liquid metals from further consideration.

Oil-base muds generally have the lowest API filtrate loss of conventional drilling fluids, and they are routinely used in high temperature applications. Unfortunately, oil-base muds have little value in coring for EOR projects since even very limited invasion would significantly increase residual oil saturation measurements.

Most water-base drilling muds use betonite, i.e. sodium montmorillinite, for increasing viscosity and reducing fluid loss. These small clay particles are very effective in minimizing fluid invasion, but often cause severe, irreversible formation damage, and could also cause changes in the relative permeability of the core.(3,4) Because of these drawbacks, water-base muds containing bentonite were considered unsuitable for pressure coring.

During recent years, water-base polymer muds have been used extensively as non-damaging completion and workover fluids. Polymer systems have several properties that are desirable in a low-invasion fluid. Polymers can be used to develop extremely high viscosities and can effectively suspend large concentrations of bridging particles. In addition, polymers are compatible with a wide variety of drilling fluids and mud additives. The polymers examined in this study included carboxymethyl cellulose (CMC), hydroxyethyl cellulose (HEC), xanthum gum (XC), guar gum, polysaccharide, and polyacrylamide.

Selection of Hydroxyethyl Cellulose Polymer

A major advantage of polymer fluids is the formulation of very viscous fluids that also have very low freezing points. Figure 2 shows that a 30 wt-pct $CaCl_2$ brine eutectic has a freezing point of about -60°F. Furthermore, $CaCl_2$ brine has been shown to stabilize swelling clays and to prevent formation damage in sensitive sands. To capitalize on these properties, the polymer must be compatible with the 30 wt-pct $CaCl_2$ brine and must itself be relatively non-damaging to the formation. Neither the CMC nor the polysaccharide tested were usable in this heavy calcium brine, and were therefore unsuitable. Guar gum and polyacrylamide have been shown to cause formation damage and were also judged to be unsuitable as coring fluids.(7) The XC polymer was found to have high fluid loss, especially in the presence of calcium ions, and consequently is not usable as a low-invasion fluid.

Table 1 lists the results from API filtrate loss tests for several different polymer systems. The HEC polymer muds (Mud A and Mud B) were clearly superior to the other polymers in reducing filtrate loss under simulated downhole environments. This was confirmed by further high pressure, high temperature testing which showed that the starch, the polysaccharide polymer, and the XC polymer began to break down rapidly at 250°F, while the HEC polymer was useable at 300°F.

By the process of elimination shown above, HEC was found to be the best polymer for use in the low-invasion fluid. The fluid consists of 15 lb/bbl of MgO stabilized high molecular weight HEC polymer and 100 lb/bbl of selectively sized $CaCO_3$ bridging particles in the low freezing point 30% $CaCl_2$ brine. The low-invasion coring fluid has the following properties:

(1) Low invasion due to extremely high viscosity and effective particle bridging of formation pores,

(2) Non-reactive with reservoir rocks and fluids and completely soluble in dilute hydrochloric acid,[7]

(3) Good bit lubrication and removal of cuttings at the very low flow rates encountered while coring,[14]

(4) Non-freezing to below -50°F to greatly simplify handling of the frozen core,

(5) Stable and effective at temperatures up to 300°F, and

(6) Highly non-Newtonian and shear thinning to reduce pressure buildup in the core barrel and to simplify handling.

CORING FLUID TESTING AND OPTIMIZATION

To reduce invasion to a minimum while coring, three areas need to be examined in greater detail. First, since invasion decreases as fluid viscosity increases, we need to know the practical upper limit on coring fluid viscosity. Second, we must determine the effects that fluid loss additives, such as lignosulfonates and starches, have on coring fluid invasion. Third, since invasion is a strong function of both bridging-particle concentration and particle size distribution, we must determine the optimum bridging-particle values.

