Formation Damage

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Editor

Formation damage is a condition most commonly caused by wellbore fluids used during drilling, completion and workover operations. It impairs the permeability of reservoir rocks, thereby reducing the natural productivity of reservoirs. Formation damage can adversely affect both drilling operations and production, which directly impacts economic viability. Although the severity of formation damage may vary from one well to another, any reduction in recovery potential is unwanted. From the initial drilling operation and completion of a well to reservoir depletion by production, the effects of formation damage can negatively impact oil and gas recovery.

Although formation damage may affect only the near-wellbore region of a well—reaching only a few centimeters from the rock face of the borehole wall—it can also extend deep into the formation. The damage may be caused by solids that migrate and block pores or by drilling fluids that alter the properties of reservoir fluids. Reservoir engineers must be vigilant about the potential for formation damage and they can mitigate the impact of formation damage by understanding its mechanisms and how various types of damage might impact production. Assessment, control and remediation of formation damage are crucial to ensuring efficient use of the world's hydrocarbon resources.

Formation Damage Mechanisms

The four main categories of formation damage mechanisms—mechanical, chemical, biological and thermal—can be divided into smaller categories.

Damage that induces a reduction in permeability as a result of direct, nonchemical interaction between equipment or fluids and the formation is referred to as *mechanical damage*. Examples include

- *fines migration*—perhaps the most common mechanism, which refers to the movement of naturally existing, fine-grained quartz or clay particles in the pore system as a result of high fluid-shear-rates (Figure 1)
- *external solids entrainment*—when particles from introduced fluids enter and plug formation pores
- *phase trapping and blocking*—when wellbore fluids contact a formation and cause a reduction in water saturation
- *glazing and mashing*—when the drill bit or rotating drillstring damages the formation at the face of the wellbore
- *perforation damage*—when explosions caused by perforation gun charges fracture rock grains into finer grains
- *proppant crushing and embedment*—when increased stress on the rock and proppant during hydraulic fracturing leads to proppant embedment into fracture faces and crushes the proppants, and this fines production impairs fracture performance.

Fines migration occurs predominantly in clastic formations because they have a high content of transportable materials within the rock. Common fines migration remedial measures include reducing production rates, increasing the flow area by adding perforations or using openhole completions. Engineers may also inject chemical stabilizers that adhere to the surface of fines and reduce their mobility to mitigate the effects of fines migration.

Figure 1. Scanning electron microscope (SEM) photograph of kaolinite clay. The photograph shows the kaolinite aggregates filling a pore. Should these aggregates be allowed to disperse into single particles or platelets, their migration can cause formation damage.

Chemical damage mechanisms are generally divided into adverse rock-fluid interactions, adverse fluid-fluid interactions and near-wellbore wettability alteration. A common chemical damage mechanism is *clay swelling,* in which hydrophilic materials in the formation, such as reactive smectite and mixed layer clays, are hydrated and expand when interacting with fresh or low-salinity water. This swelling can severely reduce permeability when clay lines the pore throats of a formation. In formations where this potential exists, engineers use high-salinity drilling fluids or add glycols and other chemical inhibitors to keep reactive clays from becoming hydrated.

Clay deflocculation, another common chemical damage mechanism, results from rapid changes in pH or salinity. Clay particles can change from a flocculated state—a condition in which clays, polymers or small charged particles attach to one another to form a fragile structure—and then deflocculate when the electrostatic forces holding the surfaces of individual clay particles are disturbed. Deflocculation can be inhibited by avoiding cationic and pH shocks.

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Formation dissolution occurs in formations containing components that are soluble in water-base fluids. This condition may lead to a collapse of the wellbore wall. If the operator uses oil-base fluids or highly inhibitive water-base fluids, formation dissolution can be avoided.

Incompatibilities between introduced fluids and native fluids can lead to the creation of emulsions and sludges that plug formation pores and impair permeability. Introduced solids from drilling and completion fluids may also be chemically incompatible with reservoir fluids.

