WELL PREPARATION FOR TERTIARY PRODUCTION

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ABSTRACT

Problems which become apparent during a conversion from secondary production to tertiary production should be corrected to help insure success of the proposed tertiary recovery project.

Some problems are inherent to secondary recovery and will carry over into the tertiary project. These problems could be tolerated during secondary recovery, but may mean the difference between success and failure for a tertiary program.

These problems can be generalized in two basic categories:

Restrictions of Injectivity
Unfavorable Injection Profiles

Some processes will be discussed in detail to aid in combatting the problems that will be presented in this paper.

INTRODUCTION

For decades the industry has made a common practice of waterflooding to recover oil otherwise not recoverable under primary production practices. This allowed us a method to recover more of the oil-in-place; however, over the last 20 years or so, studies have been made for additional ways to recover even more of the known oil-in-place which is left after a reservoir reaches its economic limit with conventional primary and secondary recovery techniques.[1]

As most of us know, problems may occur during the operation of a secondary recovery project. Problems ranging in degree of severity from salt ring build-up over perforations to gross channeling away from the zone of interest and also channeling in zone from an input well to a producing well.

As problems are encountered, their effects will change injectivity and/or injection profiles. These changes will result in a lower performance efficiency for the affected wells. As more and more companies turn to tertiary projects, it has become apparent that most secondary recovery operations today require workover considerations before initiating any form of enhanced oil recovery (EOR).

It is important the operator of a tertiary project have good control over placement of the EOR fluid in the zones of interest. Uniform volumetric coverage of the zone is necessary for maximum oil recovery and reduction of recycling injected fluid.[2] Today there are a number of accepted methods for aiding in control of injection fluids.

Injection pressures must be realistic for given reservoir properties. Input pressures are increased by formation damage. The proper placement of EOR fluids and the reduction of unnecessary input pressures will aid in a successful project.

RESTRICTIONS OF INJECTIVITY

After many years of injecting water into a formation, the formation face will act as a filter and catch insoluble particles, oil residual, and bacterial sludge. As the build up of plugging materials in the formation flow channels and on the formation face take place, injection pressures increase.

This problem exists in all injection wells in varying degrees, depending on specific conditions of each well along with the characteristics of flooded field. Evaluation of the problem may start with an analysis of the injection water to determine what might be plugging the zone and how much of the plugging material is present. This will allow an informed decision concerning what to do next.

Depending on the evaluation, a workover of the well may incorporate an acid treatment for acid soluble fines, aromatic solvents for hydrocarbon residual, or a simple flowback of the well using nitrogen displacement of the wellbore fluids and existing bottom-hole pressure.[3] A hydraulic fracturing treatment may be needed, or even mechanical jetting of the formation face.

In some injection wells there may be consideration of a hydrofluoric acid treatment.[4] This type of clean-up is popular in cases where sand, silt, and clays have reduced permeability in the formation to the point where flowback of the well has not been effective in cleaning up the input zone. Hydrochloric acid will react with some silts and clays to shrink them but only hydrofluoric acid has sufficient activity to react to consume silica materials. One precaution should be noted: Hydrofluoric acid and calcium carbonate will react and produce a calcium fluoride precipitate. Hydrofluoric acid could damage a formation when calcium carbonate is present to react and form this precipitate.

A method to remove damage by mechanical means is sometimes used. This method of blasting the formation face with a down-hole jetting tool has been very effective where a thick build-up of filtrate is present. The jetting fluid can be acid or a treated water with a low concentration of sand. The damaged formation is cut away as the erosive jetting action works on it.

Common among old injection wells in west Texas is the fact that heavy iron shows up on most waters that are injected for flood. Special precautions should be taken when treating iron scales with hydrochloric acid. Iron compounds are soluble in hydrochloric acid, but when the acid spends the iron compound will precipitate as iron hydroxide which could plug the formation permeability. Controls can be used in the HCl acid to keep the pH below 3. Acetic acid and citric acid, being a slow reacting acid, will maintain a low pH and sequester iron. The addition of acetic and citric acid will hold iron in solution until it can be removed from the well.

Hydraulic fracturing of an injection well will help increase the rate at which you will be able to inject fluid into the well. If permeability is damaged to a depth into the formation which can't be cleaned up by a more conservative approach, a sand frac may be considered. Opening up a vertical fracture of length that would reach through the damage is a viable alternative for improved injectivity. This fracture would be a path for the injected fluid to travel more easily, by passing damaged formation.

The most popular and widely used method to improve injectivity of an input well would typically be hydrochloric acid. This treatment is effective with carbonate and iron scales that may be present. Two common types of scale are calcium carbonate and calcium sulfate, commonly called gyp. To form gyp calcium and sulfate ions form microcrystalline nuclei, that act as growth sites. From this nuclei, large crystal clusters will grow and precipitate out as scale. Treating injection water with an effective scale inhibitor will help decrease the ability for the crystal clusters to form from the nuclei. When considering an EOR project, caution should be made in selection of chemicals to be added to the injection water because incompatibilities can exist between EOR fluids and many chemicals.

In many cases when secondary projects are converted to EOR projects, a combination of problems in formation plugging exists. Uses of acid, aromatic solvent, and flowback of the well is necessary to clean-up the wellbore and formation face of all acid soluble scales, paraffin, asphaltene, bitumen, silt, sand, and clays. Consideration must be given to placement technique of any fluid into an injection well, to optimize the performance of that fluid. An input well with oil carryover problems should be cleaned up with aromatic solvent before acidizing because the viscous oil materials may isolate some acid soluble materials and shield them from acid contact, resulting in poor clean-up. One solution to this problem is to treat the face of the input zone with an acid/aromatic solvent dispersion. This is a blend of special surfactants, acid and aromatic solvent to make up a single treating fluid. While the acid reacts to remove scale deposits, the aromatic solvent dissolves organic residues. This treatment is effective for removing oil saturation and scale deposit in the wellbore at the same time increasing permeability for wells in a potential EOR project that are converted from producing wells to injection wells.

An advantage can be gained by filtering the injection water used in a tertiary flood. By filtering water you diminish the possibility of plugging the input zone.

UNFAVORABLE INJECTION PROFILES

Perhaps the most effective way to increase efficiency of a flood is to evaluate and correct any anomalies in loss of injected fluids. By altering the fluid flow as it leaves the wellbore, we may be able to sweep new areas and increase the benefits per barrel of injected fluid.

Injection water can stray away from the zone of interest, such as channeling behind casing out of zone. Permeability variations throughout a reservoir can cause undue recycling of input water, not to mention bypassing oil-in-place. The amount of adverse results is directly proportional to the variance in permeability.

Old secondary recovery operations are prime candidates for tertiary projects. As the secondary recovery operation approaches its economic limit, considerations are made for enhanced oil recovery. Water control is already a problem before initiating EOR.

MOVEMENT OF WATER BEHIND PIPE

Movement of injection water behind casing is often encountered in older injection wells. The problem is caused by erosion of the cement sheath and formation due to the corrosive properties of most injection waters. Because of this, the problem may get worse if not corrected. As the water channels and breaks out of zone, the efficiency of the flood is adversely affected.

This channeling can result in a single adverse condition or a combination of more than one. Injected fluids could migrate upward or downward from the input zone and be lost into a barren zone which results in waste. Damage to casing and even contamination of ground water may result; however, in all instances the injection program may react unfavorably.

This problem is one which should be corrected. A common solution is to squeeze a cement slurry into the damaged area with the intention of plugging the channel. This is done by pumping a low water loss slurry of cement down the tubing, out the perforations and into the channel, resulting in a cement squeeze around the permeable section which is thieving the injected fluid. A low squeeze pressure is essential to help prevent excessive damage to the input zone.

In many instances a low pressure squeeze job will be tried and will not be successful. If the thief zone is accepting water at a high rate, this may be more prevalent. When these conditions exist, alternate procedures and materials should be employed.

An accepted method for these difficult squeeze jobs consists of a two stage process where a sodium silicate solution is pumped down tubing followed by a small fresh water spacer and adequate amounts of cement to fill the channel. This process is pumped at low pressure and rate to allow the sodium silicate to form a stiff gel and plug the thief zone, aiding to help hold the cement in place while setting into a permanent block, and at the same time minimizing damage to the input zone.

Correcting channeling of water behind casing in an injection well can be a complicated project and may take more than one attempt, but if an operator approaches the problem in the right way, the input well can then be restored to a level of maximum performance. This type of workover should be considered if the problem exists and an EOR project is being studied.

NATURAL PERMEABILITY VARIATIONS

Permeability variations throughout a reservoir can cause undue recycling of input water, and bypassing oil-in-place. As the difference in permeability increases between stringers across the input zone, the recovered oil will become more water cut due to possible early break-through in the higher permeability stringer.

Vertical waterflood coverage can be increased correlating to improved efficiency. Many methods have been utilized ranging in cost and effectiveness depending on the degree of problem and operation of the process used.

SILICA GEL

If evaluation of the problem results in conclusions that a highly permeable strata is present and this section of the input zone accepts more than its proportionate share of injected water causing a break-through and virtually complete recycling taking place, the problem can be rated as severe. Best results can be achieved with a permanent block which is economical enough to pump in large volumes and achieve deep penetration.

Silica gel is often used and meets both these criteria. Silica gel is a water-like fluid while being pumped, and because of this will enter the permeability of the rock and penetrate at a depth away from the wellbore; unlike cement, inert solids, paraffins, and organic resins, which affect only the formation face and immediate wellbore area.[2] Having viscosity similar to the injected water, and if pumped at rates equal or lower than the flood water, the treatment will flow into the same areas as the water.

The thickening time can be tailored such that the silica gel can be completely pumped into the higher permeability, at which time the input well is shut-in to allow the gel to stiffen.

The silica gel can be formulated for suitable use in sandstone or limestone and can be used at a temperature range from 60°F to 230°F. This process is inert to common waterflood treating chemicals, normally requires no workover unit on location, and shut-in time is short. All these advantages result in an economical and consistent process.

To determine volumes required for treatment the following formula may be used:

$$V = (0.0408)\, C_f\, \emptyset_e\, (d^2 - d_w^2)\, L$$

Where:

V = volume of gel, gallons
C_f = coverage factor
$\emptyset_e$ = effective porosity
d = desired diameter of plug, inches
d_w = wellbore diameter, inches
L = length of treated interval, feet

The coverage factor is developed from experience and is the ratio of the volume of gel actually required to that calculated to fill theoretical porosity assuming uniform penetration. A C_f of 1.5 is common.[2] This factor helps ensure the required minimum radius.

MONOMER/POLYMER SOLUTIONS

To achieve the most of any projected EOR flood situation where sweep efficiency is not adequate, a monomer solution which polymerizes in the formation is an alternative for consideration. This process is used to improve injection profiles and demonstrates remarkable broad sweep efficiency. The initial viscosity that is pumped approaches 1.3 centipoises; however, the final viscosity of solution-in-place can be tailored to optimize the injection profile. Polymerized viscosities in the range of 500,000 to 1,000,000 cps are routinely realized.

In cases where permeability variance is large enough to cause the bypass of oil-in-place, but recycling is not excessive and channeling direct to a producer does not exist, this monomer/polymer solution is a viable alternative to use.

During consideration of converting an old waterflood to enhanced recovery, it should be noted that injection water is cheaper than any injection fluid that may be used in enhanced recovery. If an operator can use less injected fluid and at the same time recover more oil, improving flood efficiency could make the difference between success and failure of a project.

The evaluation of placement techniques for a viscous polymer plug is often important because in many cases the effects of the plug on the reservoir cannot be quantified for months. The increase in production from improved volumetric sweep is a delayed result of the polymer.

Placement of a polymer plug at the wellbore can be seen from injection profile changes before and after treatment. Any wellbore clean-up job with acid or aromatic solvent should be completed before the first profile survey. This will allow a true comparison between profiles before polymer and after.

Transient pressure analysis could give a fair indication of the polymer present in the rock matrix. Pressure analysis before and after treatment will indicate a rise in skin along with a decrease in permeability.

The most popular monomer/polymer solutions can be tailored to desired viscosities to help control virtually any water problem. The thickening time can be adjusted to reach this desired viscosity from a few minutes to several hours. This enables a treatment to be designed for maximum effectiveness. The polymer plug is water soluble and can be diluted as floodwater flows around and through it. The viscosity of the plug will determine the rate at which can be diluted. The time taken for an effective plug to be completely diluted may range from a few months to a point where the plug is virtually insoluble. Because of this, a plug may be tailored to dilute in 5 - 10 years with anticipation of a new method of recovery being developed that will allow us to sweep 100% of the oil-in-place. The polymer should be reduced and this would allow a sweep of the previously blocked area.

It is suggested these treatments be monitored closely and each job be evaluated in order to increase the success ratio of future operations. These evaluations will enable an operator to determine if the present program is providing desired results.

CONCLUSIONS

1. Injection well workovers, to improve injectivity, can be reduced if injection water is properly filtered and treated for scale and bacteria.

2. A simple flowback of an injection well may improve injectivity.

3. Hydrocarbon residual is often carried over from producing wells and is deposited on the formation face of injection wells. Aromatic solvent is commonly used to help remove this.

4. Hydraulic fracture treatments and mechanical jetting is often used to improve injectivity in wells where severe damage exists deep into the permeability.

5. Several acidizing techniques make up the most common treatments for injectivity improvement.

6. Control of the injected fluid is important to the success of an EOR project.

7. Cement slurry is common for block squeezes of channeling water. A treatment of silica gel and cement will help control channeling of large amounts of water.

8. A silica gel solution is an economical and effective way to help control water channeling between injections and producers.

9. If the permeability variations throughout the input zone result in poor volumetric sweep efficiency, the use of monomer/polymer solutions are recommended because of versatility in placement and the fact that it is temporary allowing possible recovery of oil from future technology.

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