EVALUATION OF FORMATION DAMAGE CAUSED BY COMPLETION AND WORKOVER FLUIDS

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ABSTRACT

Poor productivity of promising new wells or old wells with workovers can often be traced to undesirable characteristics of the borehole fluid used in the completion.

This paper presents laboratory and field results (see table 1) that show clear examples of productivity losses, resulting from completion damage sustained during workover jobs. For these specific jobs, diesel, calcium chloride and filtered seawater were used as completion fluids. The production rates after the repair jobs suggested that calcium chloride and filtered sea water are more damaging (productivity loss up to 100%) and diesel was less damaging (productivity loss up to 48%).

Well	Completion Fluid	Rate Before Workover (BOPD)	Rate After Workover (BOPD)	Production Loss	Decline Ratio %
A-1	$CaCl_2$	2520	126	2394	95
A-2	Diesel	3000	1540	1460	48
A-3	Filtered Sea Water	2550	0	2550	100

Table (1)

Laboratory work was initiated to evaluate the wellbore damage that occurs during initial well completion or workover operation.

This lab work included the examination of the mineralogy and texture of the selected core samples by using conventional core, thin section and x-ray analysis. Also included were "return permeability test" results.

Several results are obtained from this study. First, the mineralogy and texture of the selected core are chemically and mechanically stable. Second, solids in the completion fluids appear to be the major cause of the productivity loss in the tested cores. Third, in oil wet type reservoir, use of water base mud in drilling or working-over a well, result in a trapped residual saturation.

DISCUSSION

Core samples were selected from a sandstone core to study the effect of completion and workover fluids on the Nubia formation. The core is a conventional core and was cut with an oil-based mud.

Figure (1) is the open hole logs for well-x. They show a complete section of Nubia formation, which is mainly quartz sandstone.

1. EVALUATION OF LITHOLOGY AND MINERALOGY:

Three methods were used to evaluate the lithology and mineralogy:

1.a. Conventional core analysis:

Conventional core analysis includes the determination of:

(1) Porosity,
(2) Permeability,
(3) Water saturation, and
(4) Grain density.

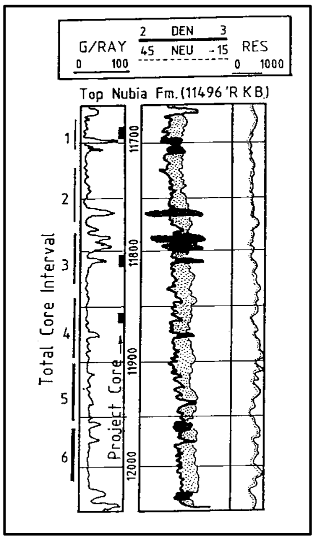

Fig. (1)

Well-x core analysis:

- The plots of horizontal permeability and Boyle's law porosity versus depth for well-x reflects a good homogeneous sand and it has an average permeability of 450 MD and an average porosity of 16% (see figure 2).

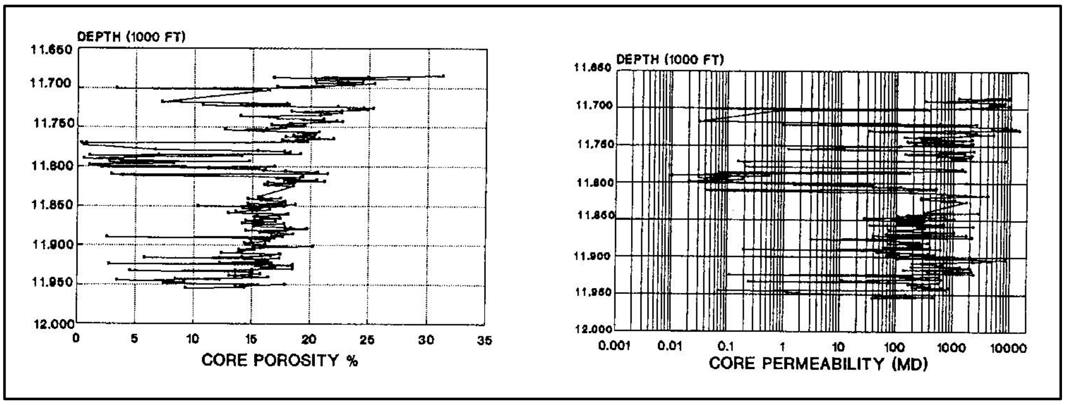

Fig. (2)

- The plots of initial water saturation versus depth for well-x shows an average water saturation of 5% (see figure 3).
- The plots of grain density versus depth for well-x shows an average grain density of 2.64 gm/cc. This is a normal grain density for quartz sandstone (see figure 4).

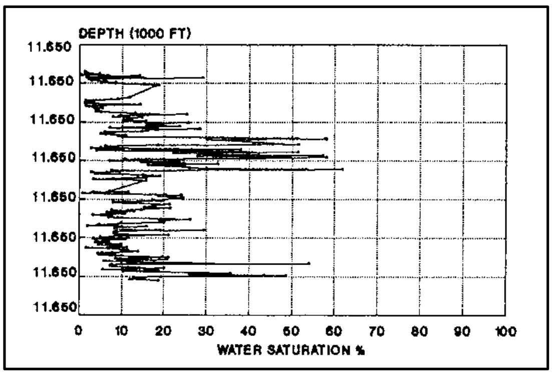

Fig. (3)

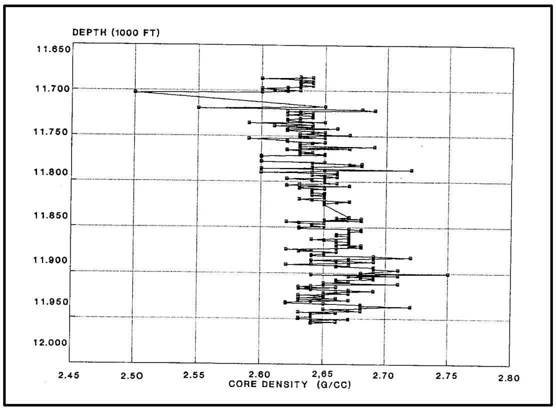

Fig. (4)

The low water saturation is an indication of an oil-wet type reservoir. The result of wettability tests for Nubia formation , which were performed by Core Lab, shows that the average wettability index to oil is 0.73 and the average wettability index of the reservoir (WI water - WI oil) is 0.728, which indicates an oil wet system.

1.b. Thin section petrology

A summary of petrographic characteristics of the Nubia formation is as follows (plate 1):
Grain Size: Fine to coarse.
Framework Grains: Predominantly subangular to rounded quartz.
Rock type: Quartz Arnite
Sorting: Poor to well
Clay: Detrital and authigenic kaolinite, some carbonate cement.
Porosity: Primary intergranular and secondary intragranular porosity

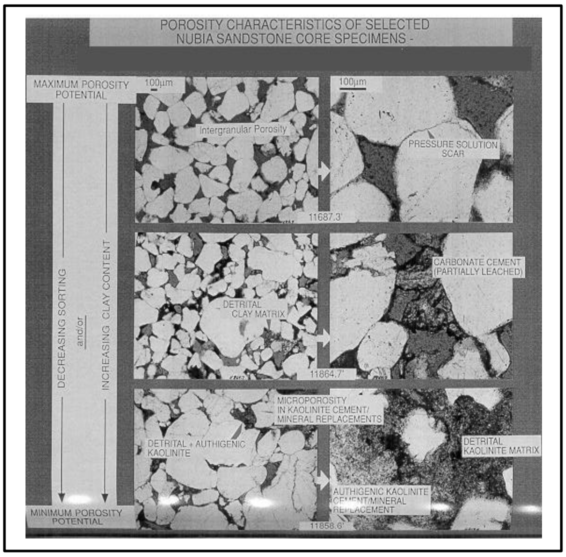

Plate (1)

1.c. X-ray diffraction

x-ray diffraction analysis was performed on a sample which were also used for thin section petrology. The mineralogy of the Nubia formation is dominated by quartz 95 weight % and kaolinite 2 weight % of the minerals. Accessory mineral components (ranging from trace amounts to 3 wt%) include chlorite and barite.

