Lecture № 11

Sand plugs

For normal flow of oil, formation should be porous, permeable and well cemented together, so that the large volumes of hydrocarbons can flow easily through the formations and into production wells.

Sand production of oil well may start during first flow or later when reservoir pressure has fallen or water breaks through. Sand production strikes with varying degrees of severity, not all of which require action. The rate of sand production may decline with time at constant production conditions and is frequently associated with cleanup after stimulation.

Sometimes, even continuous sand production is tolerated. But this option may lead to a well becoming seriously damaged, production being killed or surface equipment being disabled. What constitutes an acceptable level of sand production depends on operational constraints like resistance to erosion, separator capacity, ease of sand disposal and the capability of artificial lift equipment to remove sand laden fluid from the well.

Sand entering production wells is one of the oldest problems faced by oil companies and one of the toughest to solve. Production of sand during oil production causes severe operational problem for oil producers. Every year the petroleum industry spends millions of dollars in sand cleaning, repair problems related to sand production and lost problems related to sand production and lost revenues due to restricted production rates.

Problems with sand flow

The effects of sand production are nearly always detrimental to the short and/or long term productivity of the well. Although some wells routinely experience “manageable” sand production, these wells are the exception.

Problems with sand flow are the following:

1) **Accumulation in surface equipment:** If the production velocity is great enough to carry sand up the tubing, the sand may become trapped in the separator, production pipeline. If a large enough volume of sand becomes trapped in one of these areas, cleaning will be required to allow for efficient production of the well. To restore production, the well must be shut-in, the surface equipment opened, and the sand manually removed. In addition to the clean out cost, the cost of the deferred production must be considered.

2) **Accumulation down hole:** If the production velocity is not great enough to carry sand to the surface, the sand may bridge off in the tubing or fall and begin to fill the inside of the casing. Eventually, the producing interval may be completely covered with sand. In either case, the production rate will decline until the well becomes "sanded up" and production ceases. In situations like this, remedial operations are required to clean-out the well and restore production.

One clean-out technique is to run a "bailer" on the end of slick line to remove the sand from the production tubing or casing. Since the bailer removes only a small volume of sand at a time, multiple slick line runs are necessary to clean out the well. Another clean-out operation involves running a smaller diameter tubing string or coiled tubing down into the production tubing to agitate the sand and lift it out of the well by circulating fluid.

3) **Erosion of Down hole and Surface Equipment:** In highly productive wells, fluids flowing at high velocity and carrying sand can produce excessive erosion of both down hole and surface equipment leading to frequent maintenance to replace the damaged equipment. If the erosion is severe or occurs over a sufficient length of time, complete failure of surface and/or down hole equipment may occur, resulting in critical safety and environmental problems.

Sand choking in separator, pipe line failure and other problems with sand flow are shown in figure 1.

Figure 1 – Sand choking in separator, pipe line failure and other problems with sand flow.

The picture shows *sand choking in separator*, *pipe line failure*, *erosion of equipment* and *downhole failure*.

- **Collapse of the formation:** Large volumes of sand may be carried out of the formation with produced fluid. If the rate of sand production is great enough and continues for a sufficient period of time, an empty area or void will develop behind the casing that will continue to grow larger as more sand is produced. When the void becomes large enough, the overlying shale or formation sand above the void may collapse into the void due to a lack of material to provide support.

When this collapse occurs, the sand grains rearrange themselves to create a lower permeability than originally existed. This will be especially true for formation sand with a high clay content or wide range of grain sizes. For formation sand with a narrow grain size distribution and/or very little clay, the rearrangement of formation sand will cause a change in permeability that may be less obvious. In the case of overlying shale collapsing, complete loss of productivity is probable. In most cases, continued long term production of formation sand will usually decrease the well’s productivity and ultimate recovery.

- **Sand handling:** Sand handling and disposing also possess major problem especially in the offshore installations because Disposal of produced sands is costly.

`Sand control.` Sand (or "fines") production is common in many oil and gas wells throughout the world. The flow of abrasive sand through wells and production lines causes unwanted erosion of equipment, and its production may also exacerbate oil-water separation in the process facilities. There are a number of ways to reduce sand production mechanically, including the use of screens, gravel packing, frac-packing, and modification to the perforation technique usually carried out at the well-completion stage. For poorly consolidated reservoirs, which are still producing excessive sand, chemical sand control can be an option. This can be especially rewarding for subsea wells if expensive intervention costs can be avoided. That's why sand control is very important in oil wells.

Control methods

Sand control methods may be classified as mechanical and chemical. Mechanical methods of sand control prevent sand production by stopping the formation with liners, screens or gravel packs. Larger formation sand grains are stopped, and they in turn stop smaller formation sand grains. Chemical control methods involve in injecting consolidating materials like resins into the formation to cement the sand grains. Here the most important control measures which are in practice are enumerated.

