Sand Control Production Enhancement
Products and Services

Halliburton Sand Control offers many products and systems to prevent the loss of asset value caused by sand production. The development of these products and systems is based on customer needs as well as comprehensive research in the areas of fluids and pumping technology, resins and coatings, fluids rheology, and formation damage prevention.

As exemplified by the Halliburton Sand Control Value Proposition: providing single-source customized solutions providing integrated sand control tool and pumping technology to improve completion efficiency and maximize reservoir producibility—the key to effective sand control service is the adaptation of these products and systems to the complex array of conditions that exist in oil and gas wells throughout the world.

Thorough knowledge of worldwide sand control procedures and practices helps ensure the service treatments Halliburton recommends and uses will be the most effective available in today’s marketplace and the most compatible with the well and reservoir. Professional personnel using dedicated and specialized laboratory equipment, facilities, and computer-enhanced design programs gain insight into the critical role of formation and downhole conditions. Local experience in every part of the world, coupled with a dedicated support team, helps ensure selection of the optimum sand control technique.

Halliburton offers a variety of fluids and chemical systems for gravel pack services, FracPac™ completions, wellbore cleanup, matrix acid stimulation services, completion fluid loss control, fines damage control, and sand consolidation services as well as techniques to accommodate all sand control needs.
FracPac™ Fluid Systems

Halliburton fracturing fluid systems and services such as SeaQuest® and DeepQuest® service are designed to meet the energy industry's needs for offshore stimulation. These systems are formulated to provide reliable treatments under a wide range of well and reservoir conditions while reducing non-productive time and optimizing stimulation results.

SeaQuest®, SeaQuest HT Service

SeaQuest service features a seawater-based fluid system for stimulating offshore reservoirs up to 300°F with SeaQuest HT service—both consolidated and unconsolidated. This versatile system is appropriate for both offshore fracturing and FracPac™ service in either shelf or deepwater environments. Specifically designed for seawater mixing, the system does not produce damaging precipitates and provides greater flexibility for job design and delivery.

SeaQuest service features an HPG-based polymer and a proprietary blended crosslinker. This system combined with on-the-fly mixing ability greatly increases the volume of frac fluids an offshore stimulation vessel can deliver without returning to dock. SeaQuest service also has the latest developments in environmental advances for fracturing fluids.

- SeaQuest service:
  - Helps reduce delays due to stimulation vessel scheduling issues inherent with freshwater-based fluid systems
- InstaVis™ mixing system:
  - Helps reduce or eliminate rig operations time required to prepare frac fluid
  - On-the-fly rheology changes are simple
  - On-line quality control helps achieve desired fluid properties

Application Range

- Bottomhole temperature
  80 to 300°F (27 to 149°C)
- Base fluid density
  8.34 lb/gal to 8.7 lb/gal (1.0 to 1.04 specific gravity)

DeepQuest®, DeepQuest HT Service

DeepQuest service enables effective stimulation of ultra-deep reservoirs. This high-density borate crosslinked system provides a typical specific gravity of 1.14 to 1.50, whereas the typical specific gravity for an aqueous fracturing fluid is 1.0 to 1.04. The high density provides extra hydrostatic pressure at the formation to help reduce the pressure requirements on surface equipment. Without this fluid, many ultra-deep wells cannot be fractured due to current surface equipment pressure limitations.

Application Range

- Bottomhole temperature
  80 to 375°F (27 to 191°C)
- Base fluid density
  10.5 lb/gal to 12.5 lb/gal (1.26 to 1.50 specific gravity)

Delta Frac® Service

The classic, reduced-polymer-loading system, Delta Frac® service provides viscosity and proppant transport with up to 30% less polymer than conventional systems. The fluid systems reduced polymer loading helps reduce formation damage and provides superior regained conductivity. The fluid system is compatible with both enzyme and oxidizing breakers.

Application Range

- Bottomhole temperature
  80 to 200°F (27 to 93°C)
- Base fluid density
  8.34 lb/gal to 8.7 lb/gal (1.0 to 1.04 specific gravity)
Hybor™ Fluid Service
Hybor™ fluid is a delayed borate crosslinked fluid using guar or HPG gelling agent. Hybor fluid is recommended for wells with bottomhole static temperatures (BHST) of 125° to 300°F. It is a high viscosity fluid and can be run semi-continuously or batch mixed. The crosslinked fluid reheals after shearing. Hybor requires precise pH control and is not compatible with carbon dioxide.

Application Range
• Bottomhole temperature 125 to 300°F (52 to 149°C)
• Base fluid density 8.34 lb/gal to 8.7 lb/gal (1.0 to 1.04 specific gravity)

Liquid Sand™ Delivery System
The Liquid Sand™ delivery system is a highly concentrated blend of proppant and carrying fluid. The Liquid Sand system allows proppant to be metered at very precise rates by blending with the dilution stimulation fluid to provide the required proppant concentration. Halliburton's Liquid Sand system can help improve quality control and performance, plus reduce the amount of equipment and personnel on location, the deck space required, and the time required.

Application Range
• Bottomhole temperature Depends on dilution stimulation fluid
• Base fluid density 8.43 lb/gal (1.01 specific gravity)
Gravel Pack Fluid Systems

AquaLinear®, Aqualinear HT Gravel Pack Fluid Service

AquaLinear® service is a viscosified fluid service used for gelling a wide range of water-based brines, and treating fluids. Its properties allow simple mixing procedure and rapid viscosity development in water-based fluids including:

• Freshwater
• Organic and hydrochloric acid mixtures
• Potassium chloride brines
• Sodium chloride brines
• Sodium bromide brines
• Calcium chloride brines
• Calcium bromide brines

Applications

AquaLinear® fluid is a viscosified fluid with rheological properties different from those of hydroxyethylcellulose or similar linear gels. It is based on a biopolymer gelling agents. Brines gelled with these advanced biopolymer gelling agents are shear thinning and are uniquely efficient in static sand suspension. AquaLinear fluids allow a substantial amount of design flexibility for varying degrees of sand support for gravel packing, fluid loss control, friction pressure reduction, and other applications benefiting from a shear thinning, low damage fluid system.

This service can be designed so the gelled fluid suspends sand similar to that of a crosslinked gel. At lesser polymer levels, it produces a “slick brine” consistency giving reduced pumping friction pressures. The base polymer can be rapidly dispersed in water without going through a complex mixing protocol or extended time-consuming hydration period and its ease of mixing and rapid hydration applies to most of the brines used in completion operations. The polymer used in AquaLinear service is specially treated during its manufacturing process to enable it to yield consistently high return permeability from treated cores. The gravel pack gels attained with this polymer have another important characteristic. All gels, regardless of the level of polymer selected, possess outstanding fluid loss properties. This feature, in many instances, helps provide better sand packing by allowing tighter grain-to-grain contact than gels that rely more heavily on viscosity for sand support. This combination of features means total sand transport and excellent fluid loss can be attained in the same fluid. Field applications for AquaLinear service include:

• Gravel pack carrier fluid for Ex-tension Pac℠ service
• Gravel pack carrier fluid for Halliburton’s CAPS™ concentric annular packing system
• Viscosifying completion fluid or brines for fluid loss control
• Sand washing and coiled tubing cleanout operations
• Viscosifying acid or brine for treatment fluid diversion
• Drill-in fluids rheology control

Application Range

• Bottomhole temperature
  80 to 270°F (27 to 132°C)
• Base fluid density
  8.34 to 14 lb/gal (1.0 to 1.68 specific gravity)

Ex-tension Pac℠ Service

Ex-tension Pac℠ service applies a FracPac℠ service level of quality service techniques to high-rate water packs (HRWP). It combines the technologies of AquaLinear Gravel Pack Fluid Service, Liquid Sand™ delivery system, SandWedge℠ service, and other service tools and chemicals listed in this catalog. Application of these services is optimized using the latest engineering technology and software, such as Ex-tranalysis℠, FracPac-N℠ service, FracProPT℠, or GOHFER℠ software.
The main objective of the Ex-tension PacSM service process is to maximize the amount of proppant placed (targeting a typical range of 200 to 250 lb/ft) into the formation and reduce overall skin values through a combination of on-site data analysis and Liquid Sand technology. Increased proppant placement plus lower skin values will result in an increase in overall production for the customer. In addition, the proven benefits of SandWedge® technology (SandWedge® OS, SandWedge ABC service) can be combined in the Ex-tension Pac process to further enhance well productivity and sand control reliability.

**HydropacSM Service**

HydropacSM service uses a gravel pack technique using high concentrations of packing solids carried in a gelled aqueous fluid. The fluid is gelled with an extremely low-residue hydroxethyl cellulose (HEC) gelling agent. This polymer gelling agent provides maximum gel clarity and viscosity per pound, ease of preparation, and the best possible permeability retention after treatment. Reliable low-corrosion breaker systems, which accommodate both low and high-temperature hole conditions, are available. These breaker systems assure quicker, more thorough polymer removal after the pack is established. As much as 20 lb (9.1 kg) of pack sand can be pumped per gallon in this water-based viscous gel system.

**Benefits**
- Improved gravel packs – Relatively high leakoff potential and good sand transport enables tighter gravel packs, particularly in packing perforation tunnels.
- Fast cleanup – Recovery of original formation permeability is fast and returned fluids are disposed of easily.
- Versatility in selecting mixing water – Gels may be prepared using a wide variety of filtered brines.
- Versatility in gel break times – The sand transport life of gels can be tailored to well requirements by treating with breaker additives, which influence gel viscosity during a prescribed time.
- Versatility in initial gel texture and strength – Gels meeting a variety of needs can be prepared by increasing or decreasing the polymer concentration.

**Application Range**
- Bottomhole temperature
  75 to 230°F (24 to 110°C)
- Base fluid density
  8.34 to 12.5 lb/gal (1.00 to 1.5 specific gravity)

**High-Rate Water Pack Systems**

The high-rate water pack gravel placing method uses rates higher than a normal water pack treatment (5 to 10 bbl/min) to enhance gravel placement into the perforation tunnels. Due to the higher rates, a friction reducer or small amount of gelling agent is sometimes used to reduce friction pressures.

**Water Pack Systems**

The water pack gravel placement technique has proven efficient in openhole gravel packs, horizontal, extended reach, and highly deviated wells. Successful completion of cased hole wells (especially extended reach and highly deviated wells) normally includes a gel-sand or acid prepack stage to pack the perforation tunnels. The annular pack is then completed with a low-density water pack.

**Benefits**
- No temperature limitation
- Excellent annular packing under a variety of conditions

**Application Range**
- Bottomhole temperature
  No limitations
- Base fluid density
  8.34 to 19.20 lb/gal (1.00 to 2.30 specific gravity)

*FracProPT is a registered trademark of Pinnacle Technologies
*GOHFER is a trademark of Barree & Associates
Gravel and Proppants

All Halliburton fracturing sands, gravel pack sand, or synthetic proppants meet or exceed specifications adopted by current ISO / API standards.

A number of fracturing and gravel pack sand sizes are available. The fracturing sand size is chosen to ensure packed fractures with a high-flow capacity and sufficient strength to resist crushing. Gravel pack sand size is chosen to produce packs that will resist plugging by using Saucier’s criteria.

Synthetic proppants (i.e., proppants stronger than sand) fall into three different categories: high-strength sintered bauxite, intermediate-strength (and density) sintered bauxite, and ceramics. The size and type proppant is chosen to provide for a highly conductive fracture.

ISO / API Gravel Pack Gravel

ISO / API standard compliant gravel pack sands are available in the following sizes and have a specific gravity of 2.63 and an absolute volume of 0.0456 gal/lb.

- 12/20 US Mesh
- 16/30 US Mesh
- 20/40 US Mesh
- 30/50 US Mesh
- 40/60 US Mesh
- 50/70 US Mesh

Low Density Intermediate-Strength Ceramic Proppants

Ceramic proppants have a specific gravity and bulk density close to sand. The specific gravity ranges from approximately 2.65 to 2.75. These ceramic proppants have greater strength than sand but less strength than the intermediate- and high-strength sintered bauxite proppants.

Intermediate-Strength Proppants

Intermediate-strength sintered proppants have been introduced for closure pressures from about 3,000 psi (206.89 bar) to about 10,000 psi (689.66 bar). These are higher strength materials than sand and because of their specific gravity are more easily transported in the fracture than sintered bauxite.

High-Strength Proppants

High-strength proppants such as sintered bauxite can give higher fracture flow capacity than sand or the intermediate-strength materials under many treating and formation conditions. Sintered bauxite is especially suited for wells with closure pressures in the range of 10,000 to 15,000 psi (689.66 to 1034.50 bar). Field applications have proven its value in many operating areas. Special laboratory fracture flow tests can assist in selecting the propping agent to give maximum fracture flow capacity in a particular formation.

Conductivity Endurance Technology for High-Permeability Reservoirs

Field experience and recent third-party testing have led to a more thorough understanding of key factors about conductivity endurance for high permeability completions that involve fracturing:

- Intrusion of formation material into the pack contributes to decreased production in virtually all formations, even "clean" sands. Formation material entering the pack and plugging pore spaces continually decreases flow area and increases flow path tortuosity. The result: rapid production decline. Some multi-rate buildup tests indicate these effects account for as much as 80% of total skin.
- Stress cycling contributes to reduced effective fracture width. Stress cycling occurs, for example, when flow rates are changed or the well is temporarily shut in. This cycling causes the pack to shift and enables formation material to intrude. The result: rapid production decline.

Conductivity endurance technology helps achieve better long-term conductivity and sustained production through two primary mechanisms:

1. Stabilizes the proppant pack/formation interface which greatly reduces the intrusion of formation material into the pack.
2. Stabilizes the pack so it is resistant to damage during stress cycling. The cohesive nature of the coated grains helps prevent the pack from shifting and allowing formation material to intrude.

Conductivity endurance fracturing incorporates Halliburton’s proprietary SandWedge® agent and proppant coating technologies with treatment design and proppant selection based on understanding the formation properties.
**SandWedge® ABC Service**

SandWedge® conductivity enhancement system is specifically designed to enhance fracture conductivity resulting from treatments with water-based fluids. This technology chemically modifies the surface of the proppant grains, resulting in increased porosity and permeability of the proppant pack and enhanced frac fluid cleanup.

Extensive testing has verified the ability of the SandWedge agent to stabilize the proppant pack/formation interface to greatly reduce intrusion of formation material into the proppant pack. In addition, SandWedge enhancer has been shown to control the effects of diagenesis. It remains active almost indefinitely for long-term pack stability and conductivity to help achieve improved production.

The aqueous-based SandWedge ABC service delivers all the benefits of Halliburton’s proprietary conductivity enhancement technology and adds the benefits of being operationally more efficient, versatile, and reliable while providing improved health, safety, and environmental (HSE) performance. SandWedge ABC service also enables important applications in remedial treatments.

**Applications**

As an aqueous-based system, SandWedge ABC enhancer can be added directly to water-based treating fluids. This means it is now possible to control further damage caused by fines invasion and migration in existing propped fractures and minimize subsequent fines damage. It can also be used as part of the fracturing fluid system.

**Features and Benefits**

- Helps maintain a high production rate for a longer period of time
- Provides improved HSE performance and reliability
- Enhances frac fluid cleanup (Figure 1)
- Highly effective in both hard rock and unconsolidated formations for primary or remedial applications (Figure 2)
- Enables treatment of existing proppant packs to help prevent further damage caused by fines invasion (Figures 3 and 4)
- Delayed onset of tackiness prevents coating of mixing equipment with sticky material. This eliminates the need for special solvents on location, reducing environmental exposure. The coating process is improved resulting in more uniformly coated proppant.
- Can be used to treat most wells from low temperature to more than 450°F to provide improved and sustained fracture conductivity.

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**Figure 1:** Coating proppant with SandWedge® enhancer typically results in conductivity enhancement of 20 to 30% when measured with base brines. When conductivity is determined utilizing actual complete fracturing fluid, the enhancement is typically a 100 to 200% improvement. Improved conductivity contributes to better frac fluid cleanup and increased long-term production.

**Figure 2:** SandWedge ABC enhancer coats the proppant causing it to become permanently tacky to help control intrusion of formation material (fines) into the proppant pack, reduce proppant settling and help maintain proppant strength—all leading to improved long-term conductivity.
Figure 3: This graph shows total suspended solids in effluents collected at increasing flow rates before and after treatments of 15% HCl acid and diluted SandWedge® ABC solution. An acid treatment was introduced to the sand pack that was damaged by invaded formation fines, sand, or scale buildup to remove these materials. After the acid treatment, a diluted SandWedge ABC solution was used to treat the sand pack to lock the formation sand and fines in place. Notice that at over twice the flow rate, solids production was virtually negligible after the sand pack was treated with SandWedge ABC agent.

Figure 4: Using a standard API conductivity cell, conductivity was compared between unconsolidated sand packs with and without SandWedge® ABC enhancer. Silica flour was used in simulating the unconsolidated formation. Lightweight ceramic proppant was used as a propping material with loading concentration of 5 lb/ft². Testing was performed at 180°F and closure stresses of 2,000 and 4,000 psi. The stress cycle was repeated several times with the results indicating that the treatments were effectively stabilizing the unconsolidated fines that made up the formation. Note that conductivity declined to zero after only about 20 hours in the untreated sample but remained high throughout the stress cycles in the sample treated with SandWedge ABC agent.
SandWedge® OS Service

SandWedge® OS (offshore) enhancer is a more environmentally acceptable version of SandWedge NT enhancer optimized for dry-coating applications. In addition to having improved dry-proppant coating properties, it does not require a flammable label, and the working viscosity is reduced. This material was formulated for use in the Gulf of Mexico (GOM) offshore environment. It will pass the “Oil and Grease” test in the GOM and is currently used on more than 75% of the frac work.

PropStop® ABC Service

The aqueous-based PropStop® ABC service provides proppant flowback control in a safer and easier to use system. PropStop ABC service is essentially noncombustible and safer to handle. It is also highly compatible with many other treatment fluids, enabling simplicity in the field and easier system deployment.

Remedial treatments to apply a resin coating to the proppant pack have proved effective in controlling flowback. PropStop ABC service was developed as an alternative to solvent-based resins. It is able to create a high-strength consolidated pack using a small amount of consolidating material. The reduced material volume needed—in conjunction with the ability to be foamed—makes PropStop ABC service more economical. Since foam is self-diverting, longer intervals can be treated using a simple bullheading process. The foamed fluid also increases capillary forces and provides improved strength development in a proppant pack.

Application

This service is deployed using coiled tubing or bullheading. Enhanced placement is achieved with Pulsonix® TFA service.

Features and Benefits

- Provides cohesion between proppant grains without damaging permeability or conductivity of proppant pack
- Helps maintain highly conductive fractures and long-term productivity
- High-strength consolidation can be achieved with small amounts of material
- Helps eliminate many health and safety hazards
- High flash point makes system easier to manage
- No special solvents required on location for equipment cleaning
- Can be applied using bullheading or coiled tubing
- Enables treating long intervals; foam acts as a resin extender and is self-diverting

Expedite® Service

In formations where controlling proppant flowback following fracture treatments is a primary consideration, Expedite® service can help improve production and the net present value (NPV) of treatments in several ways:

- Enhances or maintains proppant pack conductivity
- Widely used resin-coated proppants and fibrous flowback control materials placed in the proppant pack matrix often reduce conductivity under high closure stresses
- Applied to proppant on-the-fly so no excess resin or coated proppant is left after treatment

Expedite service uses Halliburton’s exclusive direct proppant coating process to apply a proprietary resin mixture to all the proppant used in a fracturing treatment.

- Enables earlier production of hydrocarbons after fracturing than is possible with conventional resin-coated or non-coated proppants
- Promotes cleanup of fracturing fluid
- Eliminates fibrous materials plugging surface equipment
- Helps eliminate damage to coated proppants inherent in handling and storage

An Expedite service formulation is available to help improve fracture treatment results in virtually any formation. Formulated as Expedite Lite, Plus, or Max treatments based on the required coating amount, it is applicable from 80 to 550°F (27 to 288°C).
Formation Stabilization Systems

Sand control by chemical consolidation involves injecting chemicals into the unconsolidated formation to provide grain-to-grain cementation. Cementing the sand grains together at the contact points creates a strong consolidated matrix. Subsequent flushes displace excess resin material further into the formation to clear the pore spaces between grains, allowing the best possible permeability for oil and gas flow. Halliburton chemical consolidation systems help control sand without mechanical screening devices restricting the wellbore or limiting access to lower producing zones. Ideal for dual-zone completions, these systems permit access to a lower zone without disturbing the upper zone. This is accomplished by consolidating the upper zone and gravel packing the lower zone.

The following processes are currently available:
- SandTrap® ABC formation stabilization system
- SandTrap® formation stabilization system
- HYDROFIX® service

**SandTrap® ABC Formation Consolidation Service**

With recent emphasis on recovery of bypassed hydrocarbon reserves and extending mature field production, formation consolidation techniques present viable completion options. Since economics is a key decision criterion, resin consolidation offers a reliable and cost-effective sand control solution.

**Applications**

SandTrap ABC service can be applied to the following new or existing well completions:
- Cased and perforated
- Supported openhole which includes stand-alone screens or perforated liners
- Screenless through-tubing recompletions for accessing bypassed reserves
- Failed gravel pack or frac pack sand control completions

Contact of the treatment with the annular gravel pack and surrounding formation sand can be enhanced with fluidic oscillator technology provided by Pulsonix® TFA service.

**Benefits**

SandTrap® ABC service provides benefits that facilitate the use of resin consolidation for oil and gas reservoirs requiring sand control.

- High-strength consolidation can be achieved with small amounts of low-viscosity consolidating material.
- High flash point makes the system easier to manage, especially in offshore environments.
- Large over-displacement of this material is not required to re-establish permeability.
- No special solvents required on location for equipment cleanup.
- Treatments can be bullheaded due to no requirement for isolating the zones to be treated.
- Foam acts as a good diverter, helping to achieve a more effective system in long production intervals by overcoming the effects of variable permeabilities.
- Foam acts as a resin extender by increasing the bottomhole volumes and making it operationally easier to place small-volume consolidation treatments.
- The introduction of a foamed fluid into a proppant pack increases the capillary forces which results in better coating and improved strength development.

**SandTrap® Formation Consolidation Service**

Formation consolidation is not a new concept and in many applications has proved to be a successful means of providing sand control. SandTrap service provides features that facilitate the successful use of resin consolidation for oil and gas sands requiring sand control including:

- Operational simplicity with brine and solvent preflush stages, two-component consolidation fluid, and brine post-flush
- Low-viscosity fluids for more effective placement into reservoirs with variable permeability
- Good consolidation performance in sands with clay mineral content
- Post-flush displaces the consolidation fluid to retain pay sand permeability
This system incorporates a solvent/resin mixture with very unique properties that cause the resin to be deposited as a thin film on the formation and clay surfaces.

The solvent package is used to provide a very low-viscosity treating fluid and to provide a means to get the resin in contact with the formation. The resin is internally catalyzed so that no post-flush treatments are required to initiate the curing process. The resulting treatment procedure involves only five stages:

- Brine pre-flush treatment
- Solvent pre-flush
- Formation consolidation system
- Oil spacer
- Brine post-flush over-displacement

The absence of any severe contrasts in fluid rheology provides much more uniform, consistent resin placement.

**Applications**

SandTrap® service can be applied to new or existing sand completions. The treatment can be placed several ways:

- Down production tubing
- With jointed pipe and service packer
- With coiled tubing

New perforations can be treated down production tubing for zone changes or recompletions to access additional reserves.

Coiled tubing and SandTrap service can put existing zones back on production without the expense of a rig-based workover.

For wells with failed gravel packs, SandTrap service can be used to consolidate the existing gravel pack and reservoir sand in the problem area to put a shut-in well back on line. Sand consolidation treatment fluids commingled with nitrogen have proved to be an effective solution for gravel pack repair. Contact of the treatment with the gravel pack and surrounding sand can be enhanced with fluidic oscillator technology provided by Pulsonix® service.

**Operation**

Preflushes to condition the formation sand for a high-strength consolidation and improved permeability retention. The preflush allows the mineral surfaces to attract the consolidation fluid so that a thin, uniform coating of consolidation fluid coats the formation matrix grains.

Connate water is displaced from the pore spaces to improve treatment penetration into the pores and subsequent displacement by the post-flush to enhance consolidation strength and permeability retention.

The solvent-based resin systems include two epoxy systems: the SandTrap 225 service high temperature version and the SandTrap 350 service low temperature version as well as a furan-based system which can be catalyzed in different ways.
Pulsonix® TFA Service

Pulsonix® TFA service incorporates Halliburton’s coiled tubing expertise with proven fluidic oscillator technology. Tuned frequency amplitude (TFA) enables fine tuning rates and frequencies based on the requirements of the application.

Applications

Pulsonix TFA service is excellent for a wide variety of vertical and horizontal wells, both openhole and cased hole, including oil, gas, injection, geothermal, CO₂, water, disposal, monitoring, and solution mining. It provides proven performance for these operations:

- Removing deposits from the near-wellbore area, perforations, and screens
- Perforating damage
- Mud and cement damage
- Scales of all types
- Emulsions
- Formation fines
- Drilling damage
- Paraffins and asphaltenes
- Water and gas blocks
- Enhancing treatment fluid placement and effectiveness
- Stimulating high permeability formations
- Treating perforations and wellbore to improve the effectiveness of subsequent stimulation treatments including gravel packing and frac packing
- Removing fill from openhole or casing
- Optimizing injection profiles

Benefits

- Breaks up many types of near-wellbore damage.
- Helps remove debris from the perforations
- Enhances the permeability of the near-wellbore area
- Waves can penetrate deeply into the formation for more effective cleaning and stimulation
- Cleans out fill and stimulates the well in one trip resulting in fast operations
- Eliminates the stand off requirements of jetting nozzles
- Can be run in conjunction with other tools

HYDROFIX™ Service

HYDROFIX™ service is specifically designed to consolidate sandstone. The resin has an affinity for quartz. The furan resin becomes attached to the sand grains. A spacer is pumped followed by an HCl acid catalyst which overflushes the resin from the pore spaces and catalyses the residual resin coating. Nitrification of the resin and other phases of HYDROFIX service have allowed successful treatments of even long intervals [150 ft (45.72 m)].

Applications

- Gravel pack screen repair
- Stringer gas sands that would be uneconomical to gravel pack
- Through-tubing sand control
- Free pack proppant and formation flowback prevention

Application Ranges

- Bottomhole temperature
  80 to 225°F (27 to 107°C)
- Base fluid density
  9.20 lb/gal (1.10 specific gravity)
### HYDROFIX™ Service Resin Properties

**In-Situ Resin Consolidation Services with Overflush Hardener Systems**

<table>
<thead>
<tr>
<th>Product Name</th>
<th>Type Resin</th>
<th>Temperature Range</th>
<th>Base Fluid</th>
<th>Perforated Interval</th>
<th>Hardener</th>
<th>Shut In Time Required</th>
<th>Minimum Permeability for Placement</th>
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<tr>
<td>SandTrap® ABC</td>
<td>Epoxy</td>
<td>70 to 230</td>
<td>3-7% KCl</td>
<td>0 to 25*</td>
<td>Internal</td>
<td>24 to 72</td>
<td>100 mD</td>
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<td>70 to 250</td>
<td>3% KCl</td>
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<td>70 to 225</td>
<td>5% NH₄Cl</td>
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<td>5% NH₄Cl</td>
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<td>HYDROFIX™</td>
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<td>15% NaCl</td>
<td>0 to 25*</td>
<td>HCl Acid</td>
<td>4 to 24</td>
<td>35 mD</td>
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*With nitrification, the zone length can be extended much beyond the stated length utilizing foam diversion.*
Wellbore Cleaning Products

DuraKleen® Service

DuraKleen® service uses an environmentally enhanced water/aromatic solvent emulsion system that represents an important advancement in maintaining long-term production rates.

- Cleans and dissolves asphaltene deposits
- High solvency power is enhanced by the dispersing effects of the surfactant
- Strips asphaltenes and waxes from tubulars as well as the formation
- Provides a longer-lasting treatment
- Leaves the formation in a water-wet state which delays deposition of asphaltene deposits
- Improved environmental and safety footprint as compared to traditional asphaltene removal systems
- No BETX (benzene, ethyl benzene, toluene, or xylene)
- Flash point greater than 145°F (63°C)
- Requires less transport of chemical components due to high water content
- All components are fully miscible
- May be batch mixed or easily mixed on-the-fly
- Can be applied wherever heavy oils are produced

Paragon™ Solvent

The Paragon™ family of hydrocarbon solvent blends can dissolve solid or semi-solid paraffin and asphaltene deposits that form or collect near the formation face and on tubular goods. Various versions of Paragon solvent are available:

- Paragon 100E+™
- Paragon EA™

Applications

- Helps remove paraffin deposits in wellbore and production tubing
- Helps remove excess pipe dope and thread lubricants from tubing and casing
- As a preflush, helps remove oil residues before scale removal or matrix acidizing operations
- Functions as a component in emulsified stimulation systems, such as PAD™ Paragon acid dispersion system and HV-60™ high-viscosity emulsified acid
- Can either be circulated or spotted and allowed to soak depending on the application

N-Ver-Sperse™ Invert Oil-Based Mud Cleaning System

N-Ver-Sperse O™ and N-Ver-Sperse A™ Fluids

Two perforating and breakdown fluids have been developed for cleanup of invert oil-based muds. N-Ver-Sperse O™ and N-Ver-Sperse A™ dispersant fluids were specifically designed to help remove invert emulsion-type drilling muds which can greatly hinder stimulation treatments. N-Ver-Sperse O fluid is a hydrocarbon-based fluid, and N-Ver-Sperse A fluid, containing wetting agents and dispersants, is an aqueous-based fluid. Need for a hydrocarbon-based or an aqueous-based fluid, economic factors, hydrostatic pressures, and other conditions determine choice of fluid. Both fluids can be used either for removal of mud from the wellbore or as formation breakdown fluids. When used as mud cleanout fluids, they are circulated at fairly high rates to prevent the solids in the mud from settling out. As a perforating fluid, N-Ver-Sperse O fluid would be superior to an acid or common aqueous perforating solution due to the adverse effects these fluids have on the invert muds. In instances where large volumes of whole mud are lost into the producing formation during drilling, N-Ver-Sperse flush solutions can be used very effectively in a series of flushing and back flowing or swabbing stages to pull the mud solids toward the wellbore and clean them out.

