PROPER DIAGNOSIS OF FORMATION DAMAGE CAN RESULT IN HIGHER PRODUCTIVITY

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Abstract

Most exotic fluids introduced into a reservoir will cause reduction in permeability near the wellbore. Dispersed water base fluids and oil base fluids create their own unique problems, such as wettability changes, and emulsions. Prior knowledge of what drilling fluids can do to a formation will, upon completion, lead to a better diagnosis of well behavior and thus resulting in more effective clean-up and stimulation procedures.

Hydrochloric acid (HCL) as a stimulation fluid has been and continues to be misused as a method to increase reservoir permeability. Incorrect application can either create a problem greater than the original and/or cause unnecessary expense to the operator. The cause of productivity impairment should first be determined before a stimulation procedure is selected.

Scanning electron microscopy, X-ray diffraction, thin section petrography and core-flood analysis are effective techniques in determining the sensitivity of a reservoir to foreign fluids. Rock-to-fluid and fluid-to-fluid compatibility tests are extremely important to improve stimulation procedures and to ultimately improve production.

As money for drilling and completing wells gets scarce, proper utilization of current technology can result in a higher return of investment.

Formation Damage

Problems in oil and gas wells can usually be categorized by limited producing rates, excessive water production, excessive gas production for oil wells and mechanical Failures (Allen and Roberts, 1982). Aside from mechanical failures most productions problems are associated with damage to the reservoir. Formation damage or productivity impairment can be the result of numerous actions that ultimately will cause flow restrictions within the wellbore, perforations or the formation itself. Formation damage or "skin" calculations using pressure build-up and drawdown analysis are extremely useful in determining the magnitude of damage and resulting permeability. Formation damage may be the result of many different mechanisms, however, all permeability impairment may be catagorized in one of the following descriptions:

1) Reduced absolute permeability of the reservoir due to flow restrictions

2) Reduced relative permeability to oil and gas.

3) Increased viscosity of reservoir fluids.

Drilling Fluid Induced Damage

Oil base drilling fluids (invert emulsions) are typically used in high temperature environments or drilling water sensitive formations. Due to their emulsified nature and high solids content, oil base muds can cause considerable permeability impairment to the reservoir. The mechanism for formation damage is usually generated by the release of whole mud or excessive filtrate loss to the formation. Specific mechanisms for damage are:

1) Mud solids: in the form of organophilic clays and barite

2) Filtrate induced damage: oil wetting surfactants in the mud can alter the wettability of a formation, thereby altering the reservoirs permeability to oil and gas near the wellbore.

3) Emulsion Blockage: when lost whole mud comingles with formation water, the very nature of the emulsion will cause it to increase in viscosity, producing a permeability barrier in the reservoir.

Water base drilling muds are by far the most common systems in use today. In most cases a dispersed bentonite system is very practical and economical for drilling moderate temperature reservoirs. But what one gains in fluid economics, can quickly be lost in the form of damage to the potential reservoir. The high solids content and numerous reactive chemicals within these systems are just some of the damaging mechanisms present. Damage to the reservoir can be caused by:

1) Excessive pH factor (>9.5): as pH rises in a system, clays become increasingly repulsive to one another, creating dispersion and migration of clays in the reservoir.

2) Dispersants (thinners): The same mechanism that disperse bentonite in a mud system also effectively disperse clays in a formation. Emulsions are also a product of excessive dispersant (i.e. Lignite) concentrations.

3) Particle plugging: The barite and bentonite particles of a mud system are small enough to potentially lodge in pore throats.

The use of lease or artificial brines with polymers as drilling fluids continue to gain acceptance as fluids with minimal formation damaging potential. Brines that achieve a desired density with dissolved salts rather than the addition of solids (barite) are of further advantage. By eliminating these solids, the possibility of reducing permeability due to blocked pore throats can be significantly reduced. Using polymers for rheological control can further reduce the solids content, by reducing or eliminating the need for bentonite. However, formation damage can still be generated in the form of:

1) waterblocks

2) precipitation of salts

3) polymer residue

Predicting Scale Formation

Precipitation of scale from produced or injected fluids can result in significant mechanical and production problems. Change in temperature, pressure, mixing and/or evaporation of saturated waters are primary reasons for the deposition of scale. These changes, thus scale formation, can occur anywhere at or between the reservoir and stock tank. Common oil field scale deposits are calcium carbonate, calcium sulfate, barium sulfate, and sodium chloride.

Water analysis and solubility calculations may be used to predict the formation of certain types of scale. Values obtained from these calculations should be taken merely as guidelines. They indicate the degree of scaling tendency, or the likelihood of scale formation (Patton, 1981). If scale formation is indicated by calculations, caution should be taken and monitoring of the system for signs of scale formation should begin immediately. All water samples should be taken from the wellhead and tests run at time of sampling. If scale formation is already present X-ray diffraction is the best method for identification. The equation for predicting calcium sulfate (gypsum) scaling tendencies is the Modified Stiff-Davis Method (excludes pressure).

$$Ca^{++} \text{ or } SO_4^{=} \; \frac{Ksp \times F_1 \times F_2}{Ca^{++} \text{ or } SO_4^{=}} \quad \text{(highest ion \%)}$$

where: Ksp is the solubility product for $CaSO_4$
F_1 is the solubility factor due to the % of sodium ions
F_2 is the solubility factor due to the % of M_g ions
Yields the minimum concentration of Ca^{++} or $SO_4^{=}$ for precipitation.

The equation used for predicting calcium carbonate scaling tendencies is the Langelier Method (modified by Stiff-Davis).

$$SI = pH - K - pCa - pALK$$

where: Scaling Index or SI (negative number = undersaturated, positive = scale likely to form)
pH = actual pH of the water
K = constant, which is a function of salinity, composition and water temperature.
C = concentration of the ion in moles/1000g of water

$$pCA = \text{Log} \left[\frac{1}{\text{moles } Ca^{++}/\text{liter}} \right]$$

$$pALK = \text{Log} \left[\frac{1}{\text{equivalents total alkalinity/liter}} \right]$$

Paraffin Development

Wax precipitation or paraffin, like scale, can occur at any point on the surface, sub-surface equipment as well as the reservoir. The solubility of paraffin in crude oil depends on the chemical composition of the crude and the temperature and pressure of the production equipment. Paraffin will begin to crystallize in oil as soon as equillibrium temperature and pressure (cloud point) are attained.

Operators have a choice of strategy with fields that have a history of paraffin development. They can either: 1) prevent the initial formation of paraffin or 2) wait until paraffin deposits and then remove it. To predict the formation of paraffin, you first must know the paraffin content and cloud point of the produced oil. Paraffin content is usually determined by using U.O.P. Method Number A-46-64 (Gdanski, 1984). Cloud point can be determined using viscosity verses temperature plots of the oil. From this information one can estimate depositional tendency even before substantial production has begun. Keeping a record of these plots is suggested through-out the life of a well, for the reason of detecting early signs of paraffin development through changes in oil analysis.

Asphaltene development is clearly associated with paraffin development in medium to low gravity crudes. Cause and effect is generally the same for both with treatment for removal also differing only slightly.

Water Block Diagnosis

A temporary shift in relative permeability in favor of water as the mobile fluid causes water blocking. Under these conditions, oil production will decrease and water percentage will increase. Water blocking is usually caused by circulating or killing a well with water (Allen and Roberts, 1982). Clays and weathered feldspars in the formation will retain the water due to high capillary pressures of the minerals. Gas wells are most vulnerable to this condition.

Emulsion Blocking

Viscous emulsions of oil and water in the formation near the wellbore can drastically reduce the productivity of oil and gas wells. If emulsion blocks exist, the calculated average well permeability as determined by injectivity tests will be many times higher than the average permeability determined from production tests (Allen and Roberts, 1982).