Resin Injection

This is simply considered as artificial consolidation of sand. Which involves injection of plastic resins, which are attracted to the formation sand grains. The resin hardens and forms a consolidated mass, binding the sand grains together at their contact points. If successful, the increase in formation compressive strength will be sufficient to withstand the drag forces while producing at the desired rates. Three types of resins are commercially available: epoxies, furans (including furan/phenolic blends), and pure phenolic. The resins are in a liquid form when they enter the formation and a catalyst or curing agent is required for hardening. Some systems use “internal” catalysts that are mixed into the resin solution at the surface and require time and/or temperature to harden the resin.

In figure 2 resin application in perforation is shown.

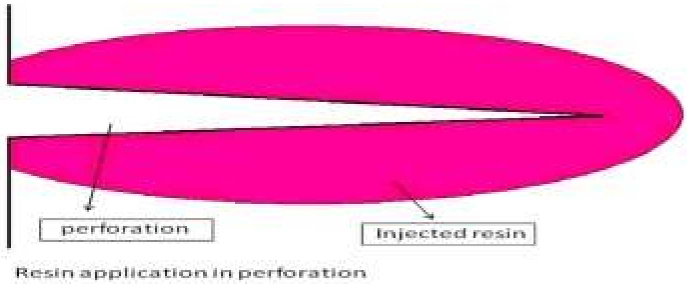

Figure 2 – Resin application in perforation

Properties of resins:

- Viscosity of resin not excessive.
- Resin must wet the formation solids
- Resin possess sufficient tensile and compressive strength
- Polymerization time must be controlled
- Final polymer must be chemically inert

Mechanism:

- Preflush diesel oil which creates wettability and remove undesired material in the zone
- Placement of resin by isolating the interval
- Over flush of high concentrated resin injected to control the permeability and compressive strength

Advantages:

- Leaves wellbore open
- Relatively low cost
- Eliminates necessity for screens and liners

Disadvantages:

- Limited zone height

- Longevity limited
- Temperature sensitivity < 250 °F
- Very difficult to evenly apply
- Reduces permeability by 10 % – 60 %

Applied in Gulf Coast with 80 % success rate where 50 % of permeability retained and compressive strength ranged from 3000 ± 12000 psi. This method represents only 10 % of overall sand treatment methods used. Main purpose is to increase formation strength and maintain permeability at the same time Cheap but comes with many disadvantages compared to other methods.

Screen with Gravel Pack

Gravel pack has been used in industry since 1930s; today it's the most widely used on sand control treatment. Gravel packing account for three quarters of the sand control treatments.

Gravel packing relies on the bridging of formation sand against larger sand with the larger sand positively retained by a slotted liner or screen. The larger sand (referred to as gravel pack sand or simply, gravel) is sized to be about 5 to 6 times larger than the formation sand. Gravel packing creates a permeable downhole filter that will allow the production of the formation fluids but restrict the entry and production of formation sand. Schematics of an open hole and cased hole gravel pack are shown in Figure. Because the gravel is tightly packed between the formation and the screen, the bridges formed are stable, which prevents shifting and resorting of the formation sand. If properly designed and executed, a gravel pack will maintain its permeability under a broad range of producing conditions.

Gravel packs are performed by running the slotted liner or screen in the hole and circulating the gravel into position using a carrier fluid. For optimum results, all the space between the screen and formation must be completely packed with high permeability gravel pack sand. Complete packing is relatively simple in open hole completions, but can be challenging in cased hole perforated completions. Although expensive, gravel packs have proven to be the most reliable sand control technique available and are, therefore, the most common approach used.

Chemical sand control. Chemical sand control has been carried out for many years with resins or epoxy, which harden unconsolidated sand. Typical systems are based on bisphenol A–epichlorohydrin resin, polyepoxide resin, polyester resin, phenol-aldehyde resin, urea-aldehyde resin, furan resin, urethane resin, and glycidyl ethers. If the resin comprises bisphenol A–epichlorohydrin polymer, a preferred curing agent is 4,4 – methylenedianiline. If the resin comprises a polyurethane, the curing agent is preferably a diisocyanate. The furan resin system is one of the most common: the key chemical is furfuryl alcohol and does not require a curing agent, as it is self-polymerizing in the presence of acid catalysts (figure 3). These systems are designed to maintain sufficient permeability of the formation to allow production. Self-diverting resin-based sand consolidation fluids have been claimed that allow a greater interval to be treated than conventional resin treatments. Most resin-based chemicals are not considered to be very environmentally friendly.

Various aqueous and nonaqueous chemicals including silyl-modified polyamides that impart a sticky character to sand particles, hindering their movement, have been claimed. Cross-linked polymer gels, similar to those used in water shut-off treatments have also been proposed for sand consolidation. Polymer gel systems, such as those based on polyacrylamides, are claimed to impart a lower probability of failure to the formation compared to resin treatments.

Inorganic chemical systems for sand consolidation have also been developed. For example, a system based on an insoluble silica source and a source of calcium hydroxide (e. g., aqueous solutions of calcium chloride and sodium hydroxide) has been claimed.

The components of the aqueous system react to produce a calcium silicate hydrate gel having cementitious properties within the pores of the formation.

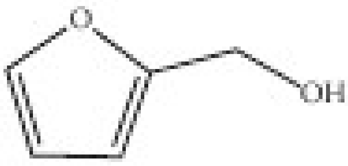

Figure 3 – Furfuryl alcohol.

An enzyme-based process for consolidation of sand with calcium carbonate has also been proposed. It requires calcium chloride, urea, and urease enzyme. The enzyme catalyzes the decomposition of urea to ammonia and carbon dioxide, raising the pH. In the presence of soluble calcium ions, insoluble calcium carbonate is formed that deposits on the sand and core, binding them together.

Since about 2005, a new sand-consolidation method based on organosilane chemistry has been developed and used in the field. In comparison to other treatments, this method only increases the residual strength of the formation by a small amount. The treatment is oil-soluble and will therefore not alter the relative permeability in the oil-bearing zones, thereby reducing the risk of increased skin due to changes in saturation. This system is especially beneficial for fields with low reservoir pressure. The method is employed by simple bullheading and can have self-diverting properties. In laboratory studies, the organosilane treatment was shown to give better overall performance with regards sand consolidation and moderate permeability reduction compared to other treatments such as water-soluble gelling polymers and the $CaCl_2$/urea/enzyme system discussed earlier.

Preferred oil-soluble organosilanes that can be used are 3-aminopropyltriethox-ysilane and bis-(triethoxy silylpropyl)amine or mixtures thereof (figure 4). They are usually mixed in diesel and bullheaded into the well. The authors suggest that the presence of the amine function appears to result in better adsorption of the organosilane to the sand grains. It is also believed that the presence of an amine group may contribute to the formation of a gel-like structure having viscoelastic properties. The authors suggest that the organosilane compounds react with water and hydrolyze. The resulting chemicals then react with siliceous surfaces in the formation (e. g., the surface of silica sand), coat any sand particles, and bind them in place by the formation of silicate bridges restricting their movement. The advantage of bifunctional organosilanes, such as bis-(triethoxy silylpropyl) amine, is their ability to bind two particles together. The organosilanes are claimed to be environmentally acceptable with low bio-accumulation potential and high biodegradation.

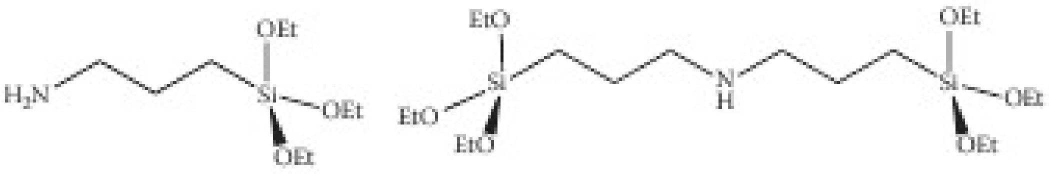

Figure 4 – 3-Aminopropyltriethoxysilane and bis-(triethoxy silylpropyl)amine.

Several types of wells have been treated with the organosilane system at a chemical concentration in the range of 5 – 7 vol. % of the active components. The first results in terms of sand production reduction were mixed, with the subsea well responding best to the treatment. A moderate reduction in permeability was observed in some wells, which reduced the PI (production index) of the well by 10–15 %. However, the production of the wells was limited by sand production levels, so such a reduction in PI was acceptable. Correct placement, especially in horizontal wells, was shown to be critical when it comes to performance with regards to increasing the maximum sand-free rate (MSFR). Organosilanes used at higher concentrations than those for sand consolidation have also been claimed as chemicals for water shut-off treatments.

Another claimed sand consolidation method, which imparts small incremental forces or a relatively weak residual strength to the formation, is by using a positively charged water-soluble polymer. Examples are polyaminoacids, such as polyaspartate and copolymers comprising aspartic acid and proline and/or histidine, and poly(diallyl ammonium salts) such as polydimethyldiallylammonium chloride and mixtures thereof (figure 5). It is thought that by virtue of its length and multiple positive charges, the polymer may interact electrostatically with a number of different particles of the formation thereby holding or binding them together. In so doing, the polymer chain is likely to span the interstitial space between sand particles of the formation. The result is simply the formation of a “mesh-like” or “net-like” structure that does not impair fluid flow. Hence, the permeability of a subterranean formation treated according to the method described by the present invention is largely unchanged after treatment.

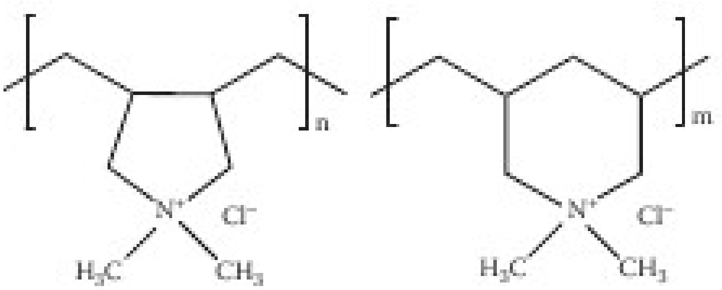

Figure 5 – Polydiallyldimethyldiallylammonium chloride. The five-ring pyrolidinium monomer is the major component and the six-ring piperidinium monomer is the minor component.