

Schlumberger

# Well Intervention Catalog

## Volumes 1, 2 & 3

Schlumberger  
3750 Briarpark Drive  
Houston, Texas 77042

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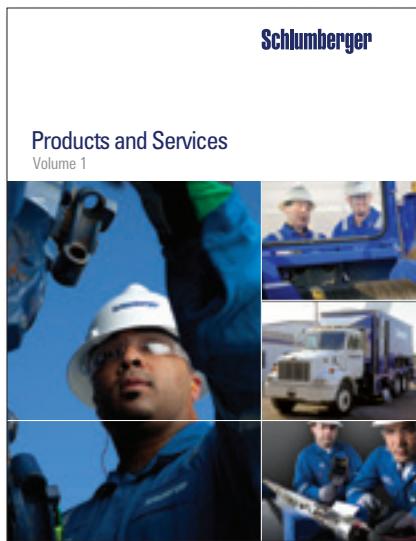
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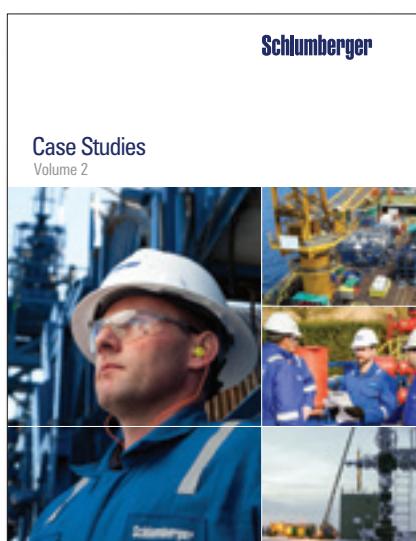
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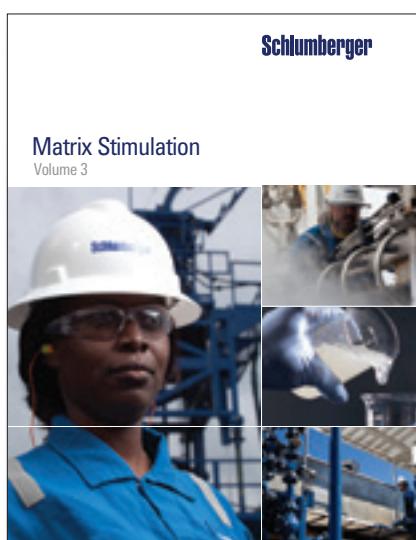
## Contents - *click on Volume to access*



### Volume 1: Products and Services



### Volume 2: Case Studies

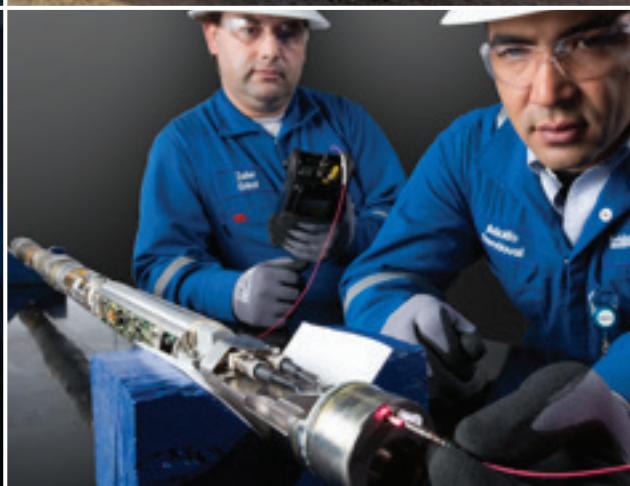
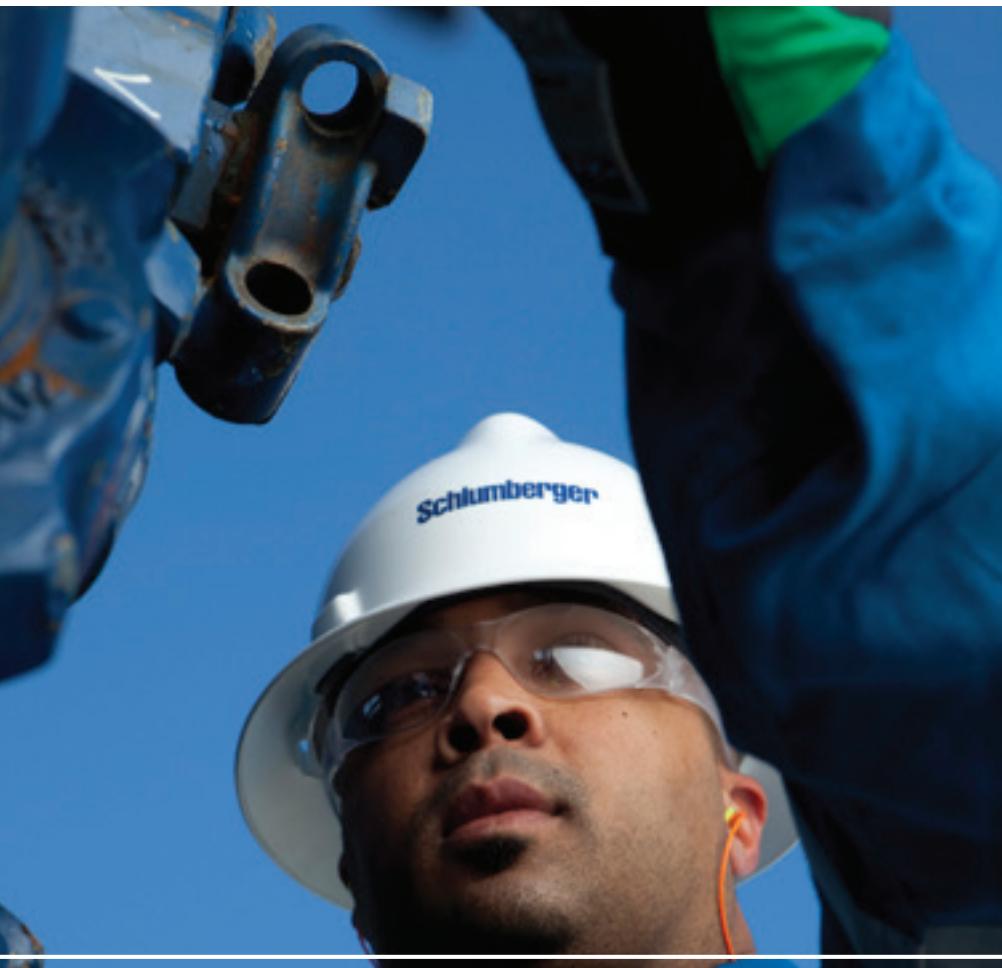


### Volume 3: Matrix Stimulation

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## Products and Services

Volume 1



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Houston, Texas 77042

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# Contents

<b>Coiled Tubing .....</b>	<b>1</b>
Coiled Tubing Surface Equipment .....	3
CT TComp.....	5
CT EXPRESS .....	7
X-11.....	9
CT SEAS.....	13
Catenary Intervention .....	16
ACTive Portfolio	
ACTive.....	21
ACTive GR .....	23
ACTive TC.....	25
ACTive PS .....	27
ACTive Straddle .....	29
ACTive MHA .....	31
ACTive OptiFIRE .....	33
Downhole Technology	
Vantage .....	37
Jet Blaster.....	39
ThorFRAC.....	41
CoilFLATE .....	43
Multicycle Circulating Valve .....	45
Discovery MLT .....	47
ReelCONNECT.....	49
CIRP.....	51
eFire-CT .....	53
Data Acquisition and Software	
CoilScan.....	57
CoilCADE .....	58
CoilCAT.....	60
InterACT .....	61
ACTive DTS Inversion .....	63
CoilTOOLS	
E-Z Connector.....	67
Internal Breech Lock Connector.....	69
Roll-On Coiled Tubing Connector .....	72
Dimple Connector.....	75
Double-Flapper Check Valve .....	77
Pump-Out Check Valve .....	79
Rugged MHA .....	81
Rugged Disconnect .....	83
Dual Tubing Pressure Circulation Valve .....	85
Downhole Filter .....	86
Surface Filter .....	87
Wash Pipe Guide .....	88

Three-Piece Stabilizer.....	89
Selectable Jet Nozzle .....	91
Wash Tools and Nozzles .....	92
Back-Pressure Valve.....	97
Hydraulic GS Retrieval Tool.....	98
Shorty MHA.....	99
Pull Plate and Pressure Test Sub.....	100
Straight Bars.....	101
Bull Nose .....	102
Mark V Disconnect .....	103
Pressure-Balanced Mechanical Disconnect.....	104
Torque Quick Connect.....	105
X-Over .....	106
<b>Matrix .....</b>	<b>111</b>
Stimulation and Conformance.....	113
MaxCO <sub>3</sub> Acid.....	115
MaxCO <sub>3</sub> Acid LT .....	117
VDA.....	119
OneSTEP .....	121
MaxCO <sub>3</sub> Acid CT.....	122
OilSEEKER .....	123
SXE .....	125
FoamSEAL .....	126
Stimulation Products.....	127
Acids.....	127
Acid Intensifiers .....	127
Activators.....	127
Antifoam Agents.....	128
Asphaltene Inhibitors .....	128
Antisludge Agents .....	128
Biocides/Bactericides.....	128
Base Oil .....	128
Breakers / Fracture Cleanup Enhancers.....	129
Breaker Aids .....	139
Buffering Agents .....	130
Chelating Agents .....	130
Clay Stabilizers .....	130
Corrosion Inhibitors .....	131
Corrosion Inhibitor Aids .....	132
Crosslinker .....	132
Crosslink Delay Agents.....	132
Demulsifier/Nonemulsifying.....	133
Dispersant .....	133
Diverting Agents .....	134
Emulsifying Agents.....	134

Fluid Loss Additives .....	135
Foaming Agent .....	135
Friction Reducing Agents .....	136
Gelling Agents .....	136
Gelling Agents (continued) .....	137
H <sub>2</sub> S Scavengers .....	138
Mutual Solvent .....	138
Iron Control Agents .....	138
Miscellaneous Additives .....	139
Oxygen Scavengers .....	139
Organic Scale Dissolvers/Inhibitors/Dispersants .....	140
Resin Consolidation System Components .....	141
Inorganic Scale Removal and Inhibition .....	141
Stabilizing Agents .....	142
Surfactants .....	142
Stimulation Systems .....	143
Matrix Stimulation Systems .....	143
Hydrochloric Acid .....	143
Mud Acid .....	143
Clay Acid .....	144
Alcoholic Acid .....	144
Gas Well Acid .....	144
Gas Well Mud Acid .....	145
DAD Dynamic Acid Dispersion .....	145
SXE Emulsified Acid .....	145
OCA Organic Clay Acid Stimulation Fluid .....	146
FinesLOK Technique to Prevent Migration .....	146
MSR Mud and Silt Remover .....	146
NARS Formation Solvent 200 and 201 .....	147
Organic Acids .....	147
Organic Mud Acids .....	147
MISCA Solvent for Iron And Sludge Control .....	148
OneSTEP Simplified Sandstone Stimulation System .....	148
Diverting Systems .....	149
OilSEEKER High-Water-Cut Acidizing Diverter .....	149
FoamMAT Foam Diversion Service for Matrix Treatments .....	149
SDA Self-Diverting Acid .....	149
Matrix Acidizing Diverting Agent J237A .....	149
VDA Viscoelastic Diverting Acid .....	150
MaxCO <sub>3</sub> Acid Degradable Diversion Acid System .....	150
Water Control Systems .....	151
MARA-SEAL <sup>SM</sup> .....	151
MARCIT <sup>SM</sup> .....	151
OrganoSEAL-R .....	151
OrganoSEAL-F .....	152

SqueezeCRETE Remedial Cementing Solution .....	152
DGS Delayed Gelation System .....	152
PERMABLOK Fluid System to Permanently Plug a Zone.....	152
ZONELOCK Permanent Zone Sealing Fluid System .....	153
Special Systems .....	153
PROTECTOZONE-VP .....	153
TubeCLEAN Completion Preflush Treatment.....	153
CLEAN SWEEP Solvent Systems for Damage Removal.....	154
OB Mud Removal System.....	154
Matrix Stimulation Services .....	155
CarboSTIM Carbonate Stimulation Service.....	155
MudSOLV Filtercake Removal Service .....	155
ScaleMAT Acid-Compatible Scale Inhibitor .....	156

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# **Coiled Tubing**

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# Coiled Tubing Surface Equipment

# CT TComp

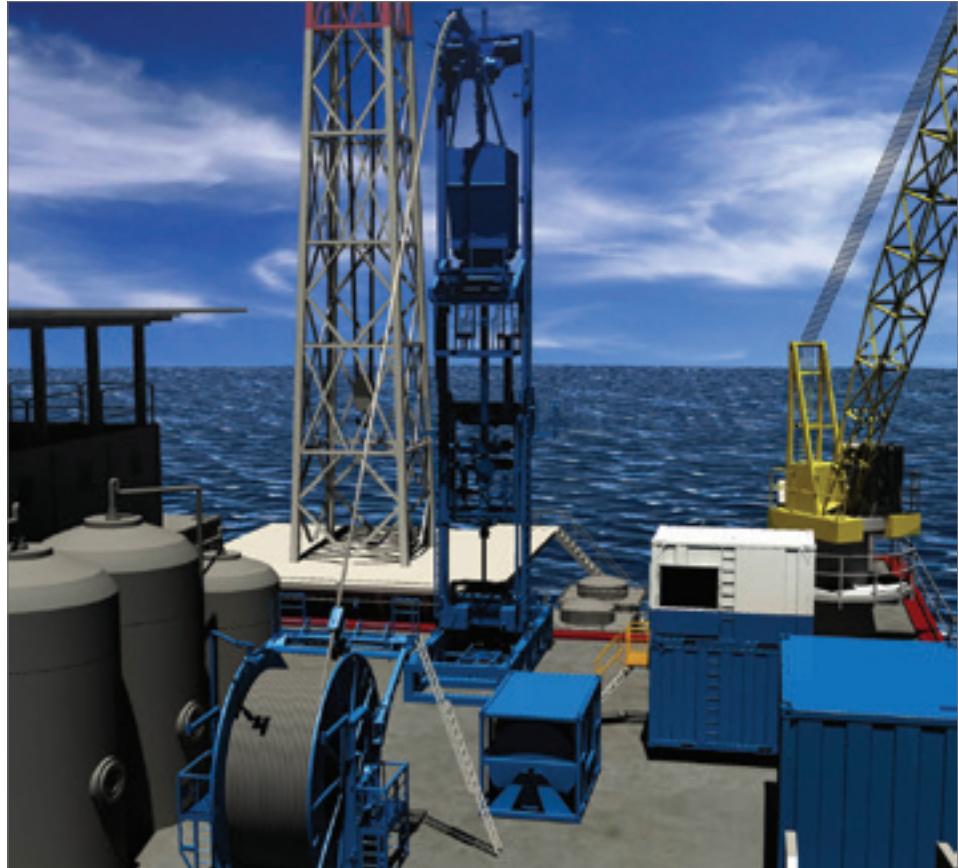
## CT offshore motion compensation system

### APPLICATIONS

- Functions as a heave-compensated jacking frame
- Serves as a tension-lift frame on semisubmersibles and drillships
- Allows simultaneous wireline or slickline operations without rigging down the CT equipment
- Performs heave compensation when blocks are not compensated in the derrick
- Provides compensation on spars after the rig is demobilized

### ADVANTAGES

- Preassembly onto three skids
- Compensation for 7 ft of vertical heave
- Efficient single-bolt clamp connections for BOPs and risers
- Class I, Division II-certified electrical system
- Automatic wellhead monitoring and maintenance within acceptable stress envelope
- Two fall arrestors and handrails on all walkways



*The CT TComp system's passive design keeps wellhead load within an acceptable range by constantly monitoring the load and adjusting the passive accumulator hydraulic pressure.*

### Safer, more efficient heave compensation and wellhead stress management

The CT TComp\* CT offshore motion compensation system has three versatile operating modes. Its 15-ft titanium stress joint allows movement during operations and relieves stress on the wellhead. The CT TComp system automatically maintains riser load and stress joint flexibility at optimum levels.

### Jacking frame mode

The vertical structure of the jacking frame is made up of the base of the BOP crash frame, which also acts as the base for the CT mast system. The jacking frame base is designed to sit on 12-ft centers with center loading up to 160,000 lbf [711,700 N], allowing it to span large well-bay slots or sit across skid beams on spars, distributing load across the platform deck.

## Thoughtful design elements add safety and save time

- Connection time reduced to 5 minutes from 45 minutes per connection by using a 15,000-psi riser and BOP Grayloc® single screw connector
- Hydraulic connections are reduced to 4 from 25
- Stabbing winch saves up to 2 hours and eliminates a major HSE hazard
- Hydraulically actuated gooseneck saves up to 90 minutes during rig up
- Hydraulic connections are frame mounted to reduce the number of connections during module assembly
- Guy wire winches and hydraulic hose and cable reels reduce deployment time and increase safety

### Tension-lift frame mode

Assembled in one or two pieces, the CT TComp system can also act as a 350-ton tension-lift frame that transmits riser load from the blocks around the CT equipment. Conventional frames require all CT equipment to be assembled after the frame is raised, requiring valuable time and risking injury to personnel. The modular CT TComp system can be assembled and swung into place with one lift.

### Internally compensated tension-lift mode

Since spars do not usually have compensated blocks, the driller is forced to monitor and adjust for load on the blocks during the entire CT operation. However, the CT TComp system monitors load and adjusts automatically. A 15-ft titanium flex joint absorbs any stress caused by horizontal misalignment, eliminating undue stress on the riser or wellhead.

#### Specifications

Injector pull	100,000 lbf [444,800 N] continuous 110,000 lbf [489,300 N] intermittent
HPU/accumulator skid rating	85 dB at 1 m [3.3 ft]
Electrical system certification	Class I, Division II hazardous service
Tension-lift frame capacity	350 metric tons
BOP size and capacity	5½ in [13.02 cm], 15,000 psi [103.42 MPa]
Riser size, capacity, and type	5½ in [13.02 cm], 15,000 psi [103.42 MPa], XG-52 seal ring hub
Hydraulic fluid	EnviroLogic® biodegradable lubricant

# CT EXPRESS

## Rapid-deployment coiled tubing unit

### APPLICATIONS

- CT services for land-based rigless wells

### ADVANTAGES

- Two tractor trailer units that have the power of four trucks
- Improved rollover stability
- Elimination of need to work under suspended load or to climb on unit
- Improved logistics that reduce risks and costs
- Elimination of onsite hose and cable makeup and breakdown
- Small environmental footprint
- Weight compliant with US and Canadian road laws
- Tubing stabbed during transport
- Assembly and pressure-testing of BHAs up to 6 ft long prior to leaving base
- Onsite BOP pressure testing
- 30-min rig up, including pressure test
- Constant checks on critical job parameters through process control
- Automated emergency procedures for pipe slip and runaway detection and control
- Real-time data monitoring using CoilCAT\* coiled tubing computer-aided treatment
- User-friendly, ergonomic work environment



*CT EXPRESS rapid-deployment CT unit.*

The CT EXPRESS\* rapid-deployment CT unit operates with two trucks and a three-person crew. Innovative unit layout and effective use of technology enable quick rig up and rig down and eliminate the need to climb on the unit or work under suspended loads. Process control of all pertinent CT and pumping functions improves job efficiency, economics, and operational safety. During field tests, CT EXPRESS units performed more than 200 jobs without a single lost-time incident. The simple design provides a high degree of reliability over rough terrain and in extreme climate conditions.

The CT unit carries a 40,000-lbf injector and 10,000-psi wellhead pressure control equipment on a 42-ft mast. The unit can be used on wellheads up to 20 ft high, with 6-ft or shorter BHAs. Longer BHAs can be accommodated on shorter wellheads. Tubing remains stabbed during transportation, and BHAs as long as 6 ft can be made up and pressure tested before arriving on location. No hydraulic or electrical connections are made on location, which makes rig up safer and more efficient. The drop-in drum reel and innovative BOP pressure-test stand also make job preparation faster and safer.

A combination-pump tractor carries the fluid pumping and liquid-additive systems and provides electrical and hydraulic power for the unit. The trailer carries the nitrogen pumping system and liquid nitrogen storage tank. The entire system is designed to complement CT operations where pump rates are relatively low, pressures are moderate, and pumping operations continue nonstop for long periods.

Although the combination pumper is designed to be operated remotely from the cab of the CT unit, local controls are also provided for standalone operation. Operational design of the CT EXPRESS unit is entirely electric over hydraulic. The operator controls both the CT unit and the pumps from the control chair, enabling better use of manpower and eliminating communication problems among operators of different units.

The CT EXPRESS unit uses proven Schlumberger CoilCAT treatment for real-time data acquisition to provide information for making onsite decisions.

## Features and Specifications

### Coiled Tubing Unit

Tubing diameter	1¼ in [3.2 cm], 1½ in [3.8 cm], 1¾ in [4.4 cm]
Max. tubing length	14,500 ft of 1½-in [4,420 m of 3.8 cm] tubing
Mast height	42 ft [12.8 m]
Injector	40,000-lbf [177,929-N] pull
Gooseneck radius	72 in [1.83 m]
BOP	3½-in [7.78-cm] bore, 10,000-psi [68.95-MPa] rating
Sidedoor stripper	2½-in bore, 10,000-psi [68.95-MPa] rating
Lubricator	6 ft [1.8 m] tall, 3½-in [7.8-cm] diameter, 10,000-psi [68.95-MPa] rating

Integrated universal tubing length monitor

Universal tubing integrity monitor

Drop-in drum reel

Integrated BOP pressure test stand

Integrated fall arrestor and man lift

### Combination Pumper

Continuous-service liquid pump	0.1–2.0 bbl/min [0.02–0.32 m <sup>3</sup> /min], 10,000-psi [68.95-MPa] rating
Liquid additive pump	0.1 to 0.6-galUS/min [0.38 to 2.3 L/min] with 60-galUS [227 L] reservoir
Nitrogen pump	150–1,500-ft <sup>3</sup> /min [4.25–42.5 m <sup>3</sup> /min], 5,000-psi [34.47-MPa] rating
Liquid nitrogen tank	3,000 galUS [11.4 m <sup>3</sup> ]

Diesel-fired vaporizer

Micromotion nitrogen flowmeter

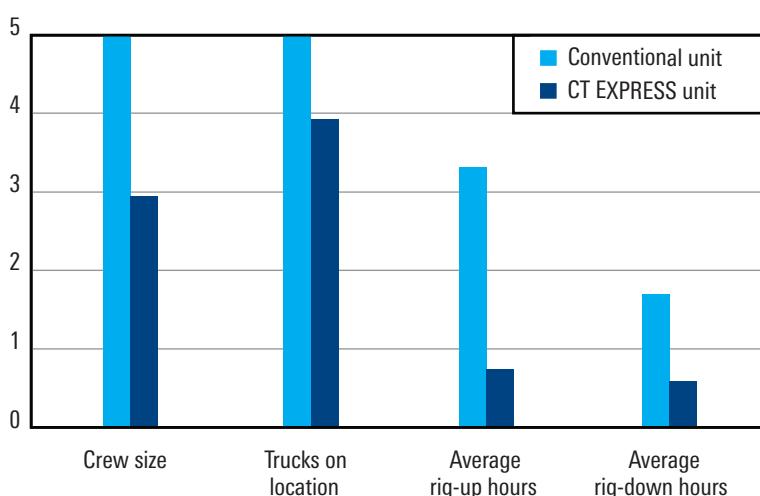
### Control System

Fly-by-wire electric over hydraulic controls

Central controls for coiled tubing and pumper inside cab of CT unit

Local controls for standalone operation of combination pumper

Redundant hydraulic controls for CT



Comparison between conventional and CT EXPRESS unit.

# X-11

## Modular offshore CT unit

### APPLICATIONS

- Designed for all offshore applications

### FEATURES

- Adaptable for platforms, barges, spars, floaters, and tension-leg platforms
- Operates with fly-by-wire controls from the control cabin to all the major skids
- Provides finite control of injector speed and applied forces
- Uses computer-controlled systems that eliminate overpull and oversnub scenarios
- Incorporates automatic hydraulic power pump management system
- Can be configured to run up to Category III well-control working pressures
- Offers automatic reel-brake fail-safe system
- Reduces the need for personnel to climb on top of the injector through use of semiautomated tubing stabbing process
- Monitors the condition of all the electronic, hydraulic, and pneumatic systems
- Works with CT sizes from 1½ to 2½ in
- Offers fail-safe systems that incorporate complete manual backup
- Enables detailed, accurate entry into the wellbore through real-time geometry inputs
- Provides constant monitoring of BOP system pressures and valve positions
- Reduces the number of hydraulic and mechanical connections required to set up
- Offers zoned, ATmosphere EXplosibles (ATEX), and CE-marked certified control cabin, hydraulic power pack, reel, and injector

### BENEFITS

- Incorporates fail-safe systems to improve safety
- Improves efficiency and safety of the wellsite delivery process
- Reduces footprint through modular design concept that allows stacking

### Flexible, fit-for-purpose design

The X-11\* modular offshore CT unit with active process control and automated safety systems was developed as a flexible, fit-for-purpose system that is easily adaptable for many offshore structures including platforms, barges, spars, floaters, and tension-leg platforms.

The unit works with CT sizes ranging from 1½ to 2½ in, and changing from one CT size to another is safer, easier, and more efficient.

### More automation, less complexity

The X-11 unit comprises five main skids:

- a hydraulic power pack
- a control cabin
- a drop-in drum reel
- two transport baskets that contain well-control equipment and the injector.



*Interior of the X-11 unit.*

Modular in design, the hydraulic power pack, the control cabin, and the transport baskets are built in standard shipping containers, and the control cabin can stack on top of the hydraulic power pack. This design reduces the total weight and footprint of the entire CT system.

The unit's automated control system monitors well parameters and the entire electric hydraulic system. This control system detects and provides timely notification to the supervisor when changes occur. In addition to providing real-time data acquisition and data transfer to offsite locations, the X-11 unit provides one central control point for the entire CT operation.

The modular package combines major CT components are easy to connect, optimize space utilization, and provide maximum versatility.

### Improved safety and efficiency

The X-11 unit improves the efficiency and safety of the wellsite delivery process, while reducing the cost of the total system. Automating several key processes also reduces the number of operating personnel that is normally required. Improved crew ergonomics, a smaller footprint, and the automated monitoring and control systems allow the CT supervisor to focus on downhole job requirements rather than equipment coordination.

## General Specifications

Operating temperatures	-4 degF [-20 degC] to 118 degF [48 degC]
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## Hydraulic Power Pack

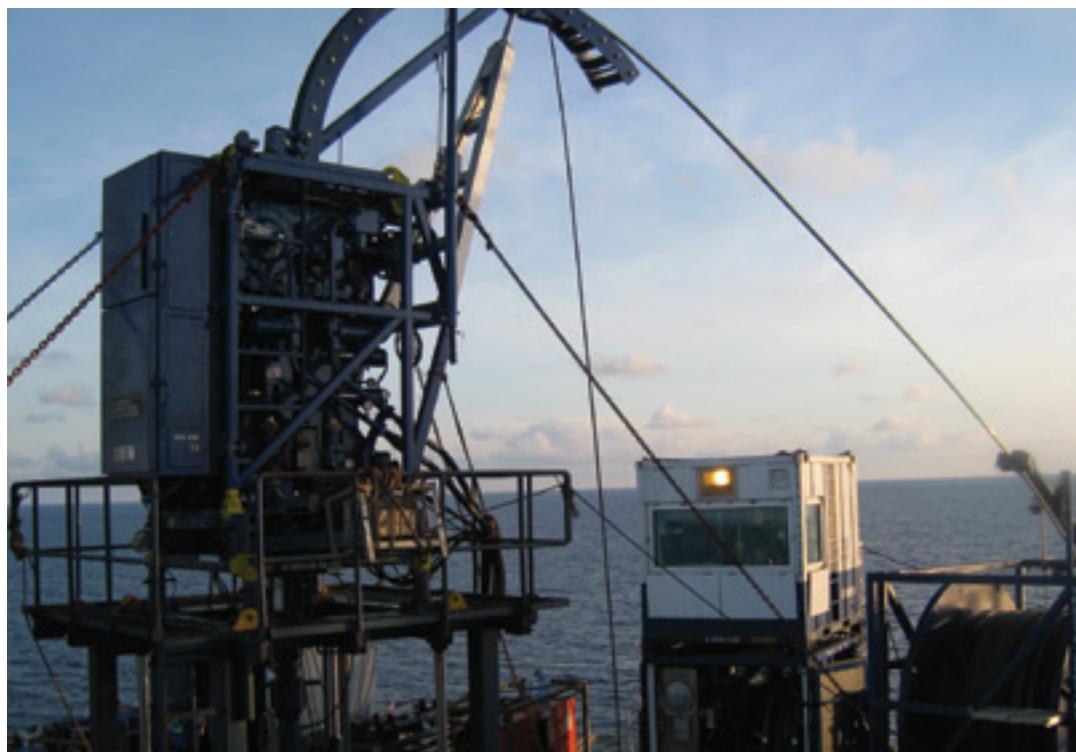
Engine	340-hp Caterpillar® C9 Tier III engine
Engine emergency shutdown system	Emergency air intake shutdown, automatic engine overspeed shutdown, gas detector sensors
Hydraulic pump	250-hp triple-stack gear pump
Hydraulic circuits	Semiclosed loop, with 3,000-psi [20.68-MPa] and 5,000-psi [34.48-MPa] circuits
Accumulators	Three 15 galUS [0.057 m <sup>3</sup> ]
Diesel tank	150 galUS [0.57 m <sup>3</sup> ]
Hydraulic tank	150 galUS [0.57 m <sup>3</sup> ]
Length × width × height	10 ft × 8 ft × 8.5 ft [3.05 m × 2.44 m × 2.59 m]
Weight	25,000 lbm [11,339.8 kg]
Lifting certification	DNV <sup>†</sup> 2.7.1
Certification	ATEX <sup>‡</sup> , CE marked, Zone II compliant

## Control Cabin

Cabin	Pressure purged
Controls	Process-controlled system
Data acquisition	CoilCAT* coiled tubing computer-aided treatment
External monitoring (video camera system)	Remote spooling, stripper, two others as required
Climate control	30,000-Btu cooling system
External view	270° view
Length × width × height	10 ft × 8 ft × 8.5 ft [3.05 m × 2.44 m × 2.59 m]
Weight	15,000 lbm [6,803.9 kg]
Lifting certification	DNV 2.7.1
Certification	ATEX, CE marked, Zone II compliant

<sup>†</sup> Det Norske Veritas

<sup>‡</sup> ATmosphere EXplosibles



X-11 in offshore Malaysia.

**Drop-In Drum Reel System**

Loading	From top and front of power stand
Levelwind	Floating arm type suitable for all tubing sizes, automated electronic overhydraulic spooling control
Drive system	Chain drive
Reel swivel	15,000-psi [103.42-MPa] rated
Circulating pressure transducer	Integral type with double isolation valve manifold
Pig launcher	Yes
Ball-dropping ability	Yes
Tubing monitoring	CT inspection device for wall thickness and ovality
Tubing lubrication (external)	Automatic lubrication with applicator on levelwind, 5-galUS tank capacity
Tubing lubrication (internal for corrosion mitigation)	Self-contained system
Safety equipment	Fall arrester, work platforms as required for levelwind access

**Tubing Spool Specifications**

Flange outside diameter	Core diameter	Width	Tubing capacity	With 95% spooling efficiency		
142 in [3.61 m]	80 in [2.03 m]	68.5 in [1.74 m]	1¼ in	37,800 ft [11,521.4 m]		
			1½ in	26,700 ft [8,138.2 m]		
			1¾ in	19,800 ft [6,035.1 m]		
			2 in	14,600 ft [4,450.1 m]		
Flange outside diameter	Core diameter	Width	Tubing capacity	With 95% spooling efficiency		
142 in [3.61 m]	70 in [1.78 m]	68.5 in [1.74 m]	1¼ in	41,300 ft [12,588.2 m]		
			1½ in	28,500 ft [8,686.8 m]		
			1¾ in	21,800 ft [6,644.6 m]		
			2 in	na <sup>†</sup>		
Length × width × height			13.83 ft × 8.5 ft × 12.25 ft [4.22 m × 2.59 m × 3.73 m]			
Weight with empty spool			19,500 lbf [8,845.1 kg]			
Weight of empty spool			5,700 lbf [2,585.5 kg]			
Skid, max. gross weight with tubing full of fluid			100,000 lbf [45,359.3 kg]			
Lifting certification			DNV 2.7.1			
Certification			ATEX, CE marked, Zone II compliant			

**Injector Specifications**

HR 560 configuration	60,000 lbf pull, 26,000 lbf snub [266,893 N pull, 115,654 N snub]
HR 580 configuration	80,000 lbf pull, 40,000 lbf snub [355,858 N pull, 177,929 N snub]
HR 5100 configuration	100,000 lbf pull, 50,000 lbf snub [444,822 N pull, 222,411 N snub]
Hydraulics	5,000-psi [34.48-MPa] circuit with condition monitoring systems
Depth system	Universal tubing length monitor mounted below the injector chains
Gooseneck	72-in [1.83-m] gooseneck with overload protection system, set up for 1¼-in [3.175-cm] to 2⅜-in [7.303-cm] CT
	100-in [2.54-m] gooseneck with overload protection system, set up for 1¼-in [3.175-cm] to 2⅜-in [7.303-cm] CT
Condition monitoring	Metallic chip detection and temperature sensors
Safety system	Fall arrester system
Lifting certification	DNV 2.7.1
Certification	ATEX, CE marked, Zone I compliant

## BOP Control Station

Operation	Can operate two strippers, two dual combi or one quad BOP system, and kill and flow valves
Mode of operation	From control cabin or from control station, with automatic ram position detection and feedback to the control system
Certification	ATEX, CE marked, Zone II compliant

## Well Control Equipment

BOP	10,000-psi [68.95-MPa] dual combi 4.06-in [10.31-cm] bore slidelock BOP
Stripper	4.06 in [10.31 cm], 10,000 psi [68.95 MPa]
2-ft riser	4.06 in [10.31 cm], 10,000 psi [68.95 MPa]
4-ft riser	4.06 in [10.31 cm], 10,000 psi [68.95 MPa]
8-ft riser	4.06 in [10.31 cm], 10,000 psi [68.95 MPa]

## Injector Transport Basket

Length × width × height	Injector, stripper, injector legs
Weight	10 ft × 8 ft × 9.5 ft [3.05 m × 2.44 m × 2.89 m]
Gross weight, fully loaded	6,000 lbm [2,721.6 kg]
Lifting certification	28,000 lbm [12,700.6 kg]
Certification	DNV 2.7.1
	CE marked

## Well Control Transport Basket

Length × width × height	BOP, gooseneck, BOP control cart, risers, stairs
Weight	10 ft × 8 ft × 9.5 ft [3.05 m × 2.44 m × 2.89 m]
Gross weight, fully loaded	6,000 lbm [2,721.6 kg]
Lifting certification	28,000 lbm [12,700.6 kg]
Certification	DNV 2.7.1
	CE marked

## Options

Soundproofed power pack	
Max. average sound pressure level	80 dB
Operating temperatures	-4 degF [-20 degC] to 108 degF [42 degC]
Certification	ATEX, CE marked, Zone II compliant
Reel conversion skid	Adapts to conventional CT reels and provides all the reel control features
Certification	ATEX, CE marked, Zone II compliant

<sup>†</sup> Not available

# CT SEAS

## Automated offshore CT unit

### APPLICATIONS

- Offshore coiled tubing (CT) operations in demanding environments on fixed and floating facilities

### ADVANTAGES

- Increases safety and efficiency
- Lowers operating costs
- Reduces the number of lifts required (typically from 53 to 36)
- Reduces personnel by up to 30%
- Reduces rig-up time
- Reduces operating time

### FEATURES

- Usability in all CT operations
- Ten primary skids
- Reduced mechanical and hydraulic coupling on location
- Preassembled and tested equipment modules and manifolds
- Soundproofed, zoned, ATmospheric EXplosives (ATEX) compliant hydraulic power unit
- Modularized hydraulic connections
- Automatic stabbing of tubing into injector head
- Reduction in high elevation work
- Improved pressure testing

### Increased safety and efficiency

With components modularized into 10 primary skids, CT SEAS\* automated offshore CT unit reduces time for offshore CT operations.

### Modular assembly

An ergonomically designed cabin enhances operator control while reducing personnel requirements, rig-up time, and costs. Pretested, preassembled modules make field assembly efficient and minimize the chances for human error during rig up. A reduction in the number of hydraulic connections saves time and reduces the risk of contamination. Single-bolt locking unions and other time saving devices enhance efficiency.

### Safer, more efficient CT system

The CT SEAS unit is flexible, fit-for-purpose, and readily adaptable for many offshore structures, including platforms, floaters, and tension-leg platforms. The system has all the capabilities of a conventional CT unit.

The unit is beneficial in all operations in which many runs are conducted in the same well. Typically, these operations include long postfracturing cleanouts. System design elements and improved ergonomics enhance safety and save time.

- The process control architecture allows faster, safer operations.
- Single-point control of CT, choke manifold, and pump improves safety and helps the engineer focus on the task at hand.
- Modules allow efficient transition between wells on sequential multiwell operations.
- Personnel reduction improves operational efficiency and safety.
- More efficient use of space through a modular design benefits platform operations, limits boat space requirements, and reduces the number of crane lifts.



*The CT SEAS unit only has 10 primary skids, which cuts crane lifts off the boat to 36 from 53 in typical operations.*



## General Specifications

Operating temperatures	-4 degF [-20 degC] to 108 degF [42 degC]
------------------------	--

## Hydraulic Power Pack

Engine	500-hp Detroit Diesel Series 60®
--------	----------------------------------

Engine emergency shutdown system	Emergency air intake shutdown, automatic engine overspeed shutdown, gas detector sensors
----------------------------------	--

Hydraulic pumps	P16 / P14
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Hydraulic circuits	Closed loop, 3,000 psi [20.68 MPa], and 5,000 psi [34.48 MPa]
--------------------	---

Length × width × height	21.3 ft × 11.5 ft × 8.2 ft [6.5 m × 3.5 m × 2.5 m]
-------------------------	--

Weight	19 metric tons
--------	----------------

Lifting certification	DNV† 2.7.1
-----------------------	------------

Certification	ATEX, Zone II compliant
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## Control Cabin

Cabin	Pressure-purged A60
-------	---------------------

Controls	Process-controlled system
----------	---------------------------

Data acquisition	CoilCAT* coiled tubing computer-aided treatment
------------------	---

External monitoring (video camera system)	Remote spooling, stripper, two others as required
---	---

External view	270° view
---------------	-----------

Length × width × height	14.8 ft × 8.2 ft × 9.8 ft [4.5 m × 2.5 m × 3 m]
-------------------------	---

Weight	7.5 metric tons
--------	-----------------

Lifting certification	DNV 2.7.1
-----------------------	-----------

Certification	ATEX, Zone II compliant
---------------	-------------------------

<sup>†</sup>Det Norske Veritas

**Drop-In Drum Reel System**

Loading	From top and front of power stand
Reel swivel	15,000-psi [103.42-MPa] rated
Safety equipment	Fall arrester, work platforms as required for levelwind access

**Tubing Spool Specifications**

2 $\frac{7}{8}$ -in tubing capacity	19,685 ft [6,000 m]
Length $\times$ width $\times$ height	17.2 ft $\times$ 10.9 ft $\times$ 17.1 ft [5.3 m $\times$ 3.3 m $\times$ 5.2 m]
Weight with empty spool	14 metric tons
Lifting certification	DNV 2.7.1
Certification	ATEX, Zone II compliant

**Injector Specifications**

HR 5100 configuration	100,000 lbf pull, 50,000 lbf snub [444,822 N pull, 222,411 N snub]
Injector connector	5.125-in [13.02-cm] mechanical connector
Hydraulics	5,000-psi [34.37-MPa] circuit with condition monitoring systems
Depth system	Universal tubing length monitor mounted below the injector chains
Gooseneck	Trifold 120-in [3.05-m] gooseneck with overload protection system, set up for 2 $\frac{7}{8}$ -in [7.303-cm] CT
Condition monitoring	Metallic chip detection and temperature sensors
Safety system	Fall arrester system
Lifting certification	DNV 2.7.1
Certification	ATEX, Zone I compliant

**Well Control Equipment**

BOP	5.125-in [13.02-cm], 10,000-psi [68.95-MPa] triple
Safety head	5.125-in [13.02-cm], 15,000-psi [103.42-MPa] single shear
Stripper	4.06-in [10.31-cm], 10,000-psi [68.95-MPa] dual stripper
Risers	5.125 in [13.02 cm], 15,000 psi [103.42 MPa]



The CT SEAS unit offers an ergonomically designed cabin which enhances operator control while reducing personnel requirements, rig-up time, and costs.

# Catenary Intervention

Floating vessel intervention system

**APPLICATIONS**

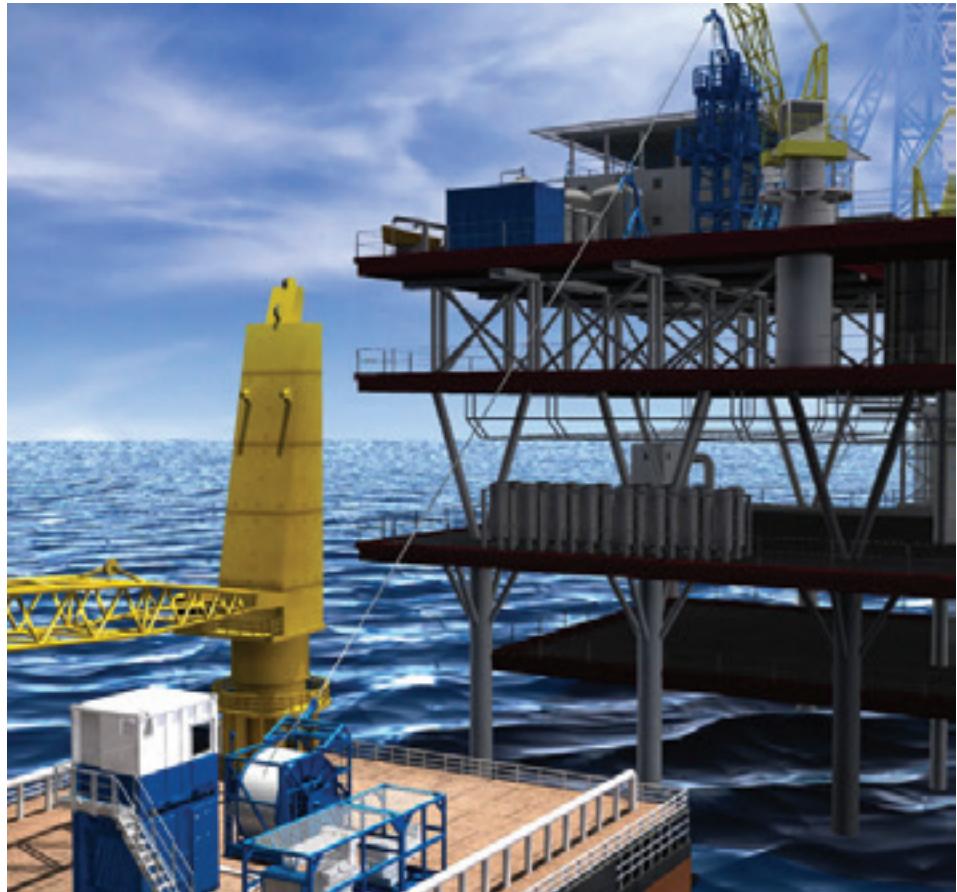
- Matrix stimulation
- Water or scale control
- Fill cleanout
- CoilTOOL\* coiled tubing intervention tools and solutions
- Zonal isolation and reperforation
- Fracturing through CT
- CT drilling

**BENEFITS**

- Reduces total intervention cost
- Increases profitability and production life
- Enables treatment of previously inaccessible wells
- Provides safer operations in adverse weather conditions

**FEATURES**

- Allows access to small offshore platforms with limited deck space and loading capacity
- Reduces number of trips to port
- Enables rapid deployment and rig up
- Offers satellite and datalink capability using InterACT\* global connectivity, collaboration, and information service



*ReelCONNECT\* seamless technology for connecting multiple coiled tubing strings assembly skid.*

**A more efficient CT intervention technique**

Interventions on small platforms with limited deck space and loading capacity often require the use of jackup barges, lift boats, or workover rigs. The high cost and limited availability of these offshore vessels has delayed or prevented many required interventions, leaving a number of wells nonproductive or producing below their optimal capacity.

The catenary CT intervention technique uses smaller floating vessels and proprietary safety and well-control systems that eliminate the need to lift the CT reel and the pumping equipment to the platform. The associated reduction in total intervention cost—and the ability to work on extremely small platforms—enables operators to perform interventions that increase profitability and production life.

### The floating vessel approach

Schlumberger has successfully used different types of small floating vessels for a number of years to perform offshore CT interventions. These vessels, which include anchored barges, dynamically positioned vessels, and standard supply boats, enable CT intervention on almost any offshore installation.

Full-scale CT operations have been performed from supply boats with deck space as limited as small as 16 × 9 m. With at least four vessel anchoring points in place, operations can be performed with wave heights up to 5 m. With a draft under 5 m, the floating CT system is an ideal solution for performing well intervention work, particularly for wells located on small-front platforms or platforms that prohibit placing CT and pumping equipment onboard.

The catenary system reduces total intervention time by approximately 25%, with less time needed for transferring equipment to platform, rigging up, and pressure testing. In addition, a shorter advance notice period is required for job preparation and mobilization.

#### CT Unit Specifications

Power pack	16,000 lbm [7,258 kg]
	Zone II, Division I compliant
Control cabin	16,000 lbm [7,258 kg]
	Hydraulic or electrical over hydraulic
	Air conditioned
	300-bhp engine
Reel	12,000–16,000 lbm [5,443–7,258 kg]
Injector skid	22,000 lbm [9,979 kg] total weight, including injector, BOPs, stripper, and accessories
	Injector head typical weight: 13,000 lbm [5,897 kg]
	Pull: 80,000–100,000 lbf [355,858–444,822 N]
	Snub: 40,000 lbf [177,929 N]
Data acquisition	CoilCAT* coiled tubing computer-aided treatment
Options	Soundproof engine package (85 dB at 7 m [23 ft])
	Zone II compliant
	DNV <sup>†</sup> certification
	Larger reel or use of clip-in drum
	Larger pressure control ID
	Higher pressure rating (Category 2 operations)
Catenary system, power pack, and cabin	Engine-air-cooled turbo diesel
	Shear-and-seal device for an emergency disconnect
	Automatic tensioning device that compensates for wave action
	Video monitoring and relay of operations that occur out of the operator's line of sight
	Dedicated cabin with reel drive, tensioner, and levelwind controls

<sup>†</sup> Det Norske Veritas

**Schlumberger**

# ACTive Portfolio

# ACTive

## Family of live downhole coiled tubing services

### APPLICATIONS

- Treatment monitoring
- Real-time logging and treating
- Intervening while the BHA is still in hole

### BENEFITS

- Improved production because the treatment is optimized with real-time data
- Reduced costs because monitoring, optimization, and intervention can be accomplished in one run

### FEATURES

- Real-time fiber-optic telemetry
- Real-time downhole quality check of tools with feedback validating downhole measurements
- Distributed temperature survey (DTS) that provides a 3D temperature profile of the entire wellbore
- Monitoring of injection rates and pressure
- Coiled tubing intervention and the most advanced production logging in one run
- Accurate depth control for perforating
- Accurate downhole pressure-buildup monitoring for well testing



*The ACTive family of live coiled tubing services uses fiber-optic CT to collect real-time measurements and optimize treatments while they are still in progress.*

### Innovative CT intervention

The ACTive\* family of live coiled tubing services enables downhole measurement, interpretation, and job optimization. These services provide the information needed to adjust job parameters, improve effectiveness, reduce risks, and optimize performance when it matters most—while the treatment is still in progress.

For every application, a customized live downhole CT service helps maximize treatment efficiency and reservoir performance.

### Technology platform

The portfolio of ACTive services provides live downhole measurements conveyed on CT that is enabled by fiber-optic telemetry. The system consists of a BHA, surface electronics, and dynamic interpretation software. It provides pressure readings inside and outside of the CT BHA, downhole and distributed temperature survey along the wellbore, casing collar locator, and depth correlation. An alternative downhole BHA allows combining real-time fiber-optic telemetry with existing advanced wireline production logging tools, making high-quality production logging data available during intervention—when it matters most.

### Enhanced downhole technology

The enhanced ACTive services downhole technology platform—through state-of-the-art electronics and sensors—delivers premium pressure measurements, improved power management, and modularity for increased confidence and overall job efficiency during a CT intervention. Real-time gamma ray and tension and compression measurements are the latest offerings in the portfolio of ACTive services. These new measurements add to the technology platform to enable informed, real-time decisions, operational control, and higher value services.

ACTive real-time CT services give you the opportunity to monitor and evaluate job progress, optimize treatment results, and intervene with one run in the hole.

**ACTive Matrix\* live CT stimulation and conformance service** optimizes CT matrix stimulation through live monitoring of injection rates and downhole pressure and temperature to allow maximum fluid penetration and diversion and to optimize treatment volumes. This real-time process improves current treatment performance and enhances the design of subsequent treatments.

**ACTive Isolation\* live CT zonal isolation service** achieves accurate depth setting, sealing element operation and integrity, and fluid placement intended for performing temporary or permanent CT zonal isolation, all in a single run. Controlling the pressure differential across the sealing elements and tools improves performance and reduces operational risk.

Where precise, controlled fluid placement is required, the ACTive Straddle\* CT real-time multiset inflatable packer extends critical zonal isolation to previously inaccessible environments, with the ability to treat multiple zones in single intervention.

**ACTive Cleanout\* live CT wellbore fill removal service** enables efficient and effective CT fill cleanout by avoiding formation dam-

age, reducing the number of trips and the total operating time, and optimizing fluid volume and penetration rate into the fill. Active monitoring of the pressure differential across the BHA greatly improves performance.

**ACTive Lift\* live CT nitrogen lifting service** improves CT nitrogen lift operation time and fluid efficiency based on continuous monitoring of wellbore pressure, leading to faster and more controlled restoration of well production while avoiding solids production. This service also aids field performance characterization and artificial lift evaluation.

**ACTive Perf\* live CT perforating service** achieves accurate depth control in a single run and ensures target zone coverage while selectively perforating. Controlling hydrostatic balance avoids formation damage, formation fluid invasion, and formation sanding. Verification of gun activation leads to improved CT perforating safety and reliability.

Going beyond conventional CT perforating, the ACTive OptiFIRE\* CT real-time selective perforating and activation system provides an even safer, more efficient method for CT-conveyed perforating.

**ACTive PS\* live CT production logging service** enables combining advanced openhole and cased hole production logging with all ACTive services. The combination of distributed measurements—both acoustic and temperature—can be captured and synergistically combined with the already robust production logging data to get the most accurate picture of well production.

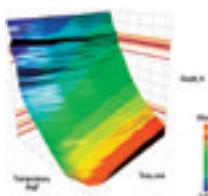
**ACTive Profiling\* live CT distributed temperature sensing service** enhances all ACTive services with DTS profiling to provide a 3D temperature profile of the entire wellbore to monitor treatment fluid placement and well production performance. Temperature profiling provides the ability to perform active point measurements and DTS spatial measurements in the same run.

## Measure, interpret, act

ACTive services enable continuous downhole monitoring of your job. Continuous monitoring makes it possible for you to watch events as they unfold to build an exact picture of progress and to alert you to any issues as they are encountered.

As you monitor, you gain unique quantitative feedback and insight directly from the wellbore in real time. Real-time interpretation through Decipher\* interpretation of coiled tubing dynamic surface and downhole events provides the information you need to cross-reference what you are seeing downhole with surface and petrophysical data for a dynamic assessment of service performance.

When you know what is happening downhole, you can act with a greater degree of confidence. For the first time, you can adjust job parameters based on real-time downhole information to optimize performance. With ACTive services, you gain the confidence to act decisively.



Distributed temperature sensing creates a 3D temperature profile.

## ACTive Specifications

	Surface (optical acquisition module mounted inside the CT reel)	
	Temperature rating	-13 to 120 degF [-25 to 49 degC]
	Power requirement	12 V DC
	Data communication	Wireless
	Total tool length	7.2 ft [2.18 m]
	Outside diameter	2.125 in [5.4 cm]
	Pressure rating	12,500 psi [86.2 MPa] at maximum tension 15,000 psi [103.4 MPa] at 0 tension
Downhole	Temperature rating	300 degF [150 degC]
	Tension (max. pressure)	45,000 lbf [200.2 kN]
	Compression (max. pressure)	10,000 lbf [44.5 kN]
	Maximum torque	800 lbf.ft [1,084.7 N.m]
	Flow rate (through the tool)	2 bbl/min [238.5 L/min] clean fluid
	Material	NACE compliant
Measurements		
Pressure	Accuracy	±3 psi
	Repeatability	0.15 psi
	Resolution	0.075 psi
	Stability	0.2 psi drift over 100 h
Temperature	Resolution	0.03 degF [0.017 degC]
	Accuracy	±1 degF [0.5 degC]
CCL depth correlation	Completion size	3½-in to 7-in casing
	Adjustable gain	Low (1x), medium (4x), high (8x)
	Logging speed	10 to 120 ft/min

# ACTive GR

## Live CT gamma ray logging tool

### APPLICATIONS

- Accurate depth correlation in real time during a CT intervention
- Qualitative evaluation of lithology and shale content
- Radioactive tracer monitoring for stimulation applications

### BENEFITS

- Improves performance and reduces risk with precise tool positioning
- Enhances operational efficiency by providing downhole data in real time

### FEATURES

- Ruggedized version for use during perforating operations
- Pump-through capability for CT intervention and gamma ray (GR) log in the same run
- Ball-drop capability through the tool for activation of tools below
- Plug-and-play combination with enhanced ACTive\* family of live coiled tubing services



Gamma ray measurements of subsurface formations gathered in real time while maintaining pump-through capability.

### Accurate depth correlation

GR measurements are available with the ACTive services which provide downhole measurements in real time, conveyed on CT that is enabled by fiber-optic telemetry. The ACTive GR\* live CT gamma ray logging tool detects naturally occurring gamma rays in the formations adjacent to the wellbore, while maintaining pump-through capability for CT intervention. The service provides you with an industry-standard measurement for depth correlation in real time.

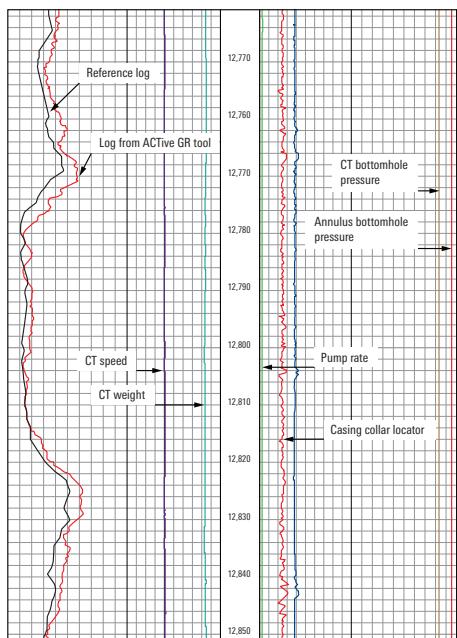
The optional GR tool enhances other ACTive services when run in combination. For instance, ACTive Perf\* live CT perforating service is further enhanced allowing accurate depth control and perforating the target zone in a single run, while monitoring the hydrostatic balance with the integral pressure sensor. ACTive Matrix\* live CT stimulation and conformance service can further enhance fluid placement by combining distributed temperature measurements with monitoring of radioactive tracers in stimulation fluids.

## ACTive GR Tool Specifications

Model	GRSM	GRNM
Equipment specifications		
OD, in	2.500	2.375
Makeup length , in	39.88	37.52
Total weight, lbfm	20	20
Max ball drop size, in	7/16	5/8
Flow path diameter, in	0.500	0.688
Material	NACE compliant	NACE compliant
Operational specifications		
Operating temperature, degF	300	300
Pressure rating, psi	12,500 (at max. tensile rating)	12,500 (at max. tensile rating)
Tensile strength, lbf	45,000 (at max. pressure rating)	45,000 (at max. pressure rating)
Max. torque, ft.lbf	800	800
Max. flow rate, bbl/min	1.5	2
Fluid compatibility	All common treating fluids including acid and H <sub>2</sub> S	All common treating fluids including acid and H <sub>2</sub> S
Shock rating	12,000 shocks at 250 gn/ms 40 shocks at 3,800 gn/0.3 ms	12,000 shocks at 250 gn/ms
Rated for perforation jobs	Yes	No

GRSM: Gamma ray shock model

GRNM: Gamma ray nonshock model



HPHT ACTive services CT perforation report.

# ACTive TC

## Live CT tension and compression tool

### APPLICATIONS

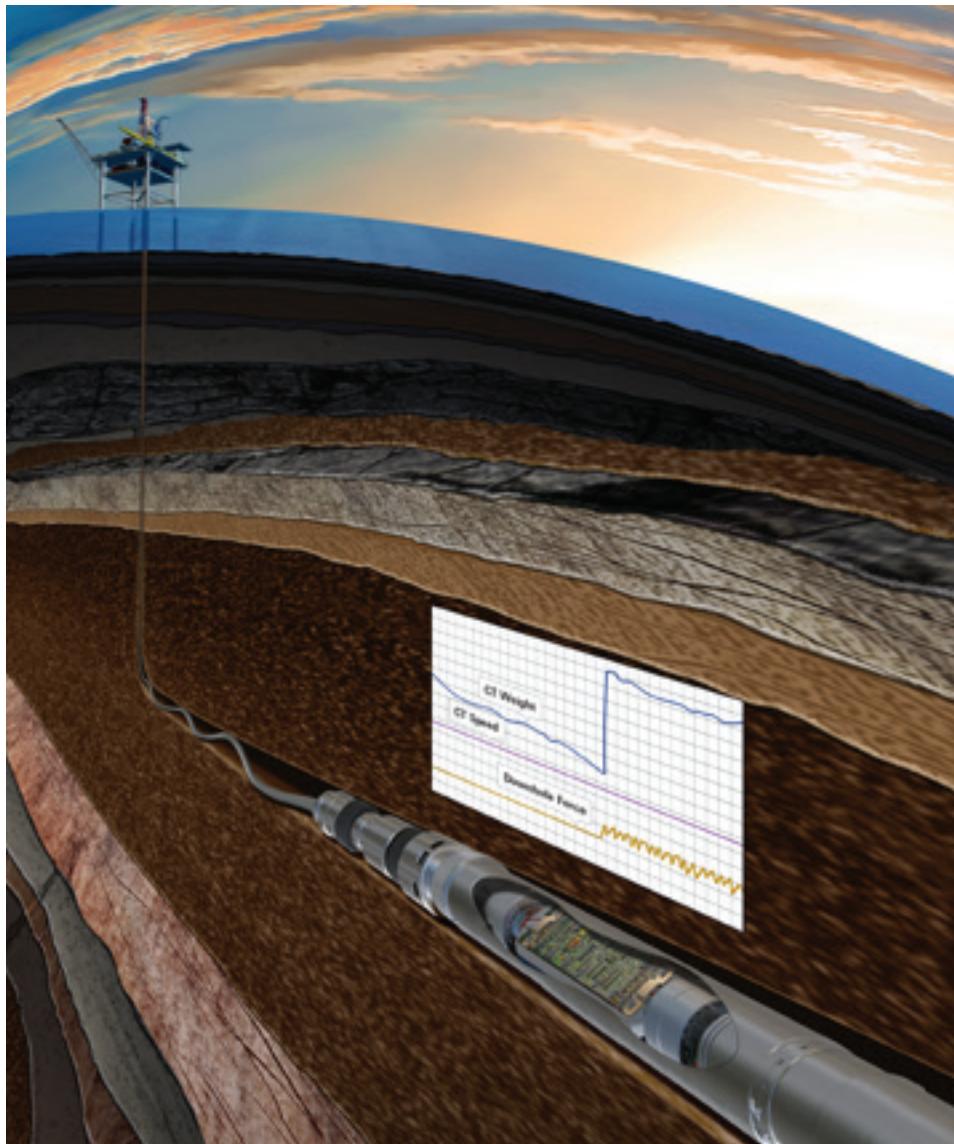
- Coiled tubing (CT) operations in deviated and horizontal wells
- Positive indication of latching or jar activation during fishing
- Confirmation of sliding sleeve activation
- Confirmation of completion hardware manipulation
- Positive indication of inflatable packer setting
- Indication of perforating guns firing

### BENEFITS

- Greater efficiency and control
- Reduced risk of unsuccessful operations

### FEATURES

- Downhole load and torque measurements in real time
- Robust design for use during perforating and fishing operations
- Pump-through capability to allow CT intervention in the same run
- Ball-drop capability through the tool for activation of tools below
- Plug-and-play combinability with enhanced ACTive\* family of live coiled tubing services



*Tension and compression measurements in real time ensure shifting tools are properly engaged, and provide confirmation of shifting sleeve activation.*

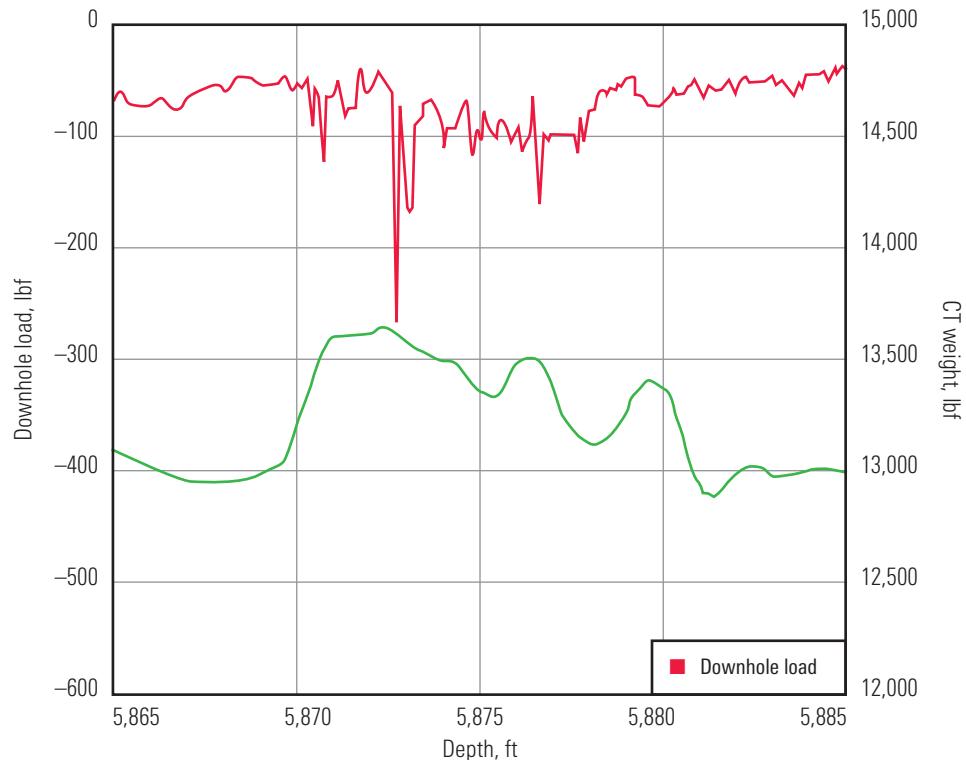
### Interventions with greater confidence and success

ACTive TC\* live CT tension and compression tool provides downhole load and torque measurements in real time with the ACTive family of live CT services, while maintaining pump-through capability. The measurements are conveyed on CT that is enabled by fiber-optic telemetry. Effective in a wide range of downhole environments, the ACTive TC tool eliminates errors introduced by extrapolating surface measurements for downhole-load-sensitive operations. You can adjust job parameters based on real-time downhole information and carry out interventions with increased confidence and success.

Combining TC measurements with other ACTive services measurements like pressure, temperature, gamma ray, and casing collar location enhances the in-well live family of CT services. Monitoring critical downhole CT load parameters to achieve successful isolation in deviated and horizontal wells improves the effectiveness of ACTive Isolation\* live CT zonal isolation services. ACTive services involving fishing or manipulation of completion hardware benefit from the accurate indication of latching, releasing, and jar and accelerator activation, when wellbore conditions do not allow a clear surface indication.

## ACTive TC Tool Specifications

Equipment specifications	OD	2.125 in
	Makeup length	47.80 in
	Total weight	38 lbm
	Flow path diameter	0.688 in
	Max. ball drop size	5/8 in
Operational specifications	Operating temperature	300 degF
	Pressure rating,	12,000 psi (at max tensile rating)
	Tensile strength	45,000 lbf (at max pressure rating)
	Max. torque	800 ft.lbf
	Max. flow rate	2 bbl/min
	Fluid compatibility	All common treating fluids including acid. H <sub>2</sub> S compatible
	Max. proppant concentration	0.45 kg
Measurement specifications	Pressure compensated measurements	Yes
	Axial load range	-10,000 to 45,000 lbf
	Axial load accuracy	Absolute: 500 lbf + 1% Applied Localized: 2% Applied
	Axial load resolution	<5 lbf
	Torque range	0–800 ft.lbf
	Torque accuracy	<50 ft.lbf
	Torque resolution	<5 ft.lbf



*Spike in downhole load curve provides confirmation of shifting of sliding sleeve; no indication is seen on the CT weight measurement at surface.*

# ACTive PS

## Live CT production logging service

### APPLICATIONS

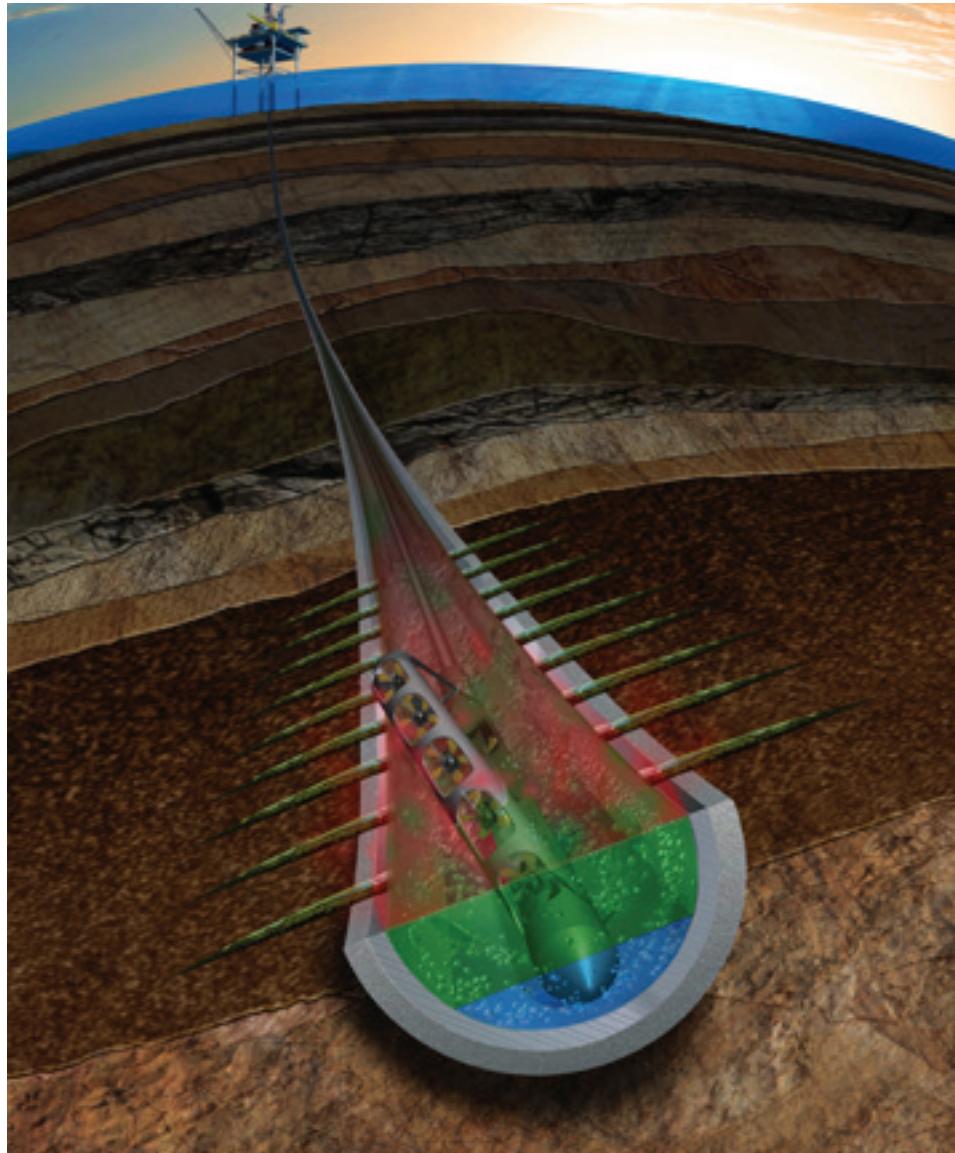
- Coiled tubing operations
- Wireline production logging operations using PS Platform\* production services platform, Flow Scanner\* horizontal and deviated well production logging system, and RSTPro\* reservoir saturation tool
- Well stimulation
- Onsite evaluation

### BENEFITS

- More operational efficiency
- Enhanced production
- Less environmental impact

### FEATURES

- Real-time fiber-optic telemetry
- Wireless data conveyance
- Self-contained technology
- Faster, higher-quality data
- Real-time data evaluation
- Simplified logistics



*The fiber optic–enabled CT string communicates with the production logging tools while power is provided by the BHA. The self-contained technology sends data wirelessly, eliminating a surface logging unit on location.*

### Optimal well intervention

ACTive PS\* live CT production logging service couples real-time fiber-optic telemetry with existing advanced wireline production logging tools. In just one trip to the wellsite, this combination enables the highest-quality onsite evaluation, well stimulation treatment design, real-time treatment diagnostics, and well production optimization.

Production logging can be acquired in real time, so reservoir and production measurements can be interpreted for subsequent interventions—where they matter most.

### Less equipment, improved logistics

Traditional production logging operations require a logging cable–equipped CT string and a standard logging unit, which typically accounts for an additional conventional CT reel

for intervention operations before and after the logging is performed. ACTive services use a fiber optic–enabled CT string for telemetry, enabling any kind of workover intervention to be performed. The ACTive PS service’s BHA powers and communicates with the conventional production logging tools. Data is sent wirelessly from the working reel to the acquisition and interpretation computer on the surface, so no surface logging unit is needed on location. Because the technology is entirely self-contained, only the ACTive PS service BHA and a production logging engineer are required on location with the CT unit.

Mobilizing this reduced amount of equipment happens only once, so logistics time and costs are saved. Operations are made safer because fewer crew members are required, and the environmental footprint is minimized with the elimination of the wireline logging unit and the second logging cable–equipped CT string.

### High-quality data for reliable well profiling

Memory production logging operations are often inconclusive because of low log quality due to the inability to gather sufficient data across critical intervals. With ACTive PS service technology, however, distributed temperature measurements are captured in real time and are synergistically combined with the already robust production logging data to get the most accurate picture of the well production profile. This real-time functionality helps avoid misruns, lost data, depth inaccuracy, controlled passes, and slickline limitations.

More data from the reservoir is easily attained and can be used to monitor or update well performance information. This data can also be used with other ACTive\* family of live downhole coiled tubing services to customize detailed treatment plans (e.g., identifying water-producing intervals or intervals of lower or higher production that require more acid or diversion fluid injection).

### ACTive PS Specifications

#### Surface (optical acquisition module mounted inside the CT reel)

Temperature rating –13 to 131 degF [–25 to 55 degC]

Power requirement 12 V DC

Data communication Wireless

#### Downhole

Total tool length 12.5 ft [3.81 m]<sup>†</sup>

Outside diameter 11½ in [4.3 cm]

Pressure rating 15,000 psi [103.4 MPa]

Temperature rating –13 to 300 degF [–25 to 149 degC]

Operating time At least 36 hours of logging time<sup>‡</sup>

Flow rate at CT head ports 1 bbl/min [120 m<sup>3</sup>/min]

Material NACE compliant

Compatible logging tools Any battery-operated PS Platform service, Flow Scanner system, or RSTPro tool

<sup>†</sup>An additional 18 ft [5.5 m] are added to the tool length with the three-battery extended power module, and an additional 30 ft [9.1 m] are added to the tool with the six-battery extended power module.

<sup>‡</sup>Over 100 hours of additional operating time are added for the Flow Scanner system, or 26 hours of running the RSTPro tool with the extended power module.



ACTive PS service tool maintenance in the field.

# ACTive Straddle

## CT real-time multiset inflatable packer

### APPLICATIONS

- Water and gas conformance shutoff
- Matrix stimulation
- Stimulation and conformance in
  - Perforated cased hole completions
  - Cased hole completions with sliding sleeves
  - Completions with inflow control devices
  - Multistage completions
- Chemical treatment
- Sand consolidation treatment

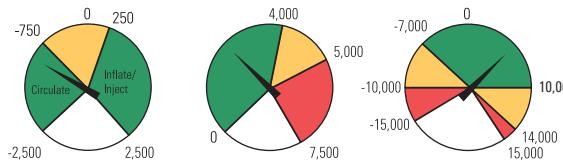
### ADVANTAGES

- Live well intervention capability
- Downtime reduction through achieving success on first attempt
- Robust multiset system
- Improved reliability on efficient and controlled setting
- No ball drop required for inflation and deflation
- Computer-engineered job design
- Materials resistant to aggressive chemicals and harsh downhole environments
- High-pressure isolation seal
- Straddle length can be configured to range from 6 to 50 ft [1.8 to 15.2 m]
- Accurate depth control and real-time pressure monitoring using the ACTive\* family of live downhole coiled tubing services to measure
  - Bottomhole pressure and bottomhole temperature for optimized fluid placement and packer pressure assurance
  - Casing collar locator, gamma ray, or both for depth control
  - Tension and compression (axial force) for flow control and setting tool manipulation

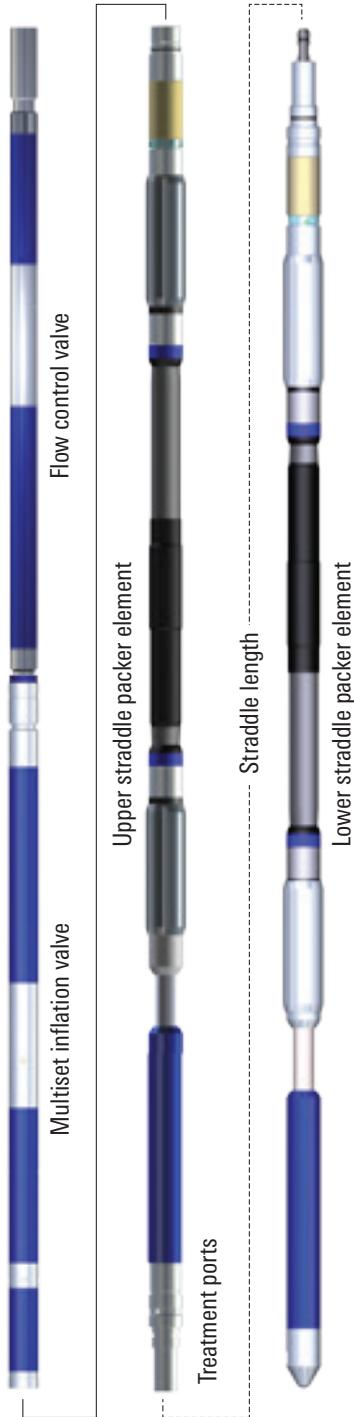
Overcoming conventional operating restrictions of inflatable packers under extreme conditions, the ACTive Straddle\* CT real-time multiset inflatable packer extends critical through-tubing zonal isolation to previously inaccessible, chemically harsh, and high-temperature (HT) environments. This inflatable straddle packer provides a rugged high-pressure seal at high inflation ratios with the added benefits of a reliable multiset mechanism.

The ACTive Straddle inflatable packer is run on CT into vertical, deviated, or horizontal wellbores, eliminating the need for a workover rig. Multiple remedial operations can be performed and repeated without killing the well on existing wellbore access points, such as open perforations, frac ports, and sliding sleeves.

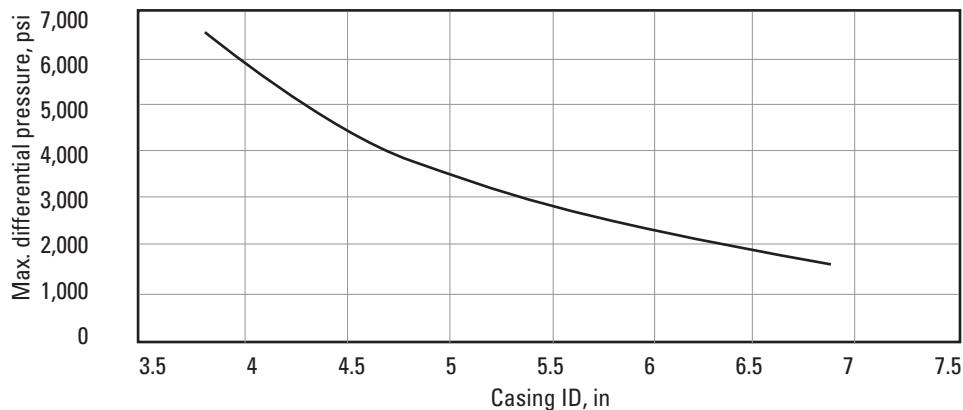
The packer is resistant to chemicals, making it ideal for selective placement of treating fluids that are required for acid stimulation, water control, gas shutoff, and chemical treatment. Manipulations from surface on the ACTive Straddle inflatable packer are confirmed through real-time measurements displayed in the control cabin using the ACTive services' nonobstructive fiber-optic technology, providing real-time depth, bottomhole annular and circulating pressures, bottomhole temperature, and bottomhole load measurements.



*Real-time pressure gauge readings of spotting valve position (left), deflation indicator (center), and packer force (right), in psi.*



*ACTive Straddle inflatable packer.*



*Pressure versus inflation ratio at maximum temperature. The engineered slat design of the ACTive Straddle inflatable packer allows higher differential pressure at varying inflation ratios.*

## Specifications

Max. packer element differential	
2:1 expansion	5,000 psi [34.5 MPa]
3:1 expansion	2,000 psi [13.8 MPa]
Max. hole deviation	90°
Max. system temperature	300 degF [149 degC]
Max. dogleg severity	
Operational	10°/100 ft
Survivable	30°/100 ft
Max. H <sub>2</sub> S level <sup>†</sup>	
Set time < 30 d at 300 degF [148.9 degC]	150 psi partial pressure
Set time > 30 d at 250 degF [121 degC]	50 psi partial pressure
Min. tubing requirements for packer setting	2.88-in [7.3-cm] OD; 2.32-in [5.89-cm] ID; 7.9-lbm/ft casing
Max. OD of element before expansion	2.125 in [5.4 cm]
Max. OD of element after expansion	6.38-in [16.2-cm] ID; 7.63-in [19.4-cm] OD; 29.7-lbm/ft casing
Fluids	Stimulation fluids: HCl, mud acid Chemical treatments: solvents Water/gas shutoff: MARA-SEAL <sup>SM</sup> , gelling agents

<sup>†</sup>Values in the table above are operational limits.

# ACTIVE MHA

## Optical motorhead assembly

### APPLICATIONS

- Standard CT interventions in oil, gas, and injector wells
- Sweet and sour services according to NACE standards
- Perforating
- Jarring/impact hammers
- Isolation packer

### ADVANTAGES

- Provides standard contingency components with preset configurations including
  - Check valves
  - Disconnect
  - Circulation port
- Enables longer ACTive\* family of live downhole coiled tubing services toolstrings and new services, such as downhole flow measurement and ACTive Perf\* live CT perforating service
- Enables logging with CT tractor, disconnect above tractor, and ACTive PS\* live CT production logging service toolstring below
- Enables PTC shut-in pressure below check valves during zonal isolation
- Replaces CT multicycle disconnect in ACTive PS service toolstring
- Compatible with
  - ACTive TC\* live CT tension and compression tool
  - ACTive PS\* service
  - ACTive GR\* live CT gamma ray tool
  - ACTive Profiling\* live CT distributed temperature sensing service
- Increased protection for fiber-optic connection integrity
- Interchangeable with ACTive services tools
- Eliminates need for separate mechanical disconnect

The ACTive MHA optical motorhead assembly is a compact form of all the standard bottomhole contingency components that are typically run for every CT operation.

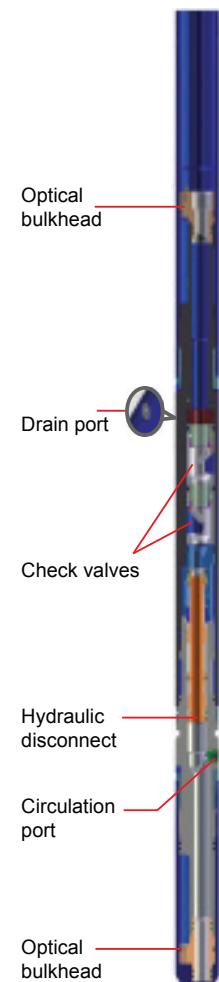
It minimizes the toolstring complexity and simplifies rig up. The ACTive MHA assembly was designed to withstand the heavy demands of milling, jarring, impact hammers, perforating, and CT applications that involve high shock or vibration loading.

### Downhole equipment

The ACTive MHA assembly is comprised of the following main components:

- Optical bulkheads—Pin and socket bulkheads allow the ACTive MHA assembly to be placed between the CT head and ACTive services BHA. Note that this reduces the system optical margin by adding one more flat polished connection.
- Drain port—A drain port allows for fluid trapped above the check valves to be removed before the ACTive MHA assembly is removed from the CT Head, helping to ensure that fiber connections are not contaminated and that environmental and spill policies are followed.
- Check valves—Dual-flapper check valves provide a double barrier to prevent wellbore fluid from returning up the CT to the surface.
- Hydraulic disconnect—A piston in the ACTive MHA assembly supports lugs that connect the upper and lower sections. A ball pumped from surface is used to shift the piston, which drops the lugs and allows the tool to separate. An external JDC style fishing profile is left exposed after the upper section is retrieved.
- Circulation port—The ACTive MHA assembly allows for a burst disc to be installed below the disconnect piston. In the event that there is no circulation through the toolstring, the burst disc can be ruptured to allow flow to the annulus in order to pump down the disconnect ball. If the burst disc is not needed, it can be replaced with a blank plug.

As ACTive services toolstrings have grown in length due to the addition of new measurements, it is not always accepted to place a conventional MHA below the ACTive services toolstring. The 2½-in ACTive MHA assembly provides standard contingency features at the top of the ACTive services toolstring.



*Cross-section of ACTive MHA assembly showing main components.*

## 2½-in ACTive MHA Assembly

### Equipment Specifications

Diameter	2½ in [5.4 cm]
Make-up length	38.2 in [97.0 cm]
Flow path diameter (min.) ID	0.563 in [1.43 cm]

### Operational Specifications

Operating temperature	20 to 329 degF [-7 to 165 degC]
Pressure rating (absolute)	12,500 psi [86.3 MPa]
Tensile strength	45,000 lbf [200,170 N]
Set down strength	10,000 lbf [44,482 N]
Torque	800 ft.lbf [1080 N.m]
Flow rate	2 bbl/min [0.318 m <sup>3</sup> /min]

# ACTive OptiFIRE

## CT real-time selective perforating and activation system

### APPLICATIONS

- Selective perforating
- Plug setting

### ADVANTAGES

- Live well intervention capability
- Selective perforating capabilities
- No need to overdisplace fractures when running plug-setting tools
- Downtime reduction through successful first attempts
- Robust selective-firing multiple-gun system in a single run
- Accurate depth control and real-time pressure and temperature monitoring using the ACTive\* family of live downhole coiled tubing services
- No ball drop or pressure pulse required for detonation
- Capability of addressing pumping issues in subhydrostatic wells
- Less formation damage
- Immunity to radio frequency (RF) interference, so no radio silence required
- Improved safety from addressing each gun with advanced switches and using the Secure2\* RF-safe electronic detonator
- Reduced footprint
- Real-time downhole measurements
  - Bottomhole pressure (BHP) and temperature (BHT) for optimized fluid placement and hydrostatic pressure control
  - Casing collar locator, gamma ray, or both for depth control
  - Fast-acquisition accelerometer for detonation confirmation
  - Real-time feedback on firing for increased safety
- No need to pump fluid to detonate
- Ability to fire up to 10 zones in single run
- Use of electronic safety key and pin for reduced risk during perforating

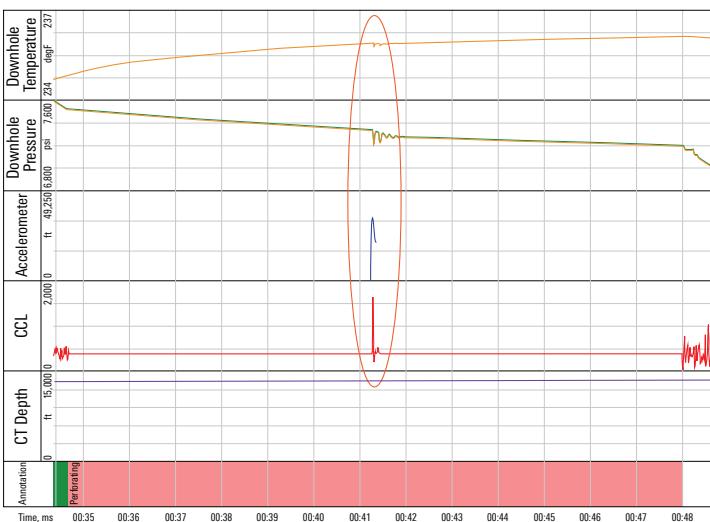
Conventional methods for perforating with CT often require some compromise, either on efficiency (multiple runs required), operating restrictions (limitations of common perforating heads), or safety (detonation confirmation).

With the ACTive OptiFIRE\* CT real-time selective perforating and activation system, all these compromises are eliminated, providing safer, more economical, and more efficient method for perforating with CT.

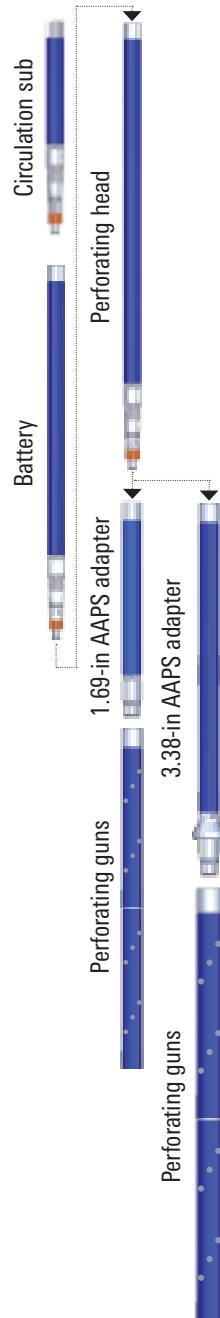
The system is designed so that it does not require a ball drop or a pressure pulse system to detonate. It can be used with a wide range of perforating guns that are compatible with Secure2 RF-safe electronic detonators and addressable switches. This flexibility enables arming the guns on demand and firing each gun individually, with unprecedented perforating optimization.

The ACTive OptiFIRE system is armed after it is run in hole and programmed using wireline protocols through a surface system in the CT cabin, eliminating the need for a wireline unit or cabin.

After the depth control procedure is performed with ACTive services' casing collar locator (CCL) and gamma ray tool, the surface system protocol arms and selectively fires individual guns from the bottom up. The system uses batteries downhole to activate the guns. Plug setting can be achieved with a command sent to the setting tool, allowing for a controlled and timely method of setting the plugs and perforating selectively on a single run.



*Real-time detonation indication (in oval) showing pressure, temperature, and CCL confirmations. The system also allows for postdetonation data download from downhole accelerometers showing shock.*



ACTive OptiFIRE system.

## Specifications

Operating temperature range, degF [degC]	–40 to 302 [–40 to 150]
Pressure rating, psi [MPa]	12,500 [86]
Flow rate, <sup>†</sup> bbl/min [ $m_3$ /min]	2 [0.31]
Max. gun size, in	3.375-in HSD* high-shot density perforating gun system
Gun compatibility	Carrier guns only
Max. number of selective zones	10
Max. OD of element before expansion, in [cm]	2.125 [5.40]
Tensile strength, lbf [N]	40,000 [177,900]
Compressive strength, lbf [N]	10,000 [44,480]
Number of total guns	Depends on tensile strength
Detonator type	Secure2 RF-safe electronic detonator

	<b>2.125-in OD Tool with 1.69-in Adapter</b>	<b>2.125-in OD Tool with 3.38-in Adapter</b>
Diameter, in [cm]	2.125 to 1.69 [5.40 to 4.30]	2.125 to 3.38 [5.40 to 8.60]
Makeup length, in [cm]	114.9 [291.8]	120.2 [305.3]
Total weight, lbm [kg]	86.4 [39.2]	102.4 [46.4]

<sup>†</sup>Pumping rate above the firing head limitation

**Schlumberger**

# Downhole Technology

# Vantage

## Modular CT logging head system

### APPLICATIONS

- All CT electric-line (e-line) interventions (e.g., production logging, perforating)
- Offshore, land, desert, and Arctic environments
- Oil, gas, and injector wells

### ADVANTAGES

- Saves rig-up time through reliable performance, modular interchangeability, and the unique design of the bayonet CT connector
- Enables rapid deployment through preassembled and pretested connector and termination head that can be stabbed through the injector and stuffing box
- Offers plug-and-play connectivity
- Improves flow paths while enabling interventions in small-ID completions
- Allows multiple runs without changeout
- Allows long string deployments

One of the main challenges in a CT e-line intervention is performing the operation as quickly as possible without equipment failure (i.e., loss of signal in the middle of the logging run). Assembling the electrical terminations at the end of the CT usually requires a significant amount of rig-up time. When multiple runs are needed, regular maintenance of the assembly is necessary to ensure adequate performance, which further increases rig-up time. In addition, when perforating is performed in the same intervention, the propensity for BHA failure increases.

The Vantage\* modular CT logging head system was designed to standardize e-line CT connectivity and improve its reliability. The Vantage system offers a versatile and reliable suite of tools suitable for logging and perforating applications that demand moderate flow-through capabilities.

The modular-component concept was designed to connect with plug-and-play connections that physically and electrically couple the components. These connections enable rapid interchange and reduced nonproductive time.

Each Vantage system component serves a unique function that, as a system, provides

- wired CT connectivity
- flowback protection
- downhole tool disconnection
- deployment under pressure.

The Vantage system incorporates an innovative CT bayonet connector and a cable termination module with flush OD that enables the connections and cable to be partially terminated and tested before they are sent to the well site. Then, at the well site, the CT with the bayonet connector and cable termination can be stabbed through the injector head.

The system's rugged design increases the reliability and safety of the CT head for perforating applications. Hardened replaceable wear rings extend the tool's life and protect Inconel® housings from abrasion and wear. This design allows increased flow rates with less pressure loss, less erosion, and more debris tolerance. High-strength corrosion-resistant-alloy materials offer superior performance in the most challenging environments.



1) Bayonet connector.

2) Cable termination tool plus wired check valve.

3) Wired cycle disconnect plus quick stab connector.

4) Deployment bar.

## Reliability

High-strength, corrosion-resistant alloy materials offer superior performance in the most challenging environments. Hardened replaceable wear rings extend the tool's life and protect expensive Inconel® housings from abrasion and wear. The rugged design

- increases the reliability and safety of the CT head for perforating applications
- allows increased flow rates with less pressure loss, less erosion, and more debris tolerance.

With the Vantage 2½-in system, flow can be diverted all the way through the assembly, enabling hydraulic operation of wired-through tools below.

## Vantage 1¹/₁₆-In Specifications

	Cable Termination Tool	Wired Check Valve	Wired Cycle Disconnect	Quick Stab Connector	Deployment Bar
Outside diameter	1.695 in [4.3 cm]	1.695 in [4.3 cm]	1.695 in [4.3 cm]	1.695 in [4.3 cm]	1.695 in [4.3 cm], 1.51-in [3.8-cm] seal
Tool length	26.77 in [68 cm] (2.23 ft [0.68 m])	24.34 in [61.8 cm] (2.021 ft [0.62 m])	26.41 in [67.1 cm] (2.20 ft [0.67 m])	2.75 in [7 cm] (0.23 ft [0.07 m])	84 in [213.4 cm] (7 ft [2.13 m])
Working pressure	13,500 psi [0.09 MPa]	13,500 psi [0.09 MPa]	13,500 psi [0.09 MPa]	na <sup>†</sup>	na
Tensile strength	40,000 lbm [18,144 kg]	40,000 lbm [18,144 kg]	40,000 lbm [18,144 kg]	40,000 lbm [18,144 kg]	40,000 lbm [18,144 kg]
Temperature range	0 degF to 375 degF [-18 degC to 191 degC]	0 degF to 375 degF [-18 degC to 191 degC]	0 degF to 375 degF [-18 degC to 191 degC]	0 degF to 375 degF [-18 degC to 191 degC]	0 degF to 375 degF [-18 degC to 191 degC]
Max. flow rate	1 bbl/min [0.16 m³/min]	1 bbl/min [0.16 m³/min]	No flow	No flow	No flow
Pressure at max. flow rate	128 psi [0.88 MPa] (with wired check valve)	128 psi [0.88 MPa] (with cable termination tool)	na	na	na
Fluid compatibility	Acid, H <sub>2</sub> S	Acid, H <sub>2</sub> S	Acid, H <sub>2</sub> S	Acid, H <sub>2</sub> S	Acid, H <sub>2</sub> S
Cable type	Mono, coaxial, hepta	na	na	na	na
Conductor	Mono	Mono	Mono	Mono	Mono

## Vantage 2½-In Specifications

	Cable Termination Tool	Wired Check Valve	Wired Cycle Disconnect	Slim Line Adapter	Quick Stab Adapter
Outside diameter	2.5 in [6.35 cm]				
Tool length	26.3 in [66.8 cm]	31.3 in [79.5 cm]	35.0 in [88.9 cm]	14.2 in [36.1 cm]	19.5 in [49.5 cm]
Working pressure	22,000 psi [151.68 MPa]				
Tensile strength	58,000 lbm [26,308 kg]				
Temperature range	0 degF to 350 degF [-18 degC to 177 degC]	0 degF to 350 degF [-18 degC to 177 degC]	0 degF to 350 degF [-18 degC to 177 degC]	0 degF to 350 degF [-18 degC to 177 degC]	0 degF to 350 degF [-18 degC to 177 degC]
Max. flow rate	3.0 bbl/min [0.48 m³/min]	3.0 bbl/min [0.48 m³/min]	3.0 bbl/min [0.48 m³/min]	3.0 bbl/min [0.48 m³/min] per plug	3.0 bbl/min [0.48 m³/min] per plug
Pressure at max. flow rate	324 psi [2.23 MPa]				
Fluid compatibility	Acid, H <sub>2</sub> S				
Bottom connection	2.1875-10 SA box	2.1875-10 SA box	2.1875-10 SA box	2½ wireline 31 pin	2½ wireline 31 pin
Cable type	Mono, coaxial, hepta	na	na	na	na
Conductor	Hepta, mono				

<sup>†</sup>na = not applicable

# Jet Blaster

## Engineered high-pressure jetting service

### APPLICATIONS

- Wellbore cleanouts, such as sand lift, tubing-scale removal, sandscreen cleaning, and near-wellbore skin removal
- Cleanout of tubing deposits, such as paraffins, waxes, soluble scales, and cement

### ADVANTAGES

- One-trip cleanout for quick job turnaround and increased ROI
- Reduced risk of damaging tubulars or downhole installations
- Lower treatment cost as a result of fewer chemical requirements
- Fluid energy that maximizes the performance of treatment fluids
- Monitoring of cleanout progress through a scalable drift ring, with no abrasive, metal-to-metal contact with completion equipment
- Treatment fluid-resistant jetting BHA
- BHA for pumping tailored chemical trains



*Jet Blaster.*

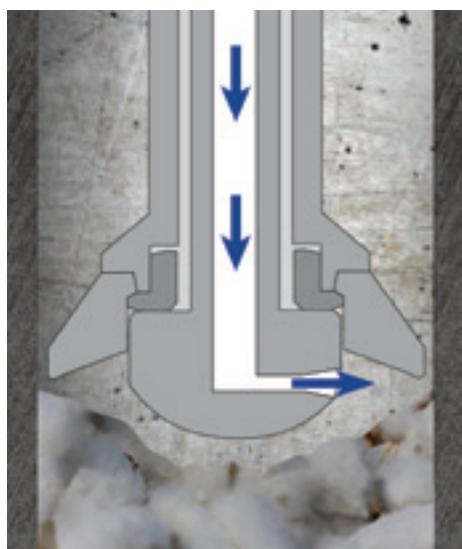
The Jet Blaster\* engineered high-pressure jetting service is part of a complete wellbore cleanout package that includes CT job design and execution and pumping and chemical treatment applications. It is used with Jet Advisor\* scale removal software and CoilCADE\* coiled tubing design and evaluation software for a designed approach to wellbore cleanouts, including sand lift, tubing-scale removal, sandscreen cleaning, and near-wellbore skin removal. Jet Blaster service operations are planned and optimized and are a fast and cost-effective alternative to nozzles, positive displacement motors, impact hammers, and other wellbore cleanout equipment.

### Job design

Based on the specific well parameters and the expected deposits, Jet Advisor software determines the best-performing Jet Blaster service configuration and helps in selecting the CT string. The type of deposit also determines the fluid selected for each treatment. The key design parameter is performance at the fluid-jet interface to minimize treatment time and the amount of chemicals required. CoilCADE software is used to verify that downhole fluid performance allows deposits to be safely carried out of the well.

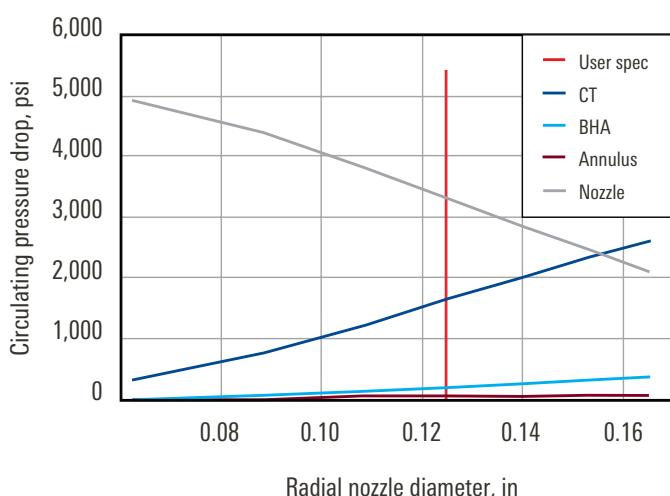
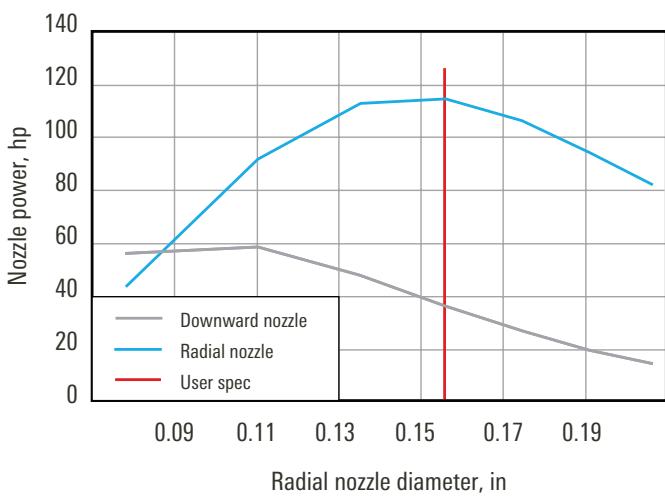
Focused, high-energy fluid streams loosen compacted fills, while the high rate of fluid passing through the Jet Blaster service tool allows safer fill removal. Because the cleaning radius is not limited by tool geometry, the Jet Blaster service enables nondamaging cleanout of complex, delicate structures such as downhole screens, installations, gas lift mandrels, and sliding sleeves. The modular BHA design allows tailored, software-aided adaptation to specific tasks. Carbide nozzles, encapsulated and lubricated heavy-duty bearings, and an operating temperature of up to 350 degF [177 degC] make the Jet Blaster service tool resistant to almost any chemical environment or abrasive fluid. It can be used in most wells and with virtually any combination of treating chemicals.

Effective downhole jetting requires the dissipation of fluid energy in the zone of interest, the tubing, the screen, or the formation—not in the tool itself or immediately at the nozzle exit. A coherent, high-velocity fluid stream is necessary. Performance enhancement is achieved through reduced energy losses across the swivel and nozzles. Effective downhole jetting does not rely on the erosion effect of cavitation; therefore, efficiency is not affected by wellbore depth.



*Carbide nozzles with swirl eliminators increase hydraulic efficiency while the drift ring controls ROP for positive, one-pass cleaning.*

Specifications	1 1/16-in tool	2 7/8-in tool
<b>Technical</b>		
Maximum temperature rating, degF [degC]	350 [177]	350 [177]
Maximum tensile load, lbf [kN]	26,667 [118.62]	72,000 [320.27]
Maximum compressive load, lbf [kN]	5,000 [22.24]	10,000 [44.48]
Chemical resistance	Entire jetting assembly for both tool sizes is H <sub>2</sub> S resistant and chemically resistant to HCl (28%), mud acid, aromatic solvents (toluene and xylene), ethylenediamine tetra-acetic acid (EDTA), barium sulfate dissolvers, and nitrified fluids	
Other	Both tool sizes offer sweet and sour services per NACE and abrasive pumping	
<b>Dimensional</b>		
Drift ring and nozzle head length, ft [m]	0.1 [0.03]	0.1 [0.03]
Jet Blaster service module length, ft [m]	2.0 [0.61]	2.55 [0.77]
Downhole filter module length, ft [m]	2.1 [0.64]	2.4 [0.73]
Motorhead assembly length, ft [m]	2.4 [0.73]	2.92 [0.89]



# ThorFRAC

## Extreme overbalanced CT stimulation system

### APPLICATIONS

- Thin, dry coalbeds
- Shallow gas reservoirs

### ADVANTAGES

- Customize formation stimulation design
- Minimize cleat damage and eliminate fluid recovery
- Reduce footprint and completion costs
- Effectively access more perforations in a single trip
- Enable variations in treatment pressures

ThorFRAC\* extreme overbalanced CT stimulation system is a way of shocking coalbed methane formations to produce longer, cleaner perforations without damaging the coal. This novel method minimizes both the cleat damage that can lead to fluid recovery problems and the complex fracture behavior that can cause excessive near-wellbore pressure.

### Conventional approach

Cleats in coal seams are often wide enough to accept whole cement slurry, not just cement filtrate. The serious damage the slurry causes to the connection between wellbore and reservoir can reduce the effectiveness of perforating and stimulating.

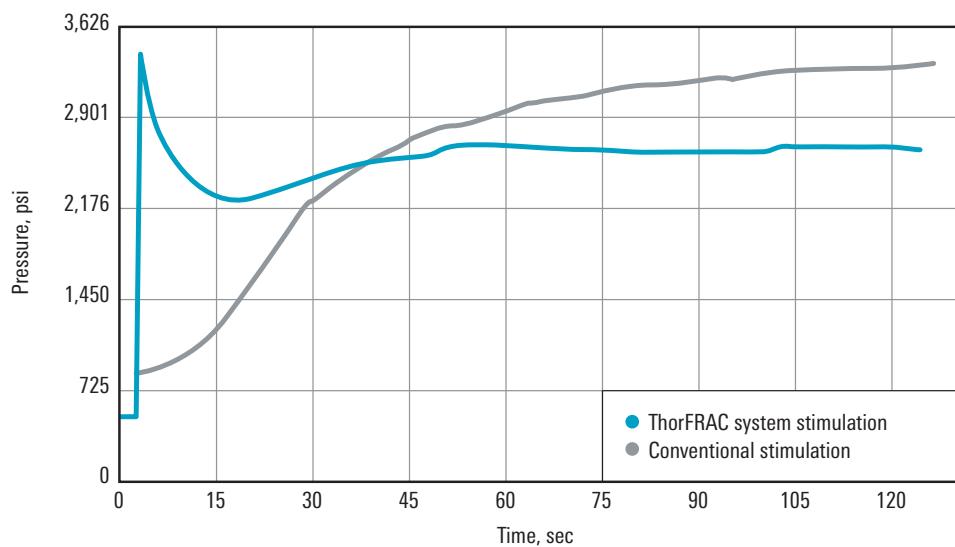
Therefore, most coalbed formations are stimulated to improve the recovery of methane. One conventional approach to stimulating coalbed methane fields involves dry nitrogen hydraulic fracturing. The well is preperforated and CT is run into the well with a straddle tool assembly to isolate separate perforation intervals. Providing effective zonal isolation is essential for subsequent stimulation treatments because coal seams store and produce gas differently than conventional clastic reservoirs.

Nitrogen is then pumped through the CT at high rates without proppant. The goal is to build up nitrogen pressure in the near wellbore onto the formation as quickly as possible by increasing the rates of the nitrogen pumps. This process requires both large CT and significant nitrogen pump horsepower on location to achieve the required nitrogen pressure in the near wellbore.

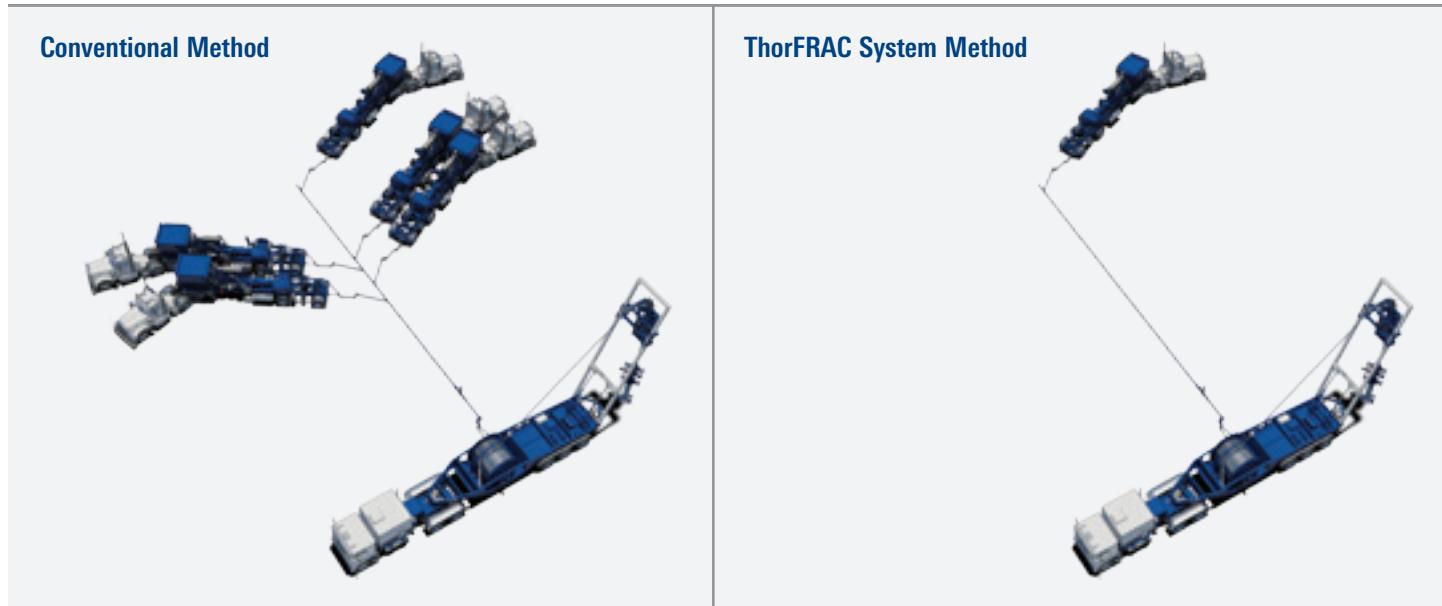
### New approach

The ThorFRAC system combines CT and fracturing technology using specially designed bottomhole assemblies. Similar to the conventional approach, a CT string and straddle tool are used to isolate separate perforation intervals. However, the tool has a multiset release valve built in to allow nitrogen pressure to be stored in the CT string. The valve releases at the preset pressure, and the stored high-pressure nitrogen is released into the formation. The nitrogen gas extends the cleats in the coal without damaging the formation. The tool is then repositioned across the next perforation interval and the process is repeated.

Shocking the formation with stored nitrogen optimizes the amount of nitrogen required and opens up a bigger area in the formation to effectively access more perforations in a single trip. This reduces footprint, lowers costs, and increases efficiency.



Comparison of pressure and time using the ThorFRAC system stimulation and conventional treatments.



*Surface rig-up of operations using conventional technology and using ThorFRAC system.*

An additional feature of the ThorFRAC system is the multiset release valve that can be set to release at various pressures in the same deployment. This allows for customized stimulation designs for each set of perforations in the wellbore. Memory gauges can also be deployed in the straddle assembly to assist in future stimulation designs.

#### **About the Contact family**

The ThorFRAC system is part of the intervention category of the Contact\* staged fracturing and completion services. These technologies maximize reservoir contact by offering the most efficient and effective services for each well. The Contact services intervention category enables multiple stages to be perforated or jetted, fractured, and isolated in one intervention. Contact services can be enhanced with real-time measurement options.



*ThorFRAC system operation in southern Alberta, Canada.*

# CoilFLATE

## Coiled tubing through-tubing inflatable packer

### APPLICATIONS

- Lower-zone abandonment
- Water shutoff
- Wellhead, pressure, and tubing integrity testing
- Cement squeeze and acidizing operations
- Chemical and water-control treatments

### ADVANTAGES

- Elimination of cost and time associated with workover rig
- Reduction in downtime by achieving success on first attempt
- Economical production optimization in harsh-environment wells
- Significant safety margin over conventional systems at similar injection pressures
- Applicability at temperatures up to 375 degF [190 degC]
- No-kill well intervention
- Reliable high-pressure seal at large inflation ratios
- Chemical resistance against aggressive chemicals
- Accurate depth control and real-time pressure monitoring using the ACTive\* family of live downhole coiled tubing services
- No ball drop required for inflation and release
- Computer-aided job design with Inflate Advisor software

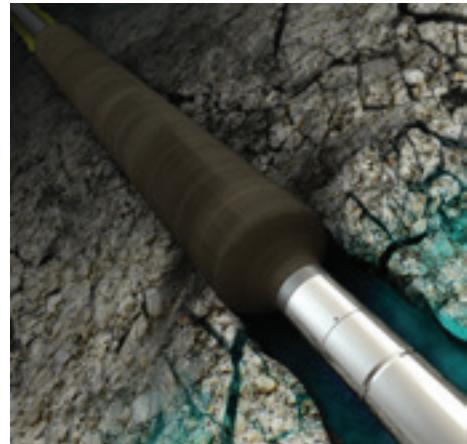
### Permanent zone abandonment, temporary isolation

Overcoming conventional operating restrictions of inflatable packers under extreme conditions, the CoilFLATE\* coiled tubing through-tubing inflatable packer extends critical zonal isolation capability to previously inaccessible, chemically harsh, and high-temperature environments. The CoilFLATE packer is run on either CT or jointed pipe into vertical, deviated, or horizontal wellbores, in both cased hole and openhole sections, eliminating the need for a workover rig.

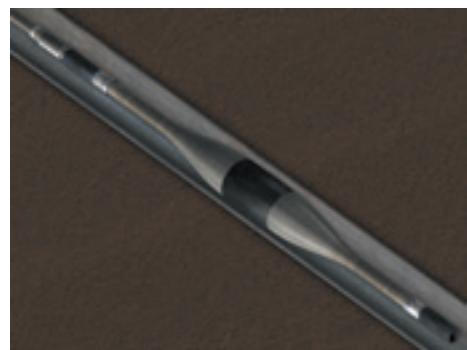
The system enables permanent abandonment of zones and temporary isolation of wellbore areas for tubing integrity testing, wellhead testing, and general pressure testing applications. Its chemical resistance makes it ideal for selective placement of treating fluids required for acid stimulation, water control, and chemical treatment.

### Robust design for severe conditions

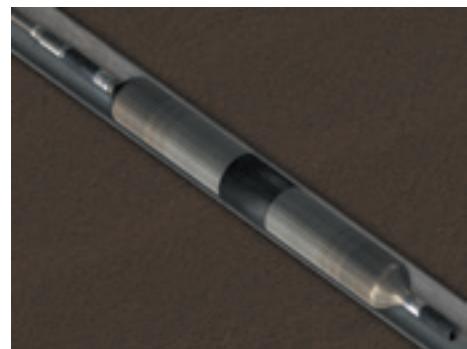
Tapered heavy-duty slats, a high-strength carcass restraint system, a composite bladder, and a chemically resistant seal compound keep the CoilFLATE packer anchored in place, providing a high-pressure seal even at large inflation ratios (>5,000 psi at 2:1, >2,000 psi at 3:1). The CoilFLATE packer design allows extended exposure of the assembly to temperatures up to 375 degF [190 degC], under harsh wellbore conditions, and in almost any chemical environment.



*Openhole packer.*



*Cased hole packer.*



*The carcass restraint system ensures uniform inflation of the bladder to maximize anchoring and sealing of the element.*

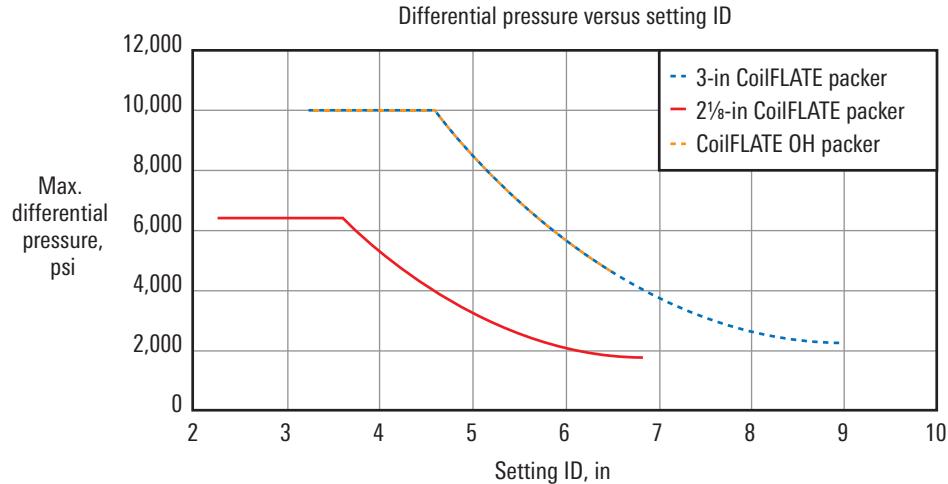
## CoilFLATE Through-Tubing Packer Specifications

Max. packer element differential	2:1 expansion: 5,000 psi [34.47 MPa]; 3:1 expansion: 2,000 psi [13.79 MPa]
Max. temperature at setting depth	2:1 expansion: 375 degF [191 degC]; 3:1 expansion: 325 degF [163 degC]; open hole: 300 degF [149 degC]
Wellbore geometry	Open hole or cased hole; vertical, deviated, or horizontal
Max. dogleg severity	30°/100 ft [30°/30.48 m]
Max. H <sub>2</sub> S levels <sup>†</sup>	150 psi [1.03 MPa] partial pressure (Set time <30 days at 300 degF [149 degC]) 50 psi [0.34 MPa] partial pressure (Set time >30 days at 250 degF [121 degC])
Connections	1.812 in [4.603 cm] 10 SA, box top and pin bottom

	2½ in [5.3975 cm]	3 in [7.62 cm]	OH
Min. tubing requirements for packer setting	2½ in OD, 2.32 in ID; 7.9 lbm/ft [7.3025 cm OD, 5.8928 cm ID; 11.8 kgm/m]	4 in OD, 3.34 in ID; 13.2 lbm/ft [10.16 cm OD, 8.4836 cm ID; 19.6 kgm/m]	N/A
Max. OD of element before expansion	2½ in [5.3975 cm]	3 in [7.62 cm]	3 in [7.62 cm]
Max. OD of packer after expansion	6½ in (7½ in OD, 29.7 lbm/ft casing) [17.4625 cm (19.3675 cm OD, 44.2 kgm/m casing)]	9 in (9½ in OD, 32.3 lbm/ft casing) [22.86 cm (24.4475 cm OD, 48.2 kgm/m casing)]	6½ in (open hole) [16.51 cm (open hole)]
ID of flow passage through CoilFLATE packer	¾ in [1.905 cm]	1 in [2.54 cm]	1 in [2.54 cm]
ID of flow passage through running assembly	¾ in [1.905 cm]	¾ in [1.905 cm]	¾ in [1.905 cm]
Packer element length (shoulder to shoulder)	72 in [182.88 cm]	91.2 in [231.648 cm]	49.2 in [124.968 cm]
Packer chassis assembly length	138 in [350.52 cm]	162 in [411.48 cm]	117.6 in [298.704 cm]
Min. nipple size for retrieval	2.205 in (2½-in XN nipple) [5.6007 cm (7.3025 cm XN nipple)]	3.135 in (4.0-in XN nipple) [7.9629 cm (10.16 cm XN nipple)]	3.135 in (4.0-in XN nipple) [7.9629 cm (10.16 cm XN nipple)]
Max. retrieval load	<3,000 lbf [<13,345 N]	<3,000 lbf [<13,345 N]	<3,000 lbf [<13,345 N]
Max. tensile load for fishing	20,000 lbf [88,964 N]	44,000 lbf [195,722 N]	44,000 lbf [195,722 N]
Element shipping weight and storage	70 lbm [31.75 kgm] in shipping tube, –40 to 140 degF [–40 to 60 degC]	100 lbm [45.36 kgm] in shipping tube, –40 to 140 degF [–40 to 60 degC]	60 lbm [27.22 kgm] in shipping tube, –40 to 140 degF [–40 to 60 degC]

<sup>†</sup>H<sub>2</sub>S concentration in parts per million is a function of downhole pressure. Not all materials meet NACE MR0175.

The engineered slat design allows higher differential pressures at varying inflation ratios.



# Multicycle Circulating Valve

## High-flow circulation for milling

### APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Milling

### ADVANTAGES

- Two modes of operation
- Ability to shift from one mode to the other at various rates, depending on the selected top orifice size
- Availability of 11 orifice sizes
- Ability to pump up to 6.5 bbl/min during circulation mode
- Six diversion orifices to keep debris out of the tool during circulation mode
- Orifice at the bottom of the tool that maintains a small flow through the motor during circulation mode
- Use in the milling BHA

The multicycle circulating valve (MCCV) has two modes of operation: milling mode and circulation mode. During milling mode, all the flow goes through the tool into the milling assembly and provides energy to the motor, which then mills through the soft or hard fill inside the wellbore. The motor converts the fluid's hydraulic energy into rotational and torque mechanical energy. Flow rates range from 0 to 3.5 bbl/min during milling mode.

When flow rates exceed 3.5 bbl/min, the tool shifts into circulation mode, which pumps fluid at high flow rates into the annulus of the wellbore. The fluid first travels through the main orifice, located in the piston of the upper mandrel, and then travels either through the circulation housing ports during circulation mode or through the plunger into the motor during milling mode. The top orifice in the piston creates the pressure drop required to shift the tool from one mode to the other. The required pressure drop to shift the tool is approximately 170 to 200 psi.

There are 11 top orifice sizes available to provide various shifting rates. A model is available to help tool operators select the right top orifice size. During circulation mode, a small portion of the flow (approximately 0.3 bbl/min) goes through six diversion orifices to help keep circulation ports free of debris.



*Multicycle circulating valve.*

## Specifications<sup>†,‡</sup>

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf	Torque Capacity, ft.lbf
100685824	2.875 [73.03]	0.64 [16.26]	2½-in PAC BOX	2½-in PAC PIN	na <sup>§</sup>	38.76 [984.50]	No	8,000 [55,158]	80,000	2,500

<sup>†</sup> Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup> At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

<sup>§</sup> Not applicable.

# Discovery MLT

## Multilateral reentry system

### APPLICATIONS

- Stimulation and cementing operations
- Well cleanouts using gelled or foamed fluids
- Cleanouts using formation jetting
- Operations involving wireline logging

### ADVANTAGES

- Reentry to all levels of multilateral wells
- Economical alternative to traditional reentry techniques
- Confirmation of correct access with only one run to TD
- Fast job turnaround in one trip using standard CT equipment
- High success rate for reentry on a first attempt
- Easy detection of subsequent windows after locating first window
- Surface-controlled, flow-activated tool orientation
- Real-time display of toolface orientation relative to lateral entry
- Pressure variation telemetry
- Acid-resistant BHA
- Operability in subhydrostatic (depleted) wells
- Compatible with logging tools such as the RSTPro\* reservoir saturation tool and logging tools

The acid-resistant system enables accurate execution of all types of fluid treatments and provides new options for cost-effective treatments of Level 1 and Level 2 laterals, which typically are not economical to access using traditional reentry techniques.

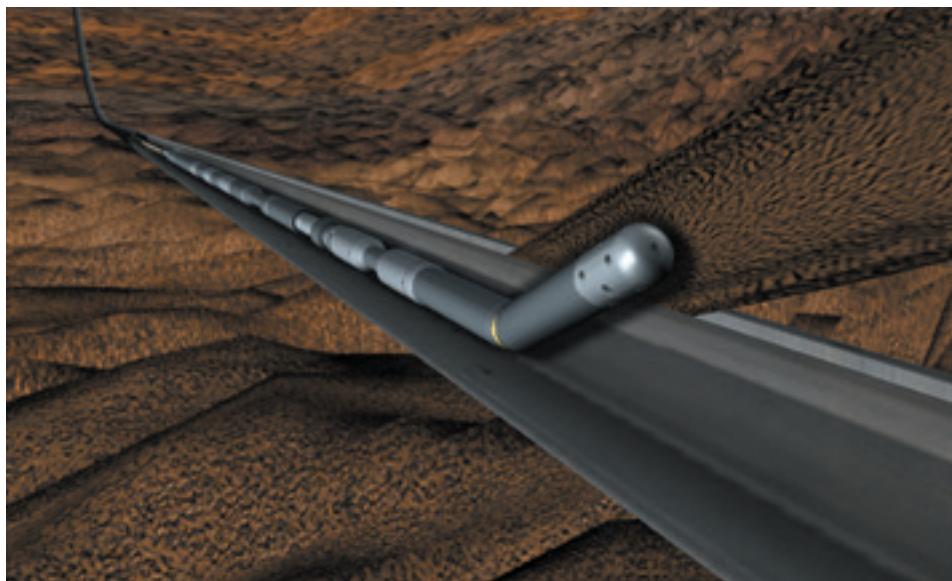
The Discovery MLT\* multilateral reentry system sends a pressure signal to the surface to confirm access to the correct lateral. The ability to adjust the sub orientation, or bend, from surface and the real-time feedback to surface of window identification save time by increasing the probability of successful reentry on the first attempt. Confirmation requires only one run to the bottom of the main wellbore. Although the Discovery MLT system operates solely on pressure and flow, a logging cable can be used to enable the use of logging tools.

Positioned in the upper part of the Discovery MLT system BHA, the orienting tool delivers the torque required to index the lower part of the BHA. In addition to the standard 2½-in outside diameter (OD) tool sub,

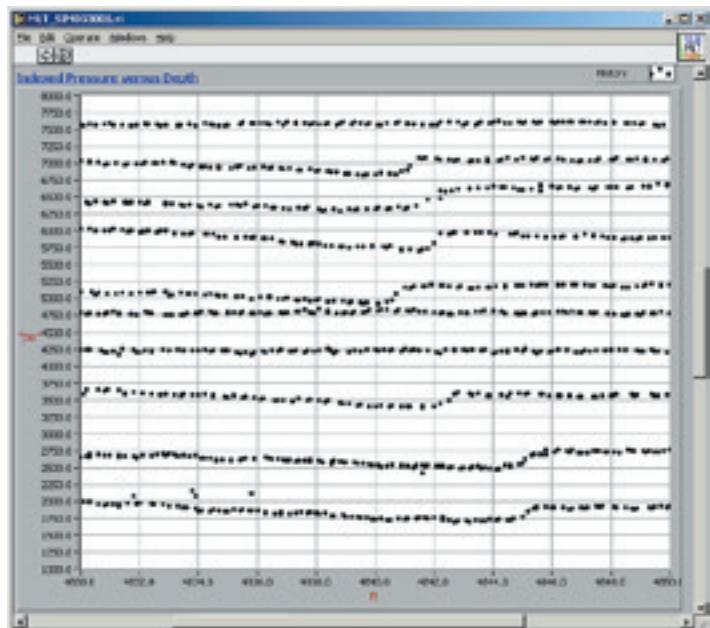
a 3½-in OD orienting sub is available for high-friction wells with severe doglegs. Torque performance for both subs is independent of tool depth.

The bent sub angle is controlled by varying the surface pump rate. When the flow rate exceeds the adjustable threshold rate, the sub changes shape from straight to angled.

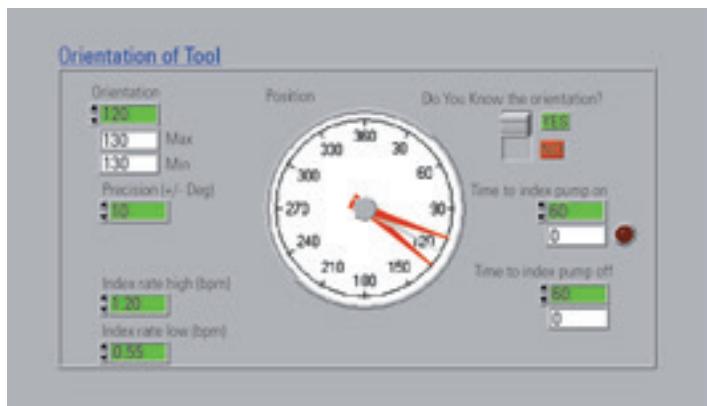
Job feasibility is determined by the CoilCADE\* coiled tubing design and evaluation software. Real-time data is monitored and recorded through the CT unit sensor interface with CoilCAT\* coiled tubing computer-aided treatment. Discovery MLT system enables displaying essential parameters such as tool orientation relative to the lateral window. The software also monitors previous indexes and guides the operator through indexing cycles, providing accurate, real-time information about the downhole environment. After the window is profiled, the software memorizes the window orientation and monitors the BHA orientation throughout the entire operation, facilitating the location of other windows.



*Technology for selective lateral reentry on the first attempt.*



Window profiling plot.



Tool orientation tracking software.

## Technical Specifications

Toolstring length	8.2 m [27 ft] (total BHA)
Max. dogleg severity	60°/30.5 m [100 ft]
Max. temperature rating	149 degC [300 degF]
Max. differential pressure	34.5 MPa [5,000 psi]
Max. flow rate	0.8 m³/min [5 bbl/min]
Max. tensile load	122.3 kN [27,500 lbf]
Rotation coverage	30° per pump cycle
Flow during window profiling	Yes
Fluid compatibility	H <sub>2</sub> S resistant and chemically resistant to HCl, mud acid, aromatic solvents (toluene, xylene), EDTA, and nitrified fluids

Tool Specifications	OD, in	Length, ft
Orienting tool (slim version)	2 1/8	7.0
Orienting tool (high-torque)	3 1/16	11.1
Controllable bent sub	2 1/8	11.3
Downhole filter	2 1/8	2.3

Note: H<sub>2</sub>S = hydrogen sulfide  
HCl = hydrochloric acid  
EDTA = ethylenediamine tetraacetic acid

# ReelCONNECT

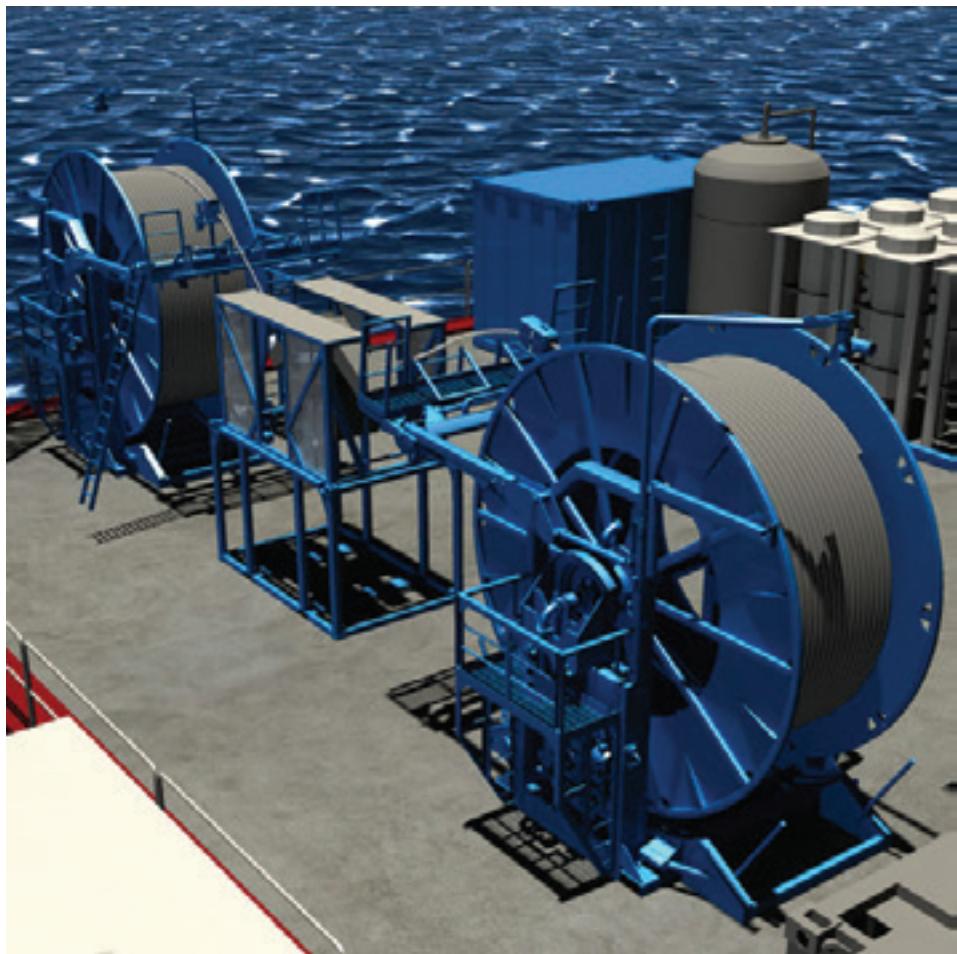
## Multiple CT string connection system

### APPLICATIONS

- Assembly of long CT strings, especially on logically challenging sites
- Field repair of damaged CT strings

### ADVANTAGES

- Reduced personnel risk because of remote control of coiled tubing string assembly
- Reduced overall CT string assembly time
- Elimination of welding-related risks
- Minimal repair downtime because of rapid turnaround
- Predictable mechanical performance
- Compatible with
  - Acid, corrosive fluids, and sour applications
  - Ball-drop-operated downhole tools and equipment
  - Downhole jarring tools or friction reduction tools
  - Downhole motors
- Suitable for use in high-pressure service applications



*The ReelCONNECT system extends CT applications to deeper wells.*

The most common application for the ReelCONNECT\* multiple CT string connection system is in offshore operating environments, where limited lifting or logistics capacities restrict the size of the CT strings. However, the system can be used in a range of onshore and offshore applications—any time a secure connection with reliable pressure integrity is required and repeated bending cycles are necessary.

The outer profile of the installed connector finishes flush with the OD of the CT string, while the internal profile remains compatible with launching operations for standard balls, darts, or pigs. The connector is compatible with standard jar and accelerator combinations in the BHA as well as with the friction and drag-reducing tool.

A connector assembly skid is used to align and make up the CT string sections to the connector. The skid enables the work platform to be raised to an optimum height for connector installation. It also provides a well-lit and protected environment for connector installation. Using a wireless remote control panel, the operator is able to control and guide the two sections of CT pipe into the skid while standing at a safer distance.



*ReelCONNECT system assembly skid.*

## Specifications

Connector sizes × wall thickness, in [mm]	2½ × 0.175 [60.3 × 4.4]	2½ × 0.190 [60.3 × 4.8]	2½ × 0.190 [73.0 × 4.8]
Min. ID, in [mm]	1.188 [30.2]	1.188 [30.2]	1.430 [36.3]
Max. ball size, in [mm]	1.125 [28.58]	1.125 [28.58]	1.375 [34.93]
Tension capacity	80% of CT	80% of CT	80% of CT
Max. pressure capacity, <sup>†</sup> MPa [psi]	55.2 [8,000]	55.2 [8,000]	55.2 [8,000]
Max. tested temperature, degF [degC]	250 [120]	250 [120]	250 [120]
CT pipe grade	HS 80 or HS 90	HS 80 or HS 90	HS 80 or HS 90
Native string fatigue life	>50%	>50%	>50%
Assembly skid weight, lbm [kg]	26,455 [12,000]	26,455 [12,000]	26,455 [12,000]
Assembly skid dimensions, <sup>‡</sup> ft [m]	16.24 × 8.17 × 8.17 [4.95 × 2.49 × 2.49]	16.24 × 8.17 × 8.17 [4.95 × 2.49 × 2.49]	16.24 × 8.17 × 8.17 [4.95 × 2.49 × 2.49]

<sup>†</sup>80% of CT

<sup>‡</sup>Certified by Det Norske Veritas

# CIRP

## Completion insertion and removal under pressure equipment

### APPLICATIONS

- Rigless perforating or reperforating, which typically involves short lubricators, limiting the length of gun string deployed
- Perforation of long intervals with controlled underbalance
- Multiple perforating runs without killing the well

### BENEFITS

- Safer operations due to separately deployed firing head not attached to a gun
- No formation damage from kill fluids
- Minimized production loss when reperforating
- Minimized personnel exposure with remote operation

### FEATURES

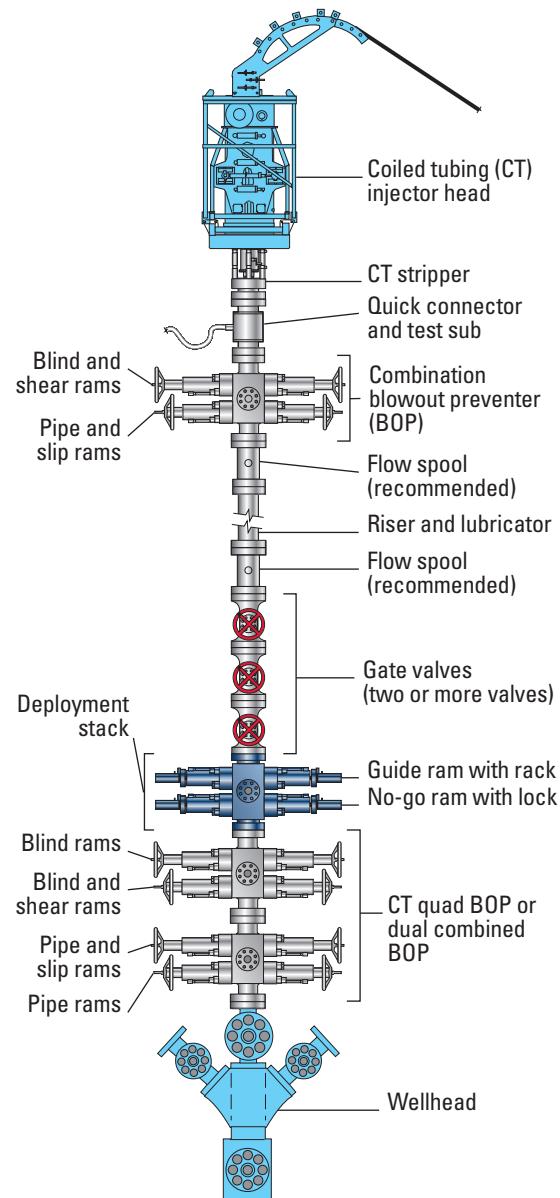
- Deployment flexibility for use in operations requiring pressure control
  - Snubbing
  - Wireline
  - Slickline
  - Coiled tubing
- Pressure control, including underbalance control, when gun strings are inserted and retrieved under pressure
- Compatibility with a variety of gun systems
- Remote operation in challenging well conditions
- Connector debris and sand tolerance

The CIRP\* completion insertion and removal under pressure equipment is used to insert and retrieve long gun strings under wellhead pressure when the surface pressure control equipment, or lubricator, is shorter than the gun string. With the CIRP equipment, a long interval can be perforated under the optimum underbalance condition, and then the guns can be retrieved without exposing the formation to damaging kill fluids. Wells can also be reperforated without killing, minimizing production loss and formation damage. Multiple perforating runs can be completed without killing the well between runs.

In extended-reach wells, for example, the perforated interval may be longer than the maximum gun string that can be conveyed, mandating multiple runs. The length of the surface lubricator determines the length of the gun string interval between two connectors. The CIRP equipment is compatible with all Schlumberger hollow carrier guns measuring 2 to 4½ in.

The CIRP equipment consists of three main components:

- connectors, which tie the gun sections together and provide sealed ballistic transfer
- deployment stack, which locks and unlocks connectors under pressure and supports the disconnected string
- two gate valves, which isolate the lubricator from well pressure to contain well pressure when short gun sections are being picked up or laid down.



CIRP equipment for CT operations.

The CIRP equipment comprises conventional lubricators, two or more gate valves, and a deployment stack with dual actuators. The lower actuator is a no-go ram with a lock to position the connector. The upper actuator is a guide ram with a rack to operate the locking mechanism on the connector. The system's connector is the mechanical and ballistic link between the gun sections deployed in the lubricator. The lock and rack allow connection or disconnection of the connectors under pressure inside the lubricator assembly. Gun string segments matching the lubricator length can be installed or removed using the gate valve to close in the well before bleeding off and opening the lubricator during

each step of the operation. Closing the gate valve allows the pressure in the lubricator to be bled off. It can then be disconnected for insertion or removal of gun sections. The sealed ballistic transfers seal the loaded guns before they are shot.

The firing head is usually deployed separately, not attached to a gun, when pressure is equalized in the riser. Afterward, it is connected to the gun string with CIRP system connector. The CIRP equipment allows completely remote operations, minimizing personnel exposure.

## Specifications

Gun Size, in	2, 2.25, 2.50	2.50, 2.88, 3.38, 3.50	3.38, 3.50, 4.50
<b>Connectors</b>			
OD, in [mm]	2.25 [57]	2.80 [71]	4.0 [102]
Temperature rating, <sup>†</sup> degF [degC]	400 [204]	400 [204]	400 [204]
Collapse pressure, <sup>‡</sup> psi [MPa]	20,000 [138]	20,000 [138]	20,000 [138]
Shot-to-shot distance, <sup>§</sup> in [cm]	46 [117]	46 [117]	47 [119]
Makeup length, in [cm]	33.94 [86.2]	33.70 [85.6]	35.33 [89.7]
Slick joint length, in [cm]	12.0 [30.5]	11.84 [30.1]	12.0 [30.5]
Tensile strength, <sup>‡</sup> lbf [kN]	60,000 [267]	145,000 [645]	245,000 [1,090]
Compressive strength, <sup>‡</sup> lbf [kN]	19,000 [85]	51,000 [227]	195,000 [867]
Nominal rotation of lock sleeve, °	15	15	15
<b>Rack and Lock</b>			
Deployment stack ID, in [mm]	4.06 [103]	4.06 [103]	5.125 [130]
Working pressure, psi [MPa]	10,000 [69]	10,000 [69]	10,000 [69]
Ram space out, center to center, in [cm]	11.5 [29.2]	11.5 [29.2]	11.5 [29.2]

<sup>†</sup> For 100 h, temperature rating can be increased with special seals.

<sup>‡</sup> Collapse pressure rating is at 67% of yield strength; tensile and compressive strengths are at yield strength.

<sup>§</sup> Nominal shot-to-shot distance; exact distance depends on shot density and phasing option of gun.

# eFire-CT

## Coiled tubing—conveyed electronic firing head

### APPLICATIONS

- Coiled tubing explosive services
  - Perforating
  - Tubing and casing cutters
  - Packers, plugs, and punchers

### BENEFITS

- Combines two field-proven technologies to provide a safer, more economical operation
- Reliable operation under changing conditions and in all well types, including highly deviated wells, improves productivity
- Reduced requirement for equipment on location simplifies operations and helps reduce costs
- Firing head is immune to radio frequency (RF) interference—no radio silence required
- Job sequence verified by the firing head job log
- No primary high explosives required
- Ability to abort the perforating operation at any time

### FEATURES

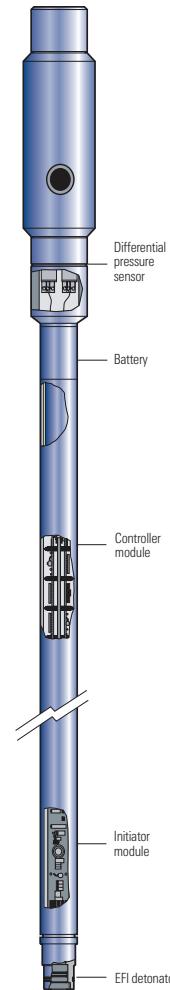
- Tool responds only to surface commands and is insensitive to well conditions
- Programmable command sequence ensures precise control of operations
- Firing head uses an RF-safe, exploding foil initiator to start the detonation chain
- Job log is stored in the tool for postjob evaluation

Conventional methods for perforating and setting packers and plugs conveyed on coiled tubing often requires presetting operating windows. Once commenced, the operation typically cannot be aborted unless the tool is removed from the operating window, or unless the operating parameters are changed, which is a major disadvantage to operations.

The eFire-CT\* coiled tubing—conveyed electronic firing head overcomes these disadvantages, providing a more efficient and more economical means of performing a wide range of downhole explosive operations—from perforating with through-tubing equipment or HSD\* high shot density perforating gun systems to setting packers or plugs and running cutter services.

The eFire-CT firing head arms after a programmable delay time. Once the delay time has passed, the controller in the eFire-CT firing head looks for a specific coded sequence of pump rate changes through the coiled tubing. Because the firing head requires a specific command, it is insensitive to other pressure and pumping operations and limited only by the coiled tubing.

Additionally, the eFire-CT firing head does not require displacing a ball to its seat to operate. The operator can abort the firing sequence at any time prior to detonation, and the firing head is less sensitive to debris, which improves reliability in harsh operating conditions.



*eFire-CT coiled tubing-deployed electronic firing head.*

### Specifications

	1 1/16-in OD eFire-CT firing head	2 7/8-in OD eFire-CT firing head
OD in [mm]	1.707 [43.3]	2.875 [73]
Temperature rating, <sup>†</sup> degF [degC]	330 [165]	330 [165]
Pressure rating, psi [MPa]	15,000 [103]	15,000 [103]
Length, in [cm]	76.31 [193.8]	100.85 [256.16]
Tensile rating, lbf [kN]	30,000 [133.4]	105,000 [467]
Shock rating, g <sup>n</sup>	500 (20 shocks at 0.5 ms)	500 (20 shocks at 0.5 ms)
Battery autonomy, h	240	240

<sup>†</sup>Ballistic components limit tool operation of version 3 to HMX time and temperature ratings.

**Schlumberger**

# Data Acquisition and Software

# CoilScan RT

## Real-time pipe inspection system

### APPLICATIONS

- Coiled tubing (CT) operations that require real-time monitoring of pipe integrity
- Pre- and postjob CT pipe integrity inspection

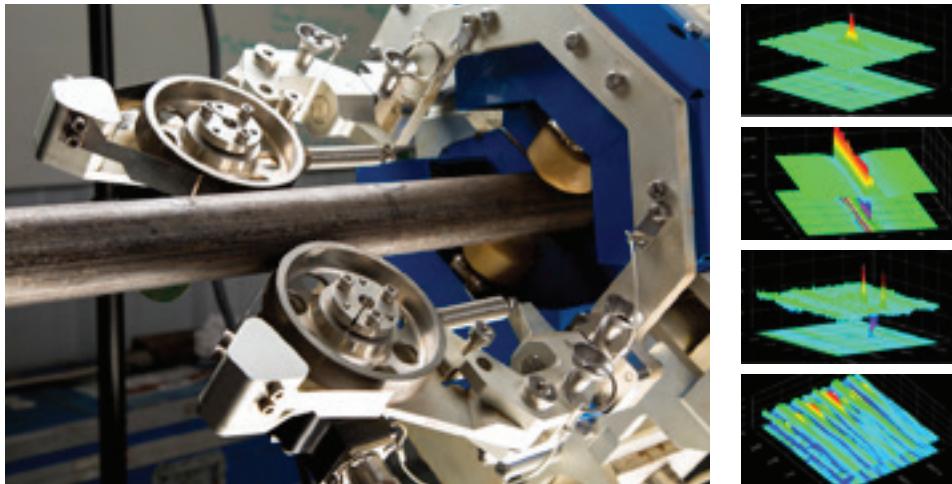
### BENEFITS

- Enables real-time pipe inspection during CT interventions
- Helps mitigate CT failure

### FEATURES

- Defect and mechanical damage identification in CT pipe sizes ranging from 1 1/4 in to 2 7/8 in
- Nonstatic pipe contact
- Pipe wear detection, including corrosion, pitting, wall thickness, and ovality
- Real-time visual and audible alarms
- Accurate CT length and speed measurements
- 3D modeling and interpretation software
- Safe area and nonzoned unit availability
- Real-time integration with CoilLIMIT\* coiled tubing pressure and tension limit model

The CoilScan RT\* real-time pipe inspection system uses magnetic flux leakage (MFL), eddy current, and depth encoders for nondestructive evaluation of pipe integrity in the manufacturing facility or in the field. The device detects pipe defects by measuring the MFL leakage, wall thickness, ovality, length, and speed of coiled tubing. The data is interpreted by 3D modeling software during real-time operations.



*The CoilScan RT system makes a full array of measurements every 0.005 in. The 3D modeling software produces MFL output signatures (right) that detect leaks such as pinhole, butt weld, excess internal metal, and seam weld.*

### Coiled Tubing Pipe Integrity Device

#### Equipment Specifications

Total weight	95, lbm
Requires contact with pipe	No
Requires lubrication for pipe	No
Detects pinholes and notches	Yes
Detects areas of corrosion	Yes

#### Operational Specifications

Diameter accuracy	0.010, in
Wall thickness accuracy	0.005, in
CT sizes	1.25–2.875, in
Max. speed	150, ft/min
Weld seam location accuracy	12, °
Min. blind pit detected OD (W × D)	1/16 in × 10%
Min. blind pit detected ID (W × D)	1/16 in × 15%
Through hole ID (W)	1/32, in
Min. transverse notch OD (L × W × D)	0.250 in × 0.020 in × 10%
Min. transverse notch ID (L × W × D)	0.250 in × 0.020 in × 15%
Min. longitudinal notch OD (L × W × D)	0.250 in × 0.020 in × 25%
Min. longitudinal notch ID (L × W × D)	0.250 in × 0.020 in × 35%

## Coiled tubing design and evaluation software

### APPLICATIONS

- CT operations
- Vertical, deviated, or horizontal wells
- Open and cased holes

### ADVANTAGES

- Better-designed CT jobs
- Accurate simulations and predictions
- Job design verification
- Twelve complementary modules
- Ability to simulate all aspects of CT operations, even workover and CT drilling

To better understand the low cycle fatigue behavior and limits of CT pipe, Schlumberger developed CoilCADE® coiled tubing design and evaluation software. CoilCADE software simulates all aspects of CT operations from start to finish, even including workover and CT drilling. Using modules created from intense research and development, CoilCADE software determines

- forces and stresses expected during operation
- force and pressure windows for safer operations
- design jobs requiring specific pulls or slackoffs at the bottom of the well
- CT reach in highly deviated wells
- optimal CT string design
- expected low-cycle fatigue during well intervention
- expected pressures while pumping liquid, nitrogen, or nitrified fluids.

### Tubing Forces module

As the main CoilCADE software module, the Tubing Forces module simulates the forces acting on a CT string as it is run in and pulled out of a well. It models buoyancy, friction, string and tool weight, wellhead pressure, and various CT strings to predict operational parameters such as weight indicator readings and helical buckling and lockup points. These predictions are particularly important for extended-reach wells because CT size, wall thickness, BHA size, and wellbore geometry all determine the depth to which CT can be conveyed.

### CoILIMIT module

CoILIMIT® coiled tubing pressure and tension limit module determines the differential pressure (burst or collapse) and the axial force (tension or compression) limits that can safely be applied to a CT section in the wellbore. Von Mises stress criteria for pressure, tension, and bending reveal the conditions under which the CT will begin to yield. This module also calculates the collapse pressure of oval CT and the maximum compressive load before corkscrewing and lockup. It defines an operational envelope that the user will follow during the live intervention.



CoilCADE software introductory screen and output plots.

### CoILIFE module

CoILIFE® coiled tubing life prediction model mathematically tracks the life of a CT string to minimize the risk of fatigue failure by forces imposed on the coil. This module was developed from an extensive laboratory and field fatigue testing program.

### Wellbore Simulator module

In CT fluid circulation operations, a sequence of fluids is pumped through the tubing while it is lifted or lowered into the wellbore. At any given time, there can be three regions of flow: (1) inside CT, (2) wellbore below CT, and (3) annulus between CT and wellbore. Each region can have different cross-sectional areas along the depth, and the length of each region may change with time.

Using the equations for mass conservation and momentum, the Wellbore Simulator models the transient multiphase transport and wellbore hydraulics that occur during fluid circulation. It also models the pickup and transport of solids to determine required circulation rates and pressures. Possible formation leakoff or inflow is calculated to model the mixing and flow of all solids, liquids, and gases in the annular flow stream. Treatment feasibility during sand fill removal, nitrogen kickoff, and CT drilling interventions can be evaluated in this module, both in horizontal and deviated wells. Solids and fluids return at surface can also be quantified with this module.

The Wellbore Simulator includes CT movement, sand pickup, sand bedding in deviated and horizontal wells, reservoir inflow and leakoff, fluid tracking, pressure drops, and the choke on the return line. Given this information, engineers can verify job design and investigate uncertain situations before actually mobilizing equipment and material.

### **Design Aids module**

The tools in the Design Aids module complement the previously listed CoilCADE software capabilities by allowing better-designed wellbore fluid circulation treatments performed by CT. The output from this module is a series of sensitivity plots that show the effects of altering job execution parameters. These plots help when studying the effects of input parameters, such as pressures, rates, and fluids on the output parameters that are critical to operations. From these plots, appropriate treatment parameters can be determined.

This module supports circulation of liquid, foam, nitrified fluid, liquid-plus-gas lift, and nitrogen lift. It also supports calculations of solids concentration, annular velocities, wellhead pressures, and flow patterns for given inputs.

### **CT String Evaluation module**

The CT String Evaluation module is used to optimize CT string design or to evaluate an existing CT string for a given set of operating and well completion conditions. The module is used to ensure that mechanical limits of the CT are not exceeded.

### **CT cleanout**

Removing sand or other fill from a wellbore using CT involves fluid circulation through CT to the sandface, where the sand is picked up by the jetting actions of the nozzles. Fill is then transported to the surface through the annulus between the CT and production tubing or casing.

The Wellbore Simulator aids in modeling this process, including multi-fluid pumping, reservoir interaction, CT movement, and sand transport in deviated wells. Also, the Design Aids module provides more guidelines for the design of cleanout operations. For specific cleanout purposes though, CoilCADE software offers three modules:

### **Solids Transport module**

For solids transport out of the wellbore, the Solids Transport module enables selection of the optimal fluid, minimum pump rate, and CT penetration rate. It is particularly effective in predicting the movement of solids beds in deviated well sections.

### **Foam Cleanout module**

To achieve the desired bottomhole foam quality and surface choke pressures required to maintain wellbore conditions, the Foam Cleanout module determines rates and volumes of liquid and gas needed.

### **PowerCLEAN module**

Developed through comprehensive research and finely tuned through extensive testing, the PowerCLEAN\* engineered fill removal service helps the engineer design a CT pumping and sweeping schedule to efficiently and more safely clean out a bed of solids, especially in deviated or horizontal wellbores. This module allows for precise, cost-effective design and execution of every cleanout job. It evaluates each fluid or fluid combination for any wellbore or operating condition and recommends the best fluid and job procedures, including

- maximum run in hole CT speed when penetrating the fill
- optimal CT pull out of hole speed while sweeping solids up the wellbore
- optimal pump rate during procedures.

In addition to the aforementioned modules, CoilCADE software also offers

- Inflate Advisor module for design guidance for the CoilFLATE\* coiled tubing through-tubing inflatable packer
- CoilDEFORMATION\* coiled tubing elongation and ballooning prediction model for elongation and ballooning due to fatigue loading
- Erosion Analysis module to predict CT wall thickness changes as a function of job parameters.

## Coiled tubing computer-aided treatment

### APPLICATIONS

- CT operations

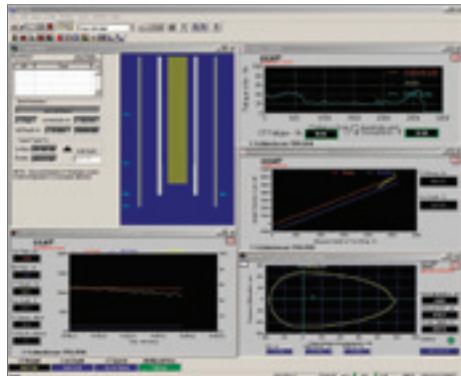
### ADVANTAGES

- Advanced job preparation
- Reduced setup time
- Allows real-time job redesign to account for unexpected conditions
- Provides visual wellbore and CT string data
- Tracks key job parameters and connects them to operational alarms
- Computes, displays, and warns of CT limits
- Updates string life using CoillIFE\* coiled tubing life prediction model
- Models pressure and tension with CoilLIMIT\* coiled tubing pressure and tension limit model
- Generates treatment report on location
- Zones I and II compliant
- Can be formatted to ASCII file format
- Has customizable plots

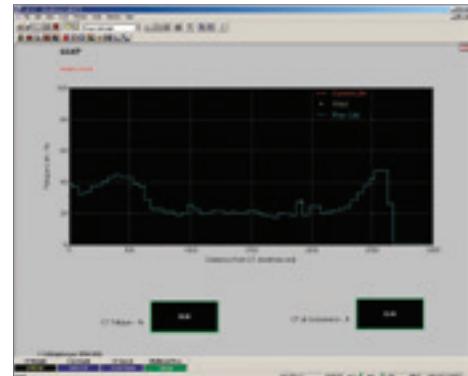
Integrated with Schlumberger CT services, the CoilCAT\* coiled tubing computer-aided treatment is a unique wellsite information management system that takes informed real-time decision making to a high level of confidence. It goes beyond just data acquisition to complete analysis and design, making well intervention operations more efficient and reliable.

The CoilCAT system directly links a PC with the numerous sensors of the CT unit to capture all required parameters. It merges design, execution, and real-time evaluation capabilities, including CoilCADE\* coiled tubing design and evaluation software, which analyze problems, suggest solutions, and predict the outcome of changing operational parameters within pressure and tension limits. Users can overlay design and real-time job parameters and redesign them if necessary.

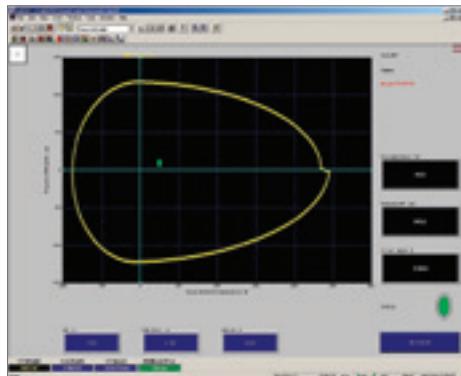
Real-time data is available for CT depth, run speed, pipe weight, cumulative volume, and pressure rate. Job monitoring and recording equipment for CT data is available for pipe depth, weight, and running speed; annulus, wellhead, and pump pressure; gripping force; pump rate; and tubing integrity.



A screen generated with the CoilCAT system—The well animation window displays restrictions and the time remaining until the CT BHA reaches the next restriction, allowing the user to be aware of the well profile in real time. The CoillIFE prediction model window is shown in real time, which enables correct CT life management throughout the entire string and eliminates time-consuming manual calculations of pipe fatigue.



CoillIFE CT life prediction.



CoillIMIT limit model envelope—The working limits of CT string pressure and tension are defined, with a green dot moving in real time to show where the limits are within the envelope at any moment.

# InterACT

## Global connectivity, collaboration, and information service

### APPLICATIONS

- Real-time, interactive access to data through the Internet or an intranet
- Modifications to job design and execution in real time
- Fewer wellsite trips, reducing costs and exposure of personnel to health, safety, and environmental problems
- Real-time access to Schlumberger experts
- Data delivery when and where needed
- Secure connection to confidential data

### BENEFITS

- Real-time monitoring and evaluation of remote CT operations
- Remote collaboration and decision making

### FEATURES

- Digital display of critical job parameters
- Real-time overlay of predicted versus actual tubing forces
- Transfer of real-time acquisition messages
- Postjob reports with historical plots
- Selective sharing of job data among several remote locations
- Two-way communication and distribution of job data
- Standard communication infrastructure and software
- Standard data files and formats



*Real-time monitoring and evaluation of remote CT operations allows collaboration and decision making.*

### Optimized operations from anywhere in the world

The oil and gas industry is constantly looking for a better way to get the job done. Collaboration has become essential to fully optimize job design, increase efficiency, and reduce operational costs. Today in critical operations such as downhole tool operations and remedial cementing in extended reach applications, offsite specialists can monitor real-time data, supervise the operations, and evaluate the actual results against the predicted design.

The Schlumberger InterACT\* global connectivity, collaboration, and information service brings real-time CT data directly from the job site to the desktop. Using a standard Web browser and a simple Internet or intranet connection, the InterACT system connects experts from multiple locations to remote job sites anywhere in the world. Specialists can collaborate in real time to leverage and focus global resources on the job as it is executed. The result is an improved data-to-decision-making process that can help ensure operational efficiency and performance.

Used with the CoilCAT\* computer-aided treatment software, the InterACT system makes CT data available on an embedded graphical and numerical display. A wide range of operational parameters can be displayed, including a historical weight-pressure-rate plot; a tubing forces overlay plot; depth correlations; and information on drilling, fracturing, and stimulation programs.

Real-time messages from the wellsite acquisition console can be transmitted, and automated postjob reports can be generated. Files generated in all standard data types and formats, including daily reports, well programs, logs, graphics, etc., can be exchanged during the operation. This capability lets operators, their partners, and Schlumberger personnel remotely monitor and supervise ongoing CT operations in real time and gives them the data to make effective decisions.

## Flexible communications

Authorized users can monitor multiple CT operations from different locations by simply logging onto the InterACT system. Since it works through the Internet or an intranet using standard, secure Web protocols, the InterACT system is inherently easy to use and does not require specialized software. Automatic link recovery and data buffering are available in the event of a communications link interruption.

InterACT system real-time data can be exported to other local applications for further processing and interpretation. Proprietary protocols ensure strong data transfer by compressing the data for efficient transmission on marginal communication links.

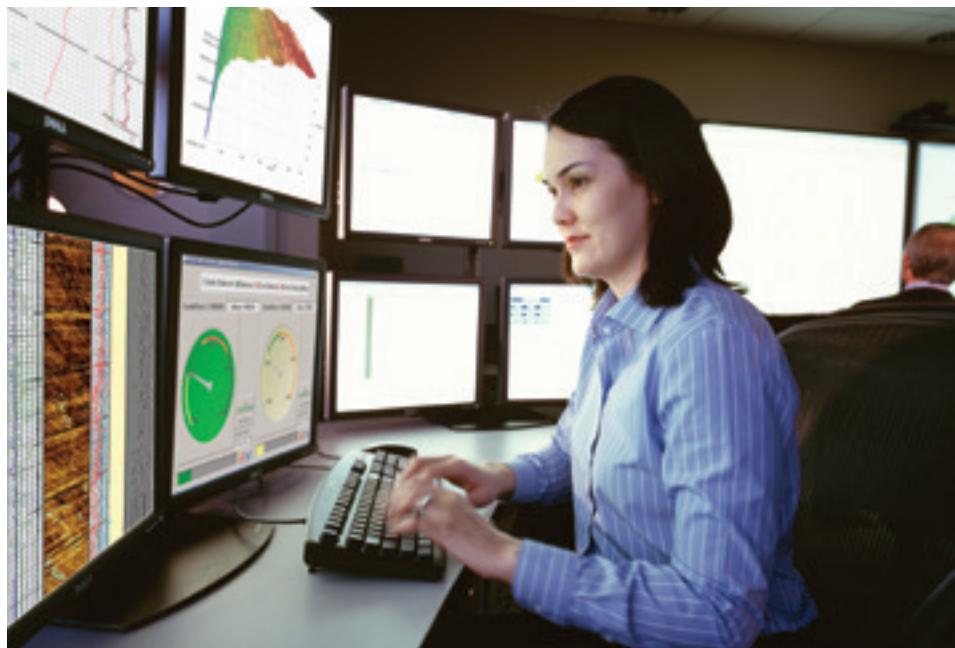
## Data security

Robust security is an integral part of the InterACT system. A 128-bit secure socket layer (SSL) encryption—a best-in-class security standard for hardware and software—secures the data. Multilevel access enables configuration to operator specifications and allows operators to control the levels of accessibility for other users.

## Case History: Lake Maracaibo, Venezuela

During a critical CT intervention on Lake Maracaibo, Venezuela, the onshore team used the InterACT system to monitor and collaborate with the wellsite team. The well had a collapsed screen section at 10,478-ft measured depth. The objective was to set a permanent bridge plug and abandon a lower interval. A CT depth correlation log was used to provide accurate depth control. During the job, an unexpected obstruction was encountered that altered both the intervention program and its objectives. With real-time access to the CCL log and CT operational parameters through the InterACT system, the onshore team was able to optimize and facilitate the decision-making process to make the appropriate corrections. The result was improved operational efficiency and reduced costs.

The Schlumberger InterACT system enables remote access to technical expertise; improves efficiency, communication, and collaboration; and reduces costs by providing real-time data to specialists located anywhere in the world.



*The secure system allows controlling levels of access for users.*

# ACTIVE DTS Inversion

## Quantitative analysis of distributed temperature sensing measurements

### APPLICATIONS

- Coiled tubing interventions using ACTive\* family of live coiled tubing services

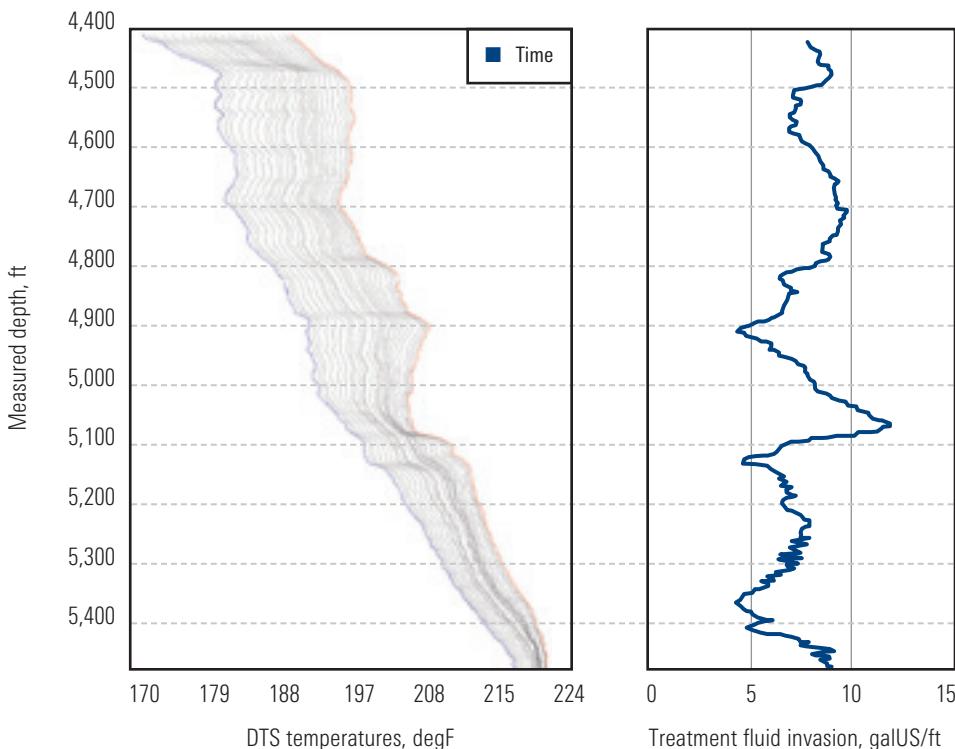
### ADVANTAGES

- Shifts distributed temperature sensing (DTS) interpretation from qualitative to quantitative
- Provides an advanced analysis of DTS wellbore-temperature logs used for calculating
  - Flow contributions
  - Water-injection profiles
  - Fracturing effectiveness
  - Top of cement
  - Crossflow between zones
- Quantifies the fluid invasion profile for the pumping stage preceding the DTS acquisition
- Loads DTS data exported from THERMA\* thermal modeling and analysis software for wells with distributed temperature sensing
- Uses detailed menu items and module structure to account for reservoir properties and zoning
- Conducts sensitivity analysis with flexible simulation parameters
- Evaluates treatments involving multiple injections
- Saves results in Log ASCII Standard (LAS) digital data format that can be opened in the Techlog\* wellbore software platform for analysis

### Quantify treatments using real-time DTS measurements

Distributed temperature sensing measurements rely on a laser beam and a continuous strand of optical fiber-optic technology to collect continuous temperature profiles along the length of the well. This technology has been used as part of ACTive services real-time CT interventions to monitor wellbore temperature evolution while pumping, as well as during shut-in periods. The tracking of temperature data down the wellbore, as well as the qualitative assessment of reservoir temperature warming or cooling—or lack thereof—during shut-in, has helped engineers gain insight into fluid placement performance and zonal coverage.

ACTive DTS inversion, the new module implemented in Decipher\* interpretation of coiled tubing dynamic surface and downhole events, allows engineers to use DTS data acquired during real-time ACTive services interventions to quantify the intake profile of treatment fluid along the wellbore.



*The DTS inversion process generates the fluid invasion profile (volume per unit length) across a selected interval based on the evolution of distributed temperature measurements, as well as key treatment and reservoir parameters.*

**Schlumberger**

# CoilTOOLS

# E-Z Connector

Avoids ID restriction of the CT

## APPLICATIONS

- Standard coiled tubing (CT) interventions
- Standard HPHT operations
- Sweet and sour wells according to NACE standards

## ADVANTAGES

- Reusable, saving cost
- Two O-ring seals on the coil (readily available) to ensure pressure integrity
- Wrench flats above the AMMT or PAC connections
- Carburized high-tensile slip for all sizes
- Pull plate with autoclave pressure fitting available
- High-strength construction for a connector stronger than the CT string
- Application of external makeup principle to avoids ID restriction of the CT, allowing unrestricted flow and the use of wiper plugs or process balls
- Slip grip for coil, with enough friction to allow the use of motors with smaller ODs than the connector

CT connectors are available in a wide range of designs and sizes. Most connectors are classified as

- setscrew (dimple)
- grapple
- roll-on
- flared
- threaded
- welded.

The E-Z Connector is an external CT slip-type connector. It utilizes the pulling force of the injector head, so it does not require any makeup tools. After beveling and smoothing the CT string end for the O-ring seal, the E-Z connector is applied to the CT string. A pulling load, at least equal to the maximum expected load on the connector throughout the operation, is then applied, forcing the slips to interlock with the CT string. After releasing the load, the connector is retorqued to remove the slack. No further load testing is required.



*E-Z connector tech unit.*

## Specifications<sup>†‡§</sup>

Part Number	OD, in [mm]	ID, in [mm]	Coil Size	Lower Thread	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100416635	2.19 [55.63]	0.81 [20.57]	1½-in CT	1-in AMMT-S PIN	0.75 [19.05]	6.72 [170.69]	Yes	10,000 [68,948]	37,000 [16,458]	449 [50.96]
100348503	2.19 [55.63]	1.03 [26.16]	1½-in CT	1½-in AMMT-S PIN	0.905 [22.99]	6.72 [170.69]	Yes	10,000 [68,948]	45,000 [20,017]	1,484 [168.43]
100348513	2.38 [60.45]	1.03 [26.16]	1¾-in CT	1½-in AMMT-S PIN	0.905 [22.99]	8.57 [217.68]	Yes	10,000 [68,948]	50,000 [22,241]	1,481 [168.09]
T1001436	2.87 [72.90]	1.44 [36.58]	1¾-in CT	2⅜-in PAC DSI PIN	1.310 [33.27]	7.32 [185.93]	Yes	10,000 [68,948]	50,000 [22,241]	2,600 [295.10]
100348516	2.69 [68.33]	1.03 [26.16]	2-in CT	1½-in AMMT-S PIN	0.905 [22.99]	8.84 [224.54]	Yes	10,000 [68,948]	72,000 [32,027]	1,484 [168.43]
100057397	2.75 [69.85]	1.38 [35.05]	2-in CT	2⅜-in PAC DSI PIN	1.25 [31.75]	8.34 [211.84]	Yes	10,000 [68,948]	72,000 [32,027]	2,600 [295.10]

<sup>†</sup> Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup> At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

<sup>§</sup> Working pressure based on nominal CT OD to nominal CT OD less 0.006 in. User should determine actual working pressure based on CT OD.

# Internal Breech Lock Connector

Removes and installs multiple times

## APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- High-tensile-stress, high-torque, and high-shock operations, such as perforating, jarring, milling, or using an impact hammer
- Sweet and sour services according to NACE standards

## ADVANTAGES

- Reduce rig-up and operating time, lower operational risks, and increase reliability through streamlined connection and removal procedures
- Minimize NPT and unsuccessful pressure tests by eliminating the need to cut and redimple the CT when changing connector
- Decrease costs through longer connector service life without loss of tensile or torque integrity
- Lower the risk of hanging up on downhole restrictions through the streamlined profile of the slimline version
- Allow preparation of CT at the base for connector make up on location
- Reusable connectors
- Rotational lock for high torque
- Minimal restriction of CT ID
- Slim or upset OD configuration

The internal breech lock (IBL) connector is used to connect CT to the BHA. Unlike many connectors used for the purpose, it can be removed and reattached multiple times without loss of tensile or torque strength. It does not have to be cut off and changed after every run or two, even during high-shock applications such as jarring, saving both time and costs. It can be installed at the base; tension, torque, and pressure tested; and then disconnected from the CT for transportation. At the wellsite, it is quickly reinstalled, tested, and ready for service. It is also less ID-restrictive than internal slip-type connectors, allowing unrestricted flow and the use of wiper plugs or process balls.

Radial lugs are formed in the CT to be received in a uniquely channeled (J-shaped) profile on the connector. The connector is pushed in, rotated 45° clockwise, and pulled back to lock it in place. Two lock rings prevent it from backing off.

Only 1.4 in [35.56 mm] of the weld bead must be removed to accommodate the O-ring sealing surface of the IBL connector.

These connectors are available in standard CT sizes of 1½, 1¾, 2, 2⅓, and 2⅝ in for a wide range of applications.



*Internal breech lock connector.*

## Specifications<sup>†‡§</sup>

Part Number	OD, in [mm]	ID, in [mm]	CT Wall Thickness, in [mm]	Lower Thread	Will-Pass Ball Size, in [mm]	Temperature, degF [degC]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, lbf.ft [daN.m]
1½-in CT										
100648044	1.5 [38.10]	0.812 [20.62]	0.095 [2.41]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	318 [36.04]
100648045	1.5 [38.10]	0.812 [20.62]	0.102 [2.59]	1-in AMMT-S	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	318 [36.04]
100648046	1.5 [38.10]	0.812 [20.62]	0.109 [2.76]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	318 [36.04]
100648047	1.5 [38.10]	0.812 [20.62]	0.116 [2.94]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	318 [36.04]
100648050	1.5 [38.10]	0.812 [20.62]	0.125 [3.17]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	318 [36.04]
100648051	1.5 [38.10]	0.812 [20.62]	0.134 [3.40]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	318 [36.04]
100648054	1.5 [38.10]	0.812 [20.62]	0.145 [3.68]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	318 [36.04]
100648055	1.5 [38.10]	0.812 [20.62]	0.156 [3.96]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	318 [36.04]
100648057	1.5 [38.10]	0.775 [19.69]	0.175 [4.44]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	318 [36.04]
1¾-in CT										
100645579	1.75 [44.45]	0.812 [20.62]	0.109 [2.76]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	378 [42.94]
100645581	1.75 [44.45]	0.812 [20.62]	0.116 [2.94]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	378 [42.94]
100645582	1.75 [44.45]	0.812 [20.62]	0.125 [3.17]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	378 [42.94]
100645583	1.75 [44.45]	0.812 [20.62]	0.134 [3.40]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	378 [42.94]
100645585	1.75 [44.45]	0.812 [20.62]	0.145 [3.68]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	378 [42.94]
100645586	1.75 [44.45]	0.812 [20.62]	0.156 [3.96]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	378 [42.94]
100645587	1.75 [44.45]	0.812 [20.62]	0.175 [4.44]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	378 [42.94]
100645589	1.75 [44.45]	0.812 [20.62]	0.19 [4.82]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	378 [42.94]
100645591	1.75 [44.45]	0.812 [20.62]	0.204 [5.18]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	31,790 [14,141]	378 [42.94]

<sup>†</sup> Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [21 degC] and a single load case.

<sup>‡</sup> At temperatures above 250 degF [121 degC], all ratings for the tool are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

<sup>§</sup> Working pressure based on nominal CT ID to nominal CT ID + 0.006 in. User should determine actual working pressure based on CT OD.

**Specifications<sup>†‡§</sup>**

Part Number	OD, in [mm]	ID, in [mm]	CT Wall Thickness, in [mm]	Lower Thread	Will-Pass Ball Size, in [mm]	Temperature, degF [degC]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, lbf.ft [daN.m]
2-in CT										
100458092	2 [50.80]	1.03 [20.62]	0.109 [2.76]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100640645	2 [50.80]	0.812 [20.62]	0.116 [2.94]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100457536	2 [50.80]	0.812 [20.62]	0.125 [3.17]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100457162	2 [50.80]	0.812 [20.62]	0.134 [3.40]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100640931	2 [50.80]	0.812 [20.62]	0.145 [3.68]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100452004	2 [50.80]	0.812 [20.62]	0.156 [3.96]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100639180	2 [50.80]	0.812 [20.62]	0.175 [4.44]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100640934	2 [50.80]	0.812 [20.62]	0.19 [4.82]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100640938	2 [50.80]	0.812 [20.62]	0.204 [5.18]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
2½-in CT										
100647025	2.375 [60.33]	1.03 [20.62]	0.109 [2.76]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100647027	2.375 [60.33]	0.812 [20.62]	0.116 [2.94]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100647028	2.375 [60.33]	0.812 [20.62]	0.125 [3.17]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100647029	2.375 [60.33]	0.812 [20.62]	0.134 [3.40]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100647031	2.375 [60.33]	0.812 [20.62]	0.145 [3.68]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100637033	2.375 [60.33]	0.812 [20.62]	0.156 [3.96]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100647033	2.375 [60.33]	0.812 [20.62]	0.175 [4.44]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100647035	2.375 [60.33]	0.812 [20.62]	0.19 [4.82]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100647036	2.375 [60.33]	0.812 [20.62]	0.204 [5.18]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
2½-in CT										
100647025	3 [76.20]	1.375 [34.93]	0.19 [4.82]	2½-in PAC-DSI PIN	1.25 [31.75]	350 [176.67]	Yes	10,000 [68,948]	141,195 [62,806]	2,749 [312.03]

<sup>†</sup> Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup> At temperatures above 250 degF [121 degC], all ratings for the tool are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

<sup>§</sup> Working pressure based on nominal CT ID to nominal CT ID +0.006 in. User should determine actual working pressure based on actual CT ID.

# Roll-On Coiled Tubing Connector

Reliably seals inside the bore of the coil

**APPLICATIONS**

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Sweet and sour services according to NACE standards

**ADVANTAGES**

- Upset OD ring
- Ball-drop capability
- Three O-rings for positive sealing
- Selectable OD configurations (slim or upset)
- Redundant sealing system

The roll-on type connector is used when restrictions exist within a wellbore that make it difficult to use external dimple or slip connectors. An external upset ring allows the user to change the OD profile of the connector for different wellbore profiles. Without the ring, the connector has the same OD as the CT (slim), while with the ring, the connector has a larger OD than the CT (upset) and can be used to tag on the brass.

With the inside of the coil prepared, the roll-on connector can reliably seal inside the bore of the coil and hold axial forces typical of CT operations. Roll-on connectors do not hold significant torque and are therefore not rated for milling or high-torque positive displacement motor (PDM) operations.



*Roll-on coiled tubing connector.*

**Specifications<sup>†‡§</sup>**

Part Number	OD, in [mm]	ID, in [mm]	CT Wall Thickness, in [mm]	Lower Thread	Will-Pass Ball Size, in [mm]	Temperature, degF [degC]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]
1½-in CT									
100731025	1.5 [38.10]	0.812 [20.62]	0.095 [2.41]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	10,000 [4,448]
100731027	1.5 [38.10]	0.812 [20.62]	0.102 [2.59]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	10,000 [4,448]
100731029	1.5 [38.10]	0.812 [20.62]	0.109 [2.76]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	10,000 [4,448]
100731030	1.5 [38.10]	0.812 [20.62]	0.116 [2.94]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	10,000 [4,448]
100731031	1.5 [38.10]	0.812 [20.62]	0.125 [3.17]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	10,000 [4,448]
100731032	1.5 [38.10]	0.812 [20.62]	0.134 [3.40]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	10,000 [4,448]
100731033	1.5 [38.10]	0.812 [20.62]	0.145 [3.68]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	10,000 [4,448]
100731034	1.5 [38.10]	0.812 [20.62]	0.156 [3.96]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	10,000 [4,448]
100731036	1.5 [38.10]	0.775 [19.69]	0.175 [4.44]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	10,000 [4,448]
1¾-in CT									
100725656	1.75 [44.45]	0.812 [20.62]	0.109 [2.76]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100725660	1.75 [44.45]	0.812 [20.62]	0.116 [2.94]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100360141	1.75 [44.45]	0.812 [20.62]	0.125 [3.17]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100372702	1.75 [44.45]	0.812 [20.62]	0.134 [3.40]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100372782	1.75 [44.45]	0.812 [20.62]	0.145 [3.68]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100725719	1.75 [44.45]	0.812 [20.62]	0.156 [3.96]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100725721	1.75 [44.45]	0.812 [20.62]	0.175 [4.44]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100725727	1.75 [44.45]	0.812 [20.62]	0.19 [4.82]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

<sup>§</sup>Working pressure based on nominal CT ID to nominal CT ID plus 0.006 in. User should determine actual working pressure based on CT ID.

## Specifications<sup>†‡§</sup>

Part Number	OD, in [mm]	ID, in [mm]	CT Wall Thickness, in [mm]	Lower Thread	Will-Pass Ball Size, in [mm]	Temperature, degF [degC]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]
100725551	1.75 [44.45]	0.812 [20.62]	0.204 [5.18]	1-in AMMT-S PIN	0.75 [19.05]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
2-in CT									
100728686	2 [50.80]	1.03 [20.62]	0.109 [2.76]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
2-in CT									
100728687	2 [50.80]	0.812 [20.62]	0.116 [2.94]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100728689	2 [50.80]	0.812 [20.62]	0.125 [3.17]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100728690	2 [50.80]	0.812 [20.62]	0.134 [3.40]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100728691	2 [50.80]	0.812 [20.62]	0.145 [3.68]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100142279	2 [50.80]	0.812 [20.62]	0.156 [3.96]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100728693	2 [50.80]	0.812 [20.62]	0.175 [4.44]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100728694	2 [50.80]	0.812 [20.62]	0.19 [4.82]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100728696	2 [50.80]	0.812 [20.62]	0.204 [5.18]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
2½-in CT									
100730595	2.375 [60.33]	0.812 [20.62]	0.175 [4.44]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100730597	2.375 [60.33]	0.812 [20.62]	0.19 [4.82]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]
100730599	2.375 [60.33]	0.812 [20.62]	0.204 [5.18]	1½-in AMMT-S PIN	1.00 [25.40]	350 [176.67]	Yes	10,000 [68,948]	15,000 [6,672]

<sup>†</sup> Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup> At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

<sup>§</sup> Working pressure based on nominal CT ID to nominal CT ID plus 0.006 in. User should determine actual working pressure based on CT ID.

# Dimple Connector

Quickly installs and removes

## APPLICATIONS

- Standard coiled tubing interventions oil, gas, and injector wells
- Standard HPHT operations
- Perforating
- Jarring/impact hammers
- Milling

## ADVANTAGES

- Rotational lock holds high amount of torque
- Reusable connectors offer multiple use
- Minimal ID restriction of the CT, allowing unrestricted flow and the use of wiper plugs or process balls
- Allows coiled tubing preparations at base
- Sweet and sour services according to NACE standards
- Quick installation and removal
- Two O-rings seal on the coil
- High-strength construction makes the connector stronger than the coiled tubing string
- Uses 12 knurled grub screws

Historically, the external set screw, or dimple connector, has been the preferred style of connector. It is attached to the coiled tubing end by set screws that engage preformed dimples, which are formed using a dimpling tool. After the dimpling, the coiled tubing end is prepared for the O-ring seal by beveling off the end and smoothing the O-ring seal area. The connector is then slipped up the coiled tubing; the set screws are torqued in place. Verification of proper installation is required with a pressure and pull test.

The dimple connectors are available standard CT sizes of 1½, 1¾, 2, 2⅓, and 2⅝-in.



Dimple connector.

## Specifications<sup>†‡</sup>

Part Number	OD, in [mm]	ID, in [mm]	CT Size	Lower Thread	Will Pass Ball Size, in [mm]	Make-up length, in [mm]	Sweet and sour services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft-lbf [daN-m]
100476698	1.69 [42.926]	0.812 [20.625]	1½-in CT	1-in AMMT-S PIN	0.75 [19.05]	6.68 [169.672]	Yes	10,000 [68,948]	31,790 [14,141]	374 [51]
100297852	2.13 [54.102]	1.03 [26.162]	1½-in CT	1½-in AMMT-S PIN	1 [25.4]	6.68 [169.672]	Yes	10,000 [68,948]	63,772 [28,367]	1,237 [168]
100297854	2.13 [54.102]	0.812 [20.625]	1½-in CT	1-in AMMT-S PIN	0.75 [19.05]	6.68 [169.672]	Yes	10,000 [68,948]	31,790 [14,141]	374 [51]
100289510	2.875 [73.025]	1.38 [35.052]	1¾-in CT	2½-in PAC DSI PIN	1.25 [31.75]	6.68 [169.672]	Yes	10,000 [68,948]	97,650 [43,437]	2,749 [373]
100288814	2.25 [57.15]	1.03 [26.162]	1¾-in CT	1½-in AMMT-S PIN	1 [25.4]	6.68 [169.672]	Yes	10,000 [68,948]	57,034 [25,370]	1,237 [168]
100297129	2.56 [65.024]	1.03 [26.162]	2-in CT	1½-in AMMT-S PIN	1 [25.4]	6.68 [169.672]	Yes	10,000 [68,948]	63,772 [28,367]	1,237 [168]
100297134	2.875 [73.025]	1.38 [35.052]	2-in CT	2½-in PAC DSI PIN	1.25 [31.75]	6.68 [169.672]	Yes	10,000 [68,948]	97,650 [43,437]	2,749 [373]
100476229	2.875 [73.025]	1.38 [35.052]	2½-in CT	2½-in PAC DSI PIN	1.25 [31.75]	8.5 [215.9]	Yes	10,000 [68,948]	74,326 [33,062]	2,749 [373]
100626341	3.13 [79.502]	1.25 [31.75]	2½-in CT	2½-in API REG PIN	1.125 [28.575]	8.5 [215.9]	No	10,000 [68,948]	124,992 [55,599]	4,000 [542]
100549919	3.13 [79.502]	1.25 [31.75]	2½-in CT	2½-in API REG PIN	1.125 [28.575]	8.5 [215.9]	Yes	10,000 [68,948]	124,992 [55,599]	4,000 [542]
100675642	3.375 [85.725]	1.75 [44.45]	2½-in CT	2½-in API IF PIN	1.625 [41.275]	8.5 [215.9]	Yes	10,000 [68,948]	84,758 [37,702]	3,778 [512]
100288815	3.375 [85.725]	1.38 [35.052]	2½-in CT	2½-in PAC DSI PIN	1.25 [31.75]	8.5 [215.9]	Yes	10,000 [68,948]	84,758 [37,702]	3,778 [512]

<sup>†</sup> Values are based on 80-ksi strength steel at 70 degF [21 degC] and a single load case.

<sup>‡</sup> At temperatures above 250 degF [121 degC] all ratings for the tool are reduced by 7%, at 350 degF [177 degC] the ratings are reduced by 12%. All users should determine the actual operating and load parameters for their own application.

# Double-Flapper Check Valve

Combines reliability with minimum flow restriction

## APPLICATIONS

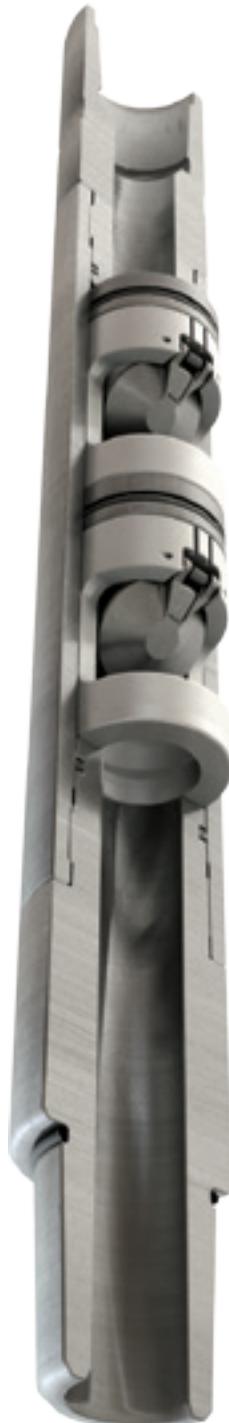
- Standard safety device for coiled tubing (CT) interventions in all oil, gas, and water wells
- High-pressure, high-temperature operations

## ADVANTAGES

- Design allows sharing components between different tool sizes to minimize inventory
- Dual-arm flappers in all sizes
- Full-opening flapper check valves with metal-to-metal seals and elastomer backups
- Sweet and sour services according to NACE standards
- Only premium materials
- Use of standard spring in all sizes
- Easy-to-assemble spring
- Seal ring retainer that is pinned to cage and will not separate
- Temperature rating of 400 degF [204 degC]

The Double-Flapper Check Valve (DFCV) combines reliability, minimum flow restrictions, the ability to pump wider plugs and drop balls through the valve for ball actuated tools. In addition to a significantly stronger spring, the DFCV uses a completely redesigned cartridge made from only premium materials. The cartridge comes in two sizes, allowing a degree of interchangeability with different diameter housings. It is also reversible, allowing maximum flexibility when designing CT jobs.

The DFCV has a temperature rating of 400 degF [204 degC] and is easy to assemble and disassemble. The DFCV combines reliability, minimum flow restrictions, the ability to pump wiper plugs and drop balls through the valve for ball actuated tools. It is resistant to clogging from rust, scale, paraffin, and dried hydrocarbons, which preserves the circulation through the check valve at all times.



*Double-Flapper Check Valve*

## Double-Flapper Check Valve Specifications

Part number	OD, in[mm]	ID, in[mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [kPa]	Torque Capacity, ft.lbf [daN.m]
100320963	1.5 [38.10]	0.514 [13.06]	1-in AMMT-S BOX	1-in AMMT-S PIN	0.5 [12.7]	16.66 [423.16]	Yes	15,000 [103,421]	22,616 [10,060]	365 [49.52]
100605530	1.688 [42.88]	0.70 [17.78]	1-in AMMT-S BOX	1-in AMMT-S PIN	0.688 [17.46]	13.3 [337.82]	Yes	15,000 [103,421]	31,790 [14,141]	604 [81.93]
100372797	1.75 [44.45]	0.70 [17.78]	1-in AMMT-S BOX	1-in AMMT-S PIN	0.688 [17.46]	15.95 [405.13]	Yes	15,000 [103,421]	31,790 [14,141]	604 [81.93]
100596113	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.4]	16.78 [426.21]	Yes	15,000 [103,421]	42,023 [18,692]	950 [128.82]
100607876	2.125 [53.98]	1.03 [26.16]	1.812-in DS BOX	1.812 DS PIN	1 [25.4]	16.78 [426.21]	Yes	15,000 [103,421]	42,023 [18,692]	950 [128.82]
100588041	2.375 [60.33]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.4]	17.16 [435.86]	Yes	15,000 [103,421]	63,772 [28,367]	1,568 [212.55]
100182999	2.875 [73.03]	1.37 [34.80]	2½-in PAC-DSI BOX	2½-in PAC-DSI PIN	1.25 [31.75]	20.8 [528.32]	Yes	15,000 [103,421]	122,313 [54,407]	4,021 [545.23]

Values are based on 80,000 lbf/in<sup>2</sup> strength steel at 70 degF [21 degC] and a single-load case.

At temperatures above 250 degF [121 degC], ratings are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%.

Users should determine the actual operating and load parameters for their own applications.

# Pump-Out Check Valve

## Selectable ball seat sizes and shear ratings

### APPLICATIONS

- Standard coiled tubing (CT) interventions
- Sweet and sour services according to NACE standards
- CT hangoffs/velocity strings

### ADVANTAGES

- Ball-drop pumpout of check valve cartridges
- Nipple profile for pressure control during retrieval
- Slimline OD with CT size
- Selectable ball seat sizes
- "PT" nipple profile
- Standard tool joints

The pump-out check valve (POCV) nozzle uses a cartridge made from only premium materials. The POCV comes with a selectable ball seat size and selectable shear ratings. All POCVs come standard with a "PT" nipple profile, which allows the user to pump a plug and to regain pressure control before retrieving the CT string. Standard tool joint threads allow the user to run any other type of BHA component with the POCV.



Pump-out check valve.

## Specifications<sup>†‡</sup>

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Nozzle Configuration	Shear Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100687424	1.5 [38.10]	0.756 [19.20]	1-in AMMT-S BOX	Three 0.156-in diameter holes Down	0.75 [19.05]	14.8 [375.92]	Yes	10,000 [68,948]	31,790	318
100709514	1.75 [44.45]	0.756 [19.20]	1-in AMMT-S BOX	Three 0.156-in diameter holes Down	0.75 [19.05]	14.8 [375.92]	Yes	10,000 [68,948]	31,790	318
100713069	2.0 [50.80]	0.937 [23.80]	1½-in AMMT-S BOX	Three 0.156-in diameter holes Down	0.75 [19.05]	15 [381.00]	Yes	10,000 [68,948]	63,772	829

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Rugged MHA

## Heavy-duty CT motorhead assembly

### APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Perforating
- Jarring/impact hammers
- Milling
- Sweet and sour services according to NACE standards

### ADVANTAGES

- Ball-drop-actuated shear-out seat with full open ports
- Sealing and pressure balancing to allow hydraulic operations
- Multiple seat options
- High-torque load design
- High-tensile strength ratings
- Internal fishing neck for easy washing and re-entry
- Lower sealing bore to allow resealing with heavy duty retrieval tool or locator seal assemblies
- Selectable shear rating

The rugged motorhead assembly (MHA) is a compact form of all the standard bottomhole contingency components that are typically run for every CT operation. It minimizes the overall tool length and number of seals, which reduces seal failure risk and can simplify rig up. The rugged MHA was designed to withstand the heavy demands of milling, jarring, impact hammers, perforating, and CT applications that involve high shock or vibration loading.

Advances incorporated in this latest generation of CT MHA include shorter assembly, improved check valve design, improved circulation sub design, and incorporation of the rugged hydraulic disconnect design features.

In standard operation, the seats are pressure balanced; therefore, the disconnect is insensitive to the tubing-to-annulus pressure differential. To disconnect, a trip ball is dropped or pumped down the CT and is allowed to be seated in the disconnect. Pressure is then applied to the CT, and the shear pins holding the seat will shear, shifting the seat downward and allowing the dogs to retract inward. Dual activation feature allows opening by direct pressure, its circulation is lost due to BMA plugging. The pressure release value varies depending on the number and type of shear pins holding the seat. Straight pickup then separates the two halves of the disconnect to allow retrieval of the CT.

The lower half of the disconnect has an internal fishing neck profile and accepts the hydraulic GS release retrieval tool.



*Rugged motorhead assembly.*

## Specifications<sup>†‡</sup>

Part Number	OD, in[mm]	ID, in[mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [kPa]	Torque Capacity, ft.lbf [aN.m]
100601922	1.69 [42.93]	0.44 [11.18]	1-in AMMT-S BOX	1-in AMMT-S PIN	0.375 [9.525]	28.74 [730.00]	Yes	10,000 [68,948]	26,200 [11,654]	374 [50.71]
100592616	2.125 [53.98]	0.68 [17.27]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	0.625 [15.875]	32.4 [822.96]	Yes	10,000 [68,948]	42,023 [18,693]	950 [128.82]
100620570	2.25 [57.15]	0.68 [17.27]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	0.625 [15.875]	32.4 [822.96]	Yes	10,000 [68,948]	44,953 [19,996]	1,208 [163.80]
100585237	2.875 [73.03]	0.91 [23.11]	2½-in PAC-DSI BOX	2½-in PAC PIN	0.875 [22.225]	35.23 [894.84]	Yes	10,000 [68,948]	70,710 [31,453]	1,818 [246.52]

<sup>†</sup> Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [21 degC] and a single load case.

<sup>‡</sup> At temperatures above 250 degF [121 degC], all ratings for the tool are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Rugged Disconnect

Withstands heavy loads

## APPLICATIONS

- Standard CT interventions in oil, gas, and injector wells
- Standard HPHT operations
- Sweet and sour services according to NACE standards
- Perforating
- Jarring/impact hammers
- Milling

## ADVANTAGES

- Ball-drop-actuated shear-out seat with full open ports
- Sealing and pressure balancing to allow hydraulic operations
- Multiple seat options
- High-torque-load abilities
- High-tensile strength ratings
- Internal fishing neck for easy washing and reentry
- Lower sealing bore
- Selectable shear rating
- Individual use or use in a motorhead assembly (MHA)

The rugged disconnect was designed to withstand the heavy demands of milling, jarring, impact hammers, perforating, and CT applications that involve high shock or vibration loading. It provides a surface-controlled means of releasing the CT from the tools attached below. It is a ball-and-seat-operated disconnect with a splined torque transmission system specifically designed for use with downhole motors and other situations requiring the disconnect to transmit torque.

Advances in design incorporated into this latest generation of CT disconnect include rugged dogs holding the axial forces and a reduced weight in the piston, allowing shock loads of much greater magnitude to be transmitted through the tool without damaging the shear release mechanism.

In standard operation, the seats are pressure balanced; therefore, the disconnect is insensitive to the tubing-to-annulus pressure differential. To disconnect, a trip ball is dropped or pumped down the CT and is allowed to be seated in the disconnect. Pressure is then applied to the CT, and the shear pins holding the seat will shear, shifting the seat downward and allowing the dogs to retract inward. The pressure release value may be varied from 700 to 8,400 psi [4,826 to 57,915 kPa] by varying the number and type of shear pins holding the seat. Straight pickup then separates the two halves of the disconnect to allow CT retrieval.

The lower half of the disconnect has an internal fishing neck profile and accepts the hydraulic GS release retrieval tool.



*Rugged disconnect.*

## Specifications<sup>†‡</sup>

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100606221	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.4]	13.5 [342.90]	Yes	10,000	42,023	950
100651337	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.4]	13.5 [342.90]	No	10,000	57,781	1,306
100622431	2.25 [57.15]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.4]	15.5 [393.70]	Yes	10,000	44,933	1,208
100651357	2.25 [57.15]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.4]	15.5 [393.70]	No	10,000	61,783	1,661
100614432	2.875 [73.03]	1.28 [32.51]	2¾-in PAC-DSI BOX	2¾-in PAC-DSI PIN	1.25 [31.75]	13.5 [342.90]	Yes	10,000	67,933	1,818
100651365	2.875 [73.03]	1.28 [32.51]	2¾-in PAC-DSI BOX	2¾-in PAC-DSI PIN	1.25 [31.75]	13.5 [342.90]	No	10,000	93,408	2,500

<sup>†</sup> Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup> At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Dual Tubing Pressure Circulation Valve

Establishes tubing-to-annulus communication

## APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Sweet and sour services according to NACE standards
- Circulation restoration if the BHA circulation point is shut or plugged

## ADVANTAGES

- Ball-drop-actuated shear-out seat with full open ports
- Large range of activation pressure settings, selectable by number of shear pins
- Selectable seat size
- Burst-disc-type operation if tool becomes plugged below the circulation valve
- Selectable shear rating
- Deployment option in a motorhead assembly (MHA)
- Large circulation flow ports

The dual tubing pressure (TP) circulation valve provides two means of establishing tubing-to-annulus communication on a selective basis when utilized with other downhole tools.

The dual TP circulation valve is normally run below a hydraulic disconnect, but it could be placed anywhere in the BHA. In the normal running position, the dual TP circulation valve allows circulation down the tubing through the BHA or radially once activated. If circulation is lost (e.g., plugged motor), increasing differential pressure across the seat allows it to be sheared down to restore circulation. This feature acts like a burst disc, and no drop ball is required to shift the seat. Alternatively, if a planned high-flow-rate cleanout is part of a job schedule (e.g., pumping N<sub>2</sub> to surface after milling with a motor), a ball can be dropped, and the seat will shift with lower differential pressure. The pressure required to activate the seat can be adjusted by selecting the number of shear pins holding the seat.



*Dual tubing pressure circulation valve.*

## Specifications<sup>†‡</sup>

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100607735	1.688 [42.88]	0.72 [18.29]	1-in AMMT-S BOX	1-in AMMT-S PIN	0.688 [17.48]	7.93 [201.42]	Yes	10,000 [68,948]	31,790 [14,141]	604 [68.57]
100607687	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1.00 [25.40]	9.89 [251.21]	Yes	10,000 [68,948]	52,314 [23,270]	1,158 [131.47]
100607593	2.875 [73.03]	1.39 [35.31]	2½-in PAC-DSI BOX	2½-in PAC-DSI PIN	1.25 [31.75]	9.81 [249.17]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [456.36]

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Downhole Filter

Reduces the chance for plugged nozzles and orifices

## APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Sweet and sour services according to NACE standards
- Abrasive pumping (abrasives smaller than 20 mesh; e.g., 20 to 40 sand)

## ADVANTAGES

- Selectable pressure-rated burst disc
- Availability for any BHA configuration
- Debris restriction from critical BHA components

Use of the downhole filter minimizes the tendency to plug small nozzles and orifices in the downhole tool string. The downhole filter is sized to prevent pumping large debris (greater than 0.040 in [1.02 mm]) into orifices or nozzles. It has a large surface area for a high debris-holding capacity.

The filter includes a bypass burst disk that ruptures if the filter clogs (1,000 psi [6,894 kPa]). If a surface filter is also used, the downhole filter will primarily filter debris (scale, etc.) originating in the CT string.



*Downhole filter.*

## Specifications<sup>†‡</sup>

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100195762	1.69 [42.93]	0.514 [13.06]	1-in AMMT-S BOX	1.5-in DS PIN	0 [0]	25.2 [640.08]	Yes	10,000 [68,948]	19,556 [8,699]	338 [38.41]
592505000	2.13 [54.10]	0.75 [19.05]	1.812-in DS BOX	1.812-in DS PIN	0 [0]	16.66 [423.16]	Yes	10,000 [68,948]	27,500 [12,233]	716 [81.25]
100674699	2.875 [73.03]	0.88 [22.35]	2.375-in PAC DSI BOX	2.375-in PAC DSI PIN	0 [0]	28.75 [730.25]	Yes	10,000 [68,948]	67,954 [30,227]	1,338 [151.90]

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Surface Filter

Eliminates debris from pumped fluids

## APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Abrasive pumping (smaller than 20 mesh; e.g., 20 to 40 sand)

## ADVANTAGES

- Selectable pressure-rated burst disc
- 1502 WECO connections
- Debris protection for critical BHA components
- Use on any job or BHA configuration

Use of the surface filter minimizes the tendency to plug small nozzles in the downhole tool string. The surface filter eliminates the possibility for debris passing through the pumping system to enter the coil and potentially clog hardware at the end of the coil that uses small orifices. The filter has a large surface area for high debris-holding capacity. The module includes a bypass burst disc, which ruptures if the filter clogs (1,000 psi [6,894 kPa]).



Surface filter.

## Specifications<sup>†‡</sup>

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Element Mesh Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]
100190680	2.82 [71.63]	1.156 [29.36]	2-in 1502 WECO Male Plug	2-in 1502 WECO Female Plug	0.04 [1.016]	24.28 [616.71]	Yes	15,000 [103,421]
100796701	2.82 [71.63]	1.16 [29.36]	2-in 1502 WECO Male Plug	2-in 1502 WECO Female Plug	0.01 [0.254]	24.28 [616.71]	Yes	15,000 [103,421]

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Wash Pipe Guide

Aids in fishing tools in horizontal or noncentralized situations

## APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Sweet and sour services according to NACE standards
- Jarring/impact hammers

## ADVANTAGES

- Optional OD guides
- Adjustable wash pipe lengths
- Industry-standard design

The wash pipe guide is designed to work with the hydraulic release type GS retrieval tool, but it will work with any tool with the same thread and will fit in the ID of the wash pipe. The guide is specifically designed to aid in fishing a tool in a horizontal or noncentralized situation by scooping it into the wash pipe and centralizing it for an internal spear-type retrieval tool. The wash pipe guide has 18-in [457.2-mm] extension housings that can be added or subtracted so that the user can wash over more than just the fishing neck of the fish.



*Wash pipe guide.*

## Specifications<sup>†‡</sup>

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100715137	2.25 [57.15]	0.81 [20.62]	1-in AMMT-S BOX	MULESHOE	0.75 [19.05]	33.18 [842.77]	Yes	10,000 [68,948]	23,235 [10,335]	687 [77.94]
100731340	2.69 [68.33]	1.03 [26.16]	1½-in AMMT-S BOX	MULESHOE	1.00 [25.40]	33.07 [839.98]	Yes	10,000 [68,948]	31,254 [13,902]	727 [82.48]
100730883	3.5 [88.90]	1.38 [35.05]	2½-in PAC-DSI BOX	MULESHOE	1.25 [31.75]	36.32 [922.53]	Yes	10,000 [68,948]	37,154 [16,527]	1,513 [171.67]

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Three-Piece Stabilizer

Provides downhole BHA centralization

## APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Standard HPHT operations
- Sweet and sour services according to NACE standards
- Packer, milling, and fishing operations

## ADVANTAGES

- Standard oilfield threads
- Interchangeable stabilizer section
- Large chamber for easy tubing reentry
- Solid fluted stabilizer for guaranteed standoff
- High-torque through and tensile ratings
- Large ID for high flow rates
- Multiple jet holes for different jetting configurations
- Jets with different IDs

The three-piece stabilizer was designed to withstand the high demands of today's downhole conditions in packer, milling, and fishing operations.

Advances incorporated in this latest generation of the CT three-piece stabilizer include a large ID for high flow rates, high tensile and torque ratings, and interchangeable stabilizer ODs.



Three-piece stabilizer.

**Specifications<sup>†‡</sup>**

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [aN.m]
1-in AMMT-S BOX										
100318254	1.75 [44.45]	0.812 [20.62]	1-in AMMT-S BOX	1-in AMMT-S PIN	0.75 [19.05]	16.25 [412.75]	Yes	10,000 [68,948]	31,790 [14.141]	604 [68.57]
100623557	2 [50.80]	0.812 [20.62]	1-in AMMT-S BOX	1-in AMMT-S PIN	0.75 [19.05]	11.25 [285.75]	Yes	10,000 [68,948]	31,790 [14.141]	604 [68.57]
100623560	2.25 [57.15]	0.812 [20.62]	1-in AMMT-S BOX	1-in AMMT-S PIN	0.75 [19.05]	11.25 [285.75]	Yes	10,000 [68,948]	31,790 [14.141]	604 [68.57]
100623562	2.5 [36.50]	0.812 [20.62]	1-in AMMT-S BOX	1-in AMMT-S PIN	0.75 [19.05]	11.25 [285.75]	Yes	10,000 [68,948]	31,790 [14.141]	604 [68.57]
100318261	2.75 [69.85]	0.812 [20.62]	1-in AMMT-S BOX	1-in AMMT-S PIN	0.75 [19.05]	11.25 [285.75]	Yes	10,000 [68,948]	31,790 [14.141]	604 [68.57]
1½-in AMMT-S BOX										
100623569	2.25 [57.15]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.40]	13.375 [339.73]	Yes	10,000 [68,948]	63,771 [28,367]	1,568 [177.91]
100623570	2.5 [63.50]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.40]	13.375 [339.73]	Yes	10,000 [68,948]	63,771 [28,367]	1,568 [177.91]
100318255	2.75 [69.85]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.40]	13.375 [339.73]	Yes	10,000 [68,948]	63,771 [28,367]	1,568 [177.91]
100318256	3 [76.20]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.40]	13.375 [339.73]	Yes	10,000 [68,948]	63,771 [28,367]	1,568 [177.91]
100318257	3.375 [85.73]	1.03 [26.16]	1½-in AMMT-S BOX	1½-in AMMT-S PIN	1 [25.40]	13.375 [339.73]	Yes	10,000 [68,948]	63,771 [28,367]	1,568 [177.91]
2¾-in PAC-DSI BOX										
100637729	3 [76.20]	1.37 [34.80]	2¾-in PAC-DSI BOX	2¾-in PAC-DSI PIN	1.25 [31.75]	21.65 [549.91]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [456.36]
100638128	3.375 [85.73]	1.37 [34.80]	2¾-in PAC-DSI BOX	2¾-in PAC-DSI PIN	1.25 [31.75]	21.65 [549.91]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [456.36]
100638132	3.5 [88.90]	1.37 [34.80]	2¾-in PAC-DSI BOX	2¾-in PAC-DSI PIN	1.25 [31.75]	21.65 [549.91]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [456.36]
100638134	3.625 [92.08]	1.37 [34.80]	2¾-in PAC-DSI BOX	2¾-in PAC-DSI PIN	1.25 [31.75]	21.65 [549.91]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [456.36]
100638155	3.75 [95.25]	1.37 [34.80]	2¾-in PAC-DSI BOX	2¾-in PAC-DSI PIN	1.25 [31.75]	21.65 [549.91]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [456.36]
100638159	4.5 [114.30]	1.37 [34.80]	2¾-in PAC-DSI BOX	2¾-in PAC-DSI PIN	1.25 [31.75]	21.65 [549.91]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [456.36]
100638186	4.75 [120.65]	1.37 [34.80]	2¾-in PAC-DSI BOX	2¾-in PAC-DSI PIN	1.25 [31.75]	21.65 [549.91]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [456.36]
100638238	5.5 [139.70]	1.37 [34.80]	2¾-in PAC-DSI BOX	2¾-in PAC-DSI PIN	1.25 [31.75]	21.65 [549.91]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [456.36]

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Selectable Jet Nozzle

## Modifiable configurations

### APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Sweet and sour services according to NACE standards

### ADVANTAGES

- Consistent jet hole size for hydraulic modeling
- Multiple jet holes for different jetting configurations
- Jets with different IDs

Selectable jet nozzles come in different configurations and can be modified on location to best fit the application for which they are being used. Jet sizes that can be used in the nozzle include

- Plug
- 0.093-ID jet
- 0.125-ID jet
- 0.156-ID jet
- 0.188-ID jet.



Selectable jet nozzle.

### Specifications<sup>†‡</sup>

Part Number	OD, in [mm]	Upper Thread	Nozzle Configuration	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100592616	2 [50.80]	1½-in DS BOX	Four-variable-diameter holes, Down	5.98 [151.89]	Yes	10,000 [68,948]	21,768 [9,683]	245 [27.81]
100620570	2.12 [53.85]	1½-in AMMT-S BOX	Four-variable-diameter holes, Down	5.98 [151.89]	Yes	10,000 [68,948]	63,772 [28,367]	1,237 [140.36]

<sup>†</sup> Values are based on 80,000-psi (551,600-kPa)-strength steel at 70 degF (39 degC) and a single load case.

<sup>‡</sup> At temperatures above 250 degF (140 degC), all ratings for the tool are reduced by 7%; at 350 degF (196 degC), ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Wash Tools and Nozzles

Enhances fill removal

**APPLICATIONS**

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Standard HPHT operations
- Sweet and sour services according to NACE standards
- Abrasive applications

**ADVANTAGES**

- Consistent hole size for hydraulic modeling
- Ball-drop capability
- Standard holes and configurations
- Extra body length to allow additional holes to be added in the field

Wash tools and nozzles come in four different configurations and can be modified on location to best fit the application for which they are being used. They have consistently sized holes for hydraulic modeling and pressure drop calculations. Configurations include down jet, side jet, ball drop, and fill removal.

The clean out nozzles are specifically designed to enhance fill removal in highly deviated wells. When used in conjunction with design software and gel packages, the system has been used to clean even the most difficult wells. The clean out nozzles come in

- high-flow, regular-strength
- high-flow, high-strength
- low-flow, regular-strength
- low-flow, high-strength.



*Wash tools and nozzles.*

**Specifications<sup>†‡</sup>**

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Nozzle Configuration	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
Down Jet										
100671021	1.5 [38.10]	0.812 [20.62]	1-in AMMT-S BOX	Three 0.190-in diameter holes down down	0 [0]	9.5 [241.30] [241.30]	Yes	10,000 [68,948]	31,790 [14,141]	318 [43.05]
100671022	1.688 [42.88]	0.812 [20.62]	1-in AMMT-S BOX	Three 0.190-in diameter holes down	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	31,790 [14,141]	318 [43.05]
100671024	1.75 [44.45]	0.812 [20.62]	1-in AMMT-S BOX	Three 0.190-in diameter holes down	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	31,790 [14,141]	318 [43.05]
100671026	2 [50.80]	1.03 [26.16]	1½-in AMMT-S BOX	Three 0.190-in diameter holes down	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	63,772 [28,367]	829 [112.44]
100671027	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S BOX	Three 0.190-in diameter holes down	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	63,772 [28,367]	829 [112.44]
100671030	2.375 [60.33]	1.03 [26.16]	1½-in AMMT-S BOX	Three 0.190-in diameter holes down	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	63,772 [28,367]	829 [112.44]
100671025	2.875 [73.03]	1.37 [34.80]	2¾-in PAC-DS BOX	Three 0.190-in diameter holes down	0 [0]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]
100671028	3.06 [77.72]	1.37 [34.80]	2¾-in PAC-DS BOX	Three 0.190-in diameter holes down	0 [0]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]
100671029	3.38 [85.85]	1.37 [34.80]	2¾-in PAC-DS BOX	Three 0.190-in diameter holes down	0 [0]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]
100671031	3.5 [88.90]	1.37 [34.80]	2¾-in PAC-DS BOX	Three 0.190-in diameter holes down	0 [0]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]
Side Jet										
100673698	1.5 [38.10]	0.812 [20.62]	1-in AMMT-S BOX	Three rows of three radial holes 0.190-in diameter at 60° phase	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	31,790 [14,141]	318 [43.05]
100673699	1.688 [42.88]	0.812 [20.62]	1-in AMMT-S BOX	Three rows of three radial holes 0.190-in diameter at 60° phase	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	31,790 [14,141]	318 [43.05]
100673700	1.75 [44.45]	0.812 [20.62]	1-in AMMT-S BOX	Three rows of three radial holes 0.190-in diameter at 60° phase	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	31,790 [14,141]	318 [43.05]
100673701	2 [50.80]	1.03 [26.16]	1½-in AMMT-S BOX	Three rows of three radial holes ¼-in diameter 60° phase	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	63,772 [28,367]	829 [112.44]
100673702	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S BOX	Three rows of three radial holes ¼-in diameter 60° phase	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	63,772 [28,367]	829 [112.44]
100673703	2.375 [60.33]	1.03 [26.16]	1½-in AMMT-S BOX	Three rows of three radial holes ¼-in diameter 60° phase	0 [0]	9.5 [241.30]	Yes	10,000 [68,948]	63,772 [28,367]	829 [112.44]
100673704	2.875 [73.03]	1.37 [34.80]	2¾-in PAC-DS BOX	Three rows of three radial holes ¼-in diameter 60° phase	0 [0]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]
100673705	3.06 [77.72]	1.37 [34.80]	2¾-in PAC-DS BOX	Three rows of three radial holes ¼-in diameter 60° phase	0 [0]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]
100673706	3.38 [85.85]	1.37 [34.80]	2¾-in PAC-DS BOX	Three rows of three radial holes ¼-in diameter 60° phase	0 [0]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]
100673708	3.5 [88.90]	1.37 [34.80]	2¾-in PAC-DS BOX	Three rows of three radial holes	0 [0]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

**Specifications<sup>†‡</sup>**

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Nozzle Configuration	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
Ball Drop										
100674617	1.5 [38.10]	0.812 [20.62]	1-in AMMT-S BOX	Downhole for $\frac{7}{16}$ DB. Three rows of three radial holes 0.125-in diameter at 60° phase.	0.375 [9.53]	9.5 [241.30]	Yes	10,000 [68,948]	31,790 [14,141]	318 [43.05]
100674618	1.688 [42.88]	0.812 [20.62]	1-in AMMT-S BOX	Downhole for $\frac{7}{16}$ DB. Three rows of three radial holes 0.125-in diameter at 60° phase.	0.375 [9.53]	9.5 [241.30]	Yes	10,000 [68,948]	31,790 [14,141]	318 [43.05]
100674619	1.75 [44.45]	0.812 [20.62]	1-in AMMT-S BOX	Downhole for $\frac{7}{16}$ DB. Three rows of three radial holes 0.125-in diameter at 60° phase.	0.375 [9.53]	9.5 [241.30]	Yes	10,000 [68,948]	31,790 [14,141]	318 [43.05]
100674620	2 [50.80]	1.03 [26.16]	1½-in AMMT-S BOX	Downhole for $\frac{1}{2}$ DB. Three rows of three radial holes 0.190-in diameter at 60° phase.	0.437 [11.10]	9.5 [241.30]	Yes	10,000 [68,948]	63,772 [28,367]	829 [112.44]
100674621	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S BOX	Downhole for $\frac{1}{2}$ DB. Three rows of three radial holes 0.190-in diameter at 60° phase.	0.437 [11.10]	9.5 [241.30]	Yes	10,000 [68,948]	63,772 [28,367]	829 [112.44]
100674622	2.375 [60.33]	1.03 [26.16]	1½-in AMMT-S BOX	Downhole for $\frac{1}{2}$ DB. Three rows of three radial holes 0.190-in diameter at 60° phase.	0.437 [11.10]	9.5 [241.30]	Yes	10,000 [68,948]	63,772 [28,367]	829 [112.44]
100674623	2.875 [73.03]	1.37 [34.80]	2½-in PAC-DS BOX	Downhole for $\frac{5}{8}$ DB. Three rows of three radial holes 0.190-in diameter at 60° phase.	0.500 [12.70]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]
100674624	3.06 [77.72]	1.37 [34.80]	2½-in PAC-DS BOX	Downhole for $\frac{5}{8}$ DB. Three rows of three radial holes 0.190-in diameter at 60° phase.	0.500 [12.70]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]
100674625	3.38 [85.85]	1.37 [34.80]	2½-in PAC-DS BOX	Downhole for $\frac{5}{8}$ DB. Three rows of three radial holes 0.190-in diameter at 60° phase.	0.500 [12.70]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]
100674626	3.5 [88.90]	1.37 [34.80]	2½-in PAC-DS BOX	Downhole for $\frac{5}{8}$ DB. Three rows of three radial holes 0.190-in diameter at 60° phase.	0.500 [12.70]	10.5 [266.70]	Yes	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

**Specifications<sup>†‡</sup>**

Part Number	Flow Level	Strength Level	OD, in [mm]	ID, in [mm]	Upper Thread	Nozzle Configuration	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
Clean Out Nozzle												
100048575	LO-FLO	REG-STR	1.5 [38.10]	0.812 [20.62]	1-in AMMT-S BOX	Clean Out Nozzle 0 design	9.5 [0]	Yes [241.30]	10,000 [68,948]	31,790 [14,141]	318 [43.05]	
100048577	HI-FLO	REG-STR										
100048578	LO-FLO	HI-STR										
100048580	HI-FLO	HI-STR										
100044854	HI-FLO	REG-STR	1.688 [42.88]	0.812 [20.62]	1-in AMMT-S BOX	Clean Out Nozzle 0 design	9.5 [0]	Yes [241.30]	10,000 [68,948]	31,790 [14,141]	318 [43.05]	
100050201	LO-FLO	REG-STR										
100050205	LO-FLO	HI-EROS										
100050208	HI-FLO	HI-STR										
100042119	LO-FLO	HI-STR	1.75 [44.45]	0.812 [20.62]	1-in AMMT-S BOX	Clean Out Nozzle 0 design	9.5 [0]	Yes [241.30]	10,000 [68,948]	31,790 [14,141]	318 [43.05]	
100048581	HI-FLO	HI-STR										
100050202	LO-FLO	REG-STR										
100050206	HI-FLO	REG-STR										
100662407	HI-FLO	HI-STR	2 [50.80]	1.03 [26.16]	1½-in AMMT-S BOX	Clean Out Nozzle 0 design	9.5 [0]	Yes [241.30]	10,000 [68,948]	63,772 [28,367]	829 [112.44]	
100662405	HI-FLO	REG-STR										
100662406	LO-FLO	HI-STR										
100662404	LO-FLO	REG-STR										
100044859	LO-FLO	REG-STR	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S BOX	Clean Out Nozzle 0 design	9.5 [0]	Yes [241.30]	10,000 [68,948]	63,772 [28,367]	829 [112.44]	
100044860	HI-FLO	REG-STR										
100044861	LO-FLO	HI-STR										
100044862	HI-FLO	HI-STR										
100044865	LO-FLO	REG-STR	2.25 [57.15]	1 [25.40]	1½-in AMMT-S BOX	Clean Out Nozzle 0 design	9.5 [0]	Yes [241.30]	10,000 [68,948]	63,772 [28,367]	829 [112.44]	
100044866	HI-FLO	REG-STR										
100044867	LO-FLO	HI-STR										
100044868	HI-FLO	HI-STR										

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

## Specifications<sup>†‡</sup>

Part Number	Flow Level	Strength Level	OD, in [mm]	ID, in [mm]	Upper Thread	Nozzle Configuration	Will-Pass Ball Size, in [mm]	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
Clean Out Nozzle												
100662412	HI-FLO	HI-STR	2.375 [60.33]	1.03 [26.16]	1½-in AMMT-S BOX	Clean Out Nozzle 0 design	9.5 [0]	Yes [241.30]	10,000 [68,948]	63,772 [28,367]	829 [112.44]	
100662409	HI-FLO	REG-STR										
100662410	LO-FLO	HI-STR										
100662408	LO-FLO	REG-STR										
100182945	HI-FLO	HI-STR	2.875 [73.03]	1.37 [34.80]	2⅓-in PAC-DSI BOX	Clean Out Nozzle 0 design	10.5 [0]	Yes [266.70]	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]	
100583801	HI-FLO	REG-STR										
100189876	LO-FLO	HI-STR										
100662413	LO-FLO	REG-STR										
100662421	HI-FLO	HI-STR	3.06 [77.72]	1.37 [34.80]	2⅓-in PAC-DSI BOX	Clean Out Nozzle 0 design	10.5 [0]	Yes [266.70]	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]	
100662422	HI-FLO	REG-STR										
100662424	LO-FLO	HI-STR										
100662425	LO-FLO	REG-STR										
100662426	HI-FLO	HI-STR	3.38 [85.85]	1.37 [34.80]	2⅓-in PAC-DSI BOX	Clean Out Nozzle 0 design	10.5 [0]	Yes [266.70]	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]	
100662428	HI-FLO	REG-STR										
100662429	LO-FLO	HI-STR										
100662430	LO-FLO	REG-STR										
100044874	HI-FLO	HI-STR	3.5 [88.90]	1.37 [34.80]	2⅓-in PAC-DSI BOX	Clean Out Nozzle 0 design	10.5 [0]	Yes [266.70]	10,000 [68,948]	122,313 [54,407]	1,712 [232.10]	
100662416	HI-FLO	REG-STR										
100044873	LO-FLO	HI-STR										
100662418	LO-FLO	REG-STR										

<sup>†</sup> Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup> At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Back-Pressure Valve

Maintains CT fluid column in low-bottomhole-pressure wells

## APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Sweet and sour service ( $H_2S$ ) per NACE
- Controlled fluid displacement in low-bottomhole-pressure wells

## ADVANTAGES

- Reliability in low-bottomhole-pressure conditions
- Transmission of pressure signals
- Prevention of U-tubing effect
- Compatibility with Discovery MLT\* multilateral tool (Type 1)
- Compatibility with CoilFLATE\* coiled tubing through-tubing inflatable packer (Type 2)
- Adjustable setting pressure to conform to overbalance conditions
- Capability to stop flow of fluid through the CT and maintain a full column of fluid above the tool string when closed
- Capability to withstand extended periods of use and perform multiple open and closed cycles
- Compatibility with nitrogen, nitrified fluids, acid, and cement
- Integrated vent port for safer pressure release

The back-pressure valve's (BPV) primary function is to maintain the fluid column in the CT string in low-bottomhole-pressure well environments. Without the control of fluid flow that a BPV provides, critical operation processes are more at risk of failure.

Low-bottomhole-pressure wells present extreme difficulties in gaining control of hydrostatic pressure balances while performing well stimulation or packer work. Manipulating well pressure or fluid levels to prevent tubing fluids from U-tubing into the annulus is often impossible. To help the operator better control these conditions, the BPV was designed to support a hydrostatic head above. The setting pressure is adjustable to support the amount of hydrostatic overbalance or pressure differential conditions of the well.

Two types of BPVs are available.

- Type 1 (Part No. 100212160) references the annulus and is adjustable from 0 to 3,500 psi. It is designed for use with the Discovery MLT tool.
- Type 2 (Part No. 100548162) has a reference point below the valve and is adjustable from 0 to 3,800 psi. It is designed for use with the CoilFLATE packer.



Back-pressure valve.

## Specifications

Part No.	OD, in [mm]	Upper Thread	Lower Thread	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]	Min. BHP, psi [kPa]	Max. Crack Pressure, psi [kPa]	Max. Flow Rate, bbl/min [L/min]
100212160	2.125 [53.98]	1.812-in DS Box	1.812-in DS Pin	44 [1,117.60]	Yes	12,000 [82,737]	50,000 [22,241]	600 [81.34]	500 [3,447]	3,500 [24,132]	2 [318]
100548162	2.125 [53.98]	1.812-in DS Box	1.812-in DS Pin	36 [914.40]	Yes	10,000 [68,948]	50,000 [22,241]	600 [81.34]	na <sup>†</sup>	3,800 [26,200]	2 [318]

Values are based on 80,000 lbf/in<sup>2</sup> strength steel at 70 degF [21 degC] and a single-load case. At temperatures above 250 degF [121 degC], ratings are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine the actual operating and load parameters for their own applications.

<sup>†</sup> Not applicable.

# Hydraulic GS Retrieval Tool

Latches to and retrieves downhole tools with long reach

## APPLICATIONS

- Standard coiled tubing interventions in oil, gas, and injector wells
- Standard HPHT operations
- Sweet and sour service ( $H_2S$ ) per NACE
- High-impact and jarring operations

## ADVANTAGES

- Industry-standard design
- Sealed and pressure-activated for hydraulic operations
- Adjustable nozzle configuration
- Ball drop to ensure and confirm retraction of the dogs
- High-tensile strength ratings
- Collet dog design to minimize assembly issues
- Lower sealing

The hydraulic GS retrieval tool is designed to latch into internal fishing necks machined in various CoilTOOLS\* coiled tubing intervention tools and solutions components. For years, an industry standard internal GS fishing neck profile has been machined into the retrieved portions of disconnects. Now, in addition to GS profiles with a standard depth, the tool offers GS profiles with a long reach, which can also be used in the standard shorterreach profile.

In standard operations, the GS retrieval tool can be lowered into the component with the GS profile, and it will latch into the recess of the profile. Applying tension will transmit load to the tool string. The GS tool can be released from the fish by circulating to cause enough pressure drop to collapse the spring and retract the dogs.



Hydraulic GS retrieval tool.

## Specifications

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]
100647365	1.69 [42.93]	0.38 [9.65]	1-in AMMT-S Box	2-in GS	0.313 [7.95]	13.56 [344.42]	Yes	10,000 [68,948]	31,169 [13,865]
100460830	2.25 [57.15]	0.44 [11.18]	1½-in AMMT-S Box	2½-in GS	0.38 [9.53]	13.62 [345.95]	Yes	10,000 [68,948]	63,772 [28,367]
100474497	2.75 [69.85]	0.44 [11.18]	2½-in PAC-DSI Box	3½-in GS	0.38 [9.65]	13.34 [338.84]	Yes	10,000 [68,948]	122,313 [54,407]
100643646	3.06 [77.72]	0.44 [11.18]	2½-in API Reg Box	3½-in GS	0.38 [9.65]	15.34 [389.64]	Yes	10,000 [68,948]	153,401 [68,236]
100645015	3.63 [92.20]	0.44 [11.18]	2½-in API Reg Box	4-in GS	0.38 [9.65]	17.34 [440.44]	Yes	10,000 [68,948]	208,611 [92,794]

Values are based on 80,000 lbf/in<sup>2</sup> strength steel at 70 degF [21 degC] and a single-load case. At temperatures above 250 degF [121 degC], ratings are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine the actual operating and load parameters for their own applications.

# Shorty MHA

## Compact CT motorhead assembly

### APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Standard HPHT operations
- Sweet and sour service ( $H_2S$ ) per NACE

### ADVANTAGES

- Selectable shear rating
- Standard double-flapper check valves (DFCV)
- Collet design to minimize accidental release
- Sealed and pressure-balanced for hydraulic operations
- Adjustable ball seat ID
- High torque loads
- High tensile strength ratings
- Internal fishing neck for easy washing and reentry
- Lower sealing bore for resealing with heavy-duty retrieval tool or locator seal assemblies

Design enhancements to this next generation of CT MHA include

- shorter assembly time
- improved check-valve design
- improved circulation-valve design
- incorporation of the Mark V hydraulic disconnect design features.

The DFCV provides full-opening flapper check valves with metal-to-metal seals and elastomer backups.

Hydraulic disconnect splines allow torque transmission through the tool. When hydraulically operated by circulating a ball to the seat, this subassembly enables disconnection from the tools below and retrieval of the tools above.

The lower part of the disconnect bottom sub has an integral dual circulating valve with large ports for unrestricted flow. These ports are isolated by a pressure-operated piston that can be activated by circulating a ball onto it or by creating a differential pressure across the ball seat.



*Shorty MHA.*

### Specifications

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]
100297871	1.688 [42.88]	0.7 [17.78]	1-in AMMT-S Box	1-in AMMT-S Pin	0.688 [17.48]	25.8 [655.32]	Yes	10,000 [68,948]	26,667 [11,862]
100318288	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S Box	1½-in AMMT-S Pin	1.0 [25.40]	27.3 [639.42]	Yes	10,000 [68,948]	39,167 [17,422]
100312135	2.875 [73.03]	1.38 [35.05]	2½-in PAC-DSI Box	2½-in PAC-DSI Pin	1.25 [31.75]	32.1 [815.34]	Yes	10,000 [68,948]	50,833 [22,612]

Values are based on 80,000 lbf/in<sup>2</sup> strength steel at 70 degF [21 degC] and a single-load case. At temperatures above 250 degF [121 degC], ratings are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine the actual operating and load parameters for their own applications.

# Pull Plate and Pressure Test Sub

Measures and pull tests CT tool connectors, disconnects, or MHAs

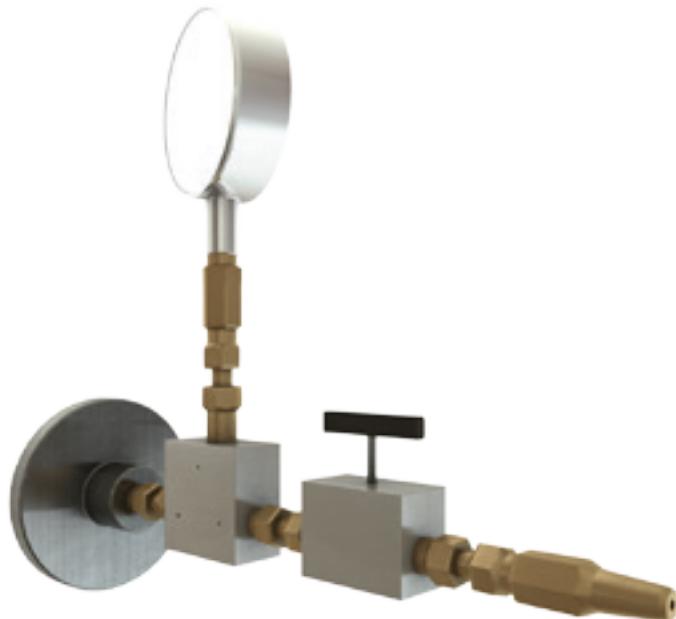
## APPLICATIONS

- Pressure and pull testing of coiled tubing (CT) BHAs

## ADVANTAGES

- Rust-resistant materials
- Pressure connections rated to 10,000 psi
- Premium materials
- Autoclave high-pressure connections

Available in several different box threads that can be made up directly to the BHA, the sub then adapts to a medium-pressure autoclave box.



*Pull plate and pressure test sub.*

## Specifications

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Makeup Length, in [mm]	Working Pressure, psi [kPa]	Tensile strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100598791	6 [152.40]	0.359 [9.12]	1-in AMMT-S Box	5/16-in AE Box	21.64 [549.66]	10,000 [68,948]	23,843 [10,606]	453 [61.42]
100599044	6 [152.40]	0.359 [9.12]	1 1/2-in AMMT-S Box	5/16-in AE Box	21.64 [549.66]	10,000 [68,948]	47,829 [21,275]	1,176 [159.44]
100599050	6 [152.40]	0.359 [9.12]	2 3/8-in PAC-DSI Box	5/16-in AE Box	21.64 [549.66]	10,000 [68,948]	93,609 [41,639]	3,016 [408.91]
100599045	6 [152.40]	0.359 [9.12]	1.50-in DS Box	5/16-in AE Box	21.64 [549.66]	10,000 [68,948]	16,276 [7,240]	297 [402.68]
100599048	6 [152.40]	0.359 [9.12]	1.812-in DS Box	5/16-in AE Box	21.64 [549.66]	10,000 [68,948]	39,172 [17,424]	866 [117.41]
100599104	6 [152.40]	0.359 [9.12]	2.062-in DS Box	5/16-in AE Box	21.64 [549.66]	10,000 [68,948]	57,936 [25,771]	1,672 [226.69]

Values are based on 80,000 lbf/in<sup>2</sup> strength steel at 70 degF [21 degC] and a single-load case. At temperatures above 250 degF [121 degC], ratings are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine the actual operating and load parameters for their own applications.

# Straight Bars

Extends BHA length

## APPLICATIONS

- Standard coiled tubing (CT) interventions
- Standard HPHT operations
- Sweet and sour wells per NACE

## ADVANTAGES

- Easy to handle
- Rugged
- Positive sealing through O-ring
- Premium materials
- Standard oilfield tool joint threads
- Standard lengths
- 350 degF [177 degC] temperature rating

Straight bars are available in standard BHA sizes of 1<sup>1</sup>/<sub>16</sub> in, 2<sup>1</sup>/<sub>2</sub> in, and 2<sup>5</sup>/<sub>8</sub> in, as well as in standard CT sizes for slimline operations.



*Straight bars.*

## Specifications

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100596085	1.50 [38.10]	0.812 [20.62]	1-in AMMT-S Box	1-in AMMT-S Pin	0.75 [19.05]	36 [914.40]	Yes	10,000 [68,948]	31,790 [14,141]	318 [43.11]
100589533	1.688 [42.88]	0.812 [20.62]	1-in AMMT-S Box	1-in AMMT-S Pin	0.75 [19.05]	36 [914.40]	Yes	10,000 [68,948]	31,790 [14,141]	374 [50.71]
100596074	1.75 [44.45]	0.812 [20.62]	1-in AMMT-S Box	1-in AMMT-S Pin	0.75 [19.05]	36 [914.40]	Yes	10,000 [68,948]	31,790 [14,141]	378 [51.25]
100596075	2.00 [50.80]	1.03 [26.16]	1½-in AMMT-S Box	1½-in AMMT-S Pin	1.00 [25.4]	48 [1219.20]	Yes	10,000 [68,948]	63,772 [28,367]	829 [112.40]
100598666	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S Box	1½-in AMMT-S Pin	1.00 [25.4]	48 [1,219.20]	Yes	10,000 [68,948]	63,772 [28,367]	1,237 [167.72]
100596667	2.375 [60.33]	1.03 [26.16]	1½-in AMMT-S Box	1½-in AMMT-S Pin	1.00 [25.4]	48 [1,219.20]	Yes	10,000 [68,948]	63,772 [28,367]	1,237 [167.72]
100183294	2.875 [73.03]	1.38 [35.05]	2¾-in PAC-DSI Box	2¾-in PAC-DSI Pin	1.25 [31.75]	48 [1,219.20]	Yes	10,000 [68,948]	122,313 [54,407]	2,745 [372.17]

Values are based on 80,000 lbf/in<sup>2</sup> strength steel at 70 degF [21 degC] and a single-load case. At temperatures above 250 degF [121 degC], ratings are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine the actual operating parameters for their own applications.

# Bull Nose

## Easily enter wellbore ID interruptions

### ADVANTAGES

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Sweet and sour services according to NACE standards

### FEATURES

- Fully round end of the tool
- Standard tool joint threads
- Extra body length to allow holes to be added in the field
- ODs to match those of standard BHAs

Bull noses come in standard tool joint thread configurations and can be modified on location to best fit the application for which they are being used. They also have a full round nose for easy entry and passage of wellbore ID interruptions.



*Bull nose.*

### Specifications<sup>†‡</sup>

Part Number	OD, in [mm]	Upper Thread	Makeup Length, in [mm]	Sweet and Sour Services	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100178721	1.69 [42.88]	1-in AMMT-S Box	3.5 [88.90]	Yes	10,000 [68,948]	30,957 [13,770]	318 [36.04]
100709937	2.13 [53.98]	1.5-in AMMT-S Box	5 [127.00]	Yes	10,000 [68,948]	63,772 [28,367]	829 [94.11]
100259884	2.88 [73.03]	2.375-in PAC-DSI Box	5 [127.00]	Yes	10,000 [68,948]	141,195 [62,806]	2,009 [228.04]

<sup>†</sup>Values are based on 80,000-psi [551,600-kPa]-strength steel at 70 degF [39 degC] and a single load case.

<sup>‡</sup>At temperatures above 250 degF [140 degC], all ratings for the tool are reduced by 7%; at 350 degF [196 degC], ratings are reduced by 12%. Users should determine their application's actual operating and load parameters.

# Mark V Disconnect

## Releases CT with surface control

### APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Standard HPHT operations
- Sweet and sour service ( $H_2S$ ) per NACE

### ADVANTAGES

- Selectable shear rating
- Standard double-flapper check valves used in retrievable plug applications
- Collet design to minimize accidental release
- Seal and pressure balance design for hydraulic operations
- Adjustable ball seat ID
- High torque load transmissions
- High tensile strength ratings
- Internal fishing neck for easy washing and reentry
- Lower sealing bore for resealing with heavy-duty retrieval tool or locator seal assemblies

The ball-and-seat-operated disconnect with splined torque lugs was specifically designed for use with bottomhole assemblies requiring torque transmittal. Advanced design features include

- reduced clearance between the upper and lower halves to better withstand both axial- and side-thrust loads
- increased strength in the load-carrying portions of the tool
- exposure of large circulating ports after shifting of the locking sleeve.

In standard operations, the seat and sleeve are pressure balanced, making the disconnect insensitive to the tubing-to-annulus pressure differential. To disconnect, a trip ball is dropped or pumped down the CT and seated in the disconnect tool. Pressure is then applied to the CT and the shear screws holding the seat and sleeve shear, shifting the seat and sleeve downward and uncovering the collet. The pressure release value varies from 250 psi [1,723.7 kPa] to 7,000 psi [48,263 kPa] as a result of the number and type of shear screws holding the seat and sleeve. Straight pick-up then separates the two halves of the disconnect to enable retrieving the CT.

The lower half of the disconnect tool has an internal fishing neck profile and is compatible with the Mark IIIA hydraulic release retrieval tool and the hydraulic GS release retrieval tool.



*Mark V disconnect.*

### Specifications

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100283002	1.699 [42.88]	0.812 [20.62]	1-in AMMT-S Box	1-in AMMT-S Pin	0.75 [19.05]	21.08 [535.43]	Yes	10,000 [68,948]	21,417 [9,527]	542 [73.49]
100312172	2.125 [53.98]	1.03 [26.16]	1½-in AMMT-S Box	1½-in AMMT-S Pin	1.0 [25.40]	20.7 [525.78]	Yes	10,000 [68,948]	30,000 [13,345]	1,208 [163.78]
100312170	2.125 [53.98]	1.03 [26.16]	1.812-in DS Box	1.812-in DS Pin	1.0 [25.40]	19.73 [501.14]	Yes	10,000 [68,948]	30,000 [13,345]	693 [93.96]
100250647	2.875 [73.03]	1.38 [35.05]	2³/₈-in PAC-DIS Box	2³/₈-in PAC-DIS Pin	1.0 [25.40]	20.7 [525.78]	Yes	10,000 [68,948]	51,667 [22,982]	2,250 [305.06]

Values are based on 80,000 lbf/in<sup>2</sup> strength steel at 70 degF [21 degC] and a single-load case. At temperatures above 250 degF [121 degC], ratings are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine the actual operating and load parameters for their own applications.

# Pressure-Balanced Mechanical Disconnect

Withstands high circulation pressures without affecting shear rating

## APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Standard HPHT operations
- Sweet and sour service ( $H_2S$ ) per NACE
- Bullplugged CT
- Packers and bridge plugs

## ADVANTAGES

- Selectable shear rating
- Compatible with standard double-flapper check valves in bridge plug applications
- Seal and pressure-balance design for hydraulic operations
- Internal fishing neck for easy washing and reentry
- No effect of internal pressure differential on overpull related to disconnect

This next generation of mechanical disconnect tools includes enhancements such as true next generation pressure balance to allow high circulation pressures within the toolstring without affecting the shear rating, as well as multioperational compatibility for flexibility within existing inventory.

To disconnect, upstrain is applied to shear the screws and separate the upper half from the lower half. The shear release value varies as a result of the number and the material of the screws that are installed.

The guidelines for differentials provide information about applications with a higher annulus pressure than internal disconnect pressure.

The pressure-balanced mechanical disconnect uses a GS-type fishing neck and can be fished with a standard or long-reach hydraulic GS fishing tool.



*Pressure-balanced mechanical disconnect.*

## Specifications

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]
100327703	2.125 [53.98]	0.76 [19.30]	1.812-in DS Box	1.812-in DS Pin	0.75 [19.05]	20 [508.00]	Yes	10,000 [68,948]	33,333 [14,827]
100312163	2.125 [53.98]	0.76 [19.30]	1.812-in DS Box	1.812-in DS Pin	0.75 [19.05]	36.43 [925.32]	Yes	10,000 [68,948]	33,333 [14,827]
100553829	2.125 [53.98]	0.76 [19.30]	1½-in AMMT-S Box	1½-in AMMT-S Pin	0.75 [19.05]	20.85 [529.59]	Yes	10,000 [68,948]	33,333 [14,827]
100447952	3.06 [77.72]	1.25 [31.75]	2½-in PAC-DIS Box	2½-in PAC-DIS Pin	1.0 [25.4]	19.43 [492.52]	Yes	10,000 [68,948]	126,000 [560,475]

Values are based on 80,000 lbf/in<sup>2</sup> strength steel at 70 degF [21 degC] and a single-load case. At temperatures above 250 degF [121 degC], ratings are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine the actual operating and load parameters for their own applications.

# Torque Quick Connect

Rapidly make-and-break connections

## APPLICATIONS

- Standard coiled tubing (CT) interventions in oil, gas, and injector wells
- Standard HPHT operations
- Sweet and sour services per NACE
- Tool deployment

## ADVANTAGES

- Torque-through capabilities
- Simple, rapid make-and-break operation
- Rugged construction
- Pressure bleed point to ensure absence of trapped pressure before connection is broken
- Steep guide angle for easy makeup
- Additional guide blocks available to ease makeup
- Fullbore

The quick connect has a bottom sub that connects to the lower tool string and a top sub that connects to the upper tool string/CT. The top sub has a nonrotating feature and housing that connects it to the bottom sub, allowing both torque and tensile loads to be transmitted through the tool. The tool length is less than 2 ft so that it can connect the CT to a long work string when the work window is only a few feet.



*Torque quick connect.*

## Specifications

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
100312186	2.125 [53.98]	0.89 [22.61]	1.812-in DS Box	1.812-in DS Pin	0.75 [19.05]	18.6 [472.44]	Yes	10,000 [68,948]	52,229 [23,233]	642 [87.04]
100472207	2.125 [53.98]	0.89 [22.61]	1½-in AMMT-S Box	1½-in AMMT-S Pin	0.75 [19.05]	19.4 [492.76]	Yes	10,000 [68,948]	54,182 [24,101]	642 [87.04]
100478025	2.875 [73.03]	1.28 [32.51]	2½-in PAC-DSI Box	2½-in PAC-DSI Pin	1.25 [31.75]	21.1 [535.94]	Yes	10,000 [68,948]	79,976 [35,575]	1,342 [181.68]

Values are based on 80,000 lbf/in<sup>2</sup> strength steel at 70 degF [21 degC] and a single-load case. At temperatures above 250 degF [121 degC], ratings are reduced by 7%; at 350 degF [177 degC], ratings are reduced by 12%. Users should determine the actual operating and load parameters for their own applications.

# X-OVER

Available in a variety of connection types, sizes, and ODs

## APPLICATIONS

- Standard coiled tubing interventions
- HPHT operations
- Sweet and sour wells per NACE

## ADVANTAGES

- Standard lengths
- Premium materials
- Standard oilfield tool joint threads
- 350 degF [177 degC] temperature rating

The standard makeup length for a box-by-pin X-over is 6 in, and the standard makeup length for a box-by-box X-over is 8 in. The ID of all X-overs is the same as the smallest thread on the part.



*X-over.*

## Specifications

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
1-in AMMT-S Box										
100598123	1.50 [38.10]	0.687 [17.45]	1-in AMMT-S Box	¾-in CS Hydril Pin	0.625 [15.88]	6.0 [152.40]	Yes	10,000 [68,948]	22,500 [10,008]	417 [56.53]
100598141	1.69 [42.93]	0.812 [20.62]	1-in AMMT-S Box	1.50-in DS Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	21,702 [9,653]	396 [53.69]
100598167	1.69 [42.93]	0.812 [20.62]	1-in AMMT-S Box	1-in CS Hydril Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	374 [50.70]
100598277	1.69 [42.93]	0.812 [20.62]	1-in AMMT-S Box	1-in AMMT-S Box	0.75 [19.05]	8.0 [203.20]	Yes	10,000 [68,948]	31,790 [14,141]	374 [50.70]
100598574	1.75 [44.45]	0.812 [20.62]	1-in AMMT-S Box	1.50-in DS Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	21,702 [9,653]	396 [53.69]
100598599	1.75 [44.45]	0.812 [20.62]	1-in AMMT-S Box	1-in CS Hydril Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]
100598612	2.13 [54.10]	0.812 [20.62]	1-in AMMT-S Box	1.812-in DS Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]
100598671	2.13 [54.10]	0.812 [20.62]	1-in AMMT-S Box	1½-in AMMT-S Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]

**Specifications**

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
1½-in AMMT-S Box										
100599018	2.0 [50.80]	0.812 [20.62]	1½-in AMMT-S Box	1-in AMMT-S Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]
100599016	2.0 [50.80]	0.937 [23.80]	1½-in AMMT-S Box	1.50-in DS Pin	0.875 [22.23]	6.0 [152.40]	Yes	10,000 [68,948]	21,702 [9,653]	396 [53.69]
100599038	2.0 [50.80]	1.03 [26.16]	1½-in AMMT-S Box	1¼-in CS Hydril Pin	1.0 [25.4]	6.0 [152.40]	Yes	10,000 [68,948]	58,788 [26,150]	1,568 [212.59]
100599087	2.13 [54.10]	0.812 [20.62]	1½-in AMMT-S Box	1-in AMMT-S Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]
100599091	2.13 [54.10]	1.03 [26.16]	1½-in AMMT-S Box	1.812-in DS Pin	1.0 [25.4]	6.0 [152.40]	Yes	10,000 [68,948]	52,229 [23,233]	1,154 [156.46]
100599064	2.13 [54.10]	1.03 [26.16]	1½-in AMMT-S Box	1¼-in CS Hydril Pin	1.0 [25.4]	6.0 [152.40]	Yes	10,000 [68,948]	58,788 [26,150]	1,568 [212.59]
100599084	2.13 [54.10]	1.03 [26.16]	1½-in AMMT-S Box	1½-in AMMT-S Box	1.0 [25.4]	8.0 203.20	Yes	10,000 [68,948]	63,772 [28,367]	1,568 [212.59]
100599109	2.88 [73.15]	1.03 [26.16]	1½-in AMMT-S Box	2¾-in PAC-DSI Pin	1.0 [25.4]	6.0 [152.40]	Yes	10,000 [68,948]	63,772 [28,367]	1,568 [212.59]
2¾-in PAC-DSI Box										
100599148	2.88 [73.15]	1.03 [26.16]	2¾-in PAC-DSI Box	1½-in AMMT-S Pin	1.0 [25.4]	6.0 [152.40]	Yes	10,000 [68,948]	63,772 [28,367]	1,568 [212.59]
100599282	2.88 [73.15]	0.812 [20.62]	2¾-in PAC-DSI Box	1-in AMMT-S Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]
100599543	2.88 [73.15]	1.25 [31.75]	2¾-in PAC-DSI Box	1.812-in DS Pin	1.125 [28.58]	6.0 [152.40]	Yes	10,000 [68,948]	52,229 [23,233]	1,154 [156.46]
100599545	2.88 [73.15]	1.38 [35.05]	2¾-in PAC-DSI Box	2.06-in DS Pin	1.25 [31.75]	6.0 [152.40]	Yes	10,000 [68,948]	77,248 [34,362]	2,229 [302.21]
100599556	2.88 [73.15]	1.38 [35.05]	2¾-in PAC-DSI Box	2¾-in PAC-DSI Box	1.25 [31.75]	8.0 [203.20]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [545.17]
100599558	3.06 [77.72]	1.38 [35.05]	2¾-in PAC-DSI Box	2¾-in API REG Pin	1.25 [31.75]	6.0 [152.40]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [545.17]
100599560	3.13 [79.50]	1.38 [35.05]	2¾-in PAC-DSI Box	2¾-in API REG Pin	1.25 [31.75]	6.0 [152.40]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [545.17]
100644698	3.13 [79.50]	1.0 [25.40]	2¾-in API REG Box	2¾-in PAC-DSI Pin	1.25 [31.75]	6.0 [152.40]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [545.17]
100644712	3.13 [79.50]	1.0 [25.40]	2¾-in API REG Box	2¾-in PAC-DSI Box	1.25 [31.75]	9.0 [228.60]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [545.17]
1.50-in DS Box										
100600837	1.69 [42.93]	0.812 [20.62]	1.50-in DS Box	1-in AMMT-S Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	21,702 [9,653]	396 [53.69]
100600841	2.13 [54.10]	0.937 [23.80]	1.50-in DS Box	1½-in AMMT-S Pin	0.875 [22.23]	6.0 [152.40]	Yes	10,000 [68,948]	21,702 [9,653]	396 [53.69]
100600843	2.13 [54.10]	0.937 [23.80]	1.50-in DS Box	1.812-in DS Pin	0.875 [22.23]	6.0 [152.40]	Yes	10,000 [68,948]	21,702 [9,653]	396 [53.69]

## Specifications

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
1.812-in DS Box										
100600844	2.13 [54.10]	0.812 [20.62]	1.812-in DS Box	1-in AMMT-S Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]
100600845	2.13 [54.10]	1.03 [26.16]	1.812-in DS Box	1½-in AMMT-S Pin	1.0 [25.4]	6.0 [152.40]	Yes	10,000 [68,948]	52,229 [23,233]	1,154 [131.00]
100578996	2.13 [54.10]	1.03 [26.16]	1.812-in DS Box	1½-in AMMT-S Box	1.0 [25.4]	8.0 [203.20]	Yes	10,000 [68,948]	52,229 [23,233]	1,154 [131.00]
100600980	2.88 [73.15]	1.25 [31.75]	1.812-in DS Box	2¾-in PAC-DSI Pin	1.125 [28.58]	6.0 [152.40]	Yes	10,000 [68,948]	52,229 [23,233]	1,154 [131.00]
100600981	2.13 [54.10]	0.937 [23.80]	1.812-in DS Box	1.50-in DS Pin	0.875 [22.23]	6.0 [152.40]	Yes	10,000 [68,948]	21,702 [9,653]	396 [53.69]
2.062-in DS Box										
100600982	2.88 [73.15]	1.5 [38.10]	2.06-in DS Box	2½-in PAC-DSI Pin	1.25 [31.75]	6.0 [152.40]	Yes	10,000 [68,948]	77,248 [34,362]	2,229 [253.01]
CS Hydril Box										
100601490	1.5 [38.10]	0.687 [17.45]	¾-in CS HYDRIL Box	1-in AMMT-S Pin	0.625 [15.875]	6.0 [152.40]	Yes	10,000 [68,948]	22,500 [10,008]	417 [56.54]
100601491	1.69 [42.93]	0.812 [20.62]	1-in CS HYDRIL Box	1-in AMMT-S Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]
100601495	1.75 [44.45]	0.812 [20.62]	1-in CS HYDRIL Box	1-in AMMT-S Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]
100601497	2.0 [50.80]	1.03 [26.16]	1¼-in CS HYDRIL Box	1½-in AMMT-S Pin	1.0 [25.4]	6.0 [152.40]	Yes	10,000 [68,948]	58,788 [26,150]	1,568 [212.59]
100601500	2.13 [54.10]	1.03 [26.16]	1¼-in CS HYDRIL Box	1½-in AMMT-S Pin	1.0 [25.4]	6.0 [152.40]	Yes	10,000 [68,948]	58,788 [26,150]	1,568 [212.59]
Treating Adapters										
100198958	3.06 [77.72]	0.812 [20.62]	2.0 WECO Female	1-in AMMT-S Box	0.75 [19.05]	8.0 [203.20]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]
100318276	3.06 [77.72]	0.812 [20.62]	2.0 WECO Female	1-in AMMT-S Pin	0.75 [19.05]	6.0 [152.40]	Yes	10,000 [68,948]	31,790 [14,141]	604 [81.89]
100602206	3.06 [77.72]	1.03 [26.16]	2.0 WECO Female	1½-in AMMT-S Box	1.0 [25.4]	8.0 [203.20]	Yes	10,000 [68,948]	63,772 [28,367]	1,568 [212.59]
100318278	3.06 [77.72]	1.03 [26.16]	2.0 WECO Female	1½-in AMMT-S Pin	1.0 [25.4]	6.0 [152.40]	Yes	10,000 [68,948]	63,772 [28,367]	1,568 [212.59]
100198415	3.06 [77.72]	1.375 [34.93]	2.0 WECO Female	2¾-in PAC-DSI Box	1.25 [31.75]	8.0 [203.20]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [545.17]
100124657	3.06 [77.72]	1.38 [35.05]	2.0 WECO Female	2¾-in PAC-DSI Pin	1.25 [31.75]	6.0 [152.40]	Yes	10,000 [68,948]	122,313 [54,407]	4,021 [545.17]
100318247	3.06 [77.72]	0.937 [23.80]	2.0 WECO Female	1.50-in DS Box	0.875 [22.225]	8.0 [203.20]	Yes	10,000 [68,948]	21,702 [9,653]	396 [53.69]
100318275	3.06 [77.72]	0.937 [23.80]	2.0 WECO Female	1.50-in DS Pin	0.875 [22.225]	6.0 [152.40]	Yes	10,000 [68,948]	21,702 [9,653]	396 [53.69]

**Specifications**

Part Number	OD, in [mm]	ID, in [mm]	Upper Thread	Lower Thread	Will Pass Ball Size, in [mm]	Makeup Length, in [mm]	Service NACE	Working Pressure, psi [kPa]	Tensile Strength, lbf [daN]	Torque Capacity, ft.lbf [daN.m]
Treating Adapters										
100173174	3.06 [77.72]	1.25 [31.75]	2.0 WECO Female	1.812-in DS Box	1.125 [28.575]	8.0 [203.20]	Yes	10,000 [68,948]	52,229 [23,233]	1,154 [131.00]
100602207	3.06 [77.72]	1.25 [31.75]	2.0 WECO Female	1.812-in DS Pin	1.125 [28.575]	6.0 [152.40]	Yes	10,000 [68,948]	52,229 [23,233]	1,154 [131.00]
100602208	3.06 [77.72]	1.38 [35.05]	2.0 WECO Female	2.062-in DS Box	1.25 [31.75]	8.0 [203.20]	Yes	10,000 [68,948]	77,248 [34,362]	2,229 [253.01]
100602209	3.06 [77.72]	1.38 [35.05]	2.0 WECO Female	2.062-in DS Pin	1.25 [31.75]	6.0 [152.40]	Yes	10,000 [68,948]	77,248 [34,362]	2,229 [253.01]

Values are based on 80,000 lbf/in<sup>2</sup> strength steel at 70 degF [21 degC] and a single-load case. At temperatures above 250 degF [121 degC], ratings are reduced by 10%; at 350 degF [177 degC], ratings are reduced by 20%. Users should determine the actual operating and load parameters for their own applications.

**Schlumberger**

# **Matrix**

**Schlumberger**

# **Stimulation and Conformance**

# MaxCO<sub>3</sub> Acid

## Degradable diversion acid system

### APPLICATIONS

- Reservoirs with high permeability contrasts and/or natural fractures
- Bottomhole temperatures between 175 and 250 degF [79 and 121 degC]
- Carbonate oil or gas wells
- Open hole or cased hole intervals, regardless of deviation

### ADVANTAGES

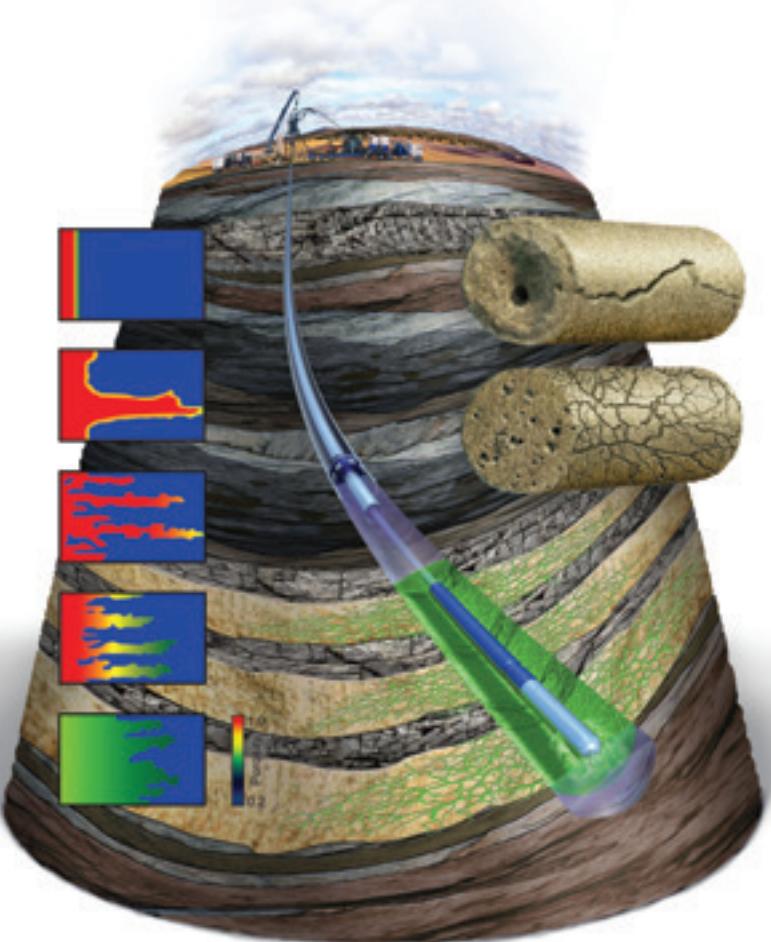
- Degrades completely, eliminating risk of costly cleanout interventions
- Targets permeability contrasts, allowing superior zonal coverage
- Effectively controls leakoff
- Requires lower treatment volumes and less well cleanup time

### FEATURES

- Diverts effectively at low treatment rates
- Continues to stimulate as it degrades
- Can be bullheaded or pumped through CT
- Can be pumped with most common acid stimulation systems
- Can be batch mixed for small volume jobs or mixed on the fly for larger treatments

### Diversion in challenging reservoirs

Stimulating high-permeability-contrast and naturally fractured reservoirs is challenging. Effective diversion is required during treatment to ensure that the largest possible surface area of the reservoir is contacted and exposed to stimulation fluids. The diversion, however, must be temporary and nondamaging to the reservoir or the natural fracture network. To meet this challenge, Schlumberger developed the innovative MaxCO<sub>3</sub> Acid\* degradable diversion acid system.



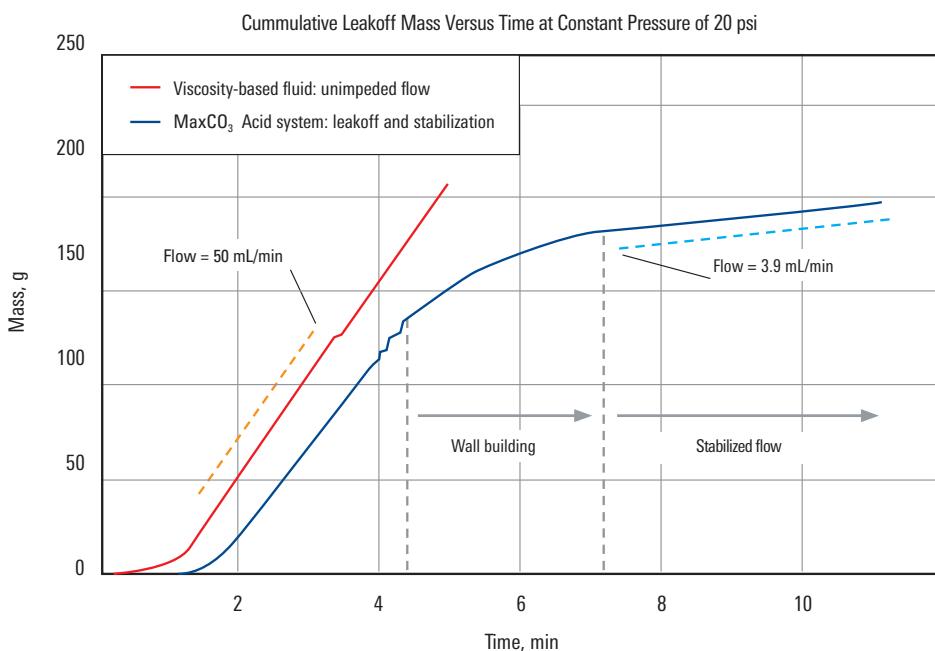
*MaxCO<sub>3</sub> Acid system diverts fluid from thief zones without reducing production from natural fractures.*

## A degradable diversion system

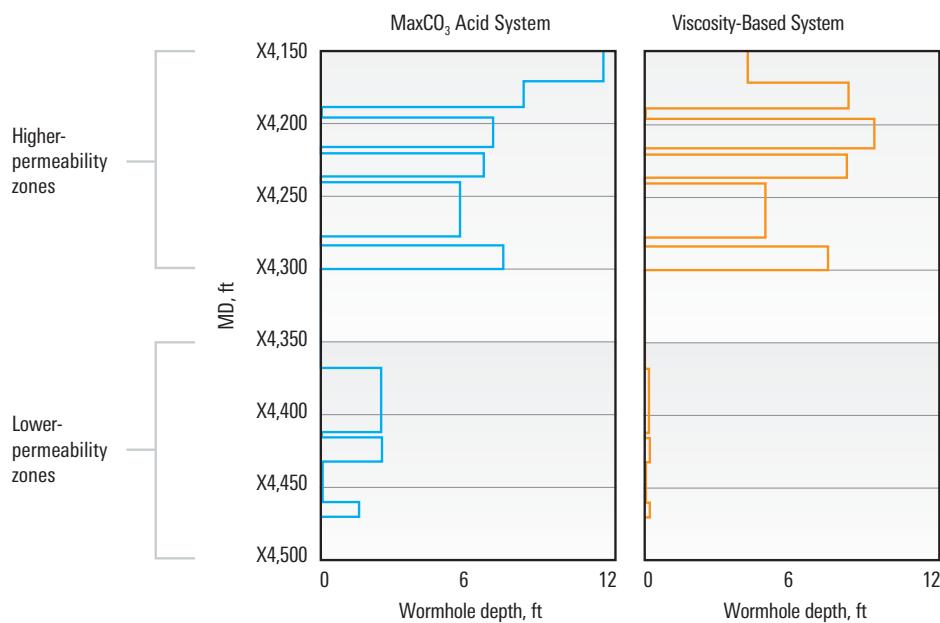
In laboratory experiments, the MaxCO<sub>3</sub> Acid system outperformed conventional viscosity-based fluids in leakoff control and wall-building capabilities. While conventional viscosity-based fluids can be injected continuously through an aperture with unimpeded flow, the MaxCO<sub>3</sub> Acid system reduces and eventually stabilizes fluid leakoff.

Significant pressure responses have been consistently observed in the field following placement of the MaxCO<sub>3</sub> Acid system stages.

After treatment, the base fluid systems break with different mechanisms on contact with hydrocarbons from the reservoir or with preflushes or overflushes containing a mutual solvent. The fibrous component, which degrades as a function of temperature and time, also requires the presence of the small amount of water supplied by the base fluid to degrade completely. The soluble by-products then flow back and can be handled at surface using conventional techniques, while the undamaged, stimulated reservoir is producing.



Flow reduction—from 50 mL/min to 3.9.



More penetration in lower-permeability zones using MaxCO<sub>3</sub> Acid system.

# MaxCO<sub>3</sub> Acid LT

## Degradable diversion low temperature acid system

### APPLICATIONS

- Reservoirs with high permeability contrasts and/or natural fractures
- Bottomhole temperatures between 140 and 200 degF
- Carbonate oil or gas wells
- Open hole or cased hole intervals, regardless of deviation

### ADVANTAGES

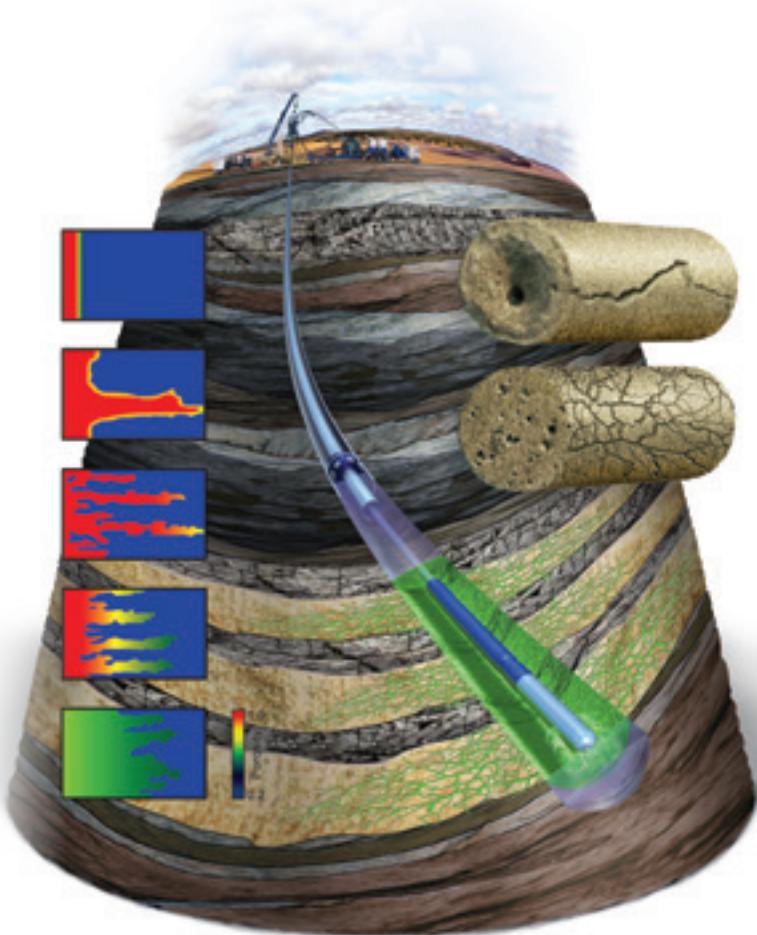
- Degrades completely, eliminating risk of costly cleanout interventions
- Targets permeability contrasts, allowing superior zonal coverage
- Effectively controls leakoff
- Enables lower treatment volumes and faster well cleanup time

### FEATURES

- Diverts effectively at low treatment rates
- Continues to stimulate as it degrades
- Can be bullheaded or pumped through CT
- Can be pumped with most common acid stimulation systems
- Can be batch mixed for small volume jobs or mixed on the fly for larger treatments

### Diversion in challenging reservoirs

Stimulating high-permeability-contrast and naturally fractured reservoirs is challenging. Effective diversion is required during treatment to ensure that the largest possible surface area of the reservoir is contacted and exposed to the stimulation fluids. The diversion, however, must be temporary and nondamaging to the reservoir or the natural fracture network. To meet this challenge in reservoirs with low temperatures, Schlumberger developed the innovative MaxCO<sub>3</sub> Acid LT degradable diversion acid system.



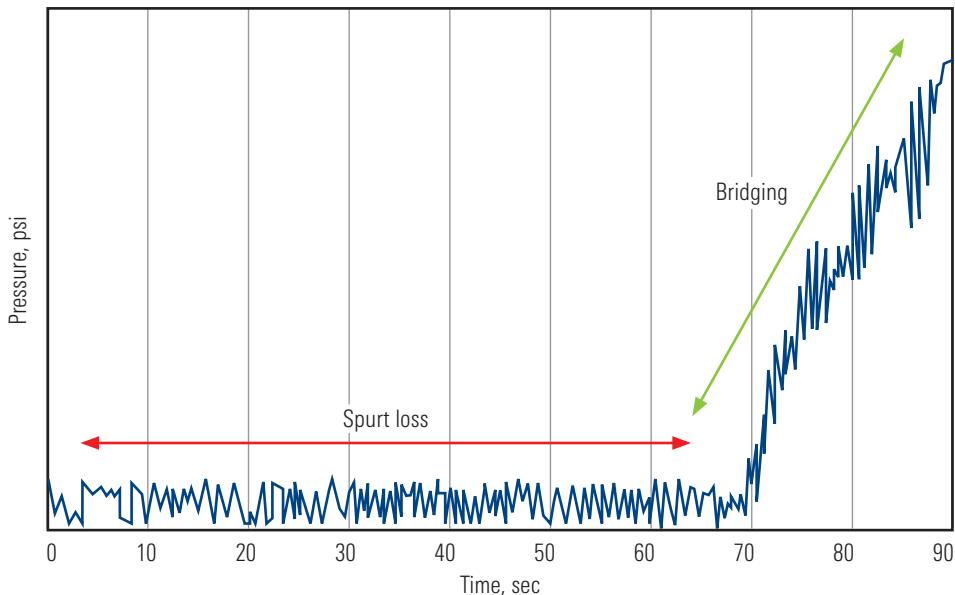
*MaxCO<sub>3</sub> Acid LT system diverts fluid from thief zones without reducing production from natural fractures.*

## Degradable diversion system

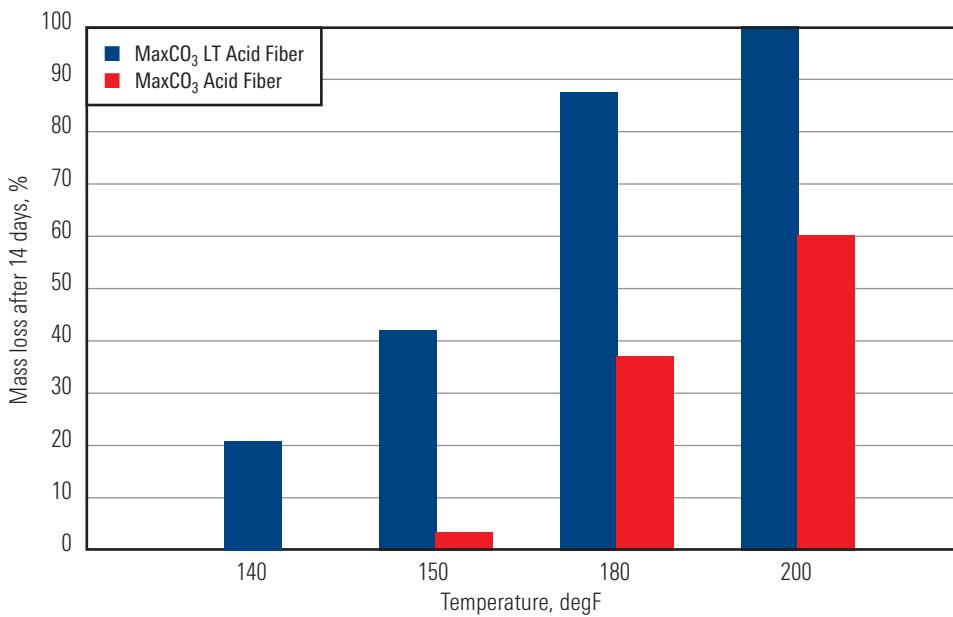
In laboratory experiments, the MaxCO<sub>3</sub> Acid LT system outperformed conventional viscosity-based fluids in leakoff control and wall-building capabilities. While conventional viscosity-based fluids can be injected continuously through an aperture with unimpeded flow, the MaxCO<sub>3</sub> Acid LT system reduces and eventually stabilizes fluid leakoff.

Significant pressure responses have been consistently observed in the field following placement of the MaxCO<sub>3</sub> Acid LT system stages.

After treatment, the base fluid systems break with different mechanisms on contact with hydrocarbons from the reservoir or with preflushes or overflushes containing a mutual solvent. The fibrous component, which degrades as a function of temperature and time, also requires the presence of the small amount of water supplied by the base fluid to degrade completely. The soluble by-products then flow back and can be handled at surface using conventional techniques while the undamaged, stimulated reservoir is producing.



Laboratory tests show that spurt loss occurs only over a short period of time. Rapid bridging action diverts flow to new zones.



At low temperatures, the MaxCO<sub>3</sub> Acid LT system fiber degrades faster than MaxCO<sub>3</sub> Acid system fiber. This speed allows the well to be turned around faster and increases the likelihood that the fiber has dissolved.

# VDA

## Viscoelastic diverting acid

### APPLICATIONS

- Stimulation of
  - Oil and gas carbonate reservoirs
  - Reservoirs with multiple layers, long production intervals, or permeability variation
  - Horizontal and vertical wells
- Multilayered and reservoirs with long production intervals
- Bullheading or pumping through coiled tubing

### BENEFITS

- Self-diverting acid system
- Operation as sole treating fluid or in combination with other fluids
- Increased zonal coverage
- No residual formation damage
- Single treatment fluid for simplified operations
- Easy fluid recovery and well cleanup
- Solids- and polymer-free
- Rated to 300 degF [149 degC]
- Rapid viscosity development on acid spending
- Viscosity reduction on contact with hydrocarbon

In matrix stimulation of oil and gas carbonate formations, the objective is total zonal coverage. While the use of diverters has been well-proven, most diverter methods use particulates that, post-treatment, can damage the formation.

For cost effectiveness and ease of operation, the ideal system is one that can be bullheaded, is self-diverting, and leaves no residual damage.

### Unique properties for extended application

Existing technologies for self-diverting systems rely on polymer-based fluids that can result in post-treatment residual damage. Additionally, conventional acid systems are limited to bottomhole conditions of approximately 200 degF [93 degC]. The VDA\* viscoelastic diverting acid is rated to 300 degF and eliminates the damage associated with solids and polymers in matrix treatment. VDA acid can be used as the sole treating fluid or with other treating acids for diversion.

### Diverted flow for ideal treatment

VDA acid maintains an ideal thin consistency while being pumped into the well. Upon acid spending, the fluid rapidly develops viscosity in situ and becomes self-diverting. The viscosity buildup serves as a barrier to reduce the development of dominating wormholes and allows fluid movement to stimulate other untreated zones.

Furthermore, VDA acid can be bullheaded and still provide total zonal coverage. In horizontal and extended-reach wells, VDA acid is ideal for pumping through coiled tubing as these wells contain no solids that could cause bridging.

In reservoirs with multiple layers or long production intervals, the rapid buildup in viscosity creates a temporary barrier that diverts the remaining fresh acid into the more highly damaged or lower-permeability zone. It is the development of viscosity that reduces fluid leakoff and gives the fluid its self-diverting property, which ensures coverage of the entire interval.



The VDA acid in 20% hydrochloric acid has a viscosity of less than 3 cP.



Upon reaction of hydrochloric acid with formation carbonate rocks, VDA acid develops viscosity rapidly. The fluid shown represents complete reaction of hydrochloric acid with carbonate.

## Low-pressure cleanup

Following treatment, the barrier is broken down by hydrocarbon production or by dilution with formation fluids, giving rise to easy recovery and well cleanup. Because only low pressures are required for well cleanup, operations are simplified and cleanup costs are reduced.

## Effective chemical diversion results in uniform production, minimal drawdown

In a recent application, the effects of VDA acid diversion to increase zonal coverage and improve permeability were evaluated by a major customer. On an existing single completion trial candidate in the Middle East, the test demonstrated that VDA acid helped achieve not only diversion goals but stimulation objectives as well. Interpretive results from this test would determine whether the advanced VDA acid could provide effective chemical diversion for use in dual completions that were scheduled.

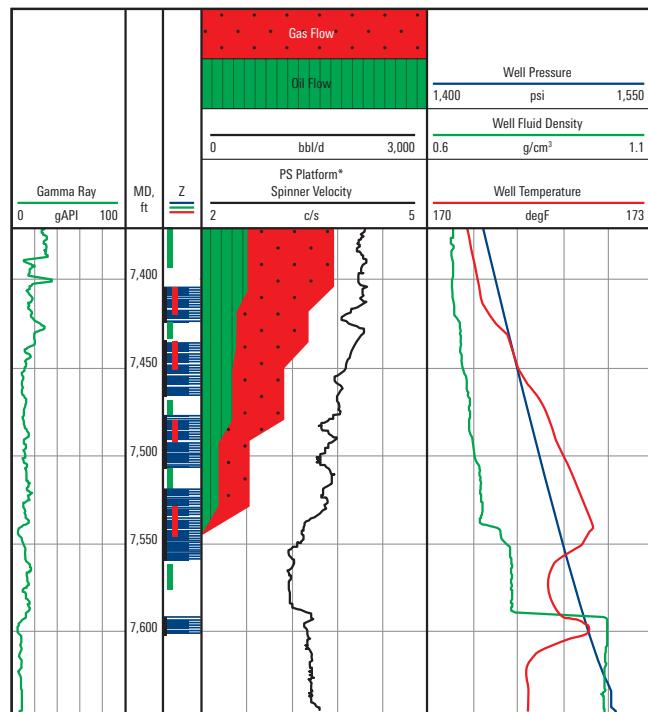
The test well had five different sets of perforations totaling 133 ft and extending through varying lithologies; the permeability contrast among the five zones varied from 3 to 600 mD.

A treatment design consisting of VDA acid for diversion and SXE\* emulsified acid for deep penetration was selected. Prior to treatment, a pressure buildup analysis showed a large skin of +100; following stimulation using VDA acid and SXE acid, a second well test showed that skin was reduced to -3. Comparisons of the prewell and postwell production logging and test analyses showed an oil production increase, from 510 to 1,730 bbl/d at the same choke size.

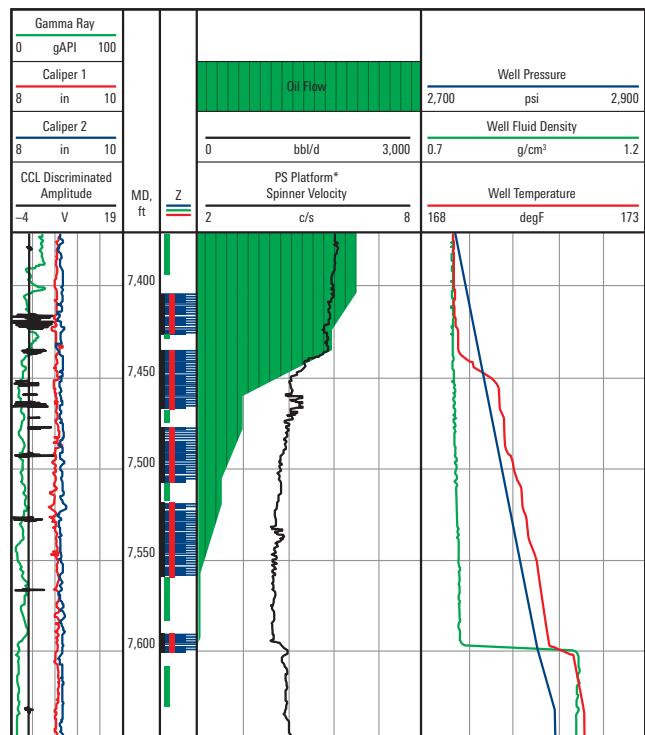
Additionally, the wellhead pressure showed a five-fold increase; flowing bottomhole pressure doubled. The self-diverting VDA acid reached all producing zones. An increase in wellbore flowing pressure and the shape of the buildup curve also showed a reduction in formation skin.

Before treatment, the production logging tool density and spinner curves indicated that the bottom set of perforations was not producing fluid. Data also indicated that only some of the perforations within the upper four zones contributed to total flow. Production logs after the acid treatment with VDA acid and SXE acid showed that all perforations throughout the five zones now contributed to total flow.

As a result of this field trial, VDA acid was deemed appropriate for use without coiled tubing in dual completions and raised expectations for future self-diverting VDA acid treatments in the area.



*The prejob well production profile shows both oil and gas being produced as a result of low bottomhole flowing pressure.*



*The postjob production profile indicates improved oil flow from all zones and no gas production as a result of higher bottomhole flowing pressure.*

# OneSTEP

## Simplified sandstone stimulation system

### APPLICATIONS

- Oil and gas production wells and injector wells
- Complex, multilayer sandstone formations
- Treatment temperatures of 200 to 375 degF [95 to 190 degC]
- Clay or calcite content greater than 5%
- Clay plus calcite content greater than 10%

### ADVANTAGES

- Production increase with minimal risk of damage
- Requires less equipment
- Less time is required at wellsite
- Safer operations with less corrosive fluid
- Mitigation of the risk of secondary and tertiary precipitations
- Reduction of the risk associated with stimulating acid-sensitive minerals/rock
- Reduction of the tendency for acid emulsion and sludge formation
- Replacement of multiple fluid stages (acid preflush, main fluid, and acid postflush) with only one stage
- Removal of damage caused by drilling fluids, clays, carbonates, and other aluminosilicates
- More uniform stimulation of sandstone reservoirs with less risk of disintegrating the rock
- Self-diverting stimulation fluid

### Small operational footprint

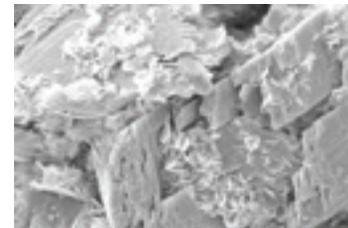
OneSTEP\* simplified sandstone stimulation system that uses only one fluid stage. Well-engineered fluid systems and reduced volumes provide a lower-risk, cost-effective solution that also removes damage caused by drilling fluids, clays, carbonates, and other aluminosilicates.

The OneSTEP system offers more uniform stimulation of sandstone reservoirs with less risk of disintegrating the rock. The system mitigates the risk of secondary and tertiary precipitations and reduces the tendency for acid emulsion and sludge formation; in addition, it offers less corrosion risk to tubulars and equipment. It increases production with minimal risk and offers effective formation damage removal. The OneSTEP system encourages the stimulation of wells that were previously bypassed because of the fear of potential damage from conventional treatments.

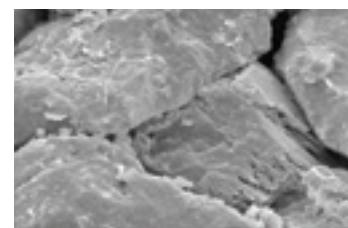
The single fluid stage formulation saves costs because it requires less equipment and saves preparation time.

In addition, the fewer equipment requirements offer a smaller operational footprint, especially important in offshore activity. A single fluid stage permits simpler operations and reduces personnel exposure to health, safety, and environmental risks. In addition, this system is easy to mix and pump.

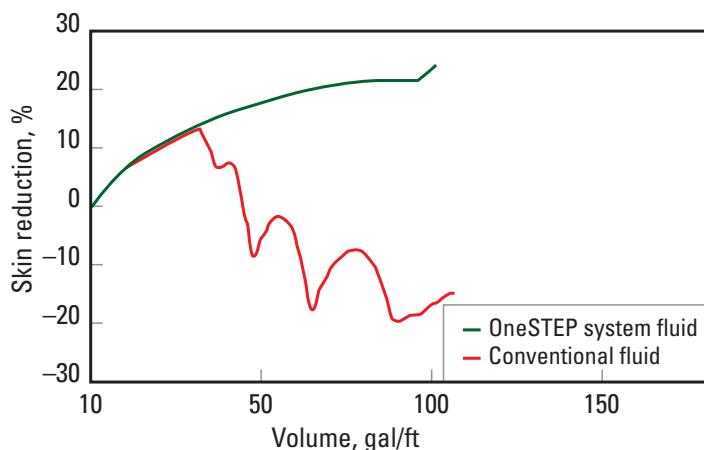
Integral to the OneSTEP system process candidate selection using Virtual Lab\* geochemical simulation software. The software incorporates the results of slurry reactor tests and the actual candidate core tests, and then makes predictions about treatment effects on damage removal and effective job volumes. Multiple treatments can be compared to select the best treatment for each well. This approach reduces the risk of mismatching fluids or using the wrong fluid design for stimulation of a particular formation.



*Formation damage.*



*Effective damage removal.*



*OneSTEP system fluid removes formation damage.*

# MaxCO<sub>3</sub> Acid CT

## Coiled tubing degradable diversion acid system

### APPLICATIONS

- Reservoirs with moderate permeability contrasts and/or natural fractures, specifically formulated for ACTive\* services
- Bottomhole temperatures between 175 and 250 degF [79 and 121 degC]
- Carbonate oil or gas wells
- Open hole or cased hole intervals, regardless of deviation
- Lower permeability contrast

### ADVANTAGES

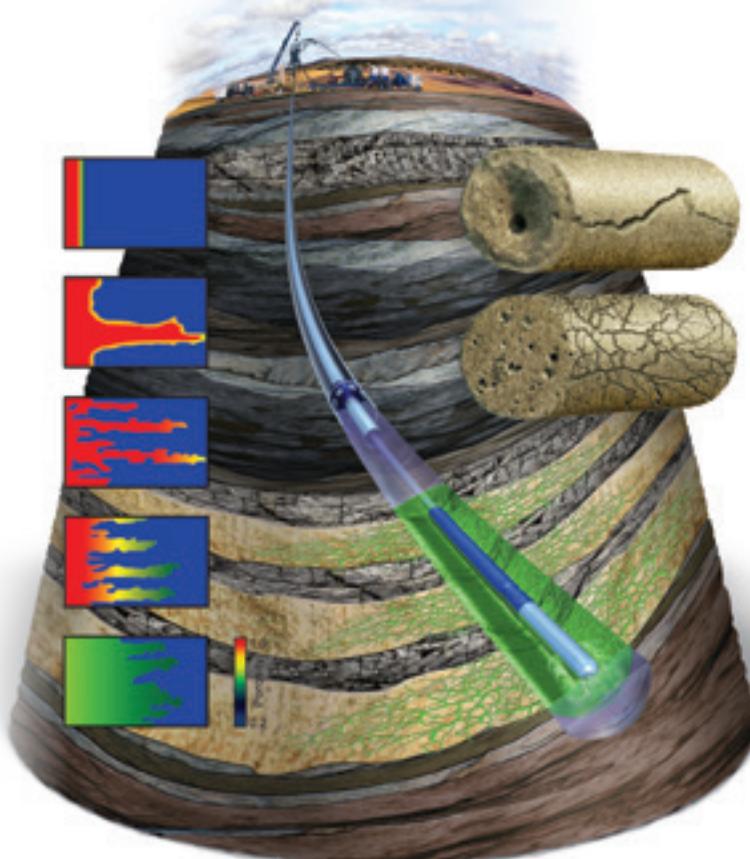
- Degrades completely, eliminating risk of costly cleanout interventions
- Targets permeability contrasts, allowing superior zonal coverage
- Effectively controls leakoff
- Requires lower treatment volumes and less well cleanup time

### FEATURES

- Diverts effectively at low treatment rates
- Continues to stimulate as it degrades
- Designed to be pumped through CT
- Can be pumped with most common acid stimulation systems
- Can be batch mixed for small volume jobs or mixed on the fly for larger treatments

### Diversion in challenging reservoirs

Stimulating high-permeability-contrast and naturally fractured reservoirs is challenging. Effective diversion is required during treatment to ensure that the largest possible surface area of the reservoir is contacted and exposed to stimulation fluids. The diversion, however, must be temporary and nondamaging to the reservoir or the natural fracture network. To meet this challenge, Schlumberger developed the innovative MaxCO<sub>3</sub> Acid CT coiled tubing degradable diversion acid system.



MaxCO<sub>3</sub> Acid CT system diverts fluid from thief zones without reducing production from natural fractures.

# OilSEEKER

## High-water-cut acidizing diverter

### APPLICATIONS

- Acid diversion during matrix stimulation of carbonate or sandstone formations in layers with high water saturation

### BENEFITS

- Avoids formation damage and slow cleanup
- Allows preferential treatment of oil zones
- Improves zonal coverage during matrix stimulation
- Improves treatment success, ultimately increasing production

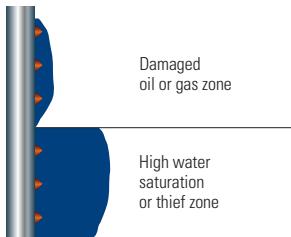
### FEATURES

- Nonpolymeric, nonparticulate aqueous system
- Gelation in water-saturated matrix or fissure
- Nondamaging to the formation
- No nitrogen requirement
- Operational range from 75 to 250 degF [24 to 121 degC]
- Easy mixing and pumping

During standard acidizing treatments, the treating fluid favors the zones with higher water saturation and/or higher permeability. Water cuts may climb even higher if nonthief hydrocarbon-bearing zones are not effectively stimulated. OilSEEKER® high-water-cut acidizing diverter, engineered for both sandstone and carbonates, selectively reduces injectivity in zones with high water saturation, forcing the acid to enter the zones with high oil saturation. OilSEEKER diverter decreases water cut while increasing the production of oil.

### Stage 1

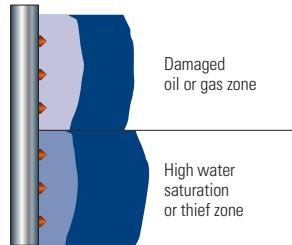
Inject a brine or acid preflush to create a region with 100% water saturation near the wellbore in the zone with high water saturation.



**Brine or acid preflush**      **Broken OilSEEKER diverter**

### Stage 2

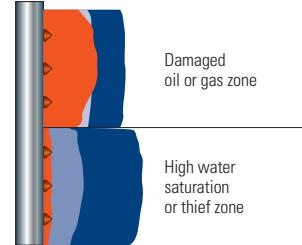
Inject OilSEEKER diverter to form a viscous plug in that zone.



**Viscous OilSEEKER diverter**

### Stage 3

Inject the main acid treating fluid. It preferentially enters the target oil zone, taking the path of least resistance.



**Damaged oil or gas zone**  
**High water saturation or thief zone**

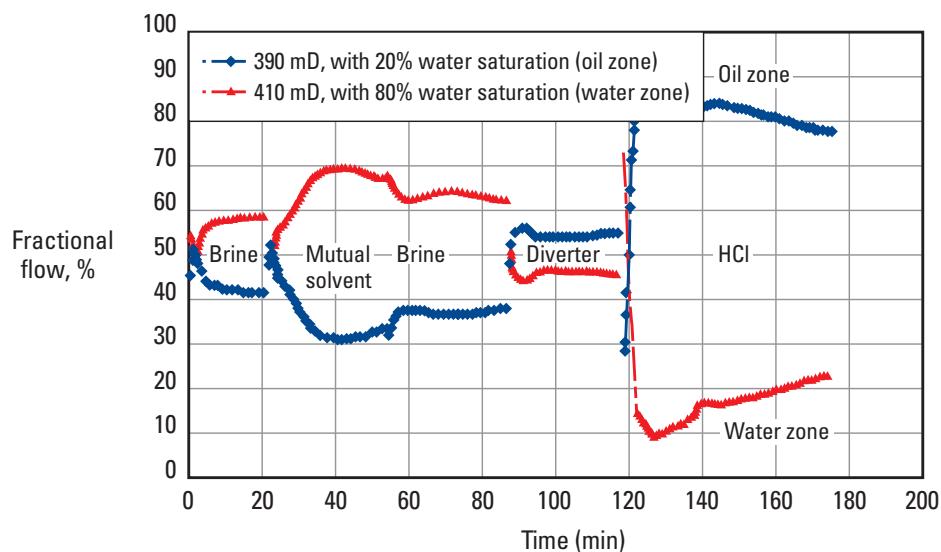
*Treatment stages using OilSEEKER diverter.*

### Laboratory tests

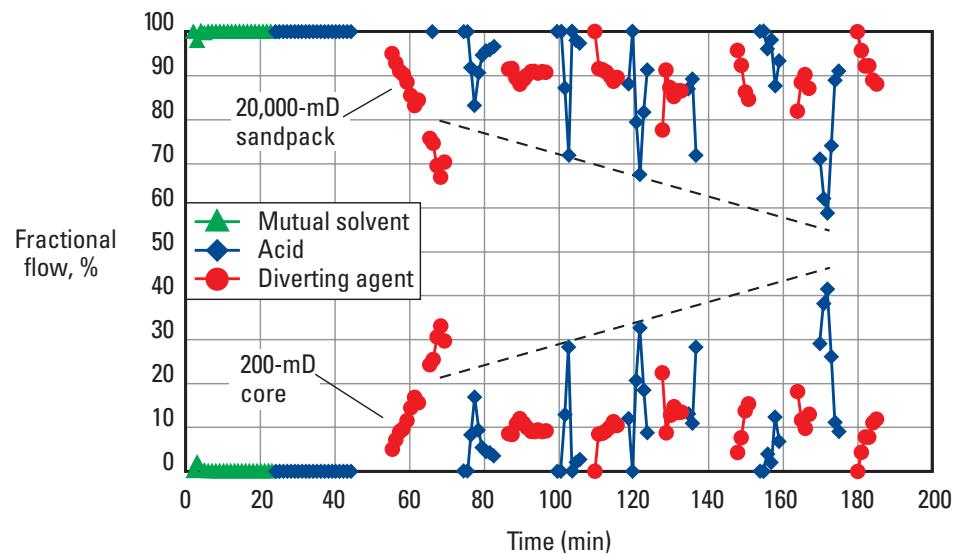
Laboratory tests were performed at 150 degF [66 degC] on cores before and after injection of OilSEEKER diverter to evaluate effectiveness in diverting fluid from a highly water-saturated or thief zone to a zone with high oil saturation. Before OilSEEKER diverter injections, fluid predominantly entered the zone with a high degree of water saturation. After injection, fluid was diverted to the oil zone.

Laboratory testing also demonstrated the superior OilSEEKER diverter performance in diverting acid from 20,000-mD sandpack to 200-mD rock, an extremely unfavorable permeability contrast. Nearly 40% of the acid could actually be injected into the low-permeability zone after several stages of OilSEEKER diverter injection.

The near-wellbore area is cleaned first, and the zone with high water saturation is then preferentially treated with OilSEEKER diverter. Acid is forced into the zones with high oil saturation, which results in effective stimulation of your pay zone.



Core tests demonstrate the diversion of acid treatment from the water zone to the oil zone using OilSEEKER diverter.



Laboratory tests demonstrate the diversion of acidic treatment from high-to-low-permeability zones using OilSEEKER diverter.



## Emulsified acid

### APPLICATIONS

- HT matrix stimulation of carbonate formations
- Acid fracturing of HT carbonate reservoirs

### BENEFITS

- Improved damage bypass via deeper wormhole penetration in HT wells
- Deeper live-acid penetration during acid fracturing and matrix stimulation
- Superior corrosion inhibition

### FEATURES

- Operational range from 75 to 350 degF [24 to 177 degC]
- High degree of retardation
- Less fluid loss



*Acid-internal emulsion results in viscosity development that aids diversion in matrix treatments and leakoff control when used for acid fracturing.*



*Laboratory core flow test results showing branching wormhole created in a limestone core.*

### Improves matrix acidizing and acid fracturing treatments in HT reservoirs

SXE<sup>\*</sup> emulsified acid is a viscous, highly retarded HCl system designed to overcome acid penetration problems while stimulating reservoirs above 75 degF [24 degC].

Standard hydrochloric acid reacts very quickly in carbonate formations. The reaction is so rapid in high temperatures that it is impossible for acid to penetrate, or wormhole, more than a few inches into the formation. In such cases, the acid is rendered ineffective in stimulating the well. The HT SXE acid retards the acid reaction rate, enabling deep, live-acid penetration. This oil-external emulsion is formed with a 70:30 HCl-to-oil ratio, stabilized with an emulsifier. HCl concentrations ranging from 7.5 to 28% may be used in either a batch or continuous mix system.

# FoamSEAL

## Stable, crosslinked foaming gel

### APPLICATIONS

- Conformance control in naturally fractured or fissured reservoirs

### BENEFITS

- Reduces or eliminates unwanted gas and water production, increasing oil production

### FEATURES

- Customized fluids
- Controlled gel-setting time for bottomhole static temperatures (BHSTs) up to 300 degF [149 degC]
- Rigless operations
- High-quality, stable foam
- Synthetic polymers
- No detrimental effects from crude oil or shear



*FoamSEAL gel produces a high-strength foam that effectively seals natural fissures and fractures, stopping the unwanted flow of gas and water.*

### Conformance control with high-quality foam

To control unwanted gas or water production—and increase oil production—FoamSEAL stable, crosslinked foaming gel is designed to create a seal in gas-producing zones, effectively trapping the gas.

By producing a high-quality foam capable of invading the gas zone and sealing it, the gel stops gas flow toward crude oil channels. A high-quality (60 to 80%) foam is generated using foaming agents selected for specific well conditions. The stability of the foam makes it particularly well-suited for use in naturally fissured or fractured carbonate and sandstone reservoirs.

FoamSEAL gel is not sensitive to crude oil or shear, and it also works to minimize damage in crude oil-producing zones.

Working time of the FoamSEAL gel is managed by adjusting the activator concentration. Setting time can be controlled from 1 to 24 hours for reservoir temperatures between 100 and 300 degF [38 and 149 degC].

# Stimulation Products

## Acids

Code	Form	Primary Purpose	Summary
H015	Liquid	Hydrochloric acid 15%	Inhibited 15% HCl for acidizing oil and gas wells.
H020	Liquid	Hydrochloric acid 20%	Inhibited 20% HCl for acidizing oil and gas wells.
H028	Liquid	Hydrochloric acid 28%	Inhibited 28% HCl for acidizing oil and gas wells.
H036	Liquid	Hydrochloric acid 36%	Uninhibited 36% HCl acidizing base fluid.
H813	Liquid	Clay Acid	Acidize high silt content sandstones and stabilize formation clay fines.
H949	Liquid	Regular mud acid	Removal of silt and clay damage in sandstone formations.
H954	Liquid	Organic mud acid	Acidizing of clay or silt-damaged formations at high temperature.
H959	Liquid	OneSTEP	Single-stage sandstone acidizing system for sandstone reservoirs at temp > 200 degF [93 degC].
H028	Liquid	Hydrochloric acid 28%	Base fluid for acidizing treatments.
L036	Liquid	Organic acid	Formic acid base fluid.
L401	Liquid	Organic acid	Acetic acid (winterized version of L400) base fluid.
L801	Liquid	Organic acid	9% formic acid solution.
L802	Liquid	Organic acid	10% acetic acid solution.

## Acid Intensifiers

Code	Form	Primary Purpose	Summary
Y001	White crystals	Intensifier	Ammonium bifluoride used in mud acid systems.
Y006	White granular powder	Intensifier	Boric acid used to generate fluoboric acid in clay acid systems.

## Activators

Code	Form	Primary Purpose	Summary
J463	White crystals	Gelling activator	Organic brine used to gel the ClearFRAC* family of polymer-free fracturing fluids surfactant J508W. This is used for applications above 200 degF.
J534	Colorless liquid	Activator	Base fluid for J551 based ClearFRAC fluids.
M007	Liquid	Activator	Sodium hydroxide. Variety of uses: pH control, neutralization, and organic cleanup.
J468	Solid	DGS: organic activator	Used in the DGS* delayed gelation system when BHST ranges from 122 to 194 degF [50 to 90 degC].
J469	Solid	DGS: gel activator for LT	Used in the DGS system below 122 degF [50 degC].
J470	Solid	DGS: gel activator for HT	Used in the DGS system when BHST is greater than 194 degF [90 degC].

## Antifoam Agents

Code	Form	Primary Purpose	Summary
D047	Colorless liquid	Antifoam agent	Antifoam surfactant; counteracts foaming tendencies of other surfactants; prevents foam but does not kill foam. Liquid form of D046.
D144	Liquid	Antifoam agent	Particularly effective in saline, organic-rich and bentonitic mix waters. Concentration ranges from 2 to 4 gal/1,000 gal.
M045	Liquid	Antifoam agent	A solids-based antifoam agent. Effective at low concentrations.

## Asphaltene Inhibitors

Code	Form	Primary Purpose	Summary
U101	Liquid	Asphaltene inhibitor	Prevent asphaltene formation when combined with P124 in squeeze inhibitor treatment. Used also to disperse asphaltene when combined with toluene (PARAN P121 solvent) or xylene (Xylene A26).

## Antisludge Agents

Code	Form	Primary Purpose	Summary
W058	Liquid	Antisludge agent	Surfactants blend used to prevent sludging in MISCA fluids.
W064	Liquid	Emulsion and sludge preventer	Prevents iron-induced asphaltic sludge and associated emulsions.

## Biocides/Bactericides

Code	Form	Primary Purpose	Summary
M091	Light yellow liquid	Formation cleaning solution	A water-base product containing a percent sodium hypochlorite (NaOCl), a strong oxidizer, and a percent of sodium hydroxide (NaOH), caustic soda. Strong oxidizing solution designed to restore permeability to formations damaged by nonpetroleum organic residues. These residues may be naturally occurring bacterial slimes or may be gums or polymers, which have been introduced into the well.
M275	Solid	Biocide	Concentrated isothiazoline compound that has been adsorbed onto an inert solid for ease of handling. Effective at killing bacteria, but does not inhibit the effect of enzymes.
M290	Liquid	Bactericide	Quaternary amine bactericide.
M291	Liquid	Bactericide	Used only in North Sea.

## Base Oil

Code	Form	Primary Purpose	Summary
J504	Colorless liquid	ES base oil	Slurry gel base oil. Meets North Sea environmental requirements.
J510	Colorless liquid	Low-aromatic base oil	Low-toxicity oil for slurriable additives.
U051	Brown liquid	Diesel	No. 2 diesel.

## Breakers / Fracture Cleanup Enhancers

Code	Form	Primary Purpose	Summary
J134	Solid	Breaker	Effective enzyme breaker (hemicellulase) for only guar and substituted guaras, provided the pH of the fluid is maintained between 3.5 and 8.5 and the temperature does not exceed 135 degF [57 degC].
J134L	Liquid	Breaker	J134L is a liquid concentrate version of J134.
J218	Solid	Breaker	Ammonium peroxydisulfate type breaker that is used in WF* linear, water-base fracturing fluids and YF* crosslinked water-base fracturing fluids at temperatures ranging from 125 to 225 degF [52 to 107 degC].
J297	Powder	Breaker	Low-temperature breaker which is an organic acid used in the SANDLOCK sand control service using resins. It is also used to break WF fluid. Temperatures are limited to less than 225 degF [102 degC].
J503	Liquid	Breaker	Intermediate-temperature enzyme breaker for linear HEC fluids with a working temperature ranging from 70 to 210 degF [22 to 100 degC].
J567	Tan granules	Breaker	Proppant pack breaker for ClearFRAC XT fluid.
J569	Tan granules	EB-Clean J569 MT breaker	J569 is a midtemperature breaker (175 to 250 degF) that is part of the CleanFRAC* service.

## Breaker Aids

Code	Form	Primary Purpose	Summary
J318	Liquid	Liquid breaker aid	Liquid breaker aid used with J218 when the fluid temperature is less than 125 degF [52 degC].
J364	Amber liquid	Breaker aid	Used with J218 to break water frac fluids at temperatures of 32 to 100 degF [0 to 38 degC].

## Buffering Agents

Code	Form	Primary Purpose	Summary
J464	Solid	Buffering agent	Sodium bicarbonate, buffering agent, pH ~8.5.
U028	Liquid	pH control agent	Sodium hydroxide in solution.
J485	Liquid	Potassium carbonate	Buffer.
M003	Solid	Sodium carbonate	Soda ash.
M002	Solid	Sodium hydroxide	Caustic soda flakes.

## Chelating Agents

Code	Form	Primary Purpose	Summary
L041	Solid	Chelating agent	Liquid Iron Chelating Agent L041 is an iron stabilizing agent used in acid to prevent ferric hydroxide precipitation. It can be used at temperatures up to 400 degF [204 degC].
L041L	Liquid	Chelating agent	L041L and U042 are identical liquid solutions containing 40% L041. It can be used at temperatures up to 400 degF [204 degC].
U042	Liquid	Chelating agent	Iron stabilizer chelating agent. L041L and U042 are identical liquid solutions containing 40% L041. It can be used at temperatures up to 400 degF [204 degC].
U106	Liquid	Chelating agent	Chelating agent used for iron control up to 10,000 ppm Fe <sup>+3</sup> or to dissolve carbonate deposits. A 50% solution will dissolve CaCO <sub>3</sub> at 750 lbm/1,000 gals. Temperature limit exceeding 315 degF [157 degC].
U044	Liquid	Biodegradable chelating agent	Chelating agent U044 is a multipurpose metal control chemical that is similar (chemically and physically) to U042.

## Clay Stabilizers

Code	Form	Primary Purpose	Summary
J285	White crystals	Ammonium chloride	Used in pre/overflush, spacers, and carrier fluids to provide temporary clay control.
J583	Liquid	Multifunctional additive	J583 is a liquid concentrated blend of clay stabilizer L064 and surfactant F108 (used as a clean up aid).
L042	Liquid	Clay stabilizer	Clay stabilizer containing a zirconium oxychloride that will effectively reduce formation damage commonly caused by dispersion and migration of formation clays. L042 is an acidic solution. When added to dilute brines.
L055	Liquid	Clay stabilizer	Permanent clay stabilizer. Quaternary amine that is an effective material for controlling clay dispersion and migration.
L064	Liquid	Clay stabilizer	Temporary Clay Stabilizer L064 (tetramethyl ammonium chloride) is an efficient liquid clay stabilizer that can be substituted for potassium chloride (KCl) in most applications. L064 is not a permanent clay stabilizer. Applicable temperature less than 300 degF [149 degC].
L071	Liquid		Temporary clay stabilizer is used with aqueous fluids to prevent damage to the formation caused by clay migration and swelling. Should be used with permanent clay stabilizers in highly water-sensitive formations.
M117	Solid	Clay stabilizer	Potassium Chloride. Control clays dispersion and migration.

## Corrosion Inhibitors

Code	Form	Primary Purpose	Summary
A205	Liquid	Downhole corrosion inhibitor CORBAN 333	CORBAN* corrosion inhibitors 333 A205 is used to reduce corrosion rates in HEVIWATER brines. It contains organic and inorganic components that act synergistically. Applicable temperature up to 400 degF [204 degC].
A231	Liquid	Downhole corrosion inhibitor CORBAN 230DH	An all-purpose downhole corrosion inhibitor designed for packer fluids, workover fluids, and flush fluids ahead of and behind primary cementing jobs. Maximum application temperature is 230 degF [110 degC]. For extremely corrosive waters and for temperatures above 180 degF [82 degC], the concentration should be increased.
A233	Liquid	Corrosion inhibitor	Corrosion inhibitor A233 will provide protection on N80, 13% chrome steel, and CT in mineral and organic acid systems up to 350 degF [177 degC].
A234	Liquid	Corrosion inhibitor	Corrosion inhibitor A234 is designed for CT operations in wells where hydrogen sulfide ( $H_2S$ ) and/or carbon dioxide ( $CO_2$ ) are present. A234 corrosion inhibitor protects HS80 and HS90 CT at temperatures up to 300 degF [149 degC] in environments with up to 10% $H_2S$ and up to 20% $CO_2$ .
A259	Red-brown liquid	Corrosion inhibitor	Corrosion Inhibitor A259 protects most oilfield steels during matrix stimulation operations with HCl and mud acid at temperatures from 75 to 300 degF [24 to 149 degC].
A261	Clear, amber, single-phase liquid	Corrosion inhibitor	Corrosion Inhibitor A261 will protect most oilfield tubulars including carbon steels and 13% Chrome steels from corrosion and pitting in hydrochloric acid and mud acid systems. A261 can be used at temperatures ranging from 75 to 300 degF [24 to 149 degC]. Inhibitor aid A201 is commonly used to enhance performance at temperatures greater than 200 degF [93 degC]. Inhibitor aid A153 or inhibitor aid A179 is added in certain formulations as required.
A262	Dark brown liquid	Corrosion inhibitor	CORBAN inhibitors A262 acid corrosion inhibitor is recommended for use when acidizing through low carbon steels, such as J55, N80 and CT, and chrome steels. A262 does not contain nonylphenol ethoxylate (NPE) and can be used at temperatures ranging from 100 to 300 degF [38 to 149 degC].
A264	Amber liquid	Corrosion inhibitor	CORBAN inhibitors A264 acid corrosion inhibitor has excellent dispersion properties and provides metal protection across most oilfield steel types. Corrosion Inhibitor A264 is designed for the corrosion inhibition at temperatures from 75 to 300 degF [24 to 149 degC].
A265	Liquid	External CT corrosion inhibitor	CT corrosion inhibitors A265 and A266 are designed to be used on CT to reduce interior and exterior corrosion of CT between CT jobs and during pipe storage periods. They are not intended for downhole corrosion inhibition that occurs during acid treatments or from $H_2S$ or $CO_2$ exposure and should not be used for that purpose.
A266	Liquid	Internal CT corrosion inhibitor	CT corrosion inhibitors A265 and A266 are designed to be used on CT to reduce interior and exterior corrosion of CT between CT jobs and during pipe storage periods. They are not intended for downhole corrosion inhibition that occurs during acid treatments or from $H_2S$ or $CO_2$ exposure and should not be used for that purpose.
A270	Liquid	Corrosion inhibitor	HT corrosion inhibitor will protect N80, CT and P105 steel alloys against hydrochloric acid (HCl) corrosion to at least 350 degF [177 degC] for up to eight hours. Applicable temperature ranges from 275 to 400 degF [135 to 204 degC]. The A270 system is not effective in the presence of $H_2S$ .
A272	Dark red-brown liquid	Corrosion inhibitor	Organic corrosion inhibitor A272 was developed for use in organic acid solutions. A272 is effective in formic acids prepared from organic acid L036 or acetic acids prepared with stabilizing agent L400 or L401. Protection is provided at temperatures up to 500 degF [260 degC] for 16 h in solutions of either 9% L036 or 10% L400.
A282	Liquid	Corrosion inhibitor	Corrosion inhibitor for high chrome steel.
A283	Liquid	Corrosion inhibitor	Corrosion inhibitor A283 was developed for protection of HS80 CT in nonacidizing against hydrogen sulfide and carbon dioxide corrosion. The product has been tested up to 300 degF [149 degC] in up to 10% $H_2S$ and 20% $CO_2$ providing protection against corrosion via film deposition on the exposed tubulars.
A286	Liquid	Corrosion inhibitor	Corrosion inhibitor A286 is designed for use with up to 15% HCl solutions and temperature up to 250 degF [121 degC]. It is applicable for low-alloy carbon steels such as L80, N80, and P110.

## Corrosion Inhibitor Aids

Code	Form	Primary Purpose	Summary
A153	White solid	Corrosion inhibitor aid	Inhibitor aid for alcoholic acid, gas well acid and gas well mud acid. It decreases the pitting tendency and maximizes corrosion protection. Potassium iodide. Applicable temperature up to 250 degF [121 degC].
A179	Blue/green crystals	Corrosion inhibitor aid	Effective in gas well acid systems.
A201	Clear liquid	Corrosion inhibitor aid	Normally used at temperatures greater than 200 degF [93 degC]. Mixture of organic acids.
A281	Colorless liquid	Corrosion inhibitor aid	Corrosion inhibitor aid, for high chrome steel.

## Crosslinker

Code	Form	Primary Purpose	Summary
J492	Liquid	Crosslinker	Used in the MARA-SEAL and MARCIT technologies. Applicable temperature up to 300 degF [149 degC] for MARA-SEAL and 200 degF [93 degC] for MARCIT.
J524	Liquid	Crosslinker	Organic secondary crosslinker used for OrganoSEAL-F* organic crosslinked gel. Applicable temperature up to 300 degF [149 degC].
J525	Solid	Crosslinker	Organic primary crosslinker used for OrganoSEAL-F gel and -R fluids. Applicable temperature up to 300 degF [149 degC].
L010	Solid	Crosslinker	A borate material that quickly crosslinks guar and HPG-thickened WF fluid when the pH is raised above 8.

## Crosslink Delay Agents

Code	Form	Primary Purpose	Summary
J493	Liquid	Delay agent	Low-temperature delay agent (less than 125 degF [52 degC]) used in the MARA-SEAL and PROTECTOZONE* fluids.

## Demulsifier/Nonemulsifying

Code	Form	Primary Purpose	Summary
J530	Liquid	Nonemulsifying agent	Anionic surfactant used to eliminate the emulsion tendency of ClearFRAC fluids with certain crudes.
W053	Clear yellow liquid	Nonemulsifying agent	Nonionic surfactant for use in acid, water, or oil-base stimulation fluids to prevent emulsions. It can also be used to break existing emulsions. W053 preferentially water-wets both sandstone and limestone rock.
W054	Liquid	Nonemulsifying agent	Multicomponent nonionic surfactant developed to provide nonemulsifying, water wetting, surface, and interfacial tension-reducing properties. It can also be used to break existing emulsions. W054 preferentially water-wets both sandstone and limestone rock. It can also be used in oil.
W059	Liquid	Nonemulsifying agent	Cationic surfactant that preferentially water-wets limestone and oil-wets sandstone rocks. Used in the SANDLOCK sand control service and in furan resin sand consolidation system as an oil-wetting agent.
W060	Liquid	Sludge and emulsion preventer	Replacement for W035.
W062	Liquid	Nonemulsifying agent	W062 is a multicomponent nonionic-cationic surfactant blend developed to provide nonemulsifying, water-wetting, surface- and interfacial-tension-reducing properties when added to stimulation fluids, whether acid or hydraulic fracturing fluids.
W063	Liquid	Nonemulsifying agent	W063 is a nonionic, microemulsion-based blend formulated to prevent emulsions from forming during fracturing treatments. It has been tested with a wide range of crude oils, proving it facilitates quick breakout of emulsions.

## Dispersant

Code	Form	Primary Purpose	Summary
F103	Liquid	EZEFLO® F103 Surfactant	Dispersant used to stabilize DAD* dynamic acid dispersion fluids. It is meant to be a replacement for Dispersing Agent U074. The applicable temperature range is up to 175 degF [79 degC].
U074	Clear, yellow liquid	Dispersing agent	Nonionic dispersant used to stabilize DAD* dynamic acid dispersion fluids. Will leave sandstone and limestone reservoirs water-wet. Applicable temperature up to 175 degF [79 degC].

## Diverting Agents

Code	Form	Primary Purpose	Summary
J059	White powder	Diverting agent FIXAFRAC* fracturing fluid-loss material	Hydrated lime. Used as a breaker for GO III systems up to 125 degF [50 degC]. Breaker for PROTECTOZONE fluid system for temperatures from 240 to 325 degF.
J066	Solid	Diverting agent FIXAFRAC material	Sodium chloride. Granular salt used as a temporary diverting agent.
J066S	Solid	Diverting agent FIXAFRAC material	100 mesh sodium chloride used as a temporary diverting agent.
J227	Solid	Diverting agent FIXAFRAC material	Diverting agent (benzoic acid flakes). Bridging materials used as diverters in carbonate matrix stimulation treatments. Concentration: typically slurried and pumped in a gelled fluid. Maximum applicable: 250 degF [121 degC].
J237A	Liquid	Diverting agent	A liquid dispersion of finely divided oil-soluble resins. The upper temperature limit is 200 degF [93 degC].
J238	Powder	Diverting agent	A finely divided oil-soluble resin. It will dissolve completely in hydrocarbons, resulting in little or no formation or gravel-pack damage. The average particle size is 4 microns. Applicable temperature up to 250 degF [121 degC].
J363	Solid	Diverting agent	Used primarily for diversion when acidizing water-injection wells at fluid temperatures up to 150 degF [65 degC]. Effective for diversion in formations having permeabilities as high as 5 darcies.
J423	Solid	Diverting agent	Buoyant, inorganic, diverting material used in the INVERTAFRAC* technique to limit upward fracture growth. It may be mixed and pumped in any water-base, oil-base, or acid-base fluid. Typically the concentration will range from 0.75 to 1.0 lbm/gal.
J122	Solid	Ball sealer	Rubber covered nylon core, $\frac{1}{8}$ in OD. Sp. Gr. of 1.3.
J123	Solid	Ball sealer	Rubber covered nylon core, 1 in OD. Sp. Gr. of 1.3.
J130	Solid	Ball sealer	Rubber covered nylon core, $\frac{1}{8}$ in OD. Sp. Gr. of 1.1.
J131	Solid	Ball sealer	Rubber covered nylon core, $\frac{1}{4}$ in OD. Sp. Gr. of 1.3.
J141	Solid	Ball sealer	Rubber covered nylon core, $\frac{5}{8}$ in OD. Sp. Gr. Of 1.1.
J144	Solid	Ball sealer	Rubber covered phenolic core, $\frac{1}{8}$ in OD. Sp. Gr. Of 0.9. HT, HP ball sealer.
J247	Solid	Ball sealer	Rubber covered phenolic core, $\frac{1}{8}$ in OD. Sp. Gr. Of 1.4. HT, HP ball sealer.
J258	Solid	Ball sealer	Rubber covered aluminum, $\frac{1}{8}$ in OD. Sp. Gr. Of 1.9.
J272	Solid	Ball sealer	Rubber covered nylon core, $\frac{5}{8}$ in OD. Sp. Gr. of 1.3.
J322	Solid	Ball sealer	Rubber covered nylon core, $\frac{1}{8}$ in OD. Sp. Gr. of 1.2.
J458	Solid	Ball sealer	RCP $\frac{1}{8}$ in OD. Sp. Gr. of 1.0.
J528	Solid	Bio-ball sealer	Soluble ball sealers. Applicable temperature up to 200 degF [93 degC]. Pumped in acid in matrix treatments. Only available in $\frac{1}{8}$ in diameter. Soluble in acid over a period of hours.
J557	Amber liquid	Gelling/diverting agent	Polymer free, self-diverting acid system for carbonates (VDA* viscoelastic diverting acid) is formulated using this additive.
J570	Amber liquid	OilSEEKER* high-water-cut acidizing diverter	OilSEEKER diverter is prepared by mixing gelling agent J570 with water. Brine could be added for formation compatibility reasons. In that case, 5% ammonium chloride is preferred as it is compatible with a large range of formations.

## Emulsifying Agents

Code	Form	Primary Purpose	Summary
U078	Clear amber liquid	Emulsifying agent	Cationic emulsifier. Applicable temperature up to 200 degF [93 degC].
U108	Light amber liquid	Emulsifying agent	Single emulsifier covers the entire temperature range (75 to 375 degF [23 to 191 degC]), for both SXE and SXE-HT fluid systems. Replaces both U080 and U103 emulsifying agents for this application.

## Fluid Loss Additives

Code	Form	Primary Purpose	Summary
J426	Solid	Fluid loss additive	Oil-soluble, 100 mesh hydrocarbon resin. The particle size and distribution are designed to bridge naturally occurring macrofractures that are greater than 50 microns in width. Applicable temperatures up to 275 degF [135 degC].
J472	Liquid	Fluid loss additive—LCA* leakoff control acids and SDA* self-diverting acid	Used in particular in the LCA systems. Applicable temperature up to 300 degF [149 degC].
J478	Solid	Fluid loss additive slurriable/degradable additive	Chemically modified starch (100%) with specific enzymes. Applicable temperature less than 250 degF [121 degC].
J484	White powder	Fluid loss additive	Is a specially sized calcium carbonate ( $\text{CaCO}_3$ ) product designed to control fluid loss to the rock matrix. It can be used for formation permeabilities ranging from 50 to 1,000 mD. J484 has been tested for use at a fluid temperatures ranging from 75 to 175 degF [24 to 80 degC].
J555	Gelled brine	CleanSEAL* perforation fluid loss control system	The CleanSEAL system is a highly crosslinked HEC fluid-loss control particle system designed for use after perforating where high loss situations require a low viscosity, nondamaging, bridging agent as is normally required in most sand control applications. It is supplied as a gel particle that is readily dispersed in most completion brines.

## Foaming Agent

Code	Form	Primary Purpose	Summary
F078	Liquid	EZEFLO* F078 Surfactant	Surfactant F078 is an excellent silt-suspending, foam generating and stability characteristics, and provides low surface and interfacial tension qualities. F078 can be used as a surfactant in water, acid, or heavy brines and leaves a water-wet surface condition in both carbonate and sandstone formations.
F100	Liquid	EZEFLO surfactants	EZEFLO F100 surfactant is an outstanding foaming and silt-suspending agent that exhibits excellent and stable foam characteristics and silt suspending qualities. F100 is an amphoteric blend; therefore, it is a good surface-active agent in low- and high-pH systems and is generally compatible (depending on the pH of the fluid system) with cationic, anionic and nonionic surfactants.
F107	Clear to yellow liquid	Methanol surfactant foamer	For foam fracturing applications, Methanol Surfactant Foamer F107 is used with methanol containing WF200 fluids. F107 has been investigated using WF220, WF230 and WF240 fluids containing methanol concentrations from 15 to 35 volume percent of the base liquid.
F109	Clear to yellow liquid	Foaming agent	Foaming Agent F109 was developed as a one-for-one replacement for F104 and F052. F109 provides improved stability at elevated temperatures, up to 250 degF [121 degC], for WF100 and WF800 fluid systems in both nitrogen and carbon dioxide foams.

## Friction Reducing Agents

Code	Form	Primary Purpose	Summary
J257	Liquid	Friction reducing agent	Friction Reducing Agent for oil. It is a polymer suspended in kerosene that can be used in crude or refined oils.
J313	Liquid	Friction reducing agent	Water-in-oil emulsion of an anionic polyacrylamide polymer.
J568	Liquid	Gelling agent	Acid gelling agent or friction reducer.
J618	Liquid	Friction reducing agent	J618 is designed to reduce pipe-friction pressure while pumping water or brine in high-rate treatments. J618 hydration occurs rapidly, even in cold water. J618 is also effective in high-salinity and high-hardness waters.

## Gelling Agents

Code	Form	Primary Purpose	Summary
J055	Solid	Gelling agent	Gelling agent for oil-based fluids.
J164	Solid	Gelling agent	Hydroxyethylcellulose. Degrades rapidly above 120 degF [49 degC].
J312	Solid	Gelling agent	Xanthan Gum used primarily in the preparation of stabilized foam fracturing fluids.
J347	Solid	Gelling agent	Hydroxypropyl guar gum (dry) designed for batch mix operations. Applicable temperature is 50 to 200 degF [10 to 93 degC].
J360	Solid	Gelling agent	Used to gel acid. Applicable temperature up to 150 degF [66 degC]. It contains iron stabilizers and provides iron control for normal levels of ferric iron.
J369	Liquid	Gelling agent	Liquid brine thickener HEVIPACK I. Applicable BHST less than 200 degF [93 degC].
J419	Liquid	Gelling agent	Liquid brine thickener HEVIPACK II. Applicable BHST less than 200 degF [93 degC].
J422	Liquid	Gelling agent	Liquid brine thickener HEVIPACK III. Applicable BHST less than 200 degF [93 degC].
J424	Solid	Gelling agent	Guar gum (dry) designed for batch mix operations. Applicable temperature is 50 to 200 degF [10 to 93 degC].
J425	Liquid	Gelling agent	Gelling agent used in the DGA200 Gelled Acid Series. Applicable temperature up to 150 degF [66 degC].
J429	Liquid	Gelling agent	Used in particular in the LCA systems. Applicable temperature up to 200 degF [93 degC].
J433	Liquid	Gelling agent	High molecular weight acrylamide-acrylate copolymer emulsified in a hydrocarbon. The polymer as delivered is 31% active. Used in the MARCIT or Organo SEAL-F technology. Applicable temperature up to 250 degF [121 degC] for Organo SEAL-F and 200 degF [93 degC] for MARCIT.
J443	White powder	Gelling agent	Acid gelling agent.
J491	Granular solid	Gelling agent	Low molecular weight polymer (500,000) with an approximate 5% degree of hydrolysis. This polymer is suitable for near-wellbore water shutoff treatments using in the MARA-SEAL or Organo SEAL-R* organic crosslinked gel. Applicable temperature up to 325 degF [163 degC].
J507	Liquid	Gelling agent	Acid/water gelling agent used in particular in the LCA systems and DGA400 fluids. Applicable temperature up to 300 degF [149 degC]. J507 is specially formulated for application in the North Sea. Effective for use as a friction reducer at low concentrations.
J509E	Milky liquid	Gelling agent	High molecular weight liquid dispersion polymer. The polymer as delivered is 50% active. Used for the MARCIT and OrganoSEAL-F gel technologies. Applicable temperature up to 250 degF [121 degC].

## Gelling Agents (continued)

Code	Form	Primary Purpose	Summary
J512	Liquid	Gelling agent	Liquid HEC used in the PROTECTOZONE-VP fluid technology.
J519	White granules	Gelling agent	High molecular weight polymer with an approximate 10% degree of hydrolysis. Used in the MARCIT and in the OrganoSEAL-F technologies. Applicable temperature up to 250 degF [121 degC].
J521	Granular powder	Gelling agent	High molecular weight polymer for use in HT and/or high-brine environments. This polymer is suitable for fracture/fissure water control treatments using the OrganoSEAL-F crosslinking technology. Applicable temperature from 175 to 325 degF [79 to 163 degC].
J522	Solid	Gelling agent	High molecular weight (2 million) polymer with a degree of hydrolysis less than 1%. Used for foamed gels.
J551A	Clear yellow liquid	Gelling agent	ClearFRAC fluids LT J551A are water-based systems composed of a viscoelastic surfactant (J551A) in J534 brine.

## H<sub>2</sub>S Scavengers

Code	Form	Primary Purpose	Summary
A255	Liquid	H <sub>2</sub> S scavenger	Is used to control the corrosive effects of H <sub>2</sub> S that may be present in acidizing fluids. It was developed to aid the inhibition of hydrochloric acid (5% to 28%), Mud Acid (6% HCl + 1.5% to 12% HCl + 3% HF) and special acid systems (MSR, DAD and Clay Acid) in sour environments. Applicable temperatures up to 325 degF [163 degC] and protection times up to 24 hr for most hydrochloric acid and Mud Acid systems.
A284	Liquid	Hydrogen sulfide scavenger	A284 H <sub>2</sub> S scavenger is designed to control the corrosive effects of hydrogen sulfide (H <sub>2</sub> S) that may be present in acidizing fluids due to dissolution of sulfide scales or contact with sour well fluids. A284 H <sub>2</sub> S scavenger removes H <sub>2</sub> S from acids by reacting to form stable organic sulfide compounds. A284 H <sub>2</sub> S scavenger aid inhibition of hydrochloric acid, mud acid, and other select acid systems (MSR*, DAD*, and clay acid) in sour environments. A284 is developed to be a replacement for H <sub>2</sub> S scavenger A255.
M295	Liquid	Scavenger for hydrogen sulfide	Hydrogen sulfide scavenger.

## Mutual Solvent

Code	Form	Primary Purpose	Summary
U066	Colorless-white liquid	Mutual solvent	A multifunctional nonionic agent, soluble in acid, oil, and water. It serves as a wetting agent, a surface-tension reducer, an interfacial tension reducer and a nonemulsifier/demulsifier.
U067	Liquid	Mutual solvent	Schlumberger mutual solvent U067 is a propyleneglycol ether that acts as a multifunctional nonionic agent. It is highly soluble in stimulation fluids, including those that have a high salt content (such as U820, U821 and OCA matrix acidizing fluid system). When these solvents are used at high concentrations, mutual solvents U066 and F105 are not soluble in them to a high enough concentration to be effective. Thus, U067 was developed to be usable in solutions where other mutual solvents are not soluble.

## Iron Control Agents

Code	Form	Primary Purpose	Summary
J471A	Liquid	Iron stabilizing agent—LCA and SDA	Iron control agent specific to LCA fluids. Applicable temperature up to 300 degF [149 degC]. This will reduce up to 12,000 ppm of ferric iron. Add 1 gal/1,000 gal for each 1,200 ppm of ferric iron in excess of 12,000 ppm.
L001	Solid	Iron stabilizing agent	Iron stabilizing agent.
L058	Solid	Iron stabilizing agent	An effective additive for preventing the precipitation of ferric hydroxide from spent acid. It reduces the ferric ion (Fe <sup>+3</sup> ) to the more soluble ferrous ion (Fe <sup>+2</sup> ) state. Treating temperature does not affect the performance of L058. Only 5 lbm of L058/1,000 gal of acid will stabilize 1,000 ppm of ferric iron.
L062	Solid	Iron stabilizing agent	L062 is a chelating agent for use in acid. Because it contains no potassium or sodium, it can be used in mud acids without the possibility of forming insoluble hexafluosilicates. Applicable temperatures to at least 400 degF [204 degC].
L063	Liquid	Iron stabilizing agent	Iron Reducing Agent L063 is recommended for use with MISCA fluid. L063 is the agent of choice if well temperature is less than 175 degF [79 degC].
L073	Liquid	Iron reducing agent	L073 iron reducing agent is designed to prevent the precipitation of ferric (Fe <sup>+3</sup> ) hydroxide during acidizing treatments. L073 iron reducing agent reduces the ferric iron to the more soluble ferrous (Fe <sup>+2</sup> ) iron. When combined with W064 emulsion and sludge preventer, L073 is very effective at reducing iron and preventing acid sludge formation in heavier oil reservoirs.
L400	Colorless liquid	Iron stabilizing agent	Iron control agent.

## Miscellaneous Additives

Code	Form	Primary Purpose	Summary
D075	Colorless liquid	Sodium silicate additive	Used in the PERMABLOK* fluids system to permanently plug a zone. For all applications up to 194 degF [90 degC] except zone consolidation. From 194 degF [90 degC] to the maximum application temperature of 266 degF [130 degC] different concentrations apply. For zone consolidation, the concentration should be higher at any temperature.
D079	White solid	Silicate additive	Sodium metasilicate.
D140	Yellow liquid	Hardener, low-temperature	Used in the PERMABLOK system. Concentration by volume of solution depending on temperature required gel time and rigidity. Applicable temperature up to 176 degF [80 degC].
J170	Solid	Plugging agent, low-temperature	LT (50 to 200 degF [10 to 93 degC]) plugging agent used in the PROTECTOZONE fluid.
J171	Solid	Plugging agent, HT	HT (200 to 325 degF [93 to 163 degC]) plugging agent used in the PROTECTOZONE fluid.
J467	Solid	Plugging agent	Used in the DGS* delayed gelation system. Applicable temperature up to 200 degF [95 degC].
J473	Yellow liquid	Coalbed methane agent	Used with fracturing treatments as well as with matrix treatments to enhance the methane gas production from coals. Its bottomhole temperature range of effectiveness is from 60 to 200 degF [16 to 93 degC].
M011	Liquid	Buffering agent	Ammonium hydroxide (aqua ammonia).
M024	Powder	Breaker	Internal chemical breaker used in the PROTECTOZONE fluid. It should be used at temperatures between 135 and 200 degF [58 and 93 degC].

## Oxygen Scavengers

Code	Form	Primary Purpose	Summary
J353	White granules	HT gel stabilizer	Oxygen scavenger. Used as HT gel stabilizer in YF fluids at temperatures greater than 200 degF [93 degC].
J353L	Liquid	HT gel stabilizer	Solution of J353 in water.

## Organic Scale Dissolvers/Inhibitors/Dispersants

Code	Form	Primary Purpose	Summary
A026	Colorless liquid	Paraffin dissolver	Xylene. Used in different stimulation systems such as CLEAN SWEEP* solvent systems for damage removal or DAD* dynamic acid diversion. Also used as paraffin solvent.
P121	Clear liquid	Solvent	P121 is a toluene solvent particularly effective for highly asphaltic paraffin deposits as well as those more paraffinic in nature. Minimum quantities to use are based on gal per net ft formation.
P124	Clear liquid	Paraffin inhibitor	Dual function inhibitor that can dissolve existing paraffin deposits while preventing the formation of additional paraffin crystals.
P124A	Liquid	Paraffin inhibitor	P124A paraffin inhibitor prevents the foamation of paraffin crystals in crude oil. It modifies wax crystalline structures present in paraffinic crude oil, lowering the pour point. To be effective, P124A paraffin inhibitor must be present in the oil before wax crystallization occurs.
P130	Clear liquid	Solvent	PARAN* paraffin solvents for wellbore cleaning.
P131	Liquid	Asphaltene dissolver	P131 is a synergistic blend of solvent and cosolvent that is highly effective for removing asphaltene deposits.
P800		Paraffin dissolver	Field blend. Will dissolve and disperse paraffin deposits. It is designed for downhole applications. It can be used as a concentrate or can be added to water- or acid-base treating fluid.
P801		Paraffin dissolver	Field blend. Will dissolve and disperse paraffin deposits. It is designed for downhole applications. It can be used as a concentrate or can be added to water- or acid-base treating fluid.
P802		Intensifier A	Used in conjunction with either P800 or P801, aids in paraffin dispersion and increases the potential for the amount of paraffin removed. It is mildly acidic and should be used with treating fluids where acid will not be detrimental.
P803		Intensifier B	Used in conjunction with either P800 or P801, aids in paraffin dispersion and increases the potential for the amount of paraffin removed. It is mildly acidic and should be used with treating fluids where acid will not be detrimental.
U082	Liquid	Paraffin dispersant	A blend of surfactants and hydrocarbon solvents which are easily dispersed in a carrier fluid of fresh water, high salinity seawater, or acid. Effective in the removal of paraffin. To avoid potential redeposition of paraffin, the temperature of the U082/carrier fluid dispersion should not be higher than the temperature in the well where the paraffin formed.

## Resin Consolidation System Components

Code	Form	Primary Purpose	Summary
K187	Liquid	Catalyst	Used in SANDLOCK sand control service.
K230B	Liquid	Resin solution	Used in the SANDLOCK sand control service. Temperatures are limited to less than 225 degF [102 degC].
K235B	Liquid	Curing agent	Used in the SANDLOCK sand control service. Temperatures are limited to less than 225 degF [102 degC].
K300	Dark liquid	Furan resin	K300 is a mixture of furan resin and a solvent, and contains a coupling agent and surfactant.

## Inorganic Scale Removal and Inhibition

Code	Form	Primary Purpose	Summary
L056	Solid	Scale dissolver	Scale removal agent L056 can be used to dissolve scale and to chelate the dissolved metal ions. Applicable temperature up to 400 degF [204 degC].
U104	Colorless liquid	Scale dissolver for sulfates	Sulfate scale remover. Stable at very high temperature (greater than 450 degF). Will remove barium, strontium, and calcium sulfate scales by chelating the scale during 24 to 36 hr soak time.
U105	Colorless liquid	Scale dissolver for carbonates	Chelating agent stable at high temperature (greater than 450 degF).
L047	Liquid	GYPBAN* scale inhibitors	L047, a strongly acidic material, is recommended to prevent deposition of calcium, strontium and barium scales. L047 is a complex phosphonate compound. Scale deposition is usually controlled by 1 to 10 ppm of active ingredient. It can be used at temperatures up to 350 degF [177 degC]. Concentration range varies for control of carbonate and sulfate scales which may form in the presence of spent acid.
L059	Solid	Scale inhibitor aid	Inorganic compound which precipitates L047 scale inhibitor to extend the life of the treatment.
L065	Liquid	Scale inhibitor	A phosphino-polyacrylate scale inhibitor system compatible with ScaleFRAC* scale inhibitor service and ClearFRAC fluids. It is effective against all common carbonate and sulfate scales. Applicable temperature up to 350 degF [177 degC]. Minimum loading of 5 gals B034/1,000 gals of carrying fluid is required for adequate inhibitor retention.
L066	Liquid	Acid compatible scale inhibitor	Acid compatible scale inhibitor L066 is a polymeric scale inhibitor that has been developed especially for use in the ScaleMAT*service when performing matrix stimulation treatments. This application provides more effective placement of the scale inhibitor compared to squeeze treatments and directly protects the stimulated matrix.
L069	Solid	Scale inhibitor	L069 is a slow-release polyphosphonate-based solid scale inhibitor that can be added during the pumping of the slurry stages of a propped-fracturing treatment. This integrates the fracturing treatment and scale inhibition into one step. The treatment lifetime depends on the temperature and the amount of water that is produced. Post-treatment monitoring is performed to determine the level of protection. L069 scale inhibitor is not for use in a fluid system with pH < 4.
L070	Liquid	Salt inhibitor	L070 is specifically formulated to prevent halite deposition in sandstone reservoirs with temperature up to 195 degF [95 degC]. In reservoirs that produce water with high salt concentration, crystallization can occur in the formation, wellbore, and surface facilities. The L070 is squeezed into the formation and slowly released into the produced water during production.

## Stabilizing Agents

Code	Form	Primary Purpose	Summary
J353	White granules	HT gel stabilizer	Oxygen scavenger. Used as HT gel stabilizer in YF fluids at temperatures greater than 200 degF [93 degC].
J353L	Liquid	HT gel stabilizer	Solution of J353 in water.
J450	Colorless liquid to straw color liquid	Stabilizer	Prevents polymer degradation above 200 degF [93 degC].

## Surfactants

Code	Form	Primary Purpose	Summary
F038	Liquid	Surfactant	Cationic surfactant for acid or water.
F040	Liquid	EZEFLO surfactant	Nonionic surfactant for acid and water. Use also as foaming agent. Recommended concentrations changes if the product is used: <ul style="list-style-type: none"> <li>• as an additive in stimulation fluids</li> <li>• for continuous treatment of injection water</li> <li>• for batch or slug treatment of injection water</li> <li>• as a foaming agent in water or brine.</li> </ul>
F078	Liquid	EZEFLO surfactant	Cationic/amphoteric surfactant with excellent silt-suspending qualities. Used also as a foaming agent.
F097	Liquid	Surfactant	Nonionic surfactant used to prepare MudCLEAN* OB chemical wash for mud removal.
F099	Liquid	Coupling additive	Coupling agent (solubilizing additive) used in MISCA* solvent for iron and sludge control. Applicable temperature up to 250 degF [121 degC].
F103	Liquid	EZEFLO surfactant	EZEFLO F103 surfactant is a surface-active agent for use in hydrochloric acid (HCl), mud acid (HCl-HF) and other aqueous-base stimulation fluids.
F105	Liquid	Multifunctional surfactant	Multifunctional surfactant F105 is a unique blend of nonionic surfactants, alcohols and glycol ethers. This proprietary multifunctional surfactant blend functions as a water-wetting agent or foaming agent in water- or acid-base stimulation fluids.
F108	Liquid	EZEFLO surfactant	EZEFLO F108 surfactant is a surface-active agent for use in aqueous-base stimulation fluids. The F108 surfactant works on an alternative principle of lowering the capillary pressure by improving the wettability of the pore throat. F108 promotes fracturing fluid cleanup of the proppant-pack and the invaded rock matrix because the contact angles resulting from the use of F108 are higher than those for other conventional cleanup surfactants. F108 will leave both sandstone and limestone formations water wet. F108 was developed for use in the Gulf of Mexico and meets the toxicity, oil, and grease and sheen criteria as set by the regulating authorities.
F110	Liquid	EZEFLO surfactant	EZEFLO F110 surfactant is a nonionic surface-active agent for use in aqueous-base stimulation fluids. The surface-active properties of F110 are similar to F103; therefore, F110 can be used in the same fracturing applications as F103.
F111	Clear light yellow Liquid	EZEFLO microemulsion surfactant	The F111 microemulsion is a microemulsion (clear mixture of solvent, surfactant, and cosurfactant) designed specifically for use in aqueous-base stimulation fluids. Used to lower the interfacial tension that restricts fluid flow in the rock matrix as well as to lower the capillary pressure by improving the wettability of the pore throat.

# Stimulation Systems

## Matrix Stimulation Systems

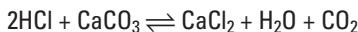
### Hydrochloric Acid

#### SUMMARY

Hydrochloric acid is a solution of hydrogen chloride (HCl) in water. The strength of acid depends on how much HCl gas is dissolved in a given quantity of water and is specified as a percentage by weight. The maximum concentration of commercial grade HCl is typically 36%, however applications for oilfield treatments is generally limited to 28%.

The concentration of HCl can be determined by measuring the specific gravity of the acid solution or by a simple titration with a known base (ex. Sodium hydroxide, NaOH).

HCl is used primarily in stimulation treatments for carbonate reservoirs due to the straightforward chemical reaction that can create additional pathways for the reservoir fluids to flow into the wellbore.



*Reaction of HCl with limestone as pure calcium carbonate*

HCl is used as a preflush for stimulation treatments in sandstone reservoirs to remove carbonate minerals prior to being contacted by the main sandstone acid system containing hydrofluoric acid (HF). The reaction of HF and carbonate minerals will form damaging, insoluble precipitates that can result in a reduction in well productivity.

HCl is also used for many other oilfield applications such as breakdown fluid for perforations, scale removal, gel damage removal, etc.

#### TEMPERATURE

HCl can be inhibited up to 300 degF [149 degC] using appropriate corrosion inhibitors and inhibitor aids. Higher temperatures are possible depending on the metallurgy of the materials that are contacted, the exposure time at temperature, and the protection time required.

#### APPLICATIONS

- Matrix stimulation treatment in carbonate reservoirs
- Hydraulic fracturing stimulation treatment in carbonate reservoirs
- Preflush for matrix stimulation treatments in sandstone reservoirs
- A component of the Mud Acid system for matrix stimulation treatments in sandstone reservoirs
- As a component of other matrix stimulation fluid systems
- Carbonate scale removal in the wellbore and the formation for both carbonate and sandstone reservoirs

### Mud Acid

#### SUMMARY

Mud acid is a mixture of inhibited hydrochloric acid (HCl) and hydrofluoric acid (HF). Mud acid will dissolve all of the minerals that are soluble in 15% HCl. In addition, it will dissolve siliceous minerals such as bentonite, naturally occurring formation clays, and other siliceous minerals, all of which are only partially soluble in HCl.

Calcium and magnesium chlorides plus sodium and potassium brines will react with HF to form insoluble precipitates. Thus, pretreatment with HCl ahead of Mud acid and as an over flush behind is technically sound and is a common practice.

#### TEMPERATURE

Mud acid and super mud acid can be inhibited at temperatures up to 400 degF [204 degC] using the appropriate corrosion inhibitors and corrosion inhibitor aids

### Main mud acid formulations

- Dilute mud acid: any solution containing up to and including 7.5% HCl and 1.5% HF. Used to restore permeability to sandstone formations.
- Regular mud acid: any solution containing 7.6 to 12.0% HCl and 1.6 to 3.0% HF. Used to restore permeability to carbonate cemented sandstone formations.
- Super mud acid: any solution containing 12.1 to 16% HCl and 3.1 to 6.0% HF. Used to restore permeability to carbonate cemented sandstone formations that are extensively damaged or have a high clay content.

### Mud acid selection

The criteria for selecting the mud acid formulation, basically the HCl/HF ratio depends on several factors that includes the rock mineralogy, formation damage, rock permeability and well conditions.

The cleaner the sandstone (lower silt and clay content) and the higher the permeability, the lower the HCl:HF ratio, and the more aggressive the treatment can be. Typically, the HCl:HF ratio is either 4:1, 6:1, or 9:1. A higher volume of weak acid must be pumped to attain the same results as a smaller volume of a stronger acid. This is an important consideration when designing treatments for environmentally sensitive areas where disposing spent acids can create problems. The ratio of HCl:HF should be increased if the formation contains clay rather than calcite cementing materials. Mud acids should only be used in formations with less than 20% carbonate (containing minerals) because of the increased risk of forming damaging calcium fluoride precipitates at higher carbonate content. HCl or acetic acids are used for these formations. The specific acid used is dependent upon

reservoir temperature and the presence of HCl sensitive clays. More information about fluid selection can be found in the Matrix Fluid Selection Guide, InTouch ID 3279225.

Treating fluid compatibility with the rock is an important factor. This concept of compatibility is more relevant for sandstones, where many damaging reactions may occur.

## APPLICATIONS

Mud acid is applicable in the following cases:

- The average formation solubility in HCl acid is less than 20%
- The formation solubility in mud acid is at least 15% and should be at least 10% greater than the solubility in HCl
- Mud acid is also applicable as a wellbore cleanup treatment when clays or other siliceous materials have damaged a formation

Super mud acid is used in formations having high Mud Acid solubility or that are extensively damaged. Special care must be taken to assure the separation of fluoride ions and ions of Na, K, Ca, and Mg.

## Clay Acid

### SUMMARY

Clay acids are designed specifically for acidizing sensitive sandstone formations. They not only provide good stimulation, but also provide permanent stabilization of clays and other fines, eliminating water sensitivity and the mobility of migratory fines. Clay acids slowly release hydrofluoric acid (HF) from the hydrolysis of fluoboric acid ( $\text{HBF}_4$ ) and can penetrate to a much greater distance from the wellbore before spending than can mud acid.

### TEMPERATURE

Clay acid can be inhibited at temperatures up to 400 degF [204 degC] using the appropriate corrosion inhibitors and corrosion inhibitor aids.

## Clay acid formulations

There are four formulations of clay acid:

- Full strength clay acid or regular clay acid: recommended for use in a treating temperature range of 130 to 300 degF [54 to 149 degC].
- Half-strength clay acid: recommended for high quartz (greater than 80%), low clay (less than 10%) content sands.
- Full strength clay acid LT (low-temperature formulation): contains more hydrochloric acid (HCl) than regular clay acid, which aids in the hydrolysis of  $\text{HBF}_4$ , releasing HF at a faster rate. Clay Acid LT allows much shorter shut-in times and is recommended in the formation temperature range of 100 to 130 degF [38 to 54 degC].
- Half-strength clay acid LT.

## APPLICATIONS

- Clay acids are suitable for a wide variety of applications, which include: use as an overflush fluid behind a conventional matrix acidizing treatment, as a preflush fluid ahead of a matrix acid treatment, and as a sole stimulation fluid

## Alcoholic Acid

### SUMMARY

Alcoholic acid formulations are a mixture of acid and alcohol. The acids normally employed are usually either hydrochloric acid (HCl) or mud acid (HCl + HF). It can be one of the organic acids such as formic or acetic. The alcohol of choice is either methyl or isopropyl. Alcohol is not intended to replace mutual solvents in most applications.

Suggested concentrations are 20% by volume of isopropyl alcohol and 30% by volume of methyl alcohol. The ratio terminology for alcoholic acid always lists the percent by volume of acid first. For example, a 70:30 mixture of acid and methanol contains 70% acid and 30% methanol by volume.

### FEATURES

- Alcohol lowers the surface tension of acid and allows deeper penetration of the acid into the matrix of the rock
- Mixing alcohol with acid lowers the acid/mineral reaction rate and provides a retarding effect
- Cleanup is facilitated because acid surface tension is decreased by alcohol while the vapor pressure of the mixture is increased, which improves gas permeability by reducing water saturation
- Alcoholic acids are often used to remove water blocks; alcohol is soluble to an extent in both acid and water, and penetration of low-surface-tension volatile alcohol into the water block will aid in its removal

### APPLICATIONS

- The main application of alcoholic acid is in low-permeability dry gas zones

## Gas Well Acid

### SUMMARY

Gas well acid is 15% hydrochloric acid (HCl) prepared by diluting concentrated HCl with methanol K46. It contains approximately 67% by volume of methanol. Its principal advantages are its slow reaction rate and improved cleanup properties. The low surface and interfacial tensions of spent acid and its increased volatility assure rapid cleanup.

### TEMPERATURE

Gas well acid may be used at temperatures up to 225 degF [107 degC]; corrosion inhibitor, A262 is the inhibitor of choice

### FEATURES

- Improved cleanup
- Retarded reaction rate
- Lower surface tension and interfacial tension reduces the capillary forces, which restrict fluid movement, causing the improved flow of the spent acid
- Increased volatility of the spent acid; the high alcohol content gives the spent acid a lower boiling point and causes it to readily vaporize, which reduces water saturation resulting in higher relative permeability to gas

- Retarded acid; when alcohol replaces part of the water in an acid solution, the degree to which HCl can effectively ionize is reduced; the rate of reaction of gas well acid is approximately one-half that of regular 15% HCl

#### APPLICATIONS

- Matrix acidizing of dry gas wells and gas storage wells

## Gas Well Mud Acid

#### SUMMARY

Gas well mud acid contains 8% hydrochloric acid (HCl) and 3% hydrofluoric acid (HF) by weight plus methanol K46. Its principal advantages are its slow reaction rate and improved cleanup properties. The surface and interfacial tensions of spent acid, as well as its high volatility assure rapid cleanup.

The concentration of K46 can vary from 53 to 80% by volume depending on the composition of bulk acids used in the preparation of this system.

Gas well super mud acid, a mixture of 8% HCl, 6% HF and K46 methyl alcohol, can be used in formations where clay content is very high (greater than 20%). Gas well acid must be used as a preflush ahead of gas well super mud acid.

#### TEMPERATURE

Gas well mud acid may be inhibited against corrosion up to 225 degF [107 degC]; corrosion inhibitor A262 is the inhibitor of choice

#### FEATURES

- Improved cleanup
- Reaction rate retardation; the presence of alcohol slows the ionization rate of the acid, thus reducing the reaction rate, and enabling deeper penetration of live acid into the formation
- Lower interfacial tension, which reduces the capillary forces restraining fluid movement, thus resulting in the improved cleanup of the spent acid
- Increased volatility of the spent acid; the high methanol content gives the spent acid a lower boiling point and causes it to evaporate much more readily than conventional acid systems. This reduces the water saturation resulting in a higher relative permeability to gas.

#### APPLICATIONS

- Gas wells are the primary candidates for treatment with gas well mud acid

## DAD\* Dynamic Acid Dispersion

#### SUMMARY

DAD\* dynamic acid dispersion is a proven and versatile acid outside-phase dispersion prepared and stabilized with dispersing agent F103, which replaces previous dispersing agent U74. The purpose of the dispersion is to simultaneously dissolve acid-soluble minerals and remove oily paraffin deposits.

The dispersion can be prepared using various acids and hydrocarbon solvents; the most common acid/hydrocarbon solvent in use is 15%

hydrochloric acid (HCl) and PARAN P121 solvent. Ratios of acid/hydrocarbon solvent can be made from 10 to 50%. Other acids may be mud acid, super mud acid, clay acid, organic mud acid or other acid such as 9% organic acid L036. The hydrocarbon solvents, other than P121, may include xylene A26, PARAN PLUS solvent P130.

#### TEMPERATURE

Schedules for corrosion inhibitors are for 90:10 and 50:50 blends of 15% HCl and P121 at temperatures up to 300 degF [149 degC]; corrosion inhibitor data were developed to provide adequate corrosion protection at higher temperatures, but it must be realized that the dispersion itself may not be stable at the higher temperatures

#### APPLICATIONS

- One-stage cleanup and acidizing of hydrocarbon-coated formations, gravel packs, wellbore and tubulars
- Preflush ahead of mud acid or clay acid during matrix treatment procedures
- Cleanup of producing wells being converted to water injection or disposal wells
- Increase of injectivity in injection or disposal wells

## SXE\* Emulsified Acid

#### SUMMARY

SXE emulsified acid is a viscous, highly retarded, concentrated acid system designed for use in matrix acidizing and acid fracturing carbonate formations. SXE acid is an oil external emulsion formed with a 70:30 hydrochloric acid-to-oil ratio, stabilized with an emulsifier. Hydrochloric acid (HCl) concentrations ranging from 7.5 to 28% may be used. The SXE acid is the most efficient acid retarding system offered by Schlumberger. The emulsion retards the acid reaction rate of 28% HCl more than 10-fold. Even greater retardation is achieved at lower acid concentrations. The SXE acid is usually batch mixed due to the time for the mulsifier to properly disperse into the oil phase.

#### TEMPERATURE

- The temperature range for the SXE acid is 75 to 375 degF [24 to 191 degC]

#### FEATURES

- High degree of retardation
- Reduced fluid loss
- Operational range up to 375 degF [191 degC]

#### BENEFITS

- Improved damage bypass via deeper wormhole penetration in HT wells
- Deeper live-acid penetration during acid fracturing and matrix stimulation
- Improved corrosion inhibition

#### APPLICATIONS

- HT matrix stimulation of carbonates reservoirs
- Acid fracturing of HT carbonate reservoirs

## OCA\* Organic Clay Acid Stimulation Fluid

### SUMMARY

OCA fluid is a matrix stimulation system designed for acidizing sandstone formations, with high silt and clay content and HCl sensitive minerals, such as zeolite and chlorite.

### TEMPERATURE

Applicable temperatures range from 80 to 350 degF [27 to 121 degC]

### FEATURES

- Remove formation damage caused by clay and other aluminosilicate minerals
- Minimize hydrated silica precipitation, known as the secondary reaction
- Prevent migration of undissolved fines post acidizing treatments

### APPLICATIONS

- Matrix stimulation in HT sandstone formations, with high silt and clay content, and HCl sensitive minerals, such as zeolite and chlorite

## FinesLOK\* Technique to Prevent Migration

### SUMMARY

FinesLOK technique for fines stabilization is a surface adsorption polymerization reaction resulting in the formation of a solid ultra thin film which is very stable. This film binds clays and fines particles on the rock surface. This process involves adsorption of an ionic surfactant followed by a monomer solution, which preferentially resides in the surfactant layer. An initiator solution is then used to polymerize the monomer on the surface of pore walls forming a solid ultra thin film.

### TEMPERATURE

FinesLOK provides fines inhibition up to more than 400 degF [205 degC]

### FEATURES

- Acid compatible
- Simple to mix and pump
- Provides high retained permeability
- Effective in consolidated and unconsolidated formations

### BENEFITS

- Prolonged fines free production
- Reduced erosion damage to tubular and surface equipment
- Reduced need for work-overs
- Reduced near wellbore damage due to fines migration
- Substantially higher production rates
- Increased recovery
- Higher draw down pressures without fines production

### APPLICATIONS

- Compatible with acid treatments to maintain peak production rates
- Fines inhibitor treatment to prevent fines migration and the resulting effects
- After a CT cleanout where fill from fines production is known to be detrimental to production

## MSR\* Mud and Silt Remover

### SUMMARY

MSR remover is an acid solution containing a clay dispersant-suspending agent and an iron chelating agent. This combination of additives provides not only good dispersion of drilling muds and formation silt, but also provides extremely effective suspension properties.

There are three distinct formulations of MSR remover:

- MSR100 is the most commonly used formulation. The 100 is referring to the amount of iron chelating agent. The carrier fluid is commonly 7.5 to 15% HCl, but it can be ammonium or potassium chloride water.
- MSR150 was developed specifically for formations that contain higher amounts of iron-bearing minerals where chelants are required to prevent reprecipitation of iron from spent acid.
- MSR123 is a special mud acid version. It contains a mutual solvent and the carrier fluid is regular mud acid. A preflush is used ahead of MSR123 (as in most mud acid treatments) to minimize formation damage caused by fluorosilicates precipitation.

### TEMPERATURE

Applicable temperatures up to 350 degF [177 degC]

### APPLICATIONS

- The removal of drilling mud damage in carbonate and sandstone formations
- As a breakdown or matrix treating fluid to open clogged perforations and restore permeability
- In matrix acidizing to remove damage from the critical matrix
- To restore natural permeability in fissured or fractured reservoirs following mud losses

## NARS\* Formation Solvent 200 and 201

### SUMMARY

NARS solvent (Nonacid Reactive Solutions) NARS 200 and NARS 201 are intended for use as formation cleanup and breakdown fluids in those formations that may be damaged by acid. These solutions do not contain low pH acids but instead are alkaline in nature and contain strong chelating and clay control additives. Additionally, they contain mutual solvents that enhance water wetting. The chelating additive present in both of these solutions behaves as a solvent, dissolving or partially dissolving some of the minerals present in sandstones. Affected minerals include those that contain iron, calcium, magnesium, and aluminium.

Containing no acid in the conventional sense, NARS solvents are slightly alkaline, having a pH of between 10 and 11. Corrosion inhibitors are not required.

### TEMPERATURE

It is recommended for use in formations with BHST between 150 to 300 degF [66 to 149 degC].

### NARS 200 solvent

NARS 200 solvent is a clay dispersing and suspending fluid that contains F78. When a strong clay dispersing agent is desired for use as a perforating fluid or a cleanup fluid NARS 200 solvent is preferred.

### NARS 201 solvent

NARS 201 solvent is a clay flocculating and stabilizing fluid that contains F103 and clay stabilizer L55. NARS 201 solvent should be used when it is required to stabilize clay particles in place. When a breakdown or spearhead fluid is used in a zone where produced fines may later become a problem, NARS 201 may be preferred to take advantage of clay flocculating and permanent stabilizing properties. For example, NARS 201 solvent would be advantageous in treating injection wells where the formation might later be exposed to fresh water.

### APPLICATIONS

- Acid-sensitive formations
- Breakdown acid
- HT, harsh-environment wells where corrosion inhibition might be a problem

## Organic Acids

### SUMMARY

Organic acid L036 (formic acid) can be used at concentrations up to 9% as an acid to stimulate oil and gas wells. L036 reacts slowly with carbonate formations and many minerals present in sandstone formations.

L036 has a reaction rate intermediate between 15% HCl and 10% aqueous acetic acid. Its dissolving power is also intermediate between 15% HCl and 10% acetic acid.

### TEMPERATURE

Applicable temperatures up to at least 400 degF [204 degC]

### APPLICATIONS

- Matrix stimulation of oil and gas wells

## Organic Mud Acids

### SUMMARY

Organic mud acid is a mixture containing 9% organic acid L036 (formic acid) and 3% hydrofluoric acid (HF). It is less corrosive than comparable HCl + HF mixtures and is easily inhibited to protect the tubulars from acid corrosion. As a result, low corrosion rates can be maintained at high treating temperatures.

In addition, it provides a reduced relative reaction and has a reduced tendency to form asphaltic sludge when it contacts crude oils.

### TEMPERATURE

Applicable temperatures up to at least 300 degF [149 degC]

### APPLICATIONS

- HT matrix acidizing and wellbore damage removal in sandstone or limestone reservoirs where extended pipe contact time is anticipated
- Reservoirs where asphaltic sludges form when contacted by hydrochloric acid (HCl)
- HT acid breakdown

## MISCA\* Solvent for Iron And Sludge Control

### SUMMARY

MISCA solvent (micellar iron and sludge control acid), is designed to prevent the formation of asphaltic sludges when acid, containing dissolved ferric iron, contacts crude oil.

Exposure of crude oil to a MISCA solvent does not normally result in the formation of asphaltic sludge. After considerable contact time, a crude oil/MISCA solvent mixture will easily pass through a 100-mesh screen. Washing any residue with warm water will cause it to easily wash through the screen.

MISCA solvent must be formulated for each individual crude oil. The acid normally used with a MISCA solvent is 15% hydrochloric acid (HCl).

### TEMPERATURE

Applicable temperature up to 250 degF [121 degC]

### APPLICATIONS

- To prevent the formation of sludge during matrix acidizing in specific reservoirs (Canada)

## OneSTEP\* Simplified Sandstone Stimulation System

### SUMMARY

The OneSTEP system is a single stage, proprietary chelant-based fluid system containing an HF source. The chelant component renders the calcium and magnesium ions unavailable for precipitation reactions, all in a single step. This also applies to any iron in solution, removing the risks of unwanted iron hydroxide precipitates. Additionally, because it is a single stage fluid, risks associated with inadequate design and execution are minimized, leading to a higher success rate. Also, its reactive nature reduces the chances of deconsolidation and near-wellbore spending of the fluid. There is less of a tendency for sludge and emulsions to form with crude oils.

### FEATURES

- Replacement of multiple fluid stages with a single stage
- Mitigation of risks associated with secondary and tertiary precipitates
- Stimulating acid-sensitive formations containing minerals such as zeolites or chlorite
- Less tendency for acid emulsion and sludge formation
- Removal of damage caused by carbonates, drilling fluids, clays, and other aluminosilicates

### BENEFITS

- Less complexity than pumping multiple fluid system sequences for several stages
- Production increase with minimal risk of damage
- Safer operations with less corrosive fluid

### APPLICATIONS

- Oil and gas production wells and injector wells
- Complex, multilayer sandstone formations
- Formation temperatures of 200 to 375 degF [95 to 190 degC]
- Formations with complex mineralogy including clays, carbonates, and a mixture of both

## Diverting Systems

### OilSEEKER® High-Water-Cut Acidizing Diverter

#### SUMMARY

OilSEEKER® diverter, a solids free fluid, is used for matrix stimulation applications to divert acid away from a high-water-saturation zone (water zone) into a hydrocarbon-rich zone. It can also be used to divert treating fluids away from a thief zone into a lower permeability and/or damaged zone.

The OilSEEKER diverter is compatible with sandstone and carbonate formations in oil and gas condensate wells.

#### TEMPERATURE

Applicable operational temperature range from 75 to 250 degF [24 to 121 degC]

#### FEATURES

- Nonpolymeric, nonparticulate aqueous system
- Gelation in water-saturated matrix or fissure
- Nondamaging to the formation
- No nitrogen requirement

#### BENEFITS

- Avoid formation damage and slow clean up
- Allows preferential treatment of oil zones
- Improves zonal coverage during matrix stimulation
- Improves treatment success

#### APPLICATIONS

- Acid diversion during matrix stimulation of sandstone or carbonate formations with or without high-water-cut

## FoamMAT® Foam Diversion Service for Matrix Treatments

#### SUMMARY

FoamMAT service is designed to improve the diversion of treating fluids during matrix acidizing treatments. Diversion is achieved by generating and maintaining a stable foam, in the high permeability zones, during the entire treatment. The result is complete zone coverage by the treating fluid and effective damage removal, even from severely damaged zones.

#### TEMPERATURE

Applicable temperature range up to 300 degF [149 degC]

#### APPLICATIONS

- Oil and gas wells
- High-water-cut wells with oil/water contact
- Water-injection wells

## SDA\* Self-Diverting Acid

#### SUMMARY

SDA acid contains a unique chemical system that reduces fluid loss during acid treatments of carbonate reservoirs. The SDA acid blocks the growth of wormholes by temporarily forming a barrier in the wormhole. This barrier halts channel growth, thereby reducing the loss of fluid from the wormholes. After the acid has spent, the barrier breaks and the SDA acid returns to its original viscosity.

SDA acids contain no solids or particulates, which could bridge when pumping through CT. They can be used in either cased or openhole completions.

#### TEMPERATURE

SDA fluids can be used at fluid temperatures less than 300 degF [149 degC]. At temperatures greater than 200 degF [93 degC], wormhole growth and the resulting acid fluid loss are not as significant as they are at lower temperatures, especially in very tight reservoirs.

#### FEATURES

- Nonparticulate aqueous system
- Crosslinks in thief zones, wormholes, and fissures
- Nondamaging to the formation
- Nitrogen-free

#### BENEFITS

- Diverts stimulation fluid into damaged and/or low-permeability zones
- Cleans up rapidly
- Can be pumped through CT or sliding sleeve for operational flexibility
- Reduces treatment cost

#### APPLICATIONS

- Matrix stimulation of limestone and dolomite reservoirs
- Wells with BHST up to 300 degF [149 degC]
- Horizontal and vertical wells
- Cased or openhole completions

## Matrix Acidizing Diverting Agent J237A

#### SUMMARY

Matrix acidizing diverting agent J237A is an excellent diverter when matrix treating sandstone reservoirs. It contains a combination of agents that produces a filtercake with a low permeability, which effectively diverts the treating acid into other zones. The solid resins that comprise the bulk of the product are completely oil soluble and clean up readily by dissolving in produced crude oil. Another effective feature of J237A is that it will pass through a gravel-packed column, yet filter out on the formation to provide diverting action.

## TEMPERATURE

The upper temperature limit of J237A is 200 degF [93 degC]. It can be used at higher temperatures providing adequate cool-down procedures are used to provide a carrier-fluid temperature of 200 degF [93 degC] or less.

## APPLICATIONS

- Matrix acidizing of sandstone reservoirs
- Matrix acidizing of oil and gas wells
- Gravel-packed wells

## VDA\* Viscoelastic Diverting Acid

### SUMMARY

The VDA\* Viscoelastic Diverting Acid displays unique properties based on Schlumberger viscoelastic surfactant technology capable of covering a wide temperature range to 300°F. The use of viscoelastic surfactant technology eliminates the damage associated with solids and polymers in matrix treatment.

The VDA system may be used as the sole treating fluid or for diversion when used in conjunction with other treating acids. The VDA fluid maintains an ideal, thin consistency while being pumped into the well. Upon acid spending, the fluid rapidly develops viscosity in-situ and becomes self-diverting. The viscosity buildup serves as a barrier to reduce the development of dominating wormholes and allows movement of the fluids to stimulate other untreated zones.

The primary benefit of VDA fluids is that they can be bullheaded and still provide total zonal coverage. In horizontal and extended reach wells, VDA fluid is ideal for pumping through coiled tubing as they contain no solids that could cause bridging. In reservoirs having either multiple layers or long production intervals, the rapid buildup in viscosity creates a temporary barrier that diverts the remaining fresh acid into the more highly damaged or lower-permeability zone. It is the development of viscosity that reduces fluid leakoff and gives the fluid its self-diverting property to ensure coverage of the entire interval.

### FEATURES

- Solids and polymer-free
- Applicable up to a reservoir temperature of 300 degF [149 degC]
- Rapid viscosity development upon acid spending
- High viscosity and stability of the spent fluid

### BENEFITS

- Self-diverting acid system for improved zonal isolation
- Easy fluid recovery and well cleanup with no residual damage
- Single treatment fluid for more simplified operational execution

### APPLICATIONS

- Stimulation in carbonate reservoirs
- Oil producers and water injection wells
- Multilayered reservoirs and long production intervals
- Reservoirs with variations in permeability
- Horizontal and vertical wells
- Bullheading or pumping through coiled tubing

## MaxCO<sub>3</sub> Acid\* Degradable Diversion Acid System

### SUMMARY

The MaxCO<sub>3</sub> Acid system is designed for use on wells where viscosity-based systems are ineffective in creating diversion. Typically, this would be in wells with high injectivity contrast or with natural fractures. MaxCO<sub>3</sub> Acid system combines viscoelastic diverting acid and degradable fibers. It is designed to temporarily block or decrease leakoff into natural fractures and wormholes in carbonate reservoirs by creating fiber bridges in the perforation tunnels and increasing viscosity as the acid spends. In matrix acidizing, MaxCO<sub>3</sub> Acid system generates more uniform stimulation of naturally fractured carbonate formations and reservoirs with high permeability contrast. In acid fracturing applications, MaxCO<sub>3</sub> Acid system reduces leakoff in fissures and natural fractures, which leads to a more efficient spending of the acid resulting in longer etched fractures.

MaxCO<sub>3</sub> Acid system can be used for diversion in matrix acidizing treatments, and for leakoff control in acid fracturing treatments in cased or openhole naturally fractured formations. It can be bullheaded from the surface using standard Schlumberger well site delivery equipment. MaxCO<sub>3</sub> Acid system treatments have successfully been pumped on sour wells containing hydrogen sulfide (H<sub>2</sub>S) and possible interactions of fibers with components of sulfur-bearing oils has not revealed any compatibility issues.

### ADVANTAGES

- Degrades completely, eliminating risk of costly cleanout interventions
- Targets permeability contrasts, allowing superior zonal coverage
- Effectively controls leakoff
- Requires lower treatment volumes and less well cleanup time

### APPLICATIONS

- Reservoirs with high permeability contrasts and/or natural fractures
- BHT between 175 and 250 degF [79 and 121 degC]
- Carbonate oil or gas wells
- Openhole or cased hole intervals, regardless of deviation

### FEATURES

- Diverts effectively at low treatment rates
- Continues to stimulate as it degrades
- Uses Schlumberger WellBook software application for treatment design, execution, and evaluation for matrix applications
- Can be bullheaded or pumped through CT
- Can be pumped with most common acid stimulation systems
- Can be batch mixed for small volume jobs or mixed on the fly for larger treatments

# Water Control Systems

## MARA-SEAL<sup>SM</sup>

### SUMMARY

MARA-SEAL gel uses a high-strength, crosslinked synthetic polymer (PA) gel capable of penetrating the matrix. MARA-SEAL gel is primarily used for water shutoff, but can be used in place of cement squeeze for casing bonding failures and for sealing the open hole section during vertical or short-radius horizontal recompletions.

### TEMPERATURE

Applicable temperature range up to 300 degF [149 degC]

### FEATURES

- Shear sensitivity: because of the molecular size of the MARA-SEAL gels are not sensitive to shear degradation
- MARA-SEAL gel should not be formulated with mix-water having Ca<sup>+2</sup> or Mg<sup>+2</sup> levels higher than 400 to 500 ppm for applications in reservoirs with BHST higher than 160 degF [71 degC]; monovalent cations appear to have little, if any, effect on the long-term gel stability
- MARA-SEAL technology has been successfully applied using seawater

### APPLICATIONS

- Near-wellbore problems where complete blockage is required, which include near-wellbore channeling, high-permeability layers without crossflow, and zone abandonment
- Matrix permeability greater than 25 mD
- MARA-SEAL has also been used in many cases in blocking unwanted gas production

## MARCIT<sup>SM</sup>

### SUMMARY

MARCIT gel is a crosslinked synthetic polymer (polyacrylamide) gel designed for water control in naturally fractured reservoirs. MARCIT treatments can be applied to both injectors and producers, where a high water cut is attributed to production through fissures. Polymers used in this treatment are high molecular weight, which limits leakoff into the matrix and results in greater viscosities per polymer concentration. Crosslinking occurs relatively early in the treatment process, further aiding in reduced leakoff and increasing fissure penetration efficiency. The crosslinked material is best described as a flowing gel, which maintains the ability to penetrate natural fractures.

### TEMPERATURE

Temperature range from 60 to 200 degF [16 to 93 degC]

### FEATURES

- Low matrix leakoff losses
- Simple metering and mixing

### APPLICATIONS

MARCIT treatment application is primarily in:

- Fissured formations, where flow selectivity favors the fissures and the high molecular weight polymer limits matrix penetration
- Injector wells that are in communication to one or more producers though a fractured network

## OrganoSEAL-R

### SUMMARY

Rigid OrganoSEAL-R gel technology produces a high strength, cross-linked synthetic polymer (PAM) gel that is capable of penetrating matrix prior to gelation. OrganoSEAL-R gel is primarily used for water shutoff, but can be used in place of cement squeeze for casing bond failures and for sealing the openhole section during vertical or short-radius horizontal recompletions.

### TEMPERATURE

Applicable temperature ranges from 125 to 325 degF [50 to 170 degC]

### FEATURES

- Synthetic polymer with low toxicity organic crosslinker
- Robust gel chemistry
- No heavy metals
- Controllable rate of gelation
- Stability to 325 degF [170 degC]
- Stability in the presence of H<sub>2</sub>S and CO<sub>2</sub>
- No delay agents needed
- Except for very hot applications, no precooling required
- Surface handling equipment does not tend to degrade the solution by polymer chain breakage

### OrganoSEAL-R fluids

- OrganoSEAL-RLT - Low-temperature gel which uses polymer, organic crosslinker and an activator
- OrganoSEAL-RHT - HT gel which uses polymer with dual organic crosslinkers
- OrganoSEAL-RHE - Harsh environment gels used for HT and/or hard-mixed waters and containing dual organic crosslinkers

### APPLICATIONS

- Water/gas shut off in near wellbore area
- Water/gas control in high permeability channels where vertical flow barriers doesn't exist
- Openhole sealing for short radius horizontal reentries (liquid liner applications)
- Used in HT reservoirs
- Zone abandonment

## OrganoSEAL-F

### SUMMARY

OrganoSEAL-F is an aqueous-based gel formed from synthetic polymer and organic crosslinker and is used for water control in naturally fractured reservoirs. OrganoSEAL-F treatments can be applied to both injectors and producers, where a high water-cut is attributed to production through fissures.

### TEMPERATURE

OrganoSEAL-F treatments can be applied at BHST ranging from 125 to 325 degF [50 to 170 degC]

### FEATURES

- Synthetic polymer with low toxicity organic crosslinker
- Low matrix leakoff losses
- Selective flow into fissures
- No heavy metals
- Stability in the presence of H<sub>2</sub>S and CO<sub>2</sub>

### OrganoSEAL-F fluids

- OrganoSEAL-F LT: low-temperature gel which uses polymer, crosslinker and an activator.
- OrganoSEAL-F HT: high-temperature gel which uses polymer with dual organic crosslinker.
- OrganoSEAL-F HE: harsh environment gels used for HT and/or hard-mixed waters and containing dual organic crosslinker.

### APPLICATIONS

- Water shut off in fissured/fractured reservoirs
- HT formation
- Water/gas control

## SqueezeCRETE\* Remedial Cementing Solution

### SUMMARY

SqueezeCRETE solution is composed of a microcement, one of several particulate fluid loss additives, and a dispersant. It applies the CemCRETE\* technology physics to slurries on a microscale. SqueezeCRETE solution can be used to isolate problems that other cements cannot fix, i.e. when it is not possible to get good injection with conventional slurries.

### TEMPERATURE

From surface temperature up to 320 degF [160 degC]

### FEATURES

- Penetrates gap widths as small as 120 micron
- Exhibits over 2,000 psi [140 kg/cm<sup>2</sup>] compressive strengths at surface temperatures 85 degF [30 degC] at only 14 lbm/gal [1.7 SG]
- Permeability lower than achievable with any other type of cement-based system and typically in the nanoDarcy region and is gas tight

### APPLICATIONS

- Sealing channels behind pipe to stop water flow and gas channeling
- Sealing perforations that would not accept conventional cements
- Liner top leaks and stage-tool leaks

## DGS\* Delayed Gelation System

### SUMMARY

The DGS system is a solution that maintains a very low viscosity until an internal catalyst/activator causes a gel to form. Several unique features allow this gel to be placed deep into the formation matrix where it can effectively block permeability. It is a total plugging solution.

### TEMPERATURE

Gel time can be controlled for most applications up to 194 degF [90 degC]; use above that temperature is limited by the ability to delay the gelation long enough to place the fluid

### FEATURES

- Effective permeability reduction by more than 90%
- Deep penetration
- Controlled working time
- Works with most mix water
- Shear insensitive
- Simple mixing
- Semiselective placement
- Acid-soluble gel

### APPLICATIONS

- Water coning during production
- Water fingering through high-permeability streaks
- Injection and sweep inefficiency caused by thief zones in injection wells

## PERMABLOK\* Fluid System to Permanently Plug a Zone

### SUMMARY

The PERMABLOK system is used for solving lost-circulation problems during drilling or prior to cementing; for permanently or in some cases temporarily plugging zones, and for consolidating weak formations.

### TEMPERATURE

The maximum static temperature that the hardened gel can withstand is 356 degF [180 degC]

### APPLICATIONS

There are four main situations where the PERMABLOK\* system can be applied:

- Lost circulation during drilling
- Expected losses during cementing
- Permanent plugging/squeezing of zones
- Zone consolidation

## **ZONELOCK® Permanent Zone Sealing Fluid System**

### **SUMMARY**

ZONELOCK system 100, 150, and 155 services are acid-catalyzed sodium silicate gels used to permanently seal matrix permeability. Acid strength and temperature control setting time. These three ZONELOCK system services are progressively more viscous and, in addition, ZONELOCK system 155 contains particulate solids to help bridge in open channels and fractures.

### **TEMPERATURE**

ZONELOCK system fluids should not be used where fluid temperature will exceed 180 degF [82 degC], but can be used in those situations where cool-down procedures are used providing the fluids used in the ZONELOCK system remain less than 180 degF [82 degC].

### **APPLICATIONS**

- To plug injection well thief zones
- To control unwanted water production
- They can be used in either sandstone or limestone formations

## **Special Systems**

### **PROTECTOZONE-VP**

#### **SUMMARY**

The PROTECTOZONE-VP system is a delayed, crosslinked-gel system that contