PRODUCTION ENHANCEMENT
Scale Prevention

What is Scale?

Scale is a solid mineral deposit usually formed from produced salt water. Because water constantly dissolves and deposits solids, scale is an endless problem in the petroleum industry. Scale occurs in primary production wells, secondary wells, injection wells, disposal wells, and pipelines that connect wells to tank batteries. Wherever water production occurs, a potential for scale formation exists. The types of scale most often encountered are listed in Table 1, Page 2.

What Causes Scale?

Scale can be caused by any one or a combination of several factors:

- Pressure changes
- Temperature changes
- Impurities
- Additives
- Variation of flow rates
- Changes in pH
- Fluid expansion
- Gas evaporation
- Mixing of incompatible waters

Mixing of incompatible waters causes the minerals in solution to form an insoluble precipitate. The precipitate deposits in the wellbore or the well pump. Scale can develop almost immediately, or it can build up over several months before becoming noticeable. Some scale, such as calcium carbonate, develops quickly but is relatively easy to treat. Barium sulfate is typically slower to form, but it is more difficult to treat.

What Damage Does Scale Cause?

The effect these scales have on a well depends largely on their location and the amount deposited in the system. Scales can restrict and completely choke production in the tubing, in the flowlines, at the sandface, or in the perforations. Scales can deposit in fractures and formations that are distant from the wellbore.

What are the Economics of Scale?
The deposition of inorganic scale in producing wells is a costly problem in the oil industry. Stuck downhole pumps, plugged perforations and tubing strings, choked flowlines, frozen valves, equipment damage, and downtime during maintenance all contribute to cost. Scale restricts production and causes inefficiency and failure of production equipment. As fields mature and require waterflood operations, the scale problems have an increased effect on well economics.

Scale disposal can be quite costly. The most economical way to manage wells that tend to scale is to use an inhibitor to prevent the scale from forming. The savings are even more significant when scale prevention treatments are combined with stimulation treatments.

**NORM in Scale**

Disposal of oilfield scale, in particular barium sulfate, has become increasingly troublesome with the introduction of regulations regarding naturally occurring radioactive materials (NORM). Radioactive materials are categorized by the amount of radiation they are likely to produce. NORM scale is categorized as a potential hazard.

NORM is common in everyday life; it is in the ground, the air, and in the body. The average person is exposed to about 100 to 300 millirems of radiation per year; half of these are from natural sources.

In the oil industry, NORM occurs in the scale that clogs pipes and equipment and in the sludge from the bottom of oil storage tanks. Health risks from the low levels of radiation in NORM are thought to be minimal in most cases; however, disposal of NORM wastes can create a problem. For instance, the radioactivity from oilfield scale is usually very low from pipe to pipe, but the total radiation level increases when all the pipe scale at one site is gathered in one place.

No low-cost, easy method of disposal is available because NORM is classified as a radioactive material. As of July 1994, the only site available for NORM waste disposal in the U.S. is in Utah at a cost of $300 to $500 per drum.

NORM scale is regulated by the individual states under Subtitle D of the Resource Conservation and Recovery Act (RCRA) as a solid waste under the drilling fluids exclusion. Texas and Louisiana implemented their own regulations. In Louisiana, equipment and piping can be used without restriction if the maximum radiation exposure level does not exceed 25 microrems/hour, according to Implementation Manual for Management of NORM in Louisiana. The contact reading maximum for Texas is 50 microrems/hour,
according to Texas Regulations for Control of Radiation, Part 46. Several other states follow the Texas regulation.

**Common Oilfield Scales**

Many mineral scales are found in the oil field, but calcium carbonate, calcium sulfate, and barium sulfate are most common and cause the most concern. Strontium sulfate is less common but also causes problems. Iron compounds from corrosion and oxidation are also common. Table 1 lists the common scales, their chemical formulas, and mineral names.

**Table 1: Oilwell Scale Deposits**

<table>
<thead>
<tr>
<th>Scale Type</th>
<th>Chemical Formula</th>
<th>Mineral Name</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Water-Soluble Deposits</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sodium Chloride</td>
<td>NaCl</td>
<td>Halite (salt)</td>
</tr>
<tr>
<td><strong>Acid-Soluble Deposits</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Calcium carbonate</td>
<td>CaCO₃</td>
<td>Calcite</td>
</tr>
<tr>
<td>Iron carbonate</td>
<td>FeCO₃</td>
<td>Siderite</td>
</tr>
<tr>
<td>Iron sulfide</td>
<td>FeS</td>
<td>Trolite</td>
</tr>
<tr>
<td>Iron oxides</td>
<td>Fe₃O₄</td>
<td>Magnetite</td>
</tr>
<tr>
<td>Magnesium hydroxide</td>
<td>Mg(OH)₂</td>
<td>Brucite</td>
</tr>
<tr>
<td><strong>Acid-Insoluble Deposits</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Calcium sulfate</td>
<td>CaSO₄ · 2H₂O</td>
<td>Gypsum</td>
</tr>
<tr>
<td>Calcium sulfate</td>
<td>CaSO₄</td>
<td>Anhydrite</td>
</tr>
<tr>
<td>Barium sulfate</td>
<td>BaSO₄</td>
<td>Barite</td>
</tr>
<tr>
<td>Strontium sulfate</td>
<td>SrSO₄</td>
<td>Celestite</td>
</tr>
<tr>
<td>Barium strontium sulfate</td>
<td>BaSr(SO₄)₂</td>
<td>Barium strontium sulfate</td>
</tr>
</tbody>
</table>

**Identifying Scale Types**

Scale types can be divided roughly into three classes:

- Water-soluble
- Acid-soluble
- Acid-insoluble
This classification is simplified. Scale is seldom deposited in its pure form. Usually the scale deposit is a mixture of one or more of the major inorganic components plus corrosion products, congealed oil, formation fines, paraffin, and other impurities. However, simple classification is adequate for field analysis.

**Laboratory Identification**

Before trying to solve a scale problem, accurately determine the material deposited. Two methods are used in the laboratory to identify scales. One is an instrumental method, and the other is a chemical method.

X-ray diffraction is the instrumental method used most. It is the fastest laboratory method available and requires the least amount of sample.

In the chemical method, the scale sample is decomposed and dissolved in chemical solutions. The compounds contained in the scale sample are then analyzed by standard techniques of titration or precipitation.

**Field Identification**

Answering a series of questions can help you make a preliminary identification of a field scale. Follow the procedure described in the flowchart below to determine what kind of scale is present (Figure 1).

To follow the flowchart, place the scale in water and observe. If the scale is not dissolved, place the scale in hydrochloric acid and observe. If the acid does not dissolve the scale, identify it by hardness, weight, and grain structure.

**Figure 1: Flowchart for Field Identification of Scale**
Characteristics of Scales

Solubility rates and precipitation tendencies for calcium carbonate, calcium sulfate, and barium sulfate are provided in this section.

**Calcium Carbonate**

Oilfield problems with calcium carbonate \((\text{CaCO}_3)\) often center around its inverse solubility
behavior. Calcium carbonate becomes less soluble at higher temperatures. This behavior is depicted in Figure 2.

The effect becomes more complicated when other precipitation factors are encountered. In general, the following physical changes cause calcium carbonate scale to form:

- Pressure decrease
- Temperature increase
- pH increase (such as the loss of CO$_2$)
- Calcium concentration increase
- Carbonate increase
- Flashing (in heat treaters)

Small changes in temperature can result in large quantities of calcium carbonate precipitation. Temperature cycling often causes calcium carbonate or dolomite (calcium magnesium carbonate) scaling in heat treaters and the connecting pipe—just as it does in home water heaters.

**Figure 2: The effect of temperature on solubility of CaCO$_3$**

![Figure 2—The effect of temperature on solubility of CaCO$_3$](image)
Changes in the concentration of calcium or carbonates occur when waters from different zones mix at the wellbore, in surface collecting equipment, or when waterflood streams reach production wells. An increase in pH can occur if carbon dioxide is liberated from the produced water. Loss of CO2 anywhere in the system creates an increase in pH and increases the possibility of scale deposits. Even a small quantity of calcium carbonate can seize valves and plug pipe elbows. Calcium carbonate precipitates are easily nucleated by the presence of any physical obstruction. Once precipitation is initiated by the nucleation agent, deposit growth is continual.

**Calcium Sulfate**

The solubility of calcium sulfate (CaSO$_4$), often called gyp or gypsum, increases from ambient to 92°F and then decreases at higher temperatures (Figure 3). This bell-shaped solubility behavior causes problems in wells with moderate bottomhole static temperatures (100°F to 140°F). Formation water becomes saturated in calcium sulfate at bottomhole conditions. As the fluid is produced, its temperature and pressure decrease, and gypsum precipitates in the wellbore or wellhead.

*Figure 3: The effect of temperature on solubility of CaSO$_4$*
Factors for CaSO₄ precipitation include the following:

- Temperatures below 75°F or above 140°F
- Decrease in pressure
- Increase in calcium or sulfate concentration by admixture with a second fluid
- Lowering of sodium chloride content (by dilution)

Gypsum crystallization is usually rapid. Pipes and valves can plug in a few days. Solid deposits occur in many physical configurations, such as needles, sheets, platelets, and conglomerates.

**Barium Sulfate**

Barium sulfate (BaSO₄) is a highly insoluble substance (solubility of 2 mg/L in water), and it usually cannot be economically dissolved by a chemical agent. In most cases, the only way to remove precipitated barium sulfate is by mechanical scraping or reaming, which is troublesome and costly. Therefore, managing barium sulfate wells economically requires preventing precipitation with an appropriate scale inhibitor.
Factors for BaSO₄ precipitation include the following:

- Lower temperatures
- Dilution of brine content
- Dilution of carbonate content
- Mixing of incompatible waters

The commingling of producing zones is the leading cause of barium sulfate scale problems in the oil field. Because barium sulfate is more soluble at higher temperatures and pressures, it is routinely encountered in waters from the deeper and hotter petroleum wells. Water produced from deep, hot wells also tends to have elevated brine and carbonate content, both of which increase the solubility of barium sulfate (Figure 4).

**Figure 4: Concentration of Saturated Barium Sulfate in Brine Solution (from Davis and Collins, Environ. Sci. and Tech., Vol. 5, No. 10, 1971)**

As deep well fluids are produced, the subsequent drop in temperature and pressure results in the precipitation of barium sulfate. Produced brine fluids typically are reinjected.
as a means of disposal. Often the brines are mixed with waters from other zones. If this water is fresh, the reduced salinity of the mixed water reduces BaSO₄ solubility, and scale forms. Barium sulfate and strontium sulfate are often deposited together because barium and strontium have similar chemical properties. Iron is another common coprecipitate. Because of these contaminants, BaSO₄ scale deposits occur in a variety of colors and shapes.

**How Scale Inhibitors Control Scale Formation**

Chemical scale inhibitors control the deposition of scale by either interacting with the microscopic scale surface and altering the crystal structure as it is forming or by sequestering the ions (calcium and barium) that precipitate as scale.

**Chelation**

One method of scale control chelates (sequesters) the ion that is causing scale, which requires one part inhibitor for each part potential scale. Because this one-to-one ratio can become expensive, chelation is not usually recommended.

**Threshold Inhibition**

The recommended scale control technique involves the process of threshold inhibition. This process occurs as follows:

1. The binding site of the scale inhibitor molecule is attracted to the charges on the small scale crystal.
2. Because the inhibitor is attached to the scale crystal, the crystal grows no larger.
3. Eventually the crystal redissolves and releases the inhibitor to repeat the process.