The upper limit on coring fluid viscosity was chosen as that viscosity which would result in a maximum pressure buildup in the core barrel of 100 psi. To calculate the pressure buildup, the annular flow between the core barrel and the moving core was approximated by laminar flow between two moving plates, and the simplified momentum equations were solved using the power law shear-stress model. The power law model that best describes these highly non-Newtonian polymer systems at low shear rates is of the form $\tau = k\gamma^n$ where τ is shear stress, k is the consistency index (the absolute viscosity at $\gamma = 1\ \sec^{-1}$ shear rate), and n is the power law exponent.[8] The resulting velocity profile and pressure buildup equations, which were rather complicated trancendental functions, were solved numerically on a computer and clearly demonstrated the advantages of using a shear-thinning fluid such as the HEC polymer. For example, Mud A (see Table 1) with k = 14,000 cp and n = 0.57, had a pressure buildup of only 31 psi, which is the same pressure buildup that a 3700 cp Newtonian fluid would yield. This mud was already semi-solid at rest and would not pour at room temperature, so little would appear to be gained by further increasing the viscosity.

There are a number of additives that may improve the fluid loss performance of the HEC polymer. Lignosulfonates are often used in drilling and completion fluids both to reduce viscosity and to decrease fluid loss, but because of their dispersant properties, lignosulfonates are not used in coring fluids. Starches are often used as fluid loss additives and are effective in sealing pore openings in permeable formations. Experimental data indicates that some starches cause severe formation damage, so their use in a coring fluid is questionable.[9] Filtration tests from 70° to 300°F were run on one proprietary fluid loss additive consisting of starch derivatives. This additive did not significantly improve the filtrate loss properties of the HEC mud, and in view of the possibility of formation damage, it will not be used. One additive that does appear to be useful in the low-invasion fluid is magnesia (MgO), a patented additive to HEC systems which reduces the filtrate loss and stabilizes the polymer at high temperatures.[10] Static filtration tests from 70° to 300°F and 500 psi differential pressure showed that the magnesia reduced the API filtrate loss. (See Table 4.) The magnesia additive significantly improved the high temperature properties of HEC and was therefore included in the low-invasion coring fluid.

There are four major effects that limit drilling mud invasion; viscosity of the mud, surface tension effects between the mud and reservoir fluids, particle bridging of formation pores, and external filter cake formation on the exposed formation face. The effectiveness of both particle bridging and the filter cake in limiting invasion is a function of the particle size distribution (PSD) of the mud. Gates [11] examined filtrate losses through filter cakes and found that the optimum PSD for minimizing fluid loss was roughly 65 wt-pct colloids (less than 1 micron), 30 wt-pct silt (1 to 74 microns), and 5 wt-pct sand (larger than 74 microns). Several authors have studied the bridging of formation pores and have shown that colloidial particles are ineffective in sealing high permeability cores, and that particles in the silt range are most effective in minimizing invasion.[3,4,12] A general guideline that is often used (the "one-third rule") says that the mud should contain bridging particles with a median size slightly larger than one-third of the median pore size.

None of the previously cited papers dealt with the effects of polymers on the optimum particle size distribution, so a static invasion study of five different polymer muds was made. The muds were made up by adding 25 lb/bbl of various sized $CaCO_3$ particles to a base mud consisting of 5 lb/bbl HEC polymer in 30 wt-pct $CaCl_2$ brine. The tests were run in a Hassler core holder using Grey Berea sandstone (20 pct porsity and 350 md permeability) and Brown sandstone cores (22 pct porosity and 1550 md permeability). A pressure differential of 500 psi and hydrostatic loading of 3000 psi were used for all tests. Table 2 lists typical test results, while Figure 3 and Table 3 show the particle size distribution of the $CaCO_3$ in the five muds.

Although it is difficult to draw general conclusions from such a limited number of tests, it is clear that the HEC polymer has a significant effect on the optimum PSD for minimizing invasion. Mud No. 1 very closely matched the one-third rule for PSD in Grey Berea Sandstone yet had much more static invasion than any of the other muds. The polymer itself appears to supply effective bridging in the smaller size range and further addition of very fine bridging particles is not effective. Mud Nos. 2, 3, and 4 varied greatly in fluid invasion despite very similar size distributions. The only major variable was the size and shape of those particles that were larger than 100 microns; Mud No. 2 had small,thin plate-like particles, Mud No. 3 had much larger plate-like particles, and Mud No. 4 had small, well-rounded particles. The small plate-like particles were the most effective in reducing invasion. Pore size distribution data from Table 3 shows that this is a surface filter cake phenomenon that should not be a factor in dynamic invasion at the bit face. These 100-micron and larger particles cannot enter the Brown Sandstone (45-micron mean pore throat diameter) or the Berea Sandstone (16-micron mean) and will be continuously scraped off the core by the pilot bit.

Drilling Tests and Mechanical Properties

The low-invasion fluid has undergone testing to evaluate a number of properties that are important in this pressure coring system. One problem encountered was the high compressibility of the fluid in the core barrel. This compressibility, which was due both to air entrainment in the extremely viscous fluid and improper filling of the barrel, could cause the first few feet of each core to undergo severe invasion from the drilling mud. A compressible fluid completely filling the 10-foot-long core barrel at the surface may occupy only 7 feet of the barrel at the high bottom-hole pressure. This would allow the first 3 feet of core to be cut before any low-invasion fluid is extruded to seal and protect the core. Planetary mixers were yielding a coring fluid with a density of 11.4 lb/gal and an air entrainment of about 4 vol-pct. Improved mixing methods utilizing a variable-speed reversible homogenizer have raised the density of this viscous fluid up to 11.8 lb/gal, greatly reducing air entrainment. This is illustrated by the acceptable compressibility data from the intermediate density fluid (11.6 lb/gal) which is shown in Figure 4. The problems in completely filling the core barrel without trapping air pockets has been overcome with the use of high pressure grease injection equipment and a wiper plug. The improved mixing and injection equipment should virtually eliminate compressibility problems.

Laboratory drilling tests indicate that, with proper bit design, the HEC-based low-invasion fluid does a good job in lubricating, cooling, and cleaning the bit at the very low flow rates encountered while coring. Plugging problems were encountered with the initial pilot bit design, so the pilot bit was redesigned to eliminate plugging of the bit with cuttings. A single-piece, pilotless bit designed by Diamond Oil Well Drilling Company has been used in field testing the low-invasion fluid since it did not experience any plugging. The cores obtained with this bit and the low-invasion fluid have been clean, unbroken, and completely covered with a protective coat of low-invasion fluid. (See Figures 5 and 6.)

Freeze tests were conducted with a core barrel containing a core surrounded by low-invasion fluid. The core barrel was frozen solid with dry ice (-110°F), and then flash heated by spraying the outside of the barrel with water to melt the outside layer of low-invasion fluid. The low-invasion fluid, despite its high viscosity, was quite "liquid" at -50°F, allowing easy removal of the frozen core from the barrel and rapid cleaning of the core. Since conventional coring fluids have a fairly high freezing point, the core barrel must be milled off of the core, and then the coring fluid must be painstakingly chipped away. Liquid nitrogen is sprayed on the core during these operations to keep the core frozen. Since the low-invasion fluid greatly simplifies the handling of the pressure cores, the use of low-invasion fluid should substantially reduce the high handling costs associated with pressure coring.

In August, two 10-foot cores were cut near Denver City, Texas, using the low-invasion fluid.[15] Sodium nitrate tracer was used in the low-invasion fluid and methanol tracer was used in the drilling mud to monitor invasion. (See Table 5.) Overall invasion was quite low, ranging from 6 to 25% of the pore water, and hydrocarbon saturations were high, ranging from 35 to 56%. Unfortunately, the dolomite/anhydrite rock was too tight (less than one millidarcy) to draw meaningful conclusions on the role of low-invasion fluid in sealing and protecting the core. Good invasion data should be available soon on several hundred feet of core taken in another Denver City well where a number of alternating cores were taken with low-invasion coring fluid and with conventional drilling fluid throughout the pay zone. This data should be much more useful in evaluating the overall effectiveness of the low-invasion fluid in reducing invasion while pressure coring.

