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Borehole Inclination Effects to the Wellbore Stability and Sand Production

by

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ABSTRACT

The paper presents the result of a laboratory study of the wellbore stability and sand particles produced from unstable perforated wellbore. Section of a perforated wellbore were generated and exposed to various loads and conclusions were drawn with respect to the failure load and sand particles produced during the loading process. The result shows that the perforated wellbore may fail during the creation process and sand particles were produced, depending on the borehole inclination angle, phasing angle and perforation pattern. The sand particles produced were found by sieve analysis to be oversized 500 micron. Generally, stable perforated wellbore produced less sand particles, therefore minimizing the rig problem i.e. deformation of formation and sand production.

Introduction

Wellbore stability is an important factor that should be considered before designing an oil and gas field. The unstable wellbore may lead to sand production which later will cause total collapse of the casing. Wellbore instabilities occurs due to several aspects such as:-

i. The Shape and direction of borehole.
ii. Perforation pattern
iii. Production rates
iv. Overburden pressure

Scope of this research paper is only considering the borehole inclination angle and the perforation pattern.

Basically, known that a reservoir rocks is in equilibrium between overburden and pore pressure. It also triaxially stressed state. When perforations are created in the production zone, rearrangement of the stress takes place. Thus, the surrounding rock must carry the redistributed load.

Sand Particles Sieve Analysis

The main reason for doing this analysis is to determine the size of sand particles produced which is very useful in designing the liner and gravel packing.

All the sand particles which collected from the failure block will weighed before being sieved. This weight will be recorded as recovered weight. Before putting the sand particles in the laboratory disc, the disc will be carefully emptied on the nested sieves. The sieve column was then closed with cover to avoid contamination by dust or loss of sand particles.

The nested sieve column was then shaken for 10 minutes using an electric sieve shaker (Vicker (1978), Craigh (1978) and Wills (1979)). 10 minutes later each sieves content then carefully brush off and weighed. Consequently the weigh of each particles size range define as mesh size range of successive sieve calculated. The amount of the oversized and undersized sand particles were than calculated. Cumulative percentage oversized is defined as cumulative percentage of particles retained on the top sieve and undersized particle defined as particles that passing through all the sieves and recovered at the bottom sieve.

Result and Discussion

Compressive Strength (C_O) of the sandstone sample is in the range from 75 MN/sq.m to 108.5 MN/sq.m and the Tensile Strength (T_O) is in the range of 39.72 MN/sq.m to 64.19 MN/sq.m.

Generally, the results of the laboratory works shows that the perforated wellbore may fail and sand particles were produced. The wellbore stability and sand produced depends on wellbore geometry i.e borehole inclination angle, perforation pattern and the phasing angle. The complete summary of the effects is shows in Table 1.

The gross deformation and stability of the perforated wellbore are basically determine the amount of sand produced. It was found that big portion of sand particles produced are larger than 500 microns, i.e. range from 13.57 gram to 194.28 gram compare to fine sand particles i.e. less than 125 microns which range from 2.5 to 46.67 gram As a whole it can be said that more stable perforated wellbore produce less sand particles.

The explanation for the failure differences is, in the spiral pattern, the perforation tunnels are in a plane inclined to the direction of applied stress (major stress). Therefore, the strength of rock mass is higher than the strength for the inplane pattern where in the inplane pattern, the perforation tunnels are in horizontal line perpendicular to the major stress leading to lower in rock structure strength. On the other hand, in an inline perforation pattern, the perforation tunnels are a line parallel to the major stress resulting in the lowest strength.

TABLE 2 Comparison Table for Stress at Failure

Stress at Failure (MN/sq.m)				
Co	75 to 108.5			
To	39.12 to 64.19			
Angle/Pattern	**0^0**	**10^0**	**20^0**	**30^0**
Spiral	49.65	36.09	28.73	22.2
Inplane	44.37	34.55	24.52	19.5
Inline	39.93	33.1	20.31	17.43

From the Table 2 it can be concluded that the failure stress for the wellbore model is lower than the Compressive Strength of the sandstone.

Produced Sand Particles

As the general observation from laboratory works it was found that more sand particles were produced as the borehole inclination angle increases and as the perforation pattern changes from spiral to inplane and inline. Fig. 2 shows the total amount of sand particles produced when the block fails under the uniaxial compression. The most sand particles produced at higher inclination angle (30^0) and perforation pattern is inline. Vise versa for the lowest inclination angle (0^0) and spiral pattern.

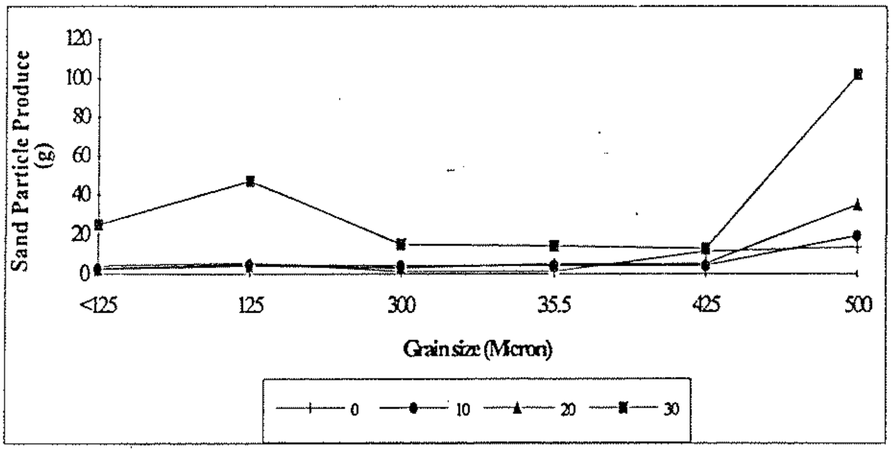

FIGURE 3 Effects of Hole Inclination Angle And Spiral Pattern On Size Distribution

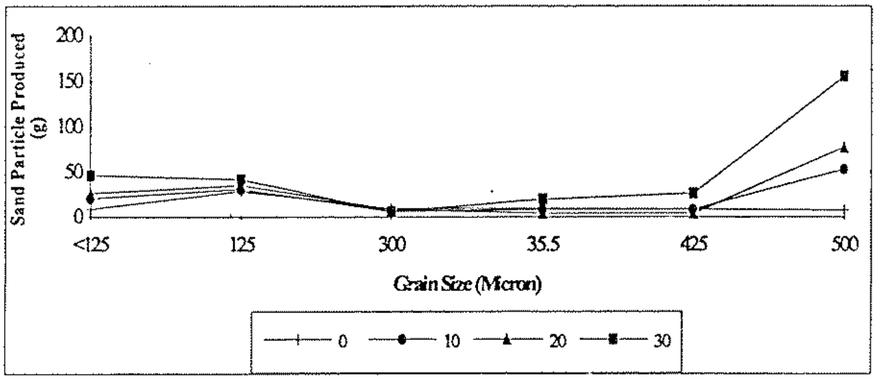

FIGURE 4 Effects of Hole Inclination Angle And Inplane Pattern On Size Distribution

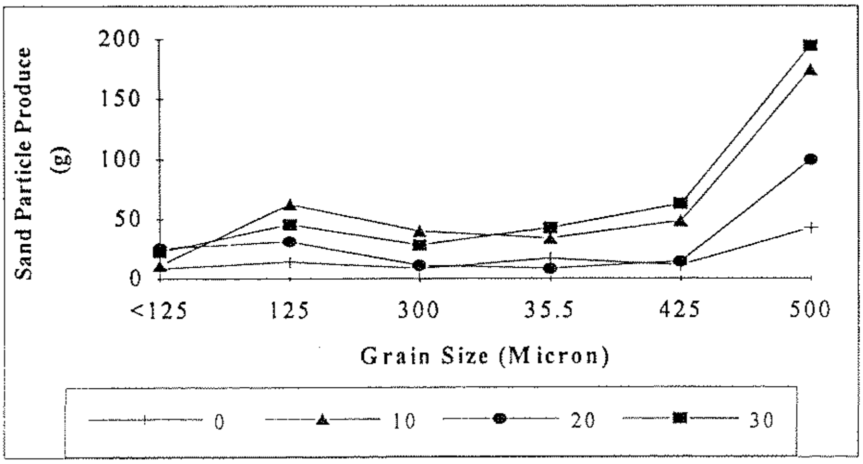

FIGURE 5 Effects of Hole Inclination Angle And Inline Pattern On Size Distribution

Possibility Studies Of Using Local Cement In Oil And Gas Wells Cementing Operation In Malaysia - Part III

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ABSTRACT

Besides the chemical and normal physical properties evaluation, neat cement must also show its compatibility towards additives when they are mixed with the additives and tested at reservoir condition. Retarder and fluid loss additive were mixed with the pfa and G cements at different percentage by cement weight and their physical properties were studied by closely followed the API Specification 10 and were tested at simulated reservoir conditions. Results proved that locally produced blended cement is compatible for cementing job as compared to G cement.

INTRODUCTION

In cementing an oil/gas well, the cement is placed from several hundred to several thousand feet below the surface of the earth and there are many factors over which the well cementer has no control i.e. temperature and pressure.[1] The cement is pumped through the casing and then back up through the small annular space between the walls of the hole and the casing. Therefore, the slurry mixed must remain as a fluid and pumpable until it is in its final resting place regardless of the temperatures and pressures to which it is subjected or to the time required.

At the setting depth, the cement slurry should set hard quickly and develop sufficient strength to withstand the tensile and compressive streses in the well and should also form a permanent and enduring bond between the formation and the casing.[2] The set cement has to seal off the undesirable water and to protect the casing from external corrosion and provides the strength and the reinforcement to the casing.

The prepared slurry is immediately poured in the prepared molds in a layer equal to 1/2 of the mold depth and puddled for 25 times per specimen with puddling rod. After puddling the layer, the remaining slurry is stirred to eliminate segregation and the molds are filled to overflowing and puddle as before. The prepared molds are then placed in the high pressure and high temperature curing chamber and cured according to schedule 5g, Well Simulation Test Schedules for Curing Compressive Strength Specimens for a period of 8 hours, 24 hours, 3 days and 7 days and the removed and crushed with the compressive strength machine.[3]

RESULTS AND DISCUSSIONS

THICKENING TIME ANALYSIS

Table1 shows the results of the thickening time for both cements when mixed with different percentage of retarder and fluid loss additive and tested at 8000 feet and 52 degree celcius. It can be seen that there is an increased in pumping time as the amount of additive is added to the cement and class G cement proved to has better pumping time in all tests run as compared to pfa cement. In this situation the pozzolanic reactivity has caused the pfa cement to set a little faster but this cement is still can be used because of its compatibility with additives. Although the pumping time for pfa is less but the time clocked is reliable and can be considered suitable for well cementing job if five hours or less operating time is required. The difference in time setting of these cements can be seen in Figure 2 and 3.

FLUID LOSS ANALYSIS

Results of fluid loss when cement were mixed with different percentage of additives are shown in Table 2. The amount of fluid loss starts to decrease as the amount of mixing additive is increased and the trend is the same for both types of cement. However, the pfa cement gives better results in the amount of water loss to the formation. Besides the additives played their role in preventing fluid loss, the finely fly ash played its part in occupying micro pores and the pozzolanic reactivity provided by the ash has help in reducing the permeability of the cement and thus reduced the amount of water, as can be clearly seen in Figure 1.

REFERENCE

1. R. Floyd Farris, A Practical Evaluation of Cement Fof Oil wells, Drillng and Production Tecnology, Volume 18, pg283-292.

2. John Bensted, Cement With a Specific Application - Oilwell Cements, World Cement March 1987, pg 72-79.

3 . API Specification 10, July 1, 1990. Specification For Material and Testing For Well Cemnets. American Petroleum Institute, 1220 L Street, Northwest, Washington DC, USA.

Table 3

Free water of samples when mixed with different percentage of additives.

Sample	G CEMENT (ml)	Pfa CEMENT (ml)
G/M 0.2%R + 0.5%FL	1.3	1
G/M 0.5%R + 0.5%FL	0.85	0.8
G/M 0.7%R + 0.5%FL	0.7	0.6
G/M 1.0%R + 0.5%FL	0.35	0.2
G/M 0.2%R + 1.0%FL	0.25	0.2
G/M 0.5%R + 1.0%FL	0	0
G/M 0.7%R + 1.0%FL	0	0
G/M 1.0%R + 1.0%FL	0	0
G/M 0.2%R + 1.5%FL	0	0
G/M 0.5%R + 1.5%FL	0	0
G/M 0.7%R + 1.5%FL	0	0
G/M 1.0%R + 1.5%FL	0	0
G/M 0.2%R + 2.0%FL	0	0
G/M 0.5%R + 2.0%FL	0	0
G/M 0.7%R + 2.0%FL	0	0
G/M 1.0%R + 2.0%FL	0	0

Table 4

Compressive strength of samples when mixed with different percentage of additives and tested at simulated reservoir condition.

SAMPLE	COMPRESSIVE STRENGTH			
	G / PFA 8 HOURS (psi)	G/PFA 1 DAY (psi)	G/PFA 3 DAYS (psi)	G/PFA 7 DAYS (psi)
G/M + 0.2 %R	1750/1820	2500/2650	3100/3300	3200/3450
G/M + 0.5 %R	1550/1660	2320/2510	2950/3190	3150/3310
G/M + 0.7 %R	1010/1250	1850/2150	2450/2920	2980/3120
G/M + 1.0 %R	NS	980/1170	1260/1490	1410/1700
G/M + 0.5 %FL	1800/1920	2610/2800	3450/3780	3340/3610
G/M + 1.0 %FL	1720/1810	2500/2650	3290/3450	3160/3300
G/M + 1.5 %FL	1540/1660	2210/2360	3120/3280	3010/3180
G/M + 2.0 %FL	1310/1410	2020/2180	3050/3190	2910/3090

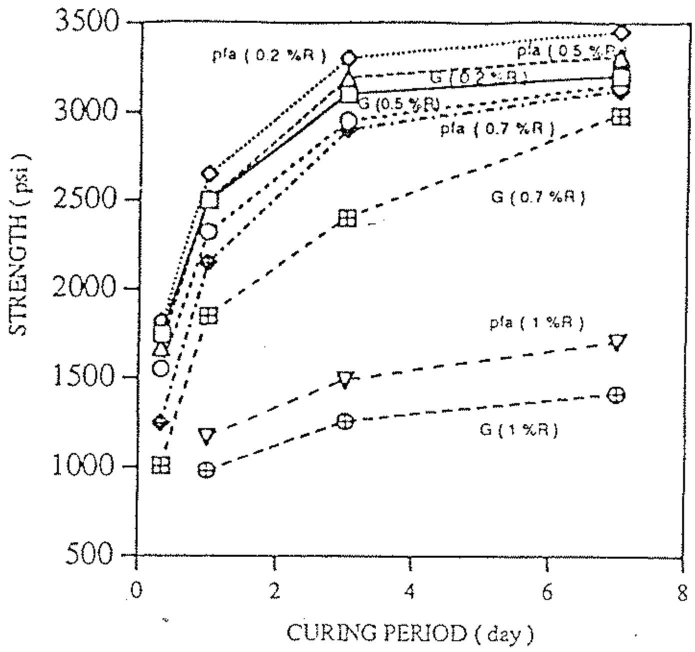

Figure 4. Strength profile of of sample when added with different percentage of retarder at simulated reservoir condition.

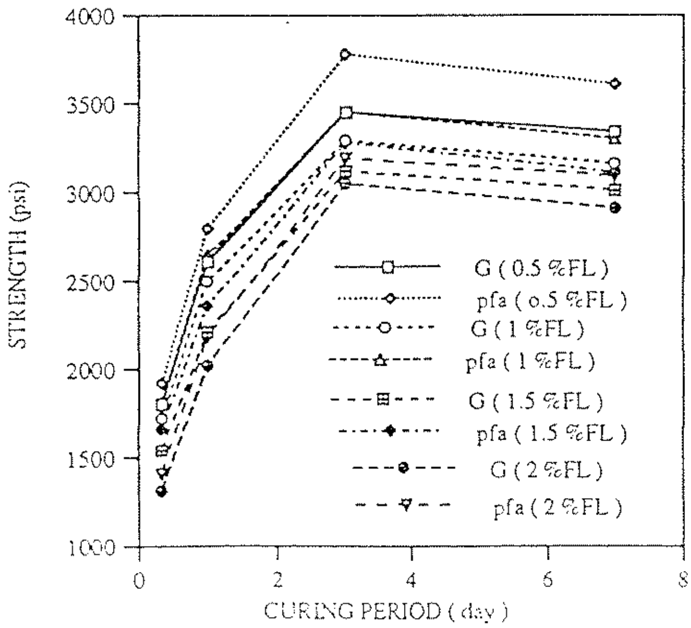

Figure 5. Strength profile of sample when added with different percentage of fluid loss additive and tested at simulated reservoir conditonre