The practical result is that the presence of as few as 1 to 30 mg/L of inhibitor is enough to maintain 100 times its weight of potential scale in solution. This level of efficiency makes scale inhibition a very economical method of scale prevention.

The nature of the binding site and the chemical identity of the scale determine the effectiveness of a threshold inhibitor. Because the three most common scales are chemically different from one another, scale inhibitors vary in effectiveness, depending on which type of scale is present. For example, a very small quantity of inhibitor might prevent CaCO₃ scale, but the same amount of that inhibitor might be ineffective against CaSO₄ scale. Increasing the dosage of inhibitor can then prevent problems with CaSO₄ precipitation.
Choosing an Inhibitor

The specific conditions determine inhibitor choice. Always test inhibitors under the existing conditions. To provide the most economical treatment for a problem, consider a variety of chemical scale inhibitors. After you have identified the scale and determined the well conditions, select the best inhibitor to prevent and control the problem.

The following section describes the various types of scale inhibitors.

Scale Inhibitors

Numerous chemical additives are effective at preventing scale precipitation. Several inhibition products are presented in this section according to their chemical category:

- Polyphosphates and phosphate esters
- Slowly soluble polyphosphates
- Phosphonates
- Polyacrylic acid and other carboxylic acid-containing polymers

Polyphosphates (Condensed Phosphate) and Phosphate Esters

Polyphosphates are the original scale inhibitors. Polyphosphates are simply long chains of phosphate units (Figure 5).

Figure 5: A polyphosphate is a phosphate chain.

![Figure 5](image)

Phosphate esters are derivatives of phosphoric acid and alcohols. In general, the molecules of esters are smaller than polyphosphate molecules (Figure 6). Inhibitors in
these groups have a long, successful history of providing economical inhibition against common scales, such as CaSO$_4$, CaCO$_3$, and BaSO$_4$.

Figure 6: Phosphate esters are derived of phosphoric acid and alcohols. A polyethylene glycol phosphate ester is shown.

Polyphosphates and phosphate esters are sensitive to acidic conditions and temperature changes. Both classes of inhibitors undergo hydrolysis (break apart into several components) at elevated temperatures and in low-pH (acidic) conditions. For that reason, they are used in wells with BHTs below 150°F.

Concentrations of polyphosphates and phosphate esters in produced water can be easily monitored with a phosphorus analysis.

**Slowly Soluble Polyphosphates**

Polyphosphates are an effective, economical class of inhibitors in routine, low-to-moderate temperature applications. If a highly soluble form of polyphosphate, such as
sodium hexametaphosphate, is used, however, it can rapidly provide high concentrations of inhibitor (overkill) and be washed away quickly by the production fluids. To control the release rate of the polyphosphate and dramatically increase the length of time of effectiveness, the polyphosphate can be chemically altered to lower its solubility. The resulting solid product provides long-term scale inhibition. Halliburton has one slowly soluble polyphosphate inhibitor, Scalechek SCP-2.

**Scalechek SCP-2**

The Scalechek SCP-2 is a slowly soluble (time-release) polyphosphate solid that has been successfully placed into the proppant bed of fractured wells. It provides excellent long-term protection. Because Scalechek SCP-2 is soluble in acid, the fractured well should not be acidized until the Scalechek SCP-2 ceases to provide protection.

In laboratory tests at 175°F, 1.2 mg/L of Scalechek SCP-2 inhibits the formation of BaSO₄ scale in simulated Gulf Coast brine. Likewise, the presence of 3.2 to 10 mg/L of Scalechek SCP-2 inhibits the formation of CaCO₃ and CaSO₄ scales.

Delayed-solubility polyphosphates, such as Scalechek SCP-2, prevent scale at temperatures of 70°F to 175°F. At higher temperatures, any soluble polyphosphate eventually converts to orthophosphate, which is not a scale inhibitor. The small amount of dissolved polyphosphate that remains, however, does provide scale inhibition.

The release rate of Scalechek SCP-2 is a function of time and is dependent on contact with water.

NOTE: Scalechek SCP-2 dissolves as long as it is in contact with water, even if the well is shut in and no water is being produced at the wellhead. Keep this in mind when recommending Scalechek SCP-2, and make the operator aware of this characteristic.

A computer model is available to help determine the correct amount of Scalechek SCP-2 needed for a particular job. For more information, see the technical data sheet entitled, Scalechek SCP-2 Service (CS5219), contact Stimulation Chemicals in Duncan, Oklahoma, U.S.A., or call your Halliburton representative.

**Phosphonates**

Phosphonates are organophosphorus compounds that were originally patented by Monsanto Chemical Company for use as scale inhibitors. Today's market includes a wide variety of phosphonate inhibitors.

These materials typically couple a phosphorous group to a backbone using a methylene
spacer group (Figure 7). They are often called aminomethylphosphonates.

**Figure 7: Diethylenetriamine penta(methylene phosphonic acid) is a phosphonate.**

![Chemical structure of Diethylenetriamine penta(methylene phosphonic acid)](image)

**Figure 7—Diethylenetriamine penta(methylene phosphonic acid) is a phosphonate.**

Phosphonate inhibitors can be used at temperatures as high as 275°F (depending on the inhibitor) without the inhibitor decomposing.

A carefully selected phosphonate inhibitor can provide excellent inhibition against CaCO₃, CaSO₄, and BaSO₄ scales at elevated temperatures. Phosphonates have the disadvantage of interfering with crosslinked polymer applications, such as fracturing fluids or conformance control fluids.

Operators on site can easily monitor the amount of phosphonate in produced water by using a common phosphate analysis, which allows on-site evaluation of the current scale protection of the well. Halliburton has one phosphonate inhibitor, Scalechek HT.

**Scalechek HT**

Scalechek HT is a phosphonate scale inhibitor designed for placement in a fracturing treatment. It is a calcium-magnesium phosphonate salt that has been coated to provide a delayed release and to prevent interference with crosslinked fracturing fluids. Scalechek HT is designed for temperatures of 150°F and greater. (It has been evaluated in the range of 150°F to 225°F.)

In laboratory tests at 175°F, the presence of 1.0 mg/L of Scalechek HT inhibits the
formation of BaSO₄ scale in simulated Gulf Coast brine.

Scalechek HT is a time-release product. After Scalechek HT is placed in a fracture, its release rate is a function of time and is dependent on contact with water.

NOTE: Scalechek HT dissolves as long as it is in contact with water, even if the well is shut in and no water is being produced at the wellhead. Keep this in mind when recommending Scalechek HT, and make the operator aware of this characteristic.

**Polyacrylic Acid and Other Carboxylic Acid-Containing Polymers**

Polyacrylic acid is a long chain of acrylic acid molecules (Figure 8). The molecular weight (the length of the chain) and the distribution of molecular weights of the polymer largely determine its effectiveness as an inhibitor. Inhibitors with molecular weights ranging from 2,000 to 10,000 appear to be effective scale inhibitors.

*Figure 8: Acrylic acid molecules link to form polyacrylic acid.*
Polyacrylic acid and derivatives of polyacrylic acid have the best temperature stability of the major types of scale inhibitors. These inhibitors are chemically stable at 300°F and above. However, the upper temperature limit for effective inhibition depends on specific water conditions.

Molecular weights determine the performance of the inhibitor on different types of scale. Polyacrylic acids are readily available with molecular weights of 800 to 10,000. Typical oilfield scales appear to respond most efficiently to a molecular weight of approximately 4,500, depending on the molecular weight distribution of the other molecules that are present.

Polyacrylic acid inhibitors are effective on the three most common scales (calcium carbonate, calcium sulfate, and barium sulfate). Halliburton has one polyacrylic acid inhibitor, Scalechek LP-55.

Polyacrylic acid inhibitors can interfere with crosslinked polymer applications (fracturing fluids and conformance control fluids), but they can be used with uncrosslinked fracturing fluids, such as water-based or foamed fluids.

A major drawback of polyacrylic acid inhibitors is the difficulty of monitoring the concentration of inhibitor in produced water. To overcome this difficulty, some polyacrylic acid inhibitors have been modified to incorporate phosphorous-tagged monomers. These monomers are detectable with a phosphate analysis.

**Scalechek LP-55**

Scalechek LP-55 is a polyacrylic acid inhibitor with excellent thermal stability. This scale inhibitor is a liquid that can be applied by several methods. These methods include

- Continuous injection of dilute solutions through the annulus or macaroni strings
- Squeeze treatments (including Chemical Placement Technique)
- Precipitation as Protex-All, a sticky liquid (Scalechek LP-55 containing surfactant)
- Precipitation of the calcium salt with the Calchek service (0.1% Scalechek LP-55 in acid)

These application methods represent ways to make the Scalechek LP-55 progressively less soluble in the produced water and more strongly adsorbed to the formation. Wells with high scaling tendencies can be treated with continuous injection. Low water-production wells with slight scaling tendencies can be treated with the Calchek service in a carbonate formation or Protex-All in a sandstone formation.

**Treatment Methods**
Three general scale-inhibitor treatment methods are currently used by the oil industry:

- Placement during a stimulation treatment
- Squeeze treatments/Chemical Placement Technique (CPT)
- Continuous injection

**Placement During Stimulation Treatment**

During a stimulation treatment, scale inhibitors are placed in one of two methods: liquid inhibitor is placed in the prepad or solid inhibitor is placed with the proppant-laden fluid.

Placing a liquid scale inhibitor, such as Scalechek LP-55, in the prepad of the fracturing fluid or in a linear gel ahead of the fracturing fluid is an established method of scale prevention. Liquid scale inhibitors are placed ahead of the fracturing fluid because they can interfere with crosslinked fluids.

Halliburton's solid inhibitors, Scalechek SCP-2 and Scalechek HT, can be placed into the proppant bed of a fracture. Usually, the inhibitor is placed with the last half of the proppant or in the last 100 ft of the propped fracture half-length to allow the solid inhibitor to more readily contact the produced water. Scalechek SCP-2 inhibitor is a solid, uniform mesh-size polyphosphate that does not interfere with fracturing-fluid crosslinkers. Scalechek HT is a solid, uniform-size phosphonate scale inhibitor that is encapsulated to control the release rate and reduce interference with crosslinking.

The minimum recommended amounts are 100 lb for Scalechek SCP-2 and 200 LB for Scalechek HT.

**NOTE** Because solid inhibitors, such as Scalechek SCP-2 and Scalechek HT, are soluble in acid, the fractured well should not be acidized until the inhibitor ceases to provide protection.

**Advantages**

Placing inhibitor during a stimulation treatment has these advantages:

- Subsequent treatment procedures are not necessary, which saves time and money.
- The inhibitor is placed with the proppant so you are more certain where it is.

**Economic Analysis**

Lower cost is one benefit of placing an inhibitor in a stimulation treatment. The following analysis shows that solid inhibitor placement in a stimulation treatment is more
economical than liquid inhibitor placement in a squeeze treatment.

Well A is in an area in which scaling problems are inhibited by small squeeze treatments every 3 months, at a cost of $4,500 per treatment ($2,500 for the service plus $2,000 for the workover rig).

A treatment on Well B in the same area used a time-released solid scale inhibitor placed with the proppant portion of the fracturing treatment. The initial cost of this treatment was $8,000. However, after 6 months, the treatment on Well B is more cost effective compared with the squeeze treatment on Well A. After adjusting to present dollar values, a solid inhibitor treatment that remains effective saves $38,000 over 3 years.

**Squeeze Treatment**

Placing scale inhibitor by the squeeze treatment method involves pumping the liquid scale inhibitor down a wellstring and forcing it into the formation. This technique enables the inhibitor to be adsorbed on or bound to the high surface area of the formation.