2. EVALUATION OF PERMEABILITY LOSS

2.a. Water sensitivity tests

Figure 5 shows the results of the water sensitivity tests which indicate that Nubia core samples are not sensitive to change in brine types or to a switch to fresh water.

2.b. Velocity test

Figure 6 shows permeability vs. flow rate for the test well. Differences in the lines are an indication of any change of pore fill material such as clays. The results of the velocity test showed no evidence of fine migration caused by high velocity liquid flow through the pores of the Nubia core samples.

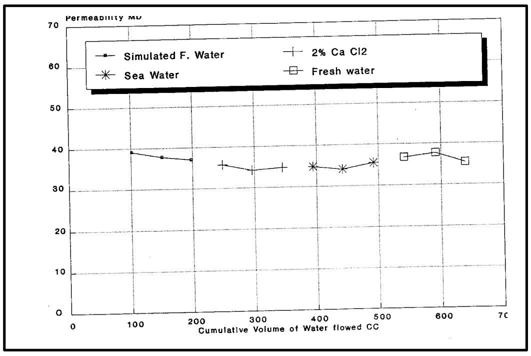

Fig. (5)

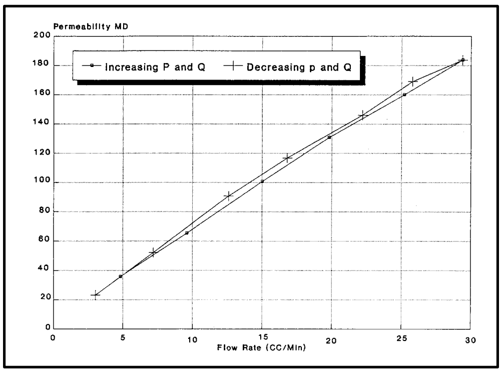

Fig. (6)

2.c. Return permeability test results for nubia formation

The flow tests were designed to simulate downhole flow directions in that the completion fluids and acid flow directions were opposite to the oil flow directions.

All fluids tested reduced core oil permeabilities. Final oil permeabilities after flowing the completion fluids ranged from 7% to 74% of the initial base oil permeabilities (see fig. 7).

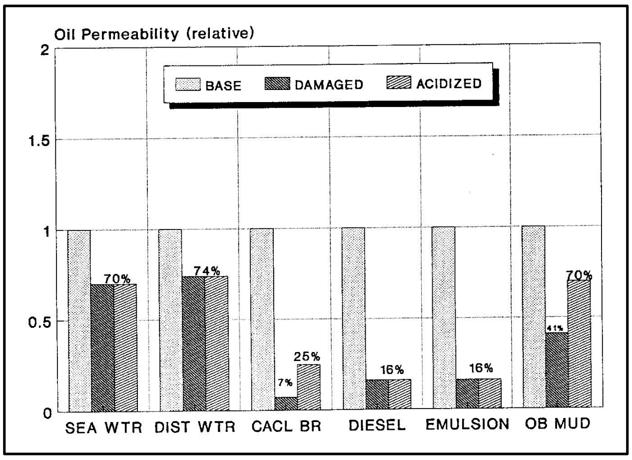

Fig. (7)

CONCLUSIONS

1. The mineralogy and texture of the selected core are chemically and mechanically stable.
2. Solids in the completion fluids appear to be the major cause of the productivity loss in the tested cores.
3. In oil wet type reservoirs, the use of water base mud in drilling or working-over a well results in a trapped residual saturation.

RECOMMENDATIONS

1. Carefully control the concentration, size and type of solids in the drilling mud.
2. Filtration of workover fluids and cleaning of casing, tubing, tanks, and manifolds are critical to the success of any type of workover.
3. Minimize fluid invasion into the formation by controlling the overbalance.
4. Study individual reservoir characteristics such as chemical composition, clay content, tendency to form slugs or emulsion, reaction precipitate and acidizing treatment to obtain the best possible stimulation.