Wellbore Cleaning Products and Services Reference Chart

<table>
<thead>
<tr>
<th>Chemical or System</th>
<th>Purpose</th>
<th>Oil-Based/ Aqueous-Based</th>
<th>Flash Point</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Paragon EA™</td>
<td>Remove paraffin/pipe dope/crude oil residue</td>
<td>Oil-Based</td>
<td>155°F (68°C)</td>
<td>Intended for use in Europe/Africa</td>
</tr>
<tr>
<td>Paragon 100E+™</td>
<td>Remove paraffin/pipe dope; degrease producing wells in waterfloods</td>
<td>Oil-Based</td>
<td>150°F (66°C)</td>
<td>Contains no BETX- 100% aromatic</td>
</tr>
<tr>
<td>N-Ver-Sperse A™</td>
<td>Disperse/remove invert emulsion-type drilling fluids</td>
<td>Aqueous-Based</td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td>N-Ver-Sperse O™</td>
<td>Disperse/remove invert emulsion-type drilling fluids</td>
<td>Oil-Based</td>
<td>N/A</td>
<td></td>
</tr>
</tbody>
</table>
Formation Damage Removal Systems

**Sandstone 2000™ Acid System**

In the 1980s, Halliburton analyzed fluid returns from an HF acidizing treatment. The results of the analysis were completely unexpected and defied chemical theory of the time. From these studies and subsequent research projects, Halliburton can now better provide an HF acid job with preferred effects. The changes in HF acidizing were primarily made to avoid precipitation products from secondary reactions occurring between spent HF fluids and aluminosilicate minerals in the formation. Previously, these reactions formed scales, partially or completely obstructing gravel pack screens. The precipitation of fluosilicate formation minerals was also discovered in wells that contained sodium feldspar and potassium feldspar. Halliburton can now provide help in finding solutions to improve wells. Through research and testing, we learned how to tailor treatments to deal with formation minerals like potassium feldspar, sodium feldspar, illite clay, zeolites, carbonates, etc. New procedures and additives minimize problems with ion exchange, acid-unstable clays, high temperatures, and more. The Sandstone 2000™ system is the product of exhaustive research and field testing. New discoveries led us to lay aside old HF acidizing theories and develop better ways to avoid problems and remove damage in sandstone formations. Sandstone 2000 acidizing system can be divided into damage removal systems and formation conditioning systems.

**Sandstone 2000 Damage Removal Fluid Systems**

**Sandstone Completion™ Acid**

Sandstone Completion™ acid promises to be the new standard for treating most sandstone formations and the safest system when mineralogy and nature of damage are uncertain. It provides maximum HF dissolving power without secondary precipitation. In addition, it prevents aluminum precipitation better than acetic acid and helps maintain formation compatibility.

**Fines Control™ Acid**

Conventional matrix acidizing with HF acid is only effective for removing shallow clay damage 2 to 4 in. from the wellbore at most. Halliburton Fines Control™ acid is a retarded HF system used for treating sandstone formations damaged by the migration and/or swelling of silica, feldspars, and clays. This retarded acid process penetrates to remove deep damage caused by fines and swelling clays. Very few sandstone formations are sensitive to this system. There is far less tendency for it to unconsolidate formations than conventional HF systems.

**K-Spar™ Acid**

K-Spar™ acid is the treatment of choice in formations high in potassium feldspar and illite. It increases production by reducing fines migration and near-wellbore damage over a wide range of temperatures.

**Volcanic™ Acid**

This organic-HF acid system replaces acetic and formic-HF fluids which produce severe secondary precipitation. It protects formations too sensitive to HCl acid. Compatible with HCl-sensitive minerals such as chlorite and zeolite, it can also be used at higher temperatures. In addition, this acid system helps avoid sludging of crude.

**Silica Scale™ Acid**

The Silica Scale™ acid system is designed especially to remove silica scale from geothermal wells.

**Guardian™ Acid Enhancement System**

This system introduces a new concept in formation protection beyond the limitations of conventional acidizing additives. Even properly designed additive blends have been known to have caused sludging and formation damage with certain crude oils. Guardian™ enhancer provides excellent sludge and emulsion control even with problem crudes. In addition, the Guardian enhancer system outperforms conventional acid inhibitors.

The Guardian system minimizes adsorption of additives on the formation. The advantages of the Guardian enhancer package include:

- Acid blends are greatly simplified.
- Generally, the additive loading is significantly reduced.
- Less mutual solvent and dispersants are required.
- Enhanced corrosion protection is attained, even during flowback.

Consider the Guardian enhancer system whenever:

- Sludging crude oils are present.
- The acid blend requires an anionic surfactant.
- Acid blend stability is required.
Formation Conditioning Systems

In addition to choosing the optimum HF fluid, selecting pretreatment and preflushes is very important and can determine the ultimate success of a treatment. Halliburton calls these fluids formation conditioning systems. These fluids prepare the formation for the damage removal fluid systems.

**N-Ver-Sperse™ O System**

N-Ver-Sperse™ O is required when oil-based whole mud is lost to the formation. Acid mixing with oil-based mud will cause emulsions resulting in severe damage. Whole mud must be removed before sandstone acidizing.

**Mud-Flush™ System**

The Mud-Flush™ system is the fluid system of choice for removing water-based whole mud.

**MCA™ Blend**

The MCA™ mixture is a blend of Morflo® III surfactant and dilute HCl. This mixture helps eliminate water and emulsion blocks, cement filtrate damage, and shrink natural clay minerals.

**Organic Solvents**

Organic solvents are required to remove any oily deposits such as heavy oil, pipe dope, paraffins, and asphaltenes from the formation face. If the aqueous HF fluid cannot contact the damaged formation, it will be unable to improve the well performance.

**HCl for Pickling Tubing**

It is very important to remove iron scales from coiled tubing, wellbore tubing, and casing prior to treatment with acid fluids. HCl is the recommended acid for this process, while organic acids such as acetic acid are not effective in dissolving the iron scales at any temperature. The fluid should be circulated and recovered without allowing the spent acid to enter the formation. Performing a pickling treatment (tubing cleanout) causes the acid preflush and HF stages to remove formation damage more effectively.

**Gidley’s CO₂ Conditioner**

In this process, carbon dioxide (CO₂) is used to improve the performance of HF acidizing treatments in oil wells. The system involves the use of about 100 to 200 gpf of CO₂ under miscible conditions to displace the oil from the matrix in the near-wellbore area. CO₂ is also used throughout the acid stages to provide enhanced energy for cleanup as well.

**Benefits**

- Reduction in terminal upsets due to emulsions created during the acidizing treatment.
- A tendency to prevent preferential acidizing of water zones: The xylene, CO₂ preflush conditions the formation in the critical wellbore area, leaving the matrix with a relative permeability to acid (water) which is fairly even across the entire zone. Due to the removal of the oil by the preflush, this occurs regardless of whether the matrix initially contained oil or water. While use of CO₂ does not prevent water production, the CO₂ treatments have resulted in less enhancement of water production than previous treatments for some operators.
- Improved treatment response attributed to two factors: better invasion of the matrix due to the removal of the oil and prevention of immobile matrix emulsions stabilized by oil wet particles.

**CLAYFIX™ 5 Conditioner**

CLAYFIX™ 5 conditioner is necessary for ion exchange and for moving formation fluids away from the wellbore to avoid incompatibilities with the acid fluids. Typical ion-exchanging minerals include Smectite, mixed layer clays, and zeolites.

**HCl Conditioners**

HCl is the most common preflush prior to the HF stage. Typical concentrations are 5 to 15%. The purpose of an acid preflush is to stimulate ion exchange, to prevent mixing of formation fluids with the HF stage, and to remove carbonates. In addition, HCl very effectively removes polymers, such as HEC, xanthan, and K-Max™ material used during completion operations.
**Clay-Safe™ H Blend**

Clay-Safe™ H blend is a special blend of an organic acid, Clayfix™ salt for ion exchange, and 5% HCl. It can be used safely ahead of HF acid blends. However, this blend has been optimized for safe removal of polymer damage and other applications where unprotected breaker acid mixtures could damage HCl-sensitive formations.

**Clay-Safe F Blend**

Clay-Safe F blend is a special blend of two organic acids, Clayfix salt for ion exchange, and no HCl. It can be used safely ahead of HF acid blends because of the inclusion of Clayfix salt. At temperatures above 180°F (82.22°C) this blend of organic acids has been shown to act synergistically to remove certain polymer damage. It has been optimized for safe use in formations with clay instability ratings of 25 or greater.