FUTURE STUDIES

Future laboratory studies will focus on dynamic invasion of cores. Equipment has been designed to scrape the surface of the core while test fluids are circulated by the core face at simulated downhole conditions. Dynamic invasion is usually much more severe than static invasion and is limited primarily by particle bridging of the formation pores, while static filtration is limited primarily by the surface filter cake. Dynamic invasion will be examined as a function of particle size distribution in the presence of HEC polymer. Other polymer and particle types will also be tested to better understand how the polymers and particles interact in reducing invasion. Additional field testing of the low-invasion coring fluid is planned. Fluid invasion will be measured with chemical tracers and/or radioactive tracers to evaluate the effectiveness of the low-invasion fluid in actual coring operations.

CONCLUSIONS

(1) The best low-invasion coring fluid found in this study was a magnesia-stabilized hydroxyethyl cellulose polymer with $CaCO_3$ bridging particles in 30 wt-pct $CaCl_2$ brine.

(2) The recommended coring fluid exhibits very low static invasion and filtrate loss, and is non-reactive with reservoir rocks and fluids, stable to 300°F, non-freezing to below -50°F, and causes little pressure buildup in the core barrel.

(3) The recommended coring fluid exhibits good bit lubrication and cleaning at the very low flow rates encountered while coring, and the use of this fluid should greatly reduce the costs associated with handling of the frozen cores.

(4) The HEC polymer changes the optimum particle size distribution and makes larger particles more effective in reducing static invasion. Thin plate-like particles form a more effective surface filter cake than well-rounded particles.

(5) Further work is required to evaluate various additives that could improve the low-invasion fluid. In particular, dynamic testing under simulated drilling conditions is needed to evaluate the effects of particle concentration and particle size distribution.

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Table 1 - Filtrate Loss of Various Polymer Muds

Mud Type	API Filtrate Loss in 30 Minutes, cc. 72°F/100 psi	200°F/500 psi
A	0.4	2.4
B	0.0	2.8
C	1.0	10.4
D	3.8	10.6
E	2.5	15.8

Mud A - 100 lb/bbl lost circulation pill containing HEC, lignosulfonates, and $CaCO_3$ in 30% $CaCl_2$ brine

Mud B - 20 lb/bbl HEC with 100 lb/bbl $CaCO_3$ in 30% $CaCl_2$ brine

Mud C - 1.5 lb/bbl XC and 5 lb/bbl starch with 100 lb/bbl $CaCO_3$ in 37% $CaCl_2$ brine