Acid and Additives Induced Damage

Using hydrochloric (HCl) acid as a stimulation fluid beyond a routine perforation wash is generally risky. Strong HCl (15%) has and will continue to be pumped in wells for no other reason than "thats how we've always done it". Properly applied HCl can be very effective in cleaning and stimulating wells. On the occasions where HCl is pumped with little planning, the operator risks plugging the formation, and spending money on something he may never have needed in the first place. Mineral identification is an important part of proper planning as well as considering the following possible results of acid in a reservoir:

1) Emulsions: form through commingling of spent acid and salt water. Also form due to incompatabilities within the treating fluids (i.e. surfactants with corrosion inhibitors).

2) Wettability alteration: improper use of cationic and anionic surfactants can result in radical changes of the formation's wettability.

3) Precipitants: the use of hydroflouric acid (HF) can create a variety of insoluble precipitates if not planned correctly (i.e. calcium flouride). Also results from excessive acid shut in times.

4) Dislodging of fines: the use of acid, especially in sandstones can destroy the binding mechanism of the formation, thereby releasing fines into the pore system.

Predicting Formation Sensitivity

Understanding reservoir behavior can be greatly enhanced by data generated from the scanning electron mircroscope, X-ray diffraction, and thin section analysis. When these analysis are combined with routine core data, the information can then be used by the engineer in designing drilling and completion programs or by the geologist when developing or characterizing a reservoir. Observing the pore system and flow channels of a formation can greatly influence an operators expectations of a well.

Scanning Electron Mircoscope (SEM): Permits the identification of minerals and where they are positioned in the rock system. Gives a three dimensional image of the sample at the microscopic level. Also can identify the type, size, and occurance of clay minerals in a pore system.

X-ray Diffraction (XRD): a semiquantitative technique to identify framework and clay minerals as well as their abundance. Crystalline mud additives and scale can also be identified.

Thin Section Petrography: used for mineral identification and quantification. Very effective in determining type and distribution of pores within a sample.

Upon determining the mineralogic composition of the reservoir, and determining whether clays are within pores or fixed in the matrix, this information can be used to select stimulation and completion fluid systems. The fluid systems are then used in core flood through-put tests to determine the susceptibility of the formation to permeability alteration by the test fluids. "Fine-tuning" of the test fluids can be accomplished by returning the core for further geologic analysis (SEM and XRD) to determine if mineralogy has been altered and if clay particles have dislodged and migrated in the pore system. Upon completion of this phase, the fluid system can be adjusted and flow tests repeated until permeability reduction or stimulation has occurred to the optimum level. This rock to fluid sensitivity study is to determine where and if any interaction has occurred and to determine whether the interaction is beneficial or detrimental to hydrocarbon production.

Ideally, geologic and engineering studies would be performed on whole-core which gives the engineer or geologist the best look at a reservoir. Unfortunately whole core is not taken on most wells and generally drill cuttings will be the only physical evidence of the reservoir the geologist or engineer will have. In most cases drill cuttings are sufficient to have analytical work carried out. XRD requires only 5 to 10 grams of sample for complete analysis and SEM and thin section analysis need only fingernail size samples (1/4" to 1/2" in dia.) for proper testing. Routine geologic testing as listed above will generally be only a slight fraction of a wells total expenditures, but the data generated can be useful in making much more costly decisions especially on regards to drilling fluids and completion fluids and techniques and the planning of future wells.

Summary

The moment the drill bit and drilling fluid first contacts the target formation to the time when hydrocarbons are flowing from the well, damage to the reservoir occurs in one form or another. Drilling fluids and drillstring action are by far the most damaging mechanisms in high permeability, unconsolidated reservoirs. Consolidated reservoirs requiring a stimulation treatment (i.e. hydraulic fracturing) can be most susceptible not only to fluids introduced to the formation but also to methods designed to remove the exotic fluid. Regardless, all wells are damaged to some extent and the economics of the well determines whether the operator can accept some reservoir damage, thus limiting production, or whether he needs to identify the problem and treat it.