**KelaStim℠ Service**

KelaStim℠ service is a simpler, more environmentally-friendly service to chemically stimulate carbonate or mixed carbonate/sandstone formations. The fluid system reduces the complexity of the treatment by eliminating some of the flush stages.

**SandStim℠ Service**

A chelant-based acidizing fluid for sandstone formations, SandStim℠ fluid has less risk of damaging the formation than traditional acid blends.

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**Chart of Formation Conditioning Systems**

<table>
<thead>
<tr>
<th>Fluid System</th>
<th>When/Why Use This System</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Mud Cleanout</strong></td>
<td></td>
</tr>
<tr>
<td>Mud-Flush™</td>
<td>Whole water-based mud losses</td>
</tr>
<tr>
<td>N-Ver-Sperse O™</td>
<td>Whole oil-based mud losses</td>
</tr>
<tr>
<td><strong>Wellbore Conditioning</strong></td>
<td></td>
</tr>
<tr>
<td>PARAGON™ or other organic solvents</td>
<td>Asphaltene/paraffin problems, heavy oils, pipe dope</td>
</tr>
<tr>
<td>HCl for pickling</td>
<td>Removal of iron scales, preventing them from entering the formation</td>
</tr>
<tr>
<td><strong>Oil Well Conditioning</strong></td>
<td></td>
</tr>
<tr>
<td>Gidley's CO₂ Conditioner</td>
<td>Emulsion problems, terminal upsets, improves acid penetration into oil zones</td>
</tr>
<tr>
<td><strong>Matrix Conditioning</strong></td>
<td></td>
</tr>
<tr>
<td>Clayfix™ 5 Conditioner</td>
<td>Preflush ahead of Sandstone acids to allow for ion exchange</td>
</tr>
<tr>
<td>5-15% HCl</td>
<td>Carbonate removal, ion exchange, removal of polymer damage</td>
</tr>
<tr>
<td>Clay-Safe™ 5 Conditioner</td>
<td>HCl-sensitive mineralogy</td>
</tr>
<tr>
<td>Clay-Safe H Conditioner</td>
<td>HCl-sensitive mineralogy, where removal of polymer damage (K-MAX™, HEC) or high carbonate levels with acid fluids is required</td>
</tr>
<tr>
<td>Clay-Safe F Conditioner</td>
<td>HCl-sensitive mineralogy</td>
</tr>
</tbody>
</table>

**Sandstone 2000™ Damage Removal Systems**

<table>
<thead>
<tr>
<th>Name</th>
<th>Advantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Silica Scale™ Acid</td>
<td>Contains a high HF concentration to remove silica scale from geothermal wells</td>
</tr>
<tr>
<td>Sandstone Completion™ Acid</td>
<td>Provides maximum dissolving power without secondary precipitation, prevents aluminum precipitation, and is the fluid of choice when mineralogy is unknown</td>
</tr>
<tr>
<td>Fines Control Acid</td>
<td>Is a retarded system, removes deep damage caused by fines and swelling clays, and prevents fines migration.</td>
</tr>
<tr>
<td>K-Spar™ Acid</td>
<td>Is compatible with formations high in feldspars and illite and prevents fines migration</td>
</tr>
<tr>
<td>Volcanic™ Acid I and II</td>
<td>Contains an organic acid system, is compatible with HCl-sensitive minerals, and can be used in higher temperature applications</td>
</tr>
</tbody>
</table>
**Filter Cake Breaker Systems**

**N-FLOW™ Stimulation Service**

Drill-in fluid (DIF) filter cake deposits are a major cause of restricted flow from the producing formation. N-FLOW™ stimulation service effectively removes drill-in fluid filter cake residue and near-wellbore formation damage in conventional or gravel packed openhole completions.

N-FLOW service has proved effective in both carbonate and sandstone reservoirs for the following applications:
- Long treatment intervals of horizontal wells
- Gravel packed wells
- Water-based drill-in fluid cleanup
- Synthetic- or oil-based drill-in fluid cleanup
- Stimulation of dolomite and limestone formations in new and mature wells

**Benefits**
- In-situ acid production delivers acid to wherever the fluid has been placed. The treatment fluid contains a precursor of an acid (which is not acidic itself) that provides time-controlled downhole organic acid release for carbonate removal.
- Avoids placement problems associated with using a reactive acid
- Helps achieve excellent zonal coverage. The controlled reaction N-FLOW™ chemicals dissolve DIF filter cake components along the entire pay section and do not cause hot spots resulting in premature loss of treating fluids
- More environmentally acceptable, less damaging and less hazardous than comparable HCl-based systems. Unlike cleanup materials containing hydrochloric acid and corrosion inhibitors, the initial non-acidic nature of the agents used in the service lowers the safety risk to personnel and the environment, and avoids corroding downhole hardware, including screens, packers, and tubulars
- Effective in a wide range of completion fluids
- N-FLOW service is available for both water-based and synthetic oil-based DIFs

**Fluid Loss Control Systems**

**LO-Gard® Service**

LO-Gard® service helps control fluid loss (leak off) in perforating/gravel pack completions and horizontal gravel pack applications where fluid loss through the filter cake could cause problems with placing the gravel. For openhole completions, the service provides important benefits:
- Solids-free, low-viscosity, lost-circulation control system
- Decreases formation permeability to aqueous fluids thus limiting leakoff into the following:
  - High permeability streaks
  - Leaky, thinned or eroded drill-in fluid wall cake
  - Breached or fractured wall cake
  - Natural or hydraulic fracture networks
- Results in no significant permeability loss to oil or gas, > 95% retention is typical with 100 md core material
- Applicable over a broad range of temperatures and permeabilities
- Effective in both sandstone and carbonate lithology
- Shut-in time not required
- Requires no breaker
- Easier mixing than with conventional viscous gel systems
- Can be formulated for a wide range of pill densities in specific brines
- Reduces water inflow during production
- Polymer can be removed if required
- Environmental performance – passes Gulf of Mexico oil and grease test for overboard discharge

The highest fluid loss level controllable with the LO-Gard system is unknown; however, in one example, an attempt to kill a 300°F well with 10-lb/gal brine was unsuccessful because the formation was taking fluid at 18 bbl/hr. Pumping 80 bbl of LO-Gard service agent reduced fluid loss to 0 bbl/hr, and the operation was completed successfully.
K-Max Plus™ Service

K-Max Plus™ service batch-mixed, non-damaging blocking material provides abrupt fluid loss control and helps control wellbore sloughing in open hole. In cased holes, it helps prevent sand sloughing, especially in highly deviated completions.

K-Max Plus service provides an HEC-based, high viscosity, crosslinked gel pill that requires no heavy-metal crosslinker. Its crosslink is pH controlled and completely reversible. The service provides clean breaks with both internal and external breaker systems. Break back times can be designed for a variety of applications. Reversible crosslinking technology has been shown to yield regain permeability of 90 to 100% with an external breaker in Berea sandstone. K-Max Plus service uses a liquid gel dispersion system, designated WG-33™ gelling agent, for easy preparation.

K-Max Plus™ material does not require shearing or filtering. Gel remains flowable in the wellbore while controlling fluid loss and sloughing at the formation face. It can also be circulated out without loss of fluid control. When time comes to remove the pill, lowering the pH of surrounding fluid reverses the crosslink state and converts the pill to a flowable fluid easily circulated or produced from the wellbore. This service has been used to control fluid loss into 10 darcy permeability sand with minimal damage. The semi-rigid pill can also be used for the following applications:

- Help support poorly consolidated formations
- Isolate zones for temporary diverting during stimulation
- Aid in other operations in multizone completions

**Application Ranges**

- **Bottomhole temperature**: 75 to 300°F (24 to 149°C)
- **Base fluid density**: 8.34 to 14.00 lb/gal (1.00 to 1.68 specific gravity)

Max Seal® Fluid Loss Control Additive

Max Seal® additive is a unique fluid loss control additive that is supplied ready-to-use and is easily dispersed into most brines with minimal mixing energy. The particles in Max Seal additive that help stop fluid loss are essentially highly crosslinked gel ready to disperse in wellbore fluids. The Max Seal additive crosslinking chemistry is the same as that in K-Max Plus™ service. Reduction of pH readily causes the polymer to uncrosslink and eventually revert to a water-thin fluid when workover activities are complete.

**Applications**

- After perforating
- After gravel packing or performing a frac pack
- During and after horizontal hole cleanup of drilling fluid filter cake
- Completion and workover operations
- Pill to enhance hole stability to reduce or prevent formation sloughing

**Application Ranges**

- **Bottomhole temperature**: 75 to 275°F (24 to 135°C)
- **Base fluid density**: 8.34 to 11.60 lb/gal (1.00 to 1.39 specific gravity)
Benefits
- Ready-to-use product requires no on-location gel preparation
- Ready disperses in most completion fluids
- Low friction pressure allows it to be placed through small diameter tubing
- Provides effective fluid loss control
- Easily removed with acid
- Little or no lost well productivity
- No special storage (will not freeze and is not damaged by summer storage)

High Viscosity Linear Gels
For controlling fluid losses in situations where permeabilities are low and overbalance pressure is not high, Halliburton offers viscous linear gels. The normal gelling agent is processed HEC used at high concentrations. Other systems, such as AquaLinear® gravel pack service gels, have seen some use due to their uniquely applicable rheology. But all these systems depend upon building up a bank of viscous fluid in the formation pore spaces away from the wellbore. For highly permeable formations or high overbalance situations, the linear gels will typically require numerous applications and ultimately may not work at all. The preferred temperature range is below 230°F (110°C) for HEC and other linear gels typically degrade at elevated temperatures.

Application Ranges
- Bottomhole temperature
  80 to 230°F (27 to 110°C)
- Base fluid density
  8.34 to 19.20 lb/gal (1.02 to 2.30 specific gravity)

Breaker Agents
- Enzymes
- Oxidizers
- Acids

Z-Max<SM> Service
Z-Max<SM> service non-particulate gel system combats fluid losses in wells where zinc bromide or other high-weight brines are being used as completion or workover fluids. Z-Max service is similar to the K-Max<SM> service crosslinkable HEC system. However, Z-Max service is specially formulated to gel ZnBr<sub>2</sub> brines. Like the K-Max system, superficial application of a mineral acid solution causes Z-Max service to break back to a water-thin texture, allowing it to be reversed out of the wellbore or produced back from perforation tunnels and the formation matrix.

Application Ranges
- Bottomhole temperature
  75 to 225°F (24 to 107°C)
- Base fluid density
  14.5 to 18.5 lb/gal (1.74 to 2.22 specific gravity)
**Fluid System Additives**

**Breaker Systems**

**HT Breaker**
HT breaker is a strong oxidizing breaker used at temperatures from 75 to 200°F (23.8 to 93.3°C). It is typically used for breaking K-Max Plus™ pills and AquaLinear® service gels.

**GBW-30™ Breaker**
GBW-30™ breaker is a water-soluble enzyme breaker for aqueous-based gelling agents at temperatures below 120°F (48.8°C). Its reactive strength is approximately 10 times that of the original GBW-3 breaker.

**SP™ Breaker**
SP™ water soluble oxidizing breaker for aqueous-based gelling agents is used at temperatures above 120°F (48.8°C).

**Oxol II™ Breaker**
Oxol II™ breaker is a delayed release oxidizing breaker for low-temperature applications where enzyme breakers may not function. It is effective in the 70 to 140°F (21 to 60°C) temperature range. Combined with CAT-3 activator, it can be used in high concentrations to give performance profiles superior to those of a persulfate breaker.

**ViCon NF™ Breaker**
ViCon NF™ breaker is an aqueous form of a strong oxidizer breaker shown to be effective in breaking a variety of oilfield polymer gels. Breaker concentration is determined by downhole temperature, stabilizer concentration, and required break time. Gels containing this breaker retain viscosity and break slowly. It can be added to batch-mixed gels or run on-the-fly throughout the entire job, including the pad volume.

**CAT®-OS-1 and CAT®-OS-2 Activators**
CAT®-OS-1 and CAT®-OS-2 activators are catalysts for the ViCon NF internal breaker used with SeaQuest® service and Delta Frac®Pac system. CAT-OS-1 activators can effectively activate the ViCon breaker above 170°F. At lower temperatures, a combination of CAT-OS-1 and CAT-OS-2 activators with ViCon NF breaker will provide an accelerated break time.

**CAT®-3 and CAT®-4 Activators**
CAT-3 and CAT®-4 activators are proprietary mixtures of chemicals that enhance the activity of many oxidizer breakers. They can be used separately or together with most fracturing fluids and traditional persulfate breakers.

CAT-3 activator can be used at bottomhole surface temperatures of 85°F (29°C) and above. It allows the use of less Oxol II breaker at temperatures higher than 120°F (48.8°C). CAT-4 activator can be used at bottomhole surface temperatures of 140 to 200°F (60 to 93°C). CAT-3 and CAT-4 activators can be either added to fracturing fluids on-the-fly or added to K-38 crosslinker to form a crosslinker/activator solution. These activators are beneficial because they are solutions instead of mixtures of solids. Their break times can be tailored to specific job times.

**Surfactants**

**LoSurf-259™ Surfactant**
LoSurf-259™ surfactant is a nonionic, nonemulsifier blend specifically designed for acidizing limestone and dolomite formations. It has also been effective in sandstone acidizing and fracturing treatments.

**LoSurf-300™ Surfactant**
LoSurf-300™ surfactant is a liquid, broad-spectrum, nonionic nonemulsifier for application in acids and other aqueous fluids. It can be used in stimulation fluids for treatments of either sandstone or limestone formations. Because it is nonionic, it should be compatible with most other acid additives, including Cla-Sta® agents. However, it is advisable to perform emulsification tests before including LoSurf surfactant in any treatment regime.

**LoSurf-357™ Surfactant**
LoSurf-357™ nonionic surfactant can be used with aqueous fluids, such as fresh water, brines, KCl solutions, and acids. It can be used in treating any type of formation rock. Since it is nonionic, it has low adsorption properties and is compatible with most other additives.

**LoSurf-360™ Surfactant**
LoSurf-360™ nonionic surfactant is for use in stimulation fluids (fracturing) to lower surface tension of the treating fluid. It has shown to be an effective non-emulsifier for a variety of crude oils and can be used in sandstone, carbonate, and shale formations and applications where LoSurf-300M non-ionic surfactant would normally be used.
**LoSurf-396™ Surfactant**
LoSurf-396™ surfactant is a nonionic blend of demulsifiers, dispersants, and solvents specifically designed for use in areas where health, safety, and environmental concerns are prevalent. The surfactant is effective at bottomhole temperatures greater than 300°F (149°C).

**LoSurf-400™ Surfactant**
LoSurf-400™ surfactant is a nonemulsifier for acidizing and fracturing operations and can be added to preflushes in general, acid preflushes, HF/HCl main flushes, and fracturing fluids crosslinked with either metal ions (neutral to moderate basic pH) or borate crosslinked fluids (high pH).

**LoSurf-2000S™ Surfactant**
LoSurf-2000S™ solid, powder surfactant is a blend of anionic nonemulsifier and an anionic hydrotrope. It can be used as a surface-tension reducer and nonemulsifier in fracturing and acidizing applications. LoSurf-2000S surfactant can be added to stimulation fluids as a solid or premixed in water and metered into the treatment for on-the-fly application. It can prevent and/or remove emulsion or water blocks during stimulation treatments, and can also be used in water-based mud dispersants, preflushes, acids, HF acid, and overflushes. It is compatible with Delta Frac®, Delta Frac PAC service and Hybor Frac™ systems.

**LoSurf-2000L™ Surfactant**
LoSurf-2000L™ liquid surfactant is a blend of anionic nonemulsifier and an anionic hydrotrope. It can be used as a surface-tension reducer and nonemulsifier in fracturing and acidizing applications. LoSurf-2000L surfactant is compatible with the following fracturing/acidizing fluids:

- Delta Frac, Delta Frac Pac, and Delta Frac 275 service
- Hybor Gel™ system
- Pur-Gel III™ service
- Thermagel™ service
- Sirocco® service
- My-T-Gel™ fluid
- Sandstone 2000™ service
- Hydrochloric acid (HCl)
- MOD™ acids
- HTA-710 acid containing HAI-81M™ or HAI-GE™ inhibitors
- SGA-II™ and SGA-HT® gelling agents
- SWIC II™ system

**NEA-96M™ Surfactant**
NEA-96M™ surfactant is a general surfactant and nonemulsifier for preflushes, acid preflushes, HCl and HF acid systems, overflushes, and fracturing fluids. When added to water-based fluids, it helps remove water blocks and aqueous external emulsion blocks. When added to water-based preflushes, it can lower breakdown pressure. NEA-96M surfactant can also be used to help clean up kill fluids, packer fluids, completion fluids, or any fluid that might invade the formation. It can be used with Musol® A or Musol® E agents if solvents are needed, and in acid systems containing either HAI-81M™ or HAI-85M™ corrosion inhibitors. Because it is an anionic blend, it is compatible with other anionics, nonionics, and anionic/nonionic blends. NEA-96M surfactant provides the following benefits:

- Helps prevent the creation of emulsions between injected fluid and formation fluid
- Helps break emulsion blocks and water blocks
- More effective in smaller amounts than many other surfactants (0.1 to 1.0% concentrations)

**Clay Stabilizers**
**Cla-Sta® Compounds**
Cla-Sta® compounds are permanent clay stabilization materials that may be used with brine systems common to sand control and fracturing processes. Cla-Sta compounds are organic polymeric materials which do not alter the water-wet condition of a sandstone formation. They are not corrosive to tubular goods. The chemical structure of these compounds is key to their effectiveness. When absorbed on a water-sensitive clay surface, the compounds are not easily replaced or desorbed as individual ions but rather act as ions linked by a chain-like structure. When formation brines flow past the treated clays, Cla-Sta compounds are not easily replaced by cations from the brine. The compounds can also effectively resist acidizing and other formation treatments.

**Cla-Sta® FS Additive**
Cla-Sta® FS additive was specifically developed for stabilizing mineral fines and clays in hydrocarbon-bearing formations. The Cla-Sta FS chemical is readily absorbed on formation surfaces. This alters the surface properties of the formation fine particles, reducing their interaction with flowing fluids (water, brines, oil, and gas) within the rock capillaries. Because the drag forces exerted on the fine particles by flowing fluids are decreased, fines migration is reduced even in the presence of very high rates of fluid flow. Stabilizing mineral fine particles significantly reduces solids production and permeability impairment.
Cla-Sta® FS additive effectively stabilizes a variety of mineral fines that do not respond to conventional stabilizers. Examples are:

- Silica
- Kaolinite
- Carbonates
- Hematite
- Magnetite
- Siderite

Cla-Sta FS additive may be applied in brine or acid solutions. Once treated, fines remain stabilized in the presence of acids, brines, oils, and even fresh water. Cla-Sta FS additive is often included in small percentages of filtered completion fluid as a perforating medium. When fluid is lost to the formation, it is instantly protected from later contact with incompatible fluids.

**Cla-Sta® XP Stabilizer**

Cla-Sta® XP stabilizer is the clay and fines stabilizer of choice for formations with permeabilities of approximately 30 md or less. It can be placed in almost all treating fluid, including FracPac™ system and gravel pack gels, acids, and brines. More information on how the Cla-Sta XP polymer controls clays in tight formations can be found in SPE paper 18881, “Clay Stabilization in Low-Permeability Formations.” This chemically resistant clay stabilizer provides superior penetration in tight formations and is compatible with most fracturing and gravel packing gel systems including crosslinked systems. A water-soluble cationic material, it is designed to surface-absorb very rapidly upon contact with clays and fines. Cla-Sta XP stabilizer helps prevent clay swelling and migration during and following fracturing, gravel packing, and acidizing treatments.

**Scalechek® HT Scale Inhibitor**

Scalechek® HT inhibitor is a solid phosphonate scale inhibitor designed to be placed in a fracturing treatment.

**Applications**

Scalechek HT inhibitor can help control calcite (calcium carbonate), gypsum (calcium sulfate), and barite (barium sulfate) scales. It can also help prevent naturally occurring radioactive material (NORM) scale that is often associated with barium sulfate scale formations.

- Effective at temperatures of 100°F (38°C) and above.
- Compatible with all of Halliburton’s current aqueous fracturing fluids.
- Incompatible with low-pH fluids, strong oxidizers, and strong acids.

**Benefits**

- Coated to prevent interference with crosslinked fracturing fluids. Compared with squeezed inhibitors, a higher percentage of Scalechek HT inhibitor remains in the formation to control scale.
- Designed to be placed in the fracturing fluid along with the proppant, eliminating the need for a separate treatment for placement.
- Placement with a planned fracturing treatment can provide up to 2 years of scale inhibition.

**Cla-Sta® O Additive**

Cla-Sta® O additive is an oil-soluble version of either Cla-Sta FS or Cla-Sta XP additive.
Friction Reducers

Friction reducers are primarily used for coiled tubing cleanout jobs where fluid losses to the formation are not expected. Friction reducers are not recommended for fluids injected into sandstone formations.

**FR-66™ Friction Reducer**

FR-66™ liquid friction reducer is used for light brines. It consists of an oil-external emulsion easily inverted and/or broken and dispersed with shear in aqueous fluids. It can tolerate more dissolved solids in the water than previous friction reducers.

- It is effective at low concentrations (0.25 to 0.5 gal per 1,000 gal) in fresh water.
- Higher concentrations of FR-66 friction reducer may be required in KCl or NaCl water.
- Easier to mix than powdered materials.

In addition, the concentrated liquid friction reducer can be mixed on-the-fly and does not cause the lumping problems associated with powdered friction reducers.

**FR-5™ Friction Reducer**

FR-5™ liquid additive is used to reduce friction pressure when pumping hydrocarbon base fluids such as kerosene, crude oil, and refined fracturing oils in turbulent flow through pipe. FR-5 friction reducer is a high molecular weight, synthetic polymer. The base fluid must be pumped in turbulent flow for this additive to be effective. Field experience has demonstrated the effectiveness of FR-5 friction reducer to produce friction reduction. For example, FR-5 friction reducer was added to a lease crude (43° API gravity) at 5 gal per 1,000 gal and injected at 10 bbl/min down a common manifold of 5 1/2-in. casing and 2 3/8-in. tubing. Calculated friction reduction was 56%.

**FR-48W Friction Reducer**

FR-48W friction reducer is a cationic liquid reducer designed to perform over a wide range of surface fluid temperatures. FR-48W friction reducer contains a new aqueous carrier fluid for delivery of the polymer, rather than a typical hydrocarbon carrier fluid. Laboratory data indicates FR-48W friction reducer is compatible with freshwater, 2% KCl, 10% NaCl, 2% CaCl₂, 11.0 lb/gal CaCl₂ brine, and acids.

**FR-38 Friction Reducer**

FR-38 cationic, liquid friction reducer is designed to perform over a wide range of surface fluid temperatures. FR-38 friction reducer does not contain a hydrocarbon carrier fluid for delivery of the polymer. FR-38 friction reducer contains a new aqueous carrier fluid that is environmentally evaluated.