The scale inhibitor slowly releases as the produced fluids from the well flow across the treated area into the wellbore. Squeezing scale inhibitor into place in the formation where the deposition of scale can occur is relatively simple. Often a secondary squeeze or overflush of a chemical, such as CaCl$_2$, is also applied to slow the return of scale inhibitor. This delayed return is the result of the inhibitor and overflush reaction, which produces a calcium salt.

The success of the treatment depends on a continued slow dissolution of the scale inhibitor from the reservoir into the produced fluid. Squeeze treatments require some shut-in time (up to 48 hours before the well can be placed back on production). A major benefit of a squeeze treatment is that it eliminates the need for personnel to check on the injection equipment and the supply of scale inhibitor solution.

After the squeeze treatment, the concentration of scale inhibitor produced typically follows an exponential decline curve. The disadvantage of this behavior is that an excessive amount of scale inhibitor is produced back initially, with subsequently smaller quantities produced over time. Some chemical is also irreversibly lost to the formation. Carbonate or clay minerals must be present in the formation to retain enough inhibitor to provide long-term scale protection.

Squeeze treatments have several other drawbacks:
The concentration of inhibitor that flows back with the brine depends on the chemistry of the inhibitor salt; control is limited. Lost production during the shut-in time of the squeeze procedure impacts the profitability of the well. Some wells do not regain original production volumes.

**Chemical Placement Technique (CPT)**

CPT is a method of placing liquid inhibitor into a fractured formation to achieve slow feedback and long-term control of scale. CPT is a squeeze treatment on a naturally or hydraulically fractured well. This technique must be used in natural or induced fractures or in conjunction with a fracturing treatment because the pressure drop profile of a fractured formation is required.

Equations help calculate total feedback time and the initial concentration of chemical being returned in the produced fluids. These equations are published in paper SPE 1771 entitled, "Design Techniques For Chemical Fracture Squeeze Treatments," by Tinsley, Lasater, and Knox. It was also published in the November 1967 issue of the Journal of Petroleum Technology. For more information, contact Stimulation Chemicals in the Duncan Technology Center, Duncan, Oklahoma, USA or your Halliburton representative.

**Continuous Injection**

The continuous injection scale treatment method is a technique in which the inhibitor is pumped down the tubing from the surface and enters the production stream at a depth where scaling is not yet occurring. Chemicals must be injected continuously. The treating string usually has a surface pump, a metering device, a connection to the wellhead, and an entry to the flow stream.

The objective of the treatment is to prevent scaling of downhole equipment and stop precipitation on the formation face near the wellbore. Liquid solutions of scale inhibitors are typically applied in this method, and the equipment is installed by the well service company. The liquid scale inhibitors are usually diluted to achieve good distribution of the inhibitor in the brine stream and to avoid precipitation caused by concentrated inhibitor contacting the brine. Treating-string inhibition is performed on injector wells and producing wells. Continuous treatment allows the most efficient application of chemical inhibitor because only the effective dosage required is actually pumped down the treating string.

The most objectionable features of continuous injection are (1) the continual need for personnel to refill chemical pumps at specified times and (2) the risk that the pump can
fail and allow scale to build up, which can result in expensive remedial operations.

**Summary**

Scale is a general term used for minerals deposited from produced water. Common scales include calcium carbonate, calcium sulfate, and barium sulfate. Scale can be caused by any one or a combination of several factors. Consider the type of scale and the conditions present when deciding what type of scale inhibitor to use.

Halliburton offers several scale inhibitor products, which vary by chemistry and recommended placement methods.

**Liquid Inhibitors—Scalechek LP-55 and Protex-All**

- Placed in the prepad or linear fluid of a fracturing treatment
- Placed by the Chemical Placement Technique
- Used in conjunction with an acidizing treatment, such as the Calchek process

**Solid Inhibitors—Scalechek SCP-2 and Scalechek HT**

- Placed during a fracturing treatment
- Simplifies the process of scale inhibition
- Computer models aid in job designs
- Economical method of providing scale inhibition