Preparation and Stimulation of Water Injection and Disposal Wells

By JOHN A. KNOX, BILL R. BROGDON AND WILLIAM C. CARLILE

Halliburton Services

Throughout the United States, great emphasis is being placed on pollution. Because of this emphasis, all phases of industry are looking for better methods of disposing of waste. One of the widely publicized methods is deep well disposal; all of industry is looking to the petroleum industry as a source of information for drilling, completion and stimulation methods.[1,2]

Even with the extensive experience of the petroleum industry in waterflooding operations and disposal of unwanted water, problems are still encountered daily in injection systems.

George Bernard Shaw once said, "No question is so difficult to answer as that to which the answer is obvious." It may be that this is true, at least to some extent, in answering questions about improving injectivity.

One obvious question which seems to be overlooked quite often is; what is the problem?

A problem can usually be solved if it can be defined, so the first and perhaps most important step is to gather all necessary information so that the culprit which is causing the loss in injectivity can be identified. Oftentimes a little time and money spent on defining the problem can save a great deal more time and money spent on treatments which are unsuccessful or only partially successful.

TYPES OF WELLS

There are three types of wells which can be considered for stimulation in injection systems: (1) new wells, drilled just for the purpose of injecting water; (2) old producing wells, being converted to injectors; and (3) injection wells currently in use.

New Injection Wells

The new injection wells should be treated in much the same manner as a new producing well. Mud damage should be removed and a stimulation treatment designed to provide the desired injectivity. In limestone and dolomite formations which predominate in the Permian Basin, acid treatments are usually preferred. The volume of acid and injection rate may be lower than for a producing well so that an extensive fracture system, other than that inherent in the formation, is not created. Sand formation with low permeability may require small fracturing treatments. In special cases involving imbibition, more extensive fracture systems may be required.

Of course the design of the flood may be such that advantage is taken of the natural fractures and injection wells and producing wells placed to utilize them in directing the flood front. This discussion is not intended to get involved in the design of waterfloods, but only to point out that it is important to consider the design of the flood when sizing the stimulation treatment.

Converting Old Producing Wells

Generally, old producing wells which are being converted to injection wells have been stimulated previously and there is very little or no control over this phase of the problem. They may be severely scaled and in addition can have extensive paraffin and asphalt deposits in and around the well bore. If possible, samples of deposits should be obtained from the openhole or perforated interval and analyzed to aid in determining what solvents should be used. Oftentimes old records on the wells can be utilized to help identify potential sources of trouble. More will be said later about types of deposits and solvents for these deposits.

If the old well has open hole it can be reamed or underreamed to help clean it; however, care should be taken in the choice of fluid used to circulate the reamed material out of the hole. Muds could damage the formation more than the deposit which is removed. Even if water or oil were used, the cuttings could be plastered back against the formation and satisfactory injectivity might not result.

Hydraulic jetting with appropriate surfactants such as foaming agents and suspending agents can be considered in this instance. The utilization of a gas (nitrogen or carbon dioxide) during the Hydrajetting can help return the debris to the surface and clean the formation face. The tubing can be reciprocated and rotated during the jetting operation. In long sections, a series of two or three jetting tools can be spaced one or two joints apart and by reciprocating the pipe, over 180 ft of formation can be covered in one operation. It may be necessary to add a friction reducer to obtain desired flow rates through the jets if too many are used but this can probably be controlled by proper sizing of the orifices.

Acid can also be jetted, perhaps after the open hole has been jetted with water, to insure a clean formation. The wellhead can be closed and acid injected into the formation either after or during the time acid is being jetted to further stimulate the zone. This may be particularly advantageous in a calcareous formation.

Organic solvents containing surfactants have been used to precede water after converting old producers.[3]

Heated organic solvents may be even more beneficial if no attempt is going to be made to ream or jet. One source of heat is magnesium pellets placed in the well in the solvent or gelled water and followed by hydrochloric or acetic acid. The acid action on the magnesium can generate 8400 BTU per pound with a maximum theoretical temperature increase of about 530°F. The acid can be followed by more organic solvent to dissolve any melted or softened bituminous material present.

If the well is cased and perforated, hydraulic jetting can be considered. Effective stimulation or scale removal must involve the distribution of the treatment over the entire pay zone. If it is a long section with several sets of perforations, circulating with the tubing on bottom may suffice. However, if the treating solution is to be pumped into the formation, suitable diverting additives should be employed. Ball sealers may be used but their effectiveness is usually dependent on perforation density. Many of the older wells are perforated with four shots per foot which seriously impairs the effectiveness of the ball sealers. In these instances, as well as in open-hole applications, rock salt has been used effectively. A sulfate-free, salt-saturated, gelled brine is used as the carrying fluid for the specially sized rock salt.

Acid and/or fracturing treatments can be designed to give the desired penetration and stimulation.

Old Injection Wells

The water pumped into the injection well determines the deposits which impair injectivity. Some operators have taken absolutely no precautions and have pumped rags, bottles, bolts, and beer cans into injection wells and they continue to take water with no problems. Others have spent a great deal of money treating their water and installing special systems to insure that only clean, clear water goes into the injection well and the wells won't take water long enough or fast enough.

The first case is the exception, however; a well-designed water handling and treating system is a must. Careful treatment and plastic-coated or cement-lined pipe are used to avoid corrosion problems.

Still, in spite of our best efforts, injection wells do get plugged.

Again, let us repeat that to provide the proper solvents the plugging agents must be identified. A sample from the perforated interval or open hole is preferred. Paraffin or asphaltic deposits are not generally found in injection wells as they are in old producers being converted. The deposits generally consist of scales from the injection water, corrosion products, grease from the pumps, clays, bacteria, insoluble bactericides, and corrosion inhibitors. Oftentimes, oil does get into the injection system and these deposits are oil wet. Oil can collect around the well bore and change the relative permeability to water also causing a decrease in injectivity. A slug of the proper surfactant in water can clean up this oil and restore the injectivity if oil is the primary plugging material.

The types of scales and solutions for their removal will be discussed in more detail later. The technique and order of the application of the solvents will be considered now.

It is difficult to obtain samples of plugging materials from many injection wells. One method commonly used is to place a solution of surfactant in water (one to five per cent surfactant) over the perforation or in the open hole and allow it to soak overnight. The volume should be about three times the volume of the open hole or perforated interval. Two-thirds of the solution can be displaced into the formation and the zone in question left covered. The well should be backflowed if possible. If it will not flow, reverse circulation, gas injection, bailing, swabbing, or any other means necessary should be used to produce this solution back out of the well.

The soaking action of the surfactant will loosen corrosion products, bacteria, bactericides, greases, clays and other materials which may be insoluble or nearly insoluble in any solvent. Samples of the material returned should be collected and analyzed. From this analysis, further treatments can be designed. It may also be possible to determine that some change in the water handling and treating system is necessary to prevent recurrence of the problem.

The soak and back-flush may be the most important treatment that is performed on the well. Quite often no other treatment is required: the desired injectivity is obtained.

If a scale is found, the appropriate solvent can be recommended. The attached Figures 1, 2, 3, 4 and 5 show the quantities of acid required to dissolve various thicknesses of different scales from different size pipe.[4] It is possible to undertreat or use too little acid and fail to effectively stimulate the well.

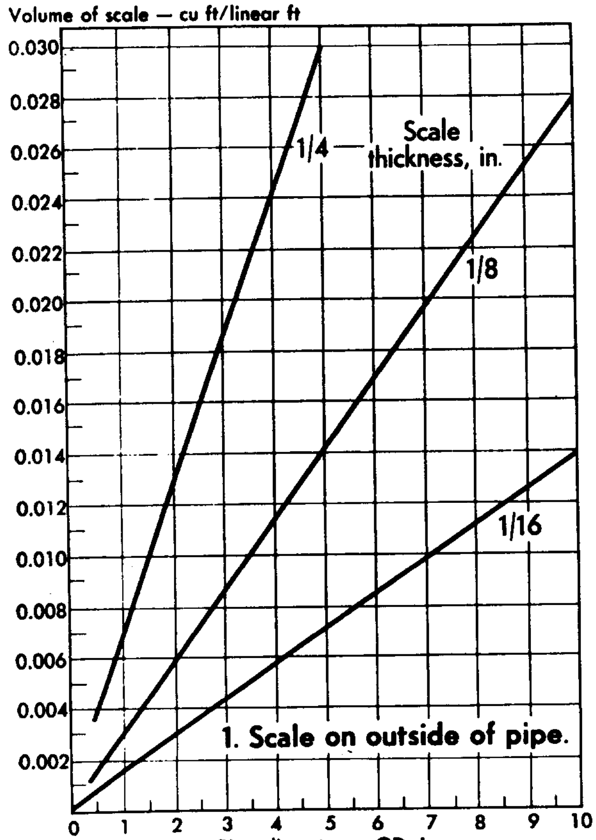

FIGURE 1

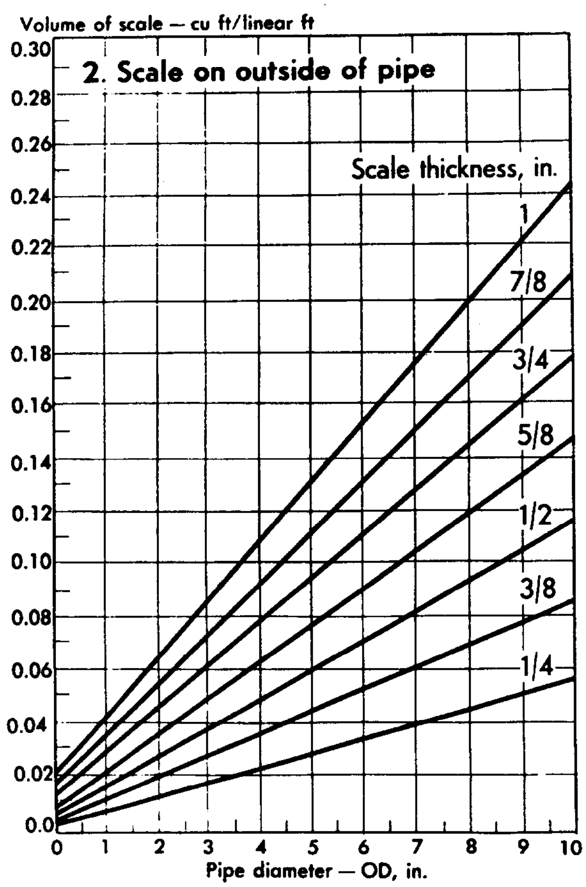

FIGURE 2

If grease, insoluble bactericides, or insoluble corrosion inhibitors are found, an organic solvent can be recommended. An aromatic naphtha or perhaps alcohol may be desirable.

Bacteria, dead or alive, should be adequately flushed from the well by the soak and backflush treatment but should it be decided that a large amount remains, oxidizing agents have been used for their removal. Care should be taken in the use of oxidizing agents because they are generally corrosive. They are also usually strongly alkaline and may damage a formation which contains water-sensitive clays. If they are used, it would be preferred to back-flush them rather than displace the solution into the formation. It should also be followed by acid whenever possible but the acid and oxidizing agent should not be mixed, again because of corrosion problems.

Jetting of the old injection wells can be considered. Water, acid or solvent can be used during this jetting operation. Adjuncts to jetting previously discussed can be utilized here as well.

Sometimes old gas injection wells are converted into water injection wells and the same techniques can be used for both. The deposits in gas injection wells will more likely be of an organic nature and organic solvents should be considered. Samples of the deposits can aid in choosing the correct solvent.

TYPES OF DEPOSITS

Gypsum ($CaSO_4 \cdot 2H_2O$) is by far the most predominant scale in the Permian Basin both in injection and producing wells. Calcite or aragonite ($CaCO_3$) is not often found alone although it is often found as a minor constituent of gyp deposits. In other areas (Abilene and the Rocky Mountains) $CaCO_3$ is the predominate scale. Silica and silicates have been identified in a number of instances again usually as a minor constituent of gyp.

Iron oxides and iron sulfides are common with many occurrences of complex sulfides such as kansite and triolite. Iron carbonate is sometimes found. These materials may be found alone or with other deposits depending on the injection system.

A fair incidence of barium sulfate ($BaSO_4$), strontium sulfate ($SrSO_4$) and barium strontium sulfate $BaSr(SO_4)_2$ has been detected. These deposits are usually the result of mixing two incompatible waters; separate injection systems should be considered for incompatible waters. No chemical means for removal is economically available and jetting should be considered.

For $\begin{bmatrix} CaCO_3 \\ Fe_2O_3 \\ FeS \end{bmatrix}$ use $\begin{bmatrix} 95 \\ 318 \\ 180 \end{bmatrix}$ gal 15% HCl/cu ft of scale

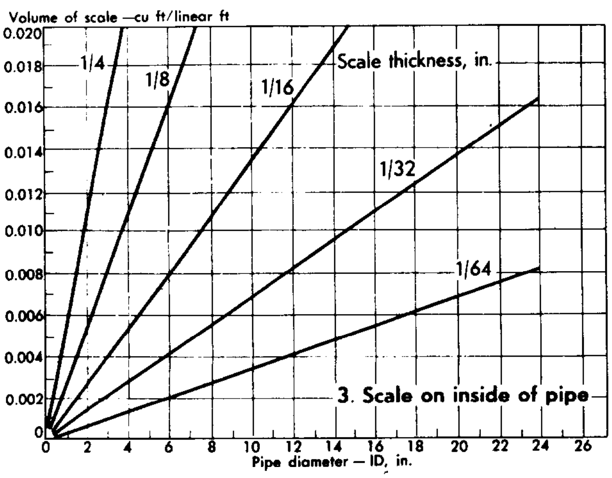

FIGURE 3

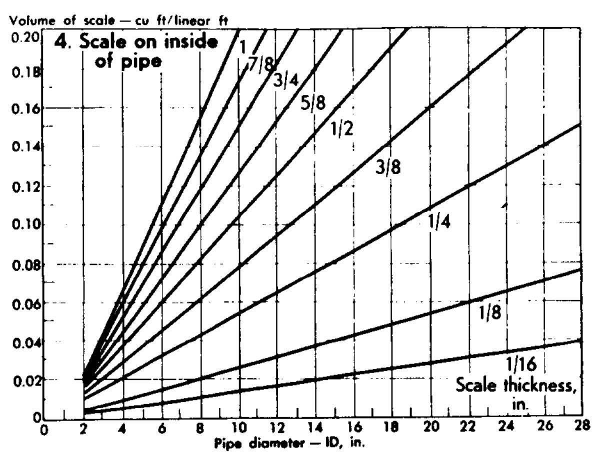

FIGURE 4

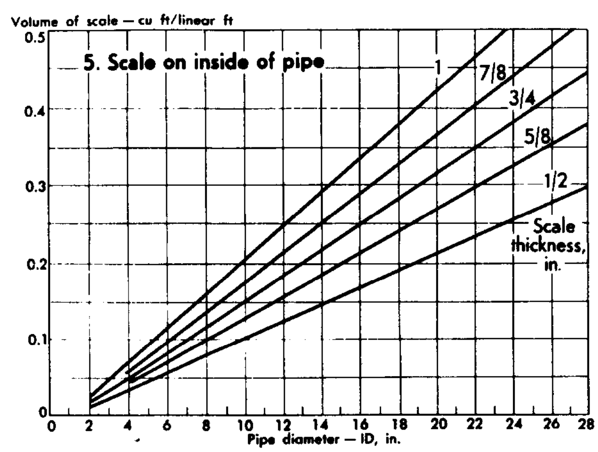

FIGURE 5

Scale deposition usually damages flow capacity in perforations or at the well bore. Restricted flow capacity can also occur in fractures, vugs or the matrix of the formation requiring stimulation penetration at some distance from the well bore.

Some water sources may contain clays and silt which are not removed before injection and they will introduce silicates and silica into any other deposit which forms.

Deposition of the sulfates and carbonates can be controlled by use of scale inhibitors.[5]

TYPES OF SOLVENTS

Organic solvents for organic deposits have been discussed. Surfactant slugs and soaks for removal of acid-insoluble materials have also been mentioned. Oxidizing agents for removal of bacterial slimes have been considered but should be used with caution.

Conversion Solutions

The predominate scale in the Permian Basin, gypsum, is not completely soluble in hydrochloric acid. In most instances, it is necessary to convert the gyp to a compound which is soluble in acid. The deposit itself will determine the preferred solution for this conversion. A number of different water-soluble carbonates, bicarbonates and hydroxides have been used alone or in combination with reasonable success. Hydroxides alone with no acid flush have been used but seem to lose effectiveness with repeated application. This may be because they tend to form a dense impenetrable scale.

A series of gypsum solubility tests were conducted by placing 20 grams of reagent grade $CaSO_4 \cdot 2H_2O$ in 200 cc of solution at room temperature for 24 hours. The conversion solution was decanted after this time and the converted gypsum was placed in contact with 250 cc of 15 per cent HCl for two hours, after which time the residue was filtered, dried, and reweighed. The results of these tests are found in Table I.

Table I

Comparison of Gypsum Solubility in Various Aqueous Conversion Systems

Type of Solution	Conc.	Gals. of Solv. to Dissolve 1 cu. ft. of Gyp (144.8 lbs)	Lbs. of Gyp Dissolved Per 1000 gals.
Standard Gyp Solvent	12%	191	755
Std. Gyp. Sol. + KOH	12%	182	797
NH_4HCO_3	12%	198	732
Na_2CO_3	12%	207	699
KOH	12%	257	563

An extensive series of tests were conducted to determine the maximum solubility of gypsum in water, brines, and acid. The following information, shown in Table II, gives this solubility in the solvents at the concentrations of solvent which provides maximum solubility. These tests were conducted at room temperature for a period of 24 hours.

Acid Solutions

Hydrochloric acid in concentrations ranging from 5 per cent to 30 per cent is the primary acidizing solution used. Fifteen per cent is generally used unless there is a high concentration of iron compounds present in the deposit. Most iron compounds are more slowly soluble and require a higher concentration to dissolve them in a reasonable period of time. Acid should not be displaced too rapidly or complete dissolution may not take place. A minimum of one hour's contact time is recommended. Iron sequestering additives in the acid are recommended to keep the iron in solution after the acid has spent.[6,7]

Removal of iron sulfide scale can present some particularly difficult problems. When the acid spends while dissolving iron sulfide, the iron sulfide will reprecipitate. Ordinary iron sequestering systems are not completely effective

Table II

Solubility of Gypsum in Aqueous Solvents

Type of Solution	Conc.	Gals. of Solv. to Dissolve 1 cu. ft. of Gyp (144.8 lbs)	Lbs. of Gyp Dissolved Per 1000 gals.
Water	—	8560	17
NaCl	16%	1797	81
NH_4Cl	14%	1477	98
HCl	8%	708	204

but the acid can be modified to keep the iron in solution so that it will not redeposit around the well bore.

Most inhibitors for acid are adversely affected by hydrogen sulfide which is released by the action of acid on iron sulfide. A properly designed inhibitor can function in H_2S saturated acid and one has been developed which can prevent hydrogen sulfide cracking of high strength steels in this environment.[8]

Acid can damage cement lining in pipe so be cautious in its use. Laboratory tests have indicated that no serious damage should occur when a low injection rate is used; however, in actual practice damage may still occur. This may be due to hairline fractures which occur in the lining with time and stress. Penetration of these cracks may allow acid to get behind the lining and cause it to flake off.

An acid-resistant cement lining has been reported but the authors have no information on how it performs during actual acid stimulation treatments.

Hydrochloric-hydrofluoric acid mixtures are sometimes used to remove clays and silt from sandstone wells. This mixture has no application in calcareous reservoirs because of the secondary precipitation of calcium fluoride. Damage can occur even in sandstone reservoirs unless proper treating techniques are used. It is generally recommended that the HCl-HF mixture be spearheaded and followed by five per cent HCl. The volume of HCl ahead and behind should be about one-half that of the HCl-HF mixture.

It should not be diverted with rock salt as suggested with HCl because of the possible secondary precipitation of sodium fluosilicate (Na_2SiF_6). Gels can be used, however. The gel may be used first if the injection profile indicates a thief zone.

If excessive water injection into a thief zone is not corrected by a stimulation treatment, the injection profile can be altered.[9]

Rarely, acids other than HCl or HCl-HF mixtures are used. Some which can be considered are acetic, formic and sulfamic acids. Sulfamic, although a convenient acid in solid form, will not dissolve iron compounds so should not be used for this purpose.

The scales are usually oily or coated with some organic material which is not soluble in acid. Acid external emulsions of the preferred acid system with an aromatic solvent as the internal phase can be used to combine the solvent and acid wash into one system. An example of the effectiveness of this type of solvent acid emulsion was reported in a laboratory test. A scale was less than 50 per cent soluble in 15 per cent acid containing surfactant but was over 90 per cent soluble in the emulsion in the same time interval and temperature.

This same approach can also be used with the gyp-converting solutions. Where it is not convenient to preflush the Gypsum with aromatic solvent and acid, and emulsion can be used and flushed with acid.

Surfactants

Surfactants have been mentioned a number of times throughout this presentation. It cannot be too strongly emphasized that a great deal of the cleaning action in injection wells comes from the action of surfactants in acids, converting solutions, and organic solvents as well as surfactants in-water. All solutions used to stimulate these wells should contain appropriate surfactants.

TREATING TECHNIQUES

A number of techniques have been described which can improve the action of the solvents.

These are again listed below:

(1) Slugging wells with surfactants
(2) Soaking wells with surfactants
(3) Back-flushing wells
(4) Soaking wells with organic solvents and surfactants
(5) Converting scales
(6) Acidizing scales
(7) Fracturing to improve injectivity
(8) Jetting with or without gas
(9) Reaming or under-reaming

Rarely will it be possible to obtain a completely satisfactory stimulation treatment with only one of these. A combination of several may be necessary and a wise choice can only be made after careful evaluation of the well and the plugging materials to be removed.

REFERENCES

1. Henkel, H. O., "Deep-well Disposal of Chemical Waste Water", Power, 82-85, March, 1968.
2. Slagle, K. A. and Stogner, J. M., "Techniques of Disposing Industrial Wastes in Deep Wells", to be presented at the National Pollution Control Exposition and Conference, Houston, Texas, April 3-5, 1968.
3. Relf, J. A. and Sears, J. R., "The Dual Solvent Slug Technique for improving Injectivity of Waterfloods", presented at the 39th Annual Fall Meeting of the SPE of AIME in Houston, Texas, October 11-14, 1964.
4. Shryock, Stan and Knox, John, "Stimulating Water Injection Wells", published in the Oil and Gas Journal, January 4, 1965.
5. Lasater, R. M., Gardner, T. R., and Glasscock, F. M., "Scale Deposits are Controlled", published in the Oil and Gas Journal, January 15, 1968, pages 88-93.
6. Slaton, Leo, Lasater, Reginald, and Knox, John, "Scale Deposition and Removal", presented at the Spring Meeting of the Rocky Mountain District API Meeting, April 26-28, 1965, Denver, Colorado.
7. 3,142,335, "Acidizing of Wells", W. R. Dill and Francis N. Harris.
8. Lasater, R. M. Keeney, B. R., and Knox, J. A., "Prevention of Hydrogen Sulfide Cracking of High Strength Carbon Steels in Acid Systems", to be published in the April Materials Protection, Vol. 7, No. 4, 1968.
9. Koch, Ronney R., Diller, John E., "An Economical Large Volume Treatment for Altering Water Injectivity Profiles", presented at the Spring Meeting of the Mid-Continent District API Meeting, March 30-April 1, 1966, Tulsa, Oklahoma.