Wettability alteration is another major formation damage concern. Many common additives, such as corrosion inhibitors, can invade the near-wellbore region and induce a change from water-wet to oil-wet conditions. The formation's permeability to water increases while oil permeability is reduced. The result is an unwelcome increase in produced formation water and a decrease in the oil/water ratio. Wettability conditions are typically controlled by the addition of surfactants and solvents to the drilling fluids.

Biological formation damage can occur when bacteria and nutrients are introduced into the formation. Bacterial contamination is most associated with water injection operations, such as fracture stimulations, but may also occur when drilling with water-base fluids. Biological damage mechanisms can be divided into three main categories: plugging, corrosion and toxicity. Polymers secreted by bacteria may adsorb to the surface of pores in the formation and eventually plug them. Some bacteria induce hydrogen-reduction reactions that can cause corrosion, pitting and stress cracking of downhole and surface equipment. Sulfate-reducing bacteria reduce sulfates in formation or injection water and create hydrogen sulfide [H_2S] gas. Biocides or oxygen scavengers may be added to drilling and hydraulic fracture fluids to prevent bacterial damage.

Thermal damage mechanisms occur in high-temperature operations, such as steam injection and in-situ combustion. *Thermal degradation* of oil and rock compounds that contain sulfate, at temperatures above 200°C [390°F], may produce undesired byproducts, such as H_2S and carbon dioxide [CO_2]. Elevated temperatures may also lead to *mineral dissolution* and *mineral transformation,* in which minerals are catalyzed and transformed from nonreactive clays to reactive products that can swell, merge and reduce formation permeability. This problem is more common at temperatures above 250°C [480°F].

Indicators and Effects of Formation Damage

If a well is producing at lower rates than expected, the source of the reduction must be determined before corrective measures can be attempted. If production engineers determine that formation damage is responsible for reduced productivity, several techniques can be used to verify the cause of the problem. Permeability impairment, skin damage and decrease of well performance are all indicators of formation damage. Skin damage—a measureable reduction in permeability in the vicinity of the wellbore—can occur for a variety of reasons, for example, incompatibility of the workover fluid with the native formation fluids. The incompatibility leads to chemical reactions and scale deposits precipitate, depending on fluid compositions and wellbore pressure. Scale precipitation, or skin, reduces permeability near the wellbore and creates what is referred to as *skin effect*. If the skin is not removed by remedial measures, such as acid stimulation and carbonate stimulation, it will reduce well productivity.

Figure 2. Core samples. If the engineers do not have core samples from the formations, they typically use cores from Berea or Ohio sandstone.

Reductions or changes in well productivity can be identified through well tests such as pressure transient analysis and productivity index measurements during flow. Laboratory tests can identify damage mechanisms and aid in determining options for avoiding or removing the damage. Drilling, completion and workover data help engineers devise laboratory tests to assess potential damage arising from fluid-to-fluid or fluid-to-formation incompatibilities. For situations in which formation damage has been detected and defined, laboratory tests are used to model the effectiveness of remedial treatments. Because some types of formation damage can be difficult or impossible to reverse, avoidance may be the best approach.

Specialized formation damage analyses can be performed on reservoir rock samples after cores have been extracted from the formation (Figure 2). Formation damage specialists measure permeability changes by testing cores before and after they have been exposed to drilling and completion fluids. The cores are tested at representative downhole temperature and pressure conditions to evaluate the formation damage potential of a specific fluid. After testing, analysts inspect the cores and measure fluid invasion. Data collected from these tests help engineers optimize fluid design and ascertain what measures can be taken to minimize the risk of formation damage.

Importance of Minimizing Damage

The ability to produce fluids from a reservoir is strongly affected by near-wellbore permeability; hence formation damage may severely reduce productivity. Operators have studied damage mechanisms and developed methods to control or prevent them. By doing so, operators can plan and execute drilling, completion and production operations with optimal efficiency and economic viability. Methods and technologies to measure and quantify formation damage will continue to evolve; the ultimate operator objectives are minimized damage and maximized productivity.