For proper diagnosis and treatment of formation damage, careful examination of well completion/workover reports, production history and drilling records are usually very helpful. Reading between the lines of these reports is often necessary to tie down significant clues (Allen and Roberts, 1982). This data used in conjunction with pressure buildup or fall-off tests and geologic petrographic analysis are effective measures in determining possible cause and treatment of a problem well. As money gets scarce for the drilling and completion of wells emphasis should be placed on taking a closer look at a reservoir to identify possible problems long before they occur.

References

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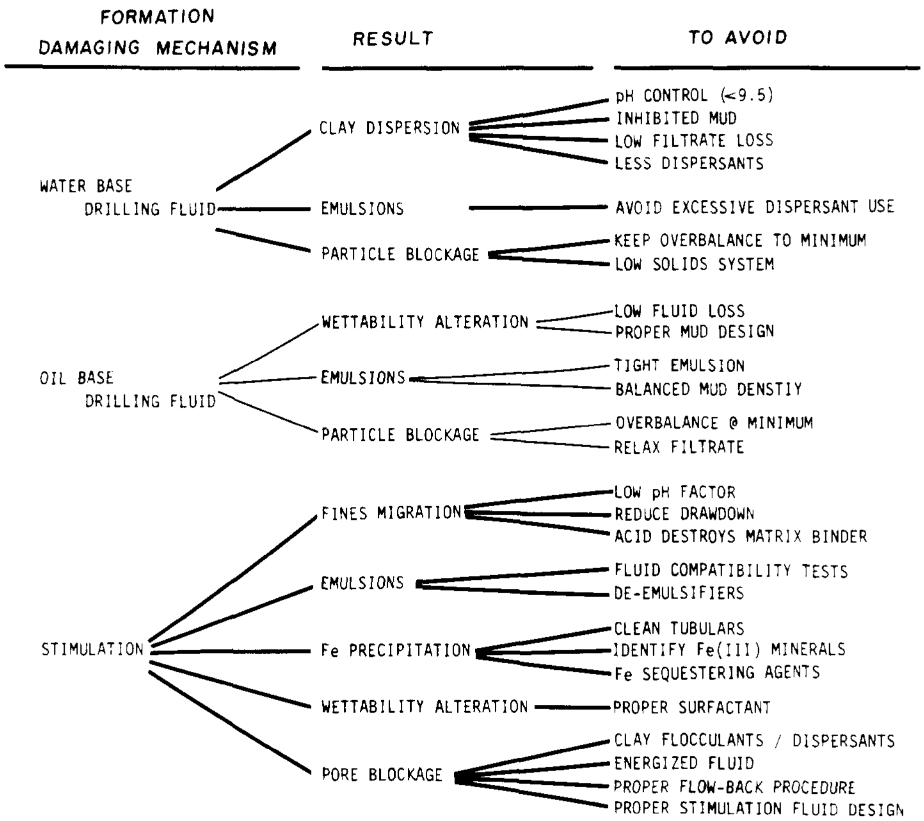
FORMATION DAMAGE CHART



APPLICATION OF GEOLOGICAL ANALYSES TO THE PETROLEUM INDUSTRY

RELIABILITY OF AVERAGE ANALYSIS	TS	SEM	XRD	X-RAD	ASA	CORE	LOG/RE-CORDS
	SQ	QL	SQ	QL	QL	QL	SQ/QL
GEOLOGICAL APPLICATIONS							
● Bulk Mineralogy	●		●				
● Clay Mineralogy		●	●				
● Pore Distribution/Geometry	●	●					
● Texture/Fabric	●	●					
● *Depositional Environment*	●			●	●	●	●
● Diagenetic History	●	●	●				
ENGINEERING APPLICATIONS							
● Identification of Formation Damage	●	●	●			●	●
● *Reservoir Description*	●			●	●	●	●
● Identification of Permeability Barriers	●			●		●	●
● Directional Permeability	●			●		●	●
PETROPHYSICAL APPLICATIONS							
● Model Identification	●	●		●		●	
● Refinement of Computation	●	●	●		●		
● Log Calibration					●	●	
● Cation Exchange Capacity		●	●				