Mud D - 20 lb/bbl XC with 100 lb/bbl $CaCO_3$ in 30% $CaCl_2$ brine

Mud E - 10 lb/bbl polysaccharide with 100 lb/bbl $CaCO_3$ in 25% KCl brine

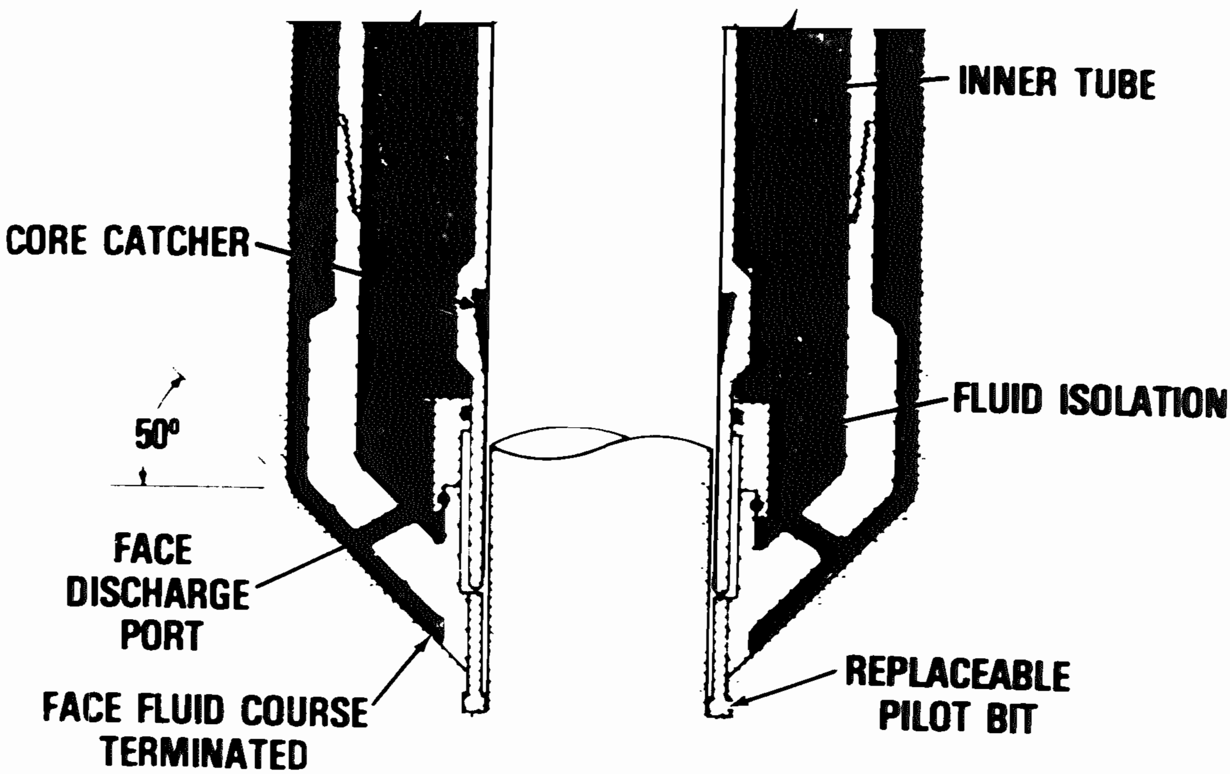

Figure 1 - Conceptual Drawing of Improved Pressure Coring System

Table 2 - Fluid Invasion and Filtrate Loss for Various Particle Size Muds, cc.

	Grey Berea Sandstone		Brown Sandstone		API Filtrate Loss	
	1 Minute	30 Minute	1 Minute	30 Minute	100 psi, 72°F	500 psi, 200°F
Mud #1	16.0	24.3	26.6	36.9	5.0	24.0
Mud #2	0.5	4.1	14.0	19.7	2.0	11.6
Mud #3	5.0	8.3	17.0	22.9	2.0	11.0
Mud #4	4.5	10.0	7.0	11.9	2.4	14.4
Mud #5	20.5	23.5	29.0	38.8	3.4	18.4

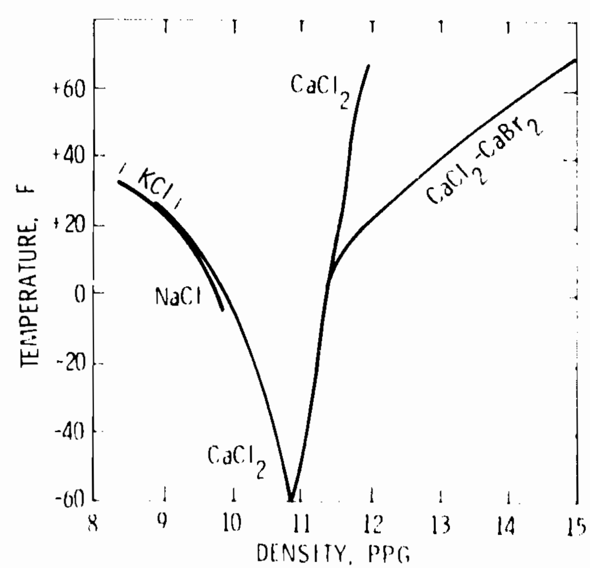

Figure ? - Freezing Temperatures of Various Brines (13)

Table 3 - Pore Size Distribution Data

Sample Identification:	Berea Sandstone	Brown Sandstone
Vertical Permeability, md:	198	1520
Porosity, percent:	19.8	22.3
Pore Entry Radius, microns	**Percent Pore Space**	
35	100.0	94.8
30	100.0	77.0
25	100.0	58.1
20	99.8	40.7
15	95.1	29.6
10	69.3	24.2
8	51.3	22.2
6	38.6	20.3
4	30.7	17.9
3	26.8	16.4
2	22.9	14.4
1	17.4	11.3
0.8	16.0	10.2
0.6	14.2	9.0
0.4	11.9	7.3
0.3	10.5	6.2
0.2	8.8	4.6
0.1	6.4	3.3
0.05	4.7	2.2

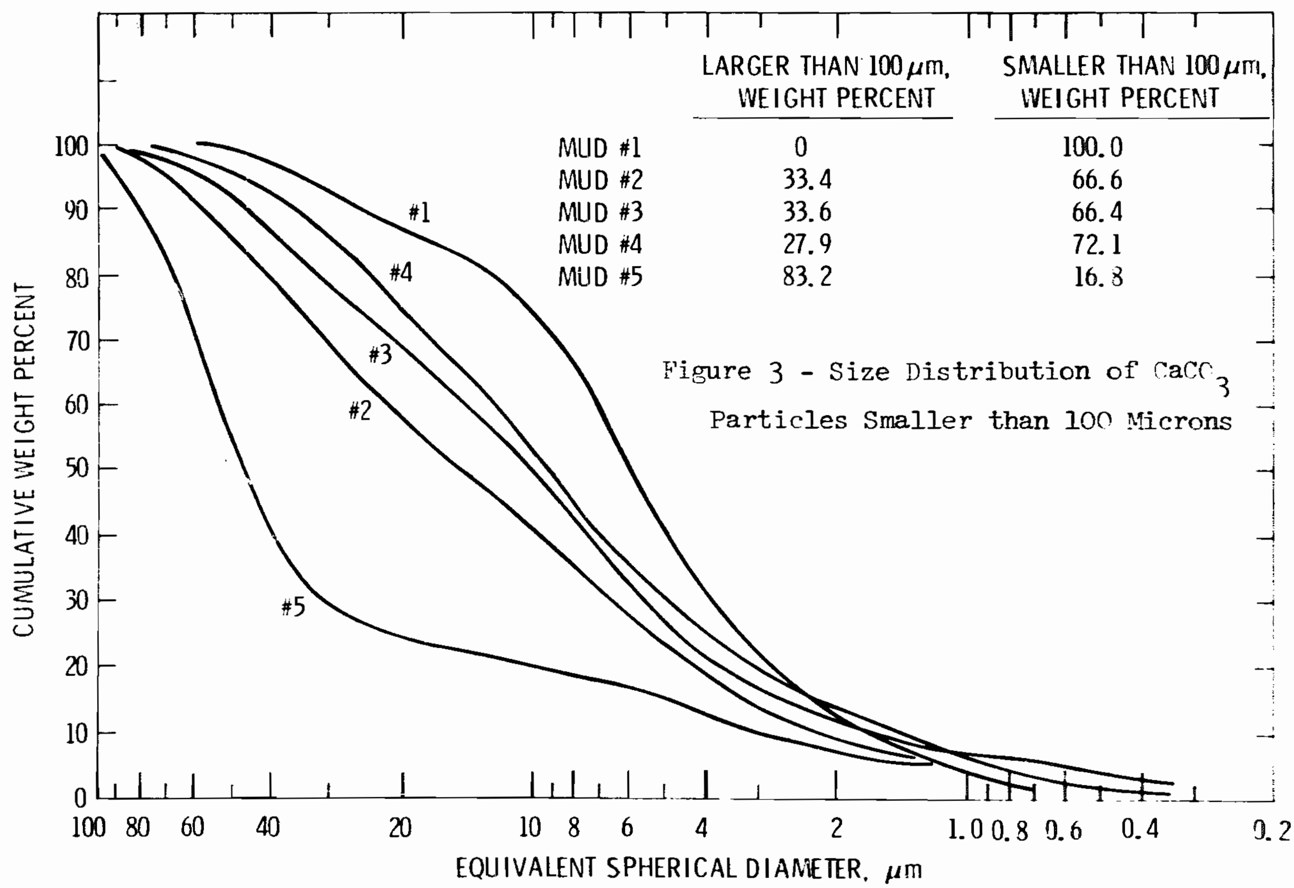

Figure 3 - Size Distribution of $CaCO_3$ Particles Smaller than 100 Microns

Table 4 - Effects of M_gO on Filtrate Loss of HEC Mud

Filtrate loss in 30 minutes @ 500 psi, CC.

	75°F	150°F	200°F	250°F	300°F
Base Mud	4.0	4.2	5.6	6.4	200±
Base Mud plus one g/liter M_gO	1.8	4.0	5.0	4.3	9.8

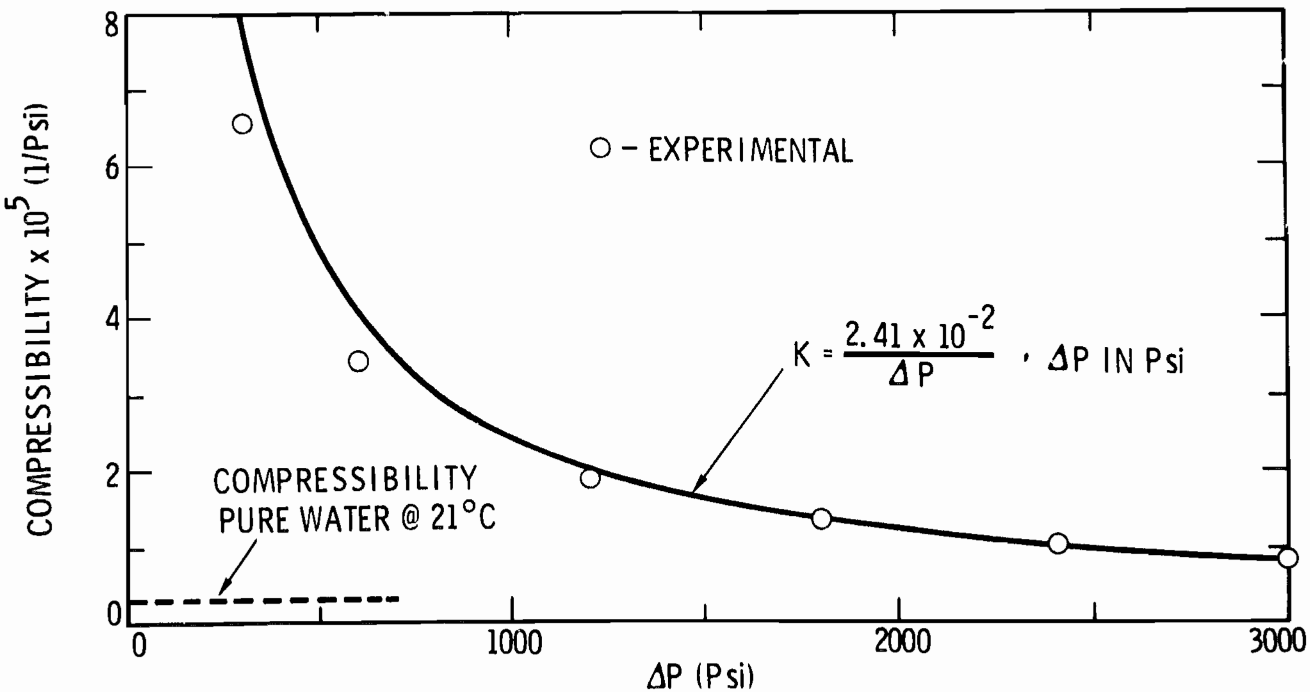

FIGURE 4 - COMPRESSIBILITY OF LOW-INVASION CORING FLUID, 11.6 lb/gal

Table 5. Tracer Concentration Data

		Core Sections					
		Flushing Head		Middle		Core Catcher	
	Filtrate	Plug	Donut	Plug	Donut	Plug	Donut
Sodium Nitrate Tracer							
Permeability, md		0.53		0.02		0.06	
Porosity, percent		13.0	14.9	4.5	4.8	5.5	5.8
Sodium Nitrate, ppm	875**	20.0	125.0	20.0	20.0	20.0	20.0
Water Saturation, percent of pore volume		56.7	55.3	51.0	65.2	43.9	52.8
Methyl Alcohol Tracer							
Permeability, md		0.01		0.09		*	
Porosity, percent		8.1	8.4	5.7	6.8	6.8	6.1
Methyl Alcohol, percent by volume	0.565***	0.031	0.076	0.029	0.072	0.025	0.063
Water Saturation, percent of pore volume		49.0	56.8	29.9	44.2	52.1	62.8

*Hairline Fracture
**Low Invasion Fluid
***Drilling Fluid

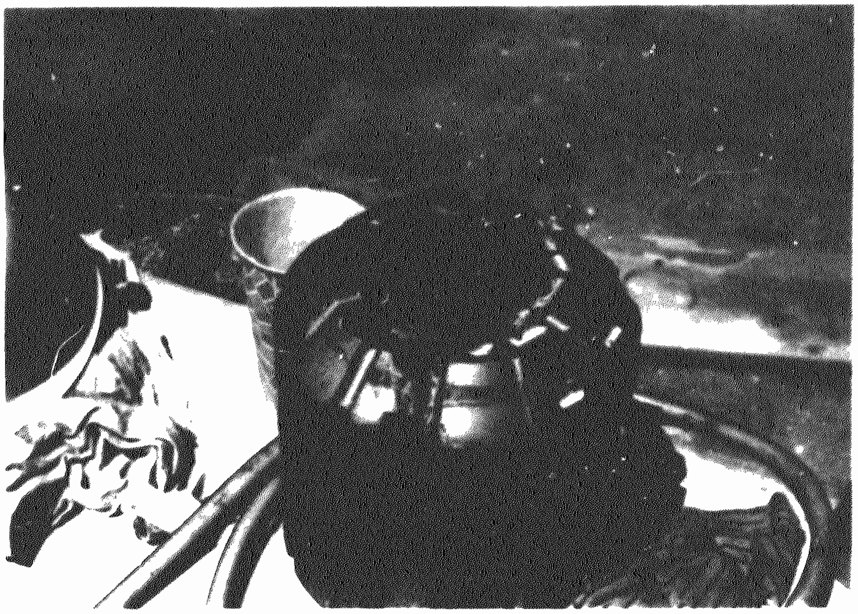

Figure 5 - Single piece core bit used in field tests.

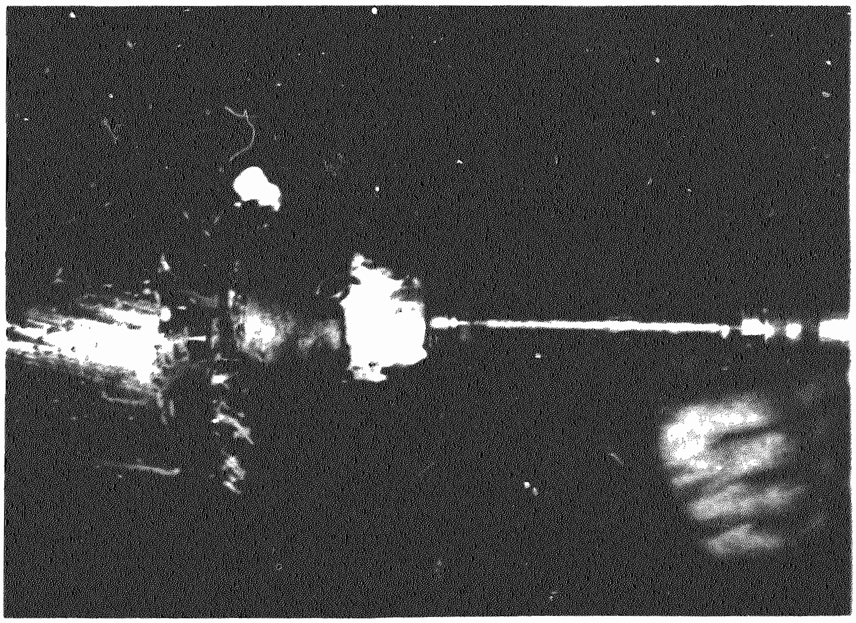

Figure 6 - Filling the core barrel with low-invasion fluid. High pressure grease injection equipment is used to pump the fluid behind a free-floating piston.

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