Diversion in Matrix-Acidizing Treatments

Introduction

The success of matrix acidizing treatments depends on the placement of acid to remove near-wellbore formation damage efficiently. The acid should be placed so that all potentially productive intervals accept a sufficient quantity of the total acid volume. If significant permeability or formation damage variations are present in the interval to be treated, acid will enter the zones with the highest permeability or least formation damage, leaving little acid to treat what may be the most productive zones.

To achieve uniform damage removal, the original flow distribution across the treated interval needs to be altered to provide generally equal acid distribution. The methods used to alter this flow distribution are called irdiversionsal methods, since their purpose is to divert the flow of fluid from one portion of the interval being acidized to another. The diversion method best suited for a particular situation depends on many factors, including the type of well completion, perforation density, the type of fluid that is produced or injected after the treatment, casing and cement sheath integrity, bottomhole temperature, and bottomhole pressure.

The surest way to uniformly treat an interval is with a mechanical isolation device such as a straddle packer. This packer allows acid to be injected into small intervals, one by one, until the entire zone has been treated. However, this method is often not practical or possible. Without a packer, diverting agents must be used during stimulation to reduce flow into nonproductive or undamaged zones and redirect this flow to zones in greater need of damage removal.

Acid Diverters: Types and Uses

Acid diversion alters the natural flow profile into a formation during injection, causing acid flow to be diverted from undamaged or high-permeability intervals to damaged or lower-permeability intervals.

The diversion methods used to alter the original flow profile may attempt to achieve complete shutoff of flow into specific intervals or to equalize flow across the entire interval being treated, regardless of permeability or damage severity. The types of diverting methods fall into four general categories:
- Ball sealers
- Degradable particulate-diverting agents
- Viscous fluids
- Foam

**Ball Strength**

Ball strength is the maximum differential pressure that can be maintained across a specific ball for a specified time at a known temperature before the balls extrude through a perforation. Figure 2 shows the relationship between differential perforation pressure and temperature for 7/8-in. RCN on a 0.52-in. hole. The time used in these tests is 1 hour.

**Figure 2: Differential Perforation Pressure and Temperature for 7/8-in. RCN in a 0.52-in. Hole**

![Graph showing the relationship between differential extrusion pressure and temperature.](image)

**Ball Seating**

The minimum ball-seating flow rate is the flow rate required to pull a single ball out of a fluid stream when there is no vertical flow beyond the perforation. As the vertical flow by a perforation increases, the rate required to seat the ball also increases. Table 2 provides information on the minimum flow rate required for ball sealers in various pipe sizes.

**Table 2: Minimum Flow Rate Required for Different Size Ball Sealers**
Ball Sealers

Perfpac balls are transported in the treating fluids and are designed to seal perforations taking fluid. This action (Figure 1) diverts the flow of the treating fluid to another perforation. Theoretically, when all perforations have taken fluid and are covered with a ball sealer, a "ballout" will occur, and the pressure at the surface should increase significantly.

Figure 1: Perfpac Balls Sealing Perforations

<table>
<thead>
<tr>
<th>Ball Type and Size</th>
<th>Specific Gravity of Ball Sealer</th>
<th>Casing and Tubing Size (in.)</th>
<th>Perforation Size (in.)</th>
<th>Minimum Flow Rate (gal/min/perf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>5/8-in. Rubber</td>
<td>1.3</td>
<td>27/8</td>
<td>3/8</td>
<td>8</td>
</tr>
<tr>
<td>7/8-in. RCN</td>
<td>1.3</td>
<td>5 1/2</td>
<td>5/8</td>
<td>17</td>
</tr>
<tr>
<td>7/8-in. Rubber</td>
<td>1.3</td>
<td>7</td>
<td>5/8</td>
<td>20</td>
</tr>
<tr>
<td>15/16-in. Rubber</td>
<td>1.3 to 1.4</td>
<td>5 1/2</td>
<td>1/2</td>
<td>23</td>
</tr>
<tr>
<td>15/16-in. Rubber</td>
<td>1.3 to 1.4</td>
<td>7</td>
<td>1/2</td>
<td>29</td>
</tr>
<tr>
<td>1.25-in. RCP</td>
<td>1.2</td>
<td>5 1/2</td>
<td>7/8</td>
<td>13</td>
</tr>
<tr>
<td>1.25-in. RCP</td>
<td>1.2</td>
<td>7</td>
<td>7/8</td>
<td>34</td>
</tr>
</tbody>
</table>
When the pumping stops and the flow reverses, the balls are released and allowed to fall into the "rathole." Ball sealers can be used in both acidizing and fracturing fluids.

Perfpac balls are available in a wide variety of materials, densities, and sizes. Table 1, contains a complete list of the Perfpac Balls available. Almost 90% of the balls used today are $\frac{7}{8}$ in.
Table 1: Types of Perfpa Balls Available

<table>
<thead>
<tr>
<th>Type and Size</th>
<th>Specific Gravity</th>
<th>Ball-Core Diameter (in.)</th>
<th>Core Type</th>
<th>Max. Recom. Perf. Size (in.)</th>
<th>Color</th>
</tr>
</thead>
<tbody>
<tr>
<td>5/8-in. rubber (solid)</td>
<td>1.30</td>
<td>None</td>
<td>None</td>
<td>0.38</td>
<td>Orange</td>
</tr>
<tr>
<td>5/8-in. RCN</td>
<td>1.10</td>
<td>0.5000</td>
<td>Nylon</td>
<td>0.38</td>
<td>Green</td>
</tr>
<tr>
<td>5/8-in. RCN</td>
<td>1.30</td>
<td>0.5000</td>
<td>Nylon</td>
<td>0.38</td>
<td>Black</td>
</tr>
<tr>
<td>3/4-in. RCN</td>
<td>1.30</td>
<td>0.6250</td>
<td>Nylon</td>
<td>0.52</td>
<td>Black</td>
</tr>
<tr>
<td>7/8-in. RCA</td>
<td>1.85</td>
<td>0.6250</td>
<td>Aluminum</td>
<td>0.52</td>
<td>Silver</td>
</tr>
<tr>
<td>7/8-in. RCN</td>
<td>1.10</td>
<td>0.7500</td>
<td>Nylon</td>
<td>0.52</td>
<td>Gray/Green</td>
</tr>
<tr>
<td>7/8-in. RCN</td>
<td>1.10</td>
<td>0.7500</td>
<td>Nylon</td>
<td>0.52</td>
<td>Green</td>
</tr>
<tr>
<td>7/8-in. RCN</td>
<td>1.20</td>
<td>0.7500</td>
<td>Nylon</td>
<td>0.52</td>
<td>Yellow</td>
</tr>
<tr>
<td>7/8-in. RCN</td>
<td>1.30</td>
<td>0.7500</td>
<td>Nylon</td>
<td>0.52</td>
<td>Black</td>
</tr>
<tr>
<td>7/8-in. RCN</td>
<td>1.30</td>
<td>0.7500</td>
<td>Nylon</td>
<td>0.52</td>
<td>Gray</td>
</tr>
<tr>
<td>7/8-in. RCP</td>
<td>1.40</td>
<td>0.7500</td>
<td>Phenolic</td>
<td>0.52</td>
<td>Blue</td>
</tr>
<tr>
<td>7/8-in. RCP</td>
<td>0.90</td>
<td>0.7500</td>
<td>Phenolic</td>
<td>0.52</td>
<td>Red</td>
</tr>
<tr>
<td>7/8-in. RCP</td>
<td>1.00</td>
<td>0.7500</td>
<td>Phenolic</td>
<td>0.52</td>
<td>Brown</td>
</tr>
<tr>
<td>7/8-in. &quot;E&quot; Ball</td>
<td>0.90</td>
<td>0.7500</td>
<td>Syntactic Foam</td>
<td>0.52</td>
<td>Gold</td>
</tr>
<tr>
<td>7/8-in. &quot;E&quot; Ball</td>
<td>1.00</td>
<td>0.7500</td>
<td>Syntactic Foam</td>
<td>0.52</td>
<td>White</td>
</tr>
<tr>
<td>15/16-in. Rubber (solid)</td>
<td>1.20</td>
<td>None</td>
<td>None</td>
<td>0.52</td>
<td>Yellow</td>
</tr>
<tr>
<td>1-in. RCN</td>
<td>1.10</td>
<td>0.8750</td>
<td>Nylon</td>
<td>0.63</td>
<td>Green</td>
</tr>
<tr>
<td>1-in. RCN</td>
<td>1.30</td>
<td>0.8750</td>
<td>Nylon</td>
<td>0.63</td>
<td>Black</td>
</tr>
<tr>
<td>1 1/4-in. RCN</td>
<td>1.20</td>
<td>1.0625</td>
<td>Nylon</td>
<td>0.87</td>
<td>Yellow</td>
</tr>
<tr>
<td>1 1/4-in. RCN</td>
<td>1.30</td>
<td>1.0625</td>
<td>Nylon</td>
<td>0.87</td>
<td>Black</td>
</tr>
</tbody>
</table>

General Guidelines for Ball Sealers

- Pipe ID should be greater than three ball diameters if balls are dropped in clusters. Pipe ID is not a concern for balls dropped individually.
- Balls should be used in the proper temperature and pressure differential ranges. In moderate temperature and pressure ranges, a solid rubber ball can be used. At higher temperature and pressure ranges, rubber-coated nylon (RCN) balls are required. Use phenolic-centered balls at temperatures of 350°F and above.
- The larger the diameter of the pipe, the higher the pump rate must be to seat the ball.
- When there is a greater difference between the ball’s specific gravity and the fluid’s specific gravity, a higher pump rate is required to seat the ball.
- The greater the viscosity of the fluid, the easier it is to seat the ball.
- The smaller the ball, the easier it is to seat, but it must fit the perforation.
- Never use a ball with a core smaller than the perforations.
- Balls should be $\frac{3}{4}$ in. or more larger than the perforations.
- A good cement job and well-shaped perforations are needed for effective use of
ball sealers.

- Excess balls are generally run with non-buoyant balls or "sinkers". Excess values range from 50 to 100% above the number of perforations to be "balled-out."
- Literature indicates that buoyant balls are 100% efficient at all flow rates greater than 0.4 gal/min per perforation. Therefore, the number of buoyant balls used in diverting a treatment generally should not exceed 110% of the number of perforations being treated.¹

Designing An Example Treatment with Ball Sealers⁴

Fluid: 15% HCl (specific gravity = 1.075)

Balls: 1.1 specific gravity balls

Rate: 4 bbl/min

Zone: 200 ft perforated length with 2 spf

Wellbore configuration: 200 ft of casing (7-in., 32lb/ft, N-80) below 5,000 ft of 2 7/8-in., 6.5 lb/ft, N-80 tubing

To design an acidizing treatment with ball sealers, complete the steps outlined below.

1. Calculate the ball’s settling velocity.

   Add a non-buoyant ball’s settling velocity to the average fluid velocity in the tubulars. A buoyant ball has a negative settling velocity and is subtracted from the fluid velocity (Figure 3).

Figure 3: Negative Settling Velocity for 7/8-in. Ball Sealers
Formula 1

\[ V_s = \sqrt[3]{\frac{4gD\Delta \rho}{3(f_b)\rho_f}} \]

where

- \( V_s \) = settling velocity
- \( g \) = gravitational constant
- \( D \) = diameter of the ball
- \( \Delta \rho \) = ball density minus fluid density
- \( \rho_f \) = fluid density
- \( f_b \) = friction factor of the ball

where

- \( V_s \) = settling velocity
- \( g \) = gravitational constant
- \( D \) = diameter of the ball
- \( \Delta \rho \) = ball density minus fluid density
\( \rho_f \) = fluid density

\( f_b \) = friction factor of the ball

Note: In the Newton's Law region, which covers the Reynolds number range of 1,000 to 200,000, the friction factor of a sphere is an approximately constant value of 0.44.\(^5\) Check the Reynold's number to ensure the balls are in the appropriate region.

Example: Settling Velocity \((V_S) = 24.4 \text{ ft/min downward}\)

2. Determine the velocity of fluid movement.

To determine the pipe velocity, divide the pump rate in ft\(^3\)/min by the cross-sectional area of the pipe size.

Example: Velocity of fluid in 7-in. casing = 111 ft/min Velocity of fluid in 2 7/8-in. tubing = 691 ft/min

3. Determine the ball's velocity.

The ball's movement or velocity will be the rate of fluid movement (Step 2) plus (or minus if the ball is buoyant) the ball's settling velocity (Step 1).

Example: Velocity of ball in 7-in. casing = 135 ft/min Velocity of ball in 2 7/8-in. casing = 716 ft/min

4. Determine the transport time of the ball.

The time required to transport the ball is the total of the transport times (each length of tubular section divided by the ball's velocity in that section).

Example: For 10,000 ft of 2 7/8-in. tubing (at 716 ft/min) + the 200 ft. of 7-in. casing (at 135 ft/min) = 15.4 minutes

5. Determine the total pipe volume and fluid transport time.

The total volume is the sum of each tubular section multiplied by the volume of fluid length. This volume, divided by the rate, provides the fluid transport time.

Example: Pipe Volume = 65.1 bbl At 4 bbl/min, fluid transport time = 16.3 minutes

6. Determine the rate the ball migrates.

The ball migration is equal to the difference between the ball's transport time (Step 4)...
and the fluid's transport time (Step 5) multiplied by the rate. Remember that a buoyant ball moves up and a heavier ball moves down.

Example: The heavier balls are 3.5 bbl ahead of the fluid.

7. Ensure that minimum stage volumes are correct.

The minimum stage volume should be equal to the volume of fluid to be diverted in that stage plus the ball-migration volume. This amount helps ensure that stage volumes are large enough to prevent balls from floating or sinking out of the fluid.

Example: When using 100 gal/ft of fluid across the entire 200 ft of perforated interval, the fluid stage will be 20,000 gal (476 bbl) plus the 3.5 bbl that the balls migrate (480 bbl).

8. Determine the ball injection schedule.

In the simplest cases, the ball injection schedule is the volume of fluid to treat the zone, plus the ball migration volume, divided by the number of balls to be injected. The ball injection schedule as a function of time is determined by dividing the new value by the injection rate.

Example: When running 0% excess, use 480 bbl of fluid and 200 balls (1 ball every 2.5 bbl of fluid or approximately every 30 seconds). When running 100% excess, use a ball every 1.25 bbl of fluid or every 15 seconds.

**Ball Sealers in Horizontal and Deviated Holes**

The major influences on ball sealer efficiency in horizontal and deviated holes are hole angle, ball density, flow rate, perforation orientation, and permeability contrast.

Floating ball sealers usually seat on the high-side perforations and "sinking" ball sealers seat on the low-side perforations. Neutrally buoyant ball sealers seat on top and bottom perforations and have a significant (though lower) tendency to seat on the horizontally oriented perforations. Neutrally buoyant ball sealers favor 0° or 180° phased perforations.

The minimum axial velocity required to seat the ball sealer is approximately 40 to 50 ft/min (0.9 specific gravity balls on top perforations and 1.2 specific gravity balls on bottom perforations). For example, in 7-in. casing, the velocity required is 3 to 4 bbl/min. A study by P.A. Bern indicates that 200 perforations is the maximum number of perforations that can be stimulated in a single interval. In Bern's study, minimum flow rates per perforation ranged from 0.025 to 0.1 bbl/perf/min.
At these minimum values, 0.9 specific gravity balls had seating efficiencies of 20 to 100% on topside perforations. The 1.0 specific gravity balls on horizontal perforations (90° phasing) had seating efficiencies of 0 to 69%. The 1.1 and 1.2 specific gravity balls on bottom-side perforations had efficiencies similar to the buoyant balls on the topside perforations. It is easier to obtain good diversion with 0° phasing than with 90° phasing perforations.

For perforations to capture a ball at other than 0° or 180° degree phasing, the forces of gravity must be overcome. Two methods have been proposed. The first method uses two different density-miscible stages in which the balls are lighter than one fluid and heavier than the other. The second method uses two different density-immiscible fluids in which the balls are lighter than one fluid and heavier than the other. The balls will then migrate to the mixing interface or the sharp immiscible interface and will be aligned better to seat on perforations.

**Ball Injectors**

One method of injection is the use of bypass ball injectors that release balls in clusters. Halliburton’s Shur Shot™ Ball Injector was developed for positive mechanical injection of balls against elevated pressures and into extremely viscous fluids. The Shur Shot unit uses positive mechanical injection that does not depend on gravity and is not affected by pressure differential.

**Degradable Particulate-Diverting Agents**

Degradable particulate-diverting agents come in a variety of chemical compositions and sizes. Selecting the best type for a particular formation depends on the formation permeability, type of completion, type of produced fluid, and type of acid used for the treatment.

All types of particulate-diverting agents function in the same general manner. When fluids containing the particulate material are pumped, they will enter high-permeability or undamaged zones, causing the buildup of a low-permeability filter cake within the perforation tunnel, on the outside of the perforation, or on the formation face. The added pressure drop caused by this filter cake increases flow resistance in the areas where the diverting agent has been deposited, causing diversion of flow to other parts of the interval where little or no diverting agent has been placed.

*Figure 4: Diversion from a High-permeability to Low-permeability Core Using an Oil-soluble Res Diverter Stage*
Figure 4 illustrates the effect of injecting a small, oil-soluble resin diverting stage simultaneous to a 470 md core and a 1,400 MD core. Once the flow rates have stabilized after the diverter stage has been completed, they equalized as a result of the build up of a thin, low-permeability filter cake at the face of the high-permeability core.

Every particulate-diverting agent must meet certain criteria:

- It should be soluble in the fluid produced from the well or fluid injected into the well after treatment.
- It must have a melting point higher than the bottomhole treating temperature of the well.
- It must be sized correctly to function in the type of well completion in place.
- It must be compatible with the treating fluids used.

Table 3 contains a list of all Halliburton degradable particulate-diverting agents with their physical properties, uses, and recommended concentrations.

**Table 3: Properties and Uses of Particulate-Diverting Agents Listed by Melting Point**
Give special consideration to the size distribution of particulate-diverting agents used in gravel-packed wells. The particles must be small enough to pass through the gravel-pack screen and the gravel pack itself, yet still be large enough to form a filter cake at the formation face. The only particulate-diverting agents available from Halliburton that meet these requirements are Matriseal® O and Matriseal® OWG. The maximum particle size of either of these two diverting agents is 100 microns.

In dry gas wells, the particulate-diverting agent used must sublime (transform from a solid to a vapor phase) in methane gas to be removed by the produced gas from the well following the treatment. Diverting agents that can be used for this purpose are TLC-80 and Matriseal OWG. Both of these diverters are benzoic acid particulates, but they have different size ranges. In low-temperature dry gas wells, the sublimation rate of these diverting agents is rather slow, and a post-acidizing overflush of methanol or isopropyl alcohol (IPA) may be needed to perform an efficient, rapid cleanup of the deposited particles.

Benzoic acid diverting agents are somewhat soluble in fluids such as acid or ammonium chloride, following the diverting stages. Therefore, all treating fluids pumped after the first

<table>
<thead>
<tr>
<th>Type of Particulate</th>
<th>Melting Point (°F)</th>
<th>Specific Gravity</th>
<th>Soluble in 1</th>
<th>Applicable Well Types</th>
<th>Type of Diversion</th>
<th>On Perforations (3/8-in.)</th>
<th>In Perforations (per perforation)</th>
<th>Open (lb/ft² of f)</th>
</tr>
</thead>
<tbody>
<tr>
<td>TBA-110 (graded rock salt)</td>
<td>1,472</td>
<td>2.164</td>
<td>water and dilute acid</td>
<td>oil 1, gas 1, and water injector</td>
<td>on perforations, in perforations, and on formation</td>
<td>16 lb at 1 lb/gal, 9 lb at 1.5 lb/gal</td>
<td>0.5 to 2 lb</td>
<td>5</td>
</tr>
<tr>
<td>Matriseal® O (oil-soluble resin)</td>
<td>328 6</td>
<td>1.062</td>
<td>oil</td>
<td>oil and gas 2</td>
<td>through gravel pack 3 and on formation</td>
<td>—</td>
<td>0.5 to 2.5 gal fluid containing 0.5% Matriseal® O 4</td>
<td>5 to 20 gal</td>
</tr>
<tr>
<td>TLC-80 (benzoic acid flakes)</td>
<td>252</td>
<td>1.316</td>
<td>oil, gas, dilute acid, and water</td>
<td>oil, gas, and water injector</td>
<td>on perforations, in perforations, and on formation</td>
<td>9 lb at 0.5 lb/gal, 2 lb at 1 lb/gal</td>
<td>0.25 to 1 lb</td>
<td>2.5</td>
</tr>
<tr>
<td>Matriseal® OWG 5</td>
<td>252</td>
<td>1.316</td>
<td>oil, gas, dilute acid, and water</td>
<td>oil, gas, and water injector</td>
<td>through gravel pack 3 and on formation</td>
<td>—</td>
<td>25 gal fluid containing 4% Matriseal® OWG</td>
<td>25 gal fluid containing 4% Matroseal® OWG</td>
</tr>
<tr>
<td>Frax 140.10 (wax beads)</td>
<td>97 to 163</td>
<td>0.850</td>
<td>oil</td>
<td>oil and gas</td>
<td>in perforations and on formation</td>
<td>—</td>
<td>0.25 to 1 lb</td>
<td>2.5</td>
</tr>
<tr>
<td>Frax 160.10 (wax beads)</td>
<td>95 to 185</td>
<td>0.900</td>
<td>oil</td>
<td>oil and gas</td>
<td>in perforations and on formation</td>
<td>—</td>
<td>0.25 to 1 lb</td>
<td>2.5</td>
</tr>
</tbody>
</table>

1. If an oil or gas well makes little or no water, a cleanup treatment using dilute acid or brine may be required.
2. These diverting agents are applicable for gas wells only when the well is producing significant condensate at the perforations (the gas reservoir is at or below its dew point).
3. Matriseal® O will pass through a 40/80 gravel pack and leave a filter cake on the formation. When Matriseal® OWG is used in gravel-packed wells, add 0.5% HC-2 or Pen-5 to the carrier fluid as a dispersant to attain particle size distribution small enough to pass through the gravel pack.
4. Field experience in high-permeability sands shows that up to 1 gal of fluid per perforation containing 4% Matriseal® O may be required for adequate diversion.
5. Treating fluids following Matriseal® OWG diversion stages should contain a sufficient quantity of Matriseal® OWG to saturate the filter cake at bottomhole treating temperature. This procedure prevents premature dissolution of the filter cake during the treatment (Figure 5).
6. The softening point of oil-soluble resin is 250°F. Poor performance should be expected in higher temperatures.
benzoic acid diverting stage should be saturated with benzoic acid to prevent premature dissolution of the filter cake. For 15% HCl, approximately 45 LB of benzoic acid/Mgal of acid at 150°F would be required. Figure 5 shows the solubility of benzoic acid in various fluids as a function of temperature.

**Figure 5: Solubility of Benzoic Acid in Various Fluids**

![Solubility of Benzoic Acid in Various Fluids](image)

Apply wax beads for diversion in high-rate treatments on horizontal wells where the bottomhole static temperature is 25°F to 35°F higher than the melting point of the diverting agent, but the bottomhole treating temperature is below the diverter's melting point resulting from significant cooling in the near-wellbore region.

This practice allows effective placement of the diverting agent during the treatment and quick cleanup following the treatment as the wax diverter melts. Cleanup may also be accomplished by dissolving the wax particles in oil or gas condensate once the well is returned to production.

**Viscosified Fluids**

For matrix acidizing in carbonates, the process of alternating stages of Halliburton's Viscosity Controlled Acid (VCA) with 15 to 28% HCl has produced excellent diversion results in many formations. VCA has an initial viscosity of approximately 20 cp, allowing for ease of pumping. As the VCA enters the zones offering the least resistance to flow, the acid crosslinks in the formation as it spends to a pH of 2 to 4. A buffer is added to help maintain this pH range for as long as possible. As the pH of the VCA increases above 4, the crosslinked gelled acid will break to a viscosity of approximately 5 cp, allowing for ease of flowback. An internal breaker is also included. The resistance to flow provided by the crosslinked gel causes diversion of regular acid to other intervals. The rate of
diversion can be controlled by adjustments to the HCl concentrations in the VCA.

HCl concentrations as low as 1% can be used for VCA stages in cool formations where acid spending occurs slowly. The typical ratio of the volume of neat acid stages to VCA stages is 4:1. When pumped as a single stage at high rates, VCA can act as a continuous diverting acid if pressures are kept below fracturing pressure. The upper temperature limitation on VCA is 225°F; however, a high-temperature version has also been introduced that can be used up to 300°F.

In zones containing extremely high-permeability thief zones, a condition in which other diversion methods have failed, Temblok® 100 has proven effective in diverting acid to the remainder of the zone. Temblok 100 is pumped as a relatively thin gel that can be spotted across the thief zone as a balanced plug with coiled tubing. The increased temperature of the formation then causes hydration of a large quantity of secondary gelling agent, forming a tough semi-solid gel plug in the casing. The time required for the secondary gelling agent to begin to hydrate can be modified to fit different temperature conditions and tubing transit times.

Before hydration of the secondary gelling agent, the end of the coiled tubing is run through the still liquid plug to the required depth and the gel plug is allowed to set. An acid treatment can then be performed with the thief zone isolated from acid contact, since the Temblok plug acts as a temporary packer.

Acid contact causes the gel plug to begin to break at the acid and gel interface, and several Temblok plugs may be required to maintain diversion during extended treatments. This technique has also been used successfully to keep acid from entering water zones below the pay zone during treatment. The upper temperature limitation on Temblok® 100 is 225°F. Temblok 90 can be used from 225°F to 350°F.

**Foam**

In recent years, the use of foams for diversion has gained acceptance and is widely practiced in many areas. The three integral parts of foam are a gas phase, a liquid phase, and a foaming surfactant, which gives the foam its stability. The percentage of gas contained in the foam is referred to as the foam quality. The gas used for foam diversion is typically N₂, while the liquid phase may be either an acid or a non-reactive salt solution, such as ammonium chloride.

The process that causes the flow reduction when foam enters a rock formation is different than the process used with a particulate-diverting agent or a viscous gel. Because foam
contains a large amount of gas, it causes an increase in gas saturation and a decrease in liquid saturation near the wellbore as it enters the rock. This saturation reduces the liquid relative permeability of the formation in the zones where foam has entered. This reduction in relative permeability can increase the resistance to liquid flow 100 to 1,000 times over the resistance originally exhibited by the formation before foam entry.

As foam is injected and enters the highest permeability or least damaged zones of the interval, subsequent acid stages will be diverted to zones where foam has not entered. Figure 6 shows the effect of a foam-diversion slug during simultaneous injection to a damaged and undamaged core at a total injection rate of 50 mL/min. The initial flow distribution during the injection of 2% NH₄Cl showed that only 9% of the flow was entering the damaged core.

**Figure 6: Foam Diversion to a Damaged Core**

Following the injection of a small foam slug, 500 ml of hydrofluoric (HF) acid was injected into the cores. At the beginning of the acid stage, the foam slug had caused the flow to the damaged core to increase to 50% of the total flow rate. This diversion caused the majority of the HF acid stage to enter the damaged core. As damage removal occurred, the percentage of the total flow rate entering the damaged core increased to 84% of the total. During the injection of a large 2% NH₄Cl overflush, the individual flow rates to each core began to slowly converge as the foam decayed.
Design Considerations for Foam Diversion

The behavior of foams in rock is extremely complex and is not well understood. However, field experience and laboratory testing provide guidelines for designing foam-diverted, matrix-acidizing treatments.

Permeability

Lab testing shows that extremely high-pressure gradients will be generated in sandstone having a permeability of less than 50 Md. Generally, foam should not be considered for matrix acid diversion in low-permeability formations because of its potential to exceed allowable pressure limitations. The best candidate wells for foam diversion in sandstones will typically have permeabilities greater than 100 MD but less than 2,000 Md.

Carbonate acidizing can be viewed as a process that generates wormholes and interconnects natural fractures and vugs. The acid dissolves the rock matrix and leaves open, void spaces. In this situation, foam is not limited to entering only matrix porosity, as in sandstones, since foam will also enter the void spaces created by acid dissolution of the formation. This action creates a different diversion mechanism when foam is used in carbonate matrix acidizing than when it is used in sandstones. Because of these differences, the use of foam diversion in carbonates could be considered in formations with permeabilities as low as 1 Md.

Foam Slug Volume

The complex nature of foam used in rock formations makes it difficult to predict the pressure response that the injection of a specific volume of foam will produce. A general guideline from field experience is that 1 bbl of foam for each foot of diverted interval be used when sandstone formations are acidized. For example, a 100-ft thick sandstone formation might be treated in five foam-diverted acid stages consisting of an HCl preflush stage, an HF acid stage, an overflush stage, and a foam stage. Each stage would treat a 20-ft segment of the total interval. The volume of each of the foam stages separating the nonfoamed stages would be 20 bbl. Previous experience in the formation being treated (and the response of the formation during the actual treatment) could indicate the use of larger or smaller foam volumes.

In carbonate formations, the size of a foam diversion slug depends on the size of the acid stage pumped before it. Unlike sandstone acidizing, the dissolution of the rock matrix by HCl creates a significant volume of void space in the formation. For diversion to occur, the minimum foam slug volume would be the amount of foam required to fill the void space.
created by the acid stage pumped before the diversion stage. Table 4 shows the amount of void space created, depending on acid strength and formation porosity.

**Table 4: Void Space Created by Hydrochloric Acid in Limestone**

<table>
<thead>
<tr>
<th>HCl (%)</th>
<th>ϕ=0%</th>
<th>ϕ=10%</th>
<th>ϕ=20%</th>
<th>ϕ=50%</th>
</tr>
</thead>
<tbody>
<tr>
<td>28</td>
<td>16</td>
<td>18</td>
<td>20</td>
<td>32</td>
</tr>
<tr>
<td>20</td>
<td>11</td>
<td>12</td>
<td>14</td>
<td>22</td>
</tr>
<tr>
<td>15</td>
<td>8</td>
<td>9</td>
<td>10</td>
<td>16</td>
</tr>
<tr>
<td>5</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>5</td>
</tr>
</tbody>
</table>

A 100-bbl stage of 15% HCl in a formation with 20% porosity would create 10 bbl of void space. A foam-diversion stage following this acid stage would require a minimum of 10 bbl of foam. Approximately 25 to 50% of the foam can be expected to enter the matrix beyond the created void space, so a reasonable volume for this foam-diversion stage would be 12 to 15 bbl. If 28% HCl has been used, this foam volume would be increased to 24 to 30 bbl because of the additional void space created by the stronger acid.

**Tubing Size**

The size of the tubing used in the treatment is important in determining tubing volume and transit time. Using a foam slug volume that occupies at least 30%, and preferably 50% or more, of the tubing volume is recommended to help minimize mixing effects when foam and liquid stages are simultaneously occupying the tubing string. Transit time from surface to the formation should also be considered in minimizing the mixing of foam-diverting slugs with liquid stages in the tubing.

Generally, the transit time of the foam slug must be limited to less than 30 minutes. Because satisfying these recommendations when large-diameter tubing is in place can be difficult, the use of coiled tubing to minimize tubing volume and transit time may be appropriate. An additional benefit of minimizing tubing volume and transit time of foam slugs is that the formation pressure response to the foam stages is produced quickly, allowing the volume of subsequent foam stages to be modified during the treatment if treating pressures are excessive or pressure response is insufficient.

**Foam Quality**
Laboratory testing and field experience show that foam qualities in the range of 65 to 80% provide the maximum benefit in attaining fluid diversion. Halliburton's testing also shows that the pressure gradients induced in lower-permeability formations of 50 to 200 MD can become excessive when high-quality foams are used; therefore, an initial foam quality of 65% is recommended to avoid the possibility of producing excessively high treating pressures when formations are acidized in this permeability range.

In high-permeability formations, higher quality foams could be considered, particularly if lower quality foams previously produced inadequate pressure increases during diversion stages.

**Injection Rates**

Laboratory testing shows that the pressure gradient produced in a rock formation during foam injection depends both on foam quality and injection rate. At high injection rates, increasing foam quality produces an exponential increase in the pressure gradient. At low injection rates, the pressure gradient appears to be much less dependent on the foam quality. This factor is illustrated for a high-permeability sandstone in Figure 7.

**Figure 7: Effect of Foam Injection Rate on Pressure (2,600-MD Sandstone)**

![Figure 7: Effect of Foam Injection Rate on Pressure (2,600-MD Sandstone)](image)

This figure suggests that pressure increases in high-permeability formations during foam diversion could be exponentially increased by maximizing the injection rate as high-quality foam enters the formation, provided the fracture gradient of the formation is not exceeded.

**Foaming Agents**
HC-2 has proven to be the most effective and versatile foaming agent used in foam-diverted treatments. It is applicable in either acid or salt solutions up to 300°F. Use a concentration of 0.5% foaming agent in the base fluid at temperatures below 225°F. In temperature ranges from 225°F to 300°F, the concentration should be increased to 1%. Alternative foaming agents, such as Sperse-All can be used for foaming acid at temperatures up to 300°F at 1% concentration, and Pen-5 can be used to foam acid up to 250°F at 0.5% concentration. These two foaming agents can also be used to foam salt solutions, but the upper temperature restriction is 180°F.

**Continuous Foam Diversion**

In the foam-diversion methods discussed above, it was assumed that the stages intended for damage removal would be unfoamed and separated by discrete foam slugs intended to promote diversion. In some cases though, the best option may be to foam all fluids pumped. This option might be used in extremely long sandstone or carbonate intervals or in high-permeability or high-porosity carbonates. In these situations, small-volume foam slugs may not be adequate to promote diversion.

One approach to continuous foam diversion is to increase the foam quality of all fluids throughout the treatment. Because research has shown that foam qualities less than 50% have little diverting effect, 50% should be considered the minimum foam quality for use in continuous diversion with increasing foam quality. For example, a five-sequence treatment might use fluids that increase foam quality in 5% increments for each stage, resulting in sequences of 50, 55, 60, 65, and 70-quality foam.

For an HF acidizing treatment, the foamed fluids would include preflush, HCl, HCl/HF, and overflush stages in each sequence. In a carbonate acidizing treatment, only HCl, foamed to increasingly higher qualities, would be used.

One carbonate-acidizing situation in which non-HCl fluids should be considered during foam diversion is in high-porosity chalks. Testing shows that foamed acid will penetrate rapidly through such formations with little diverting effect. Foamed brine is recommended for diverting stages in high-porosity chalks, regardless of whether all fluids are foamed or discrete foam slugs are used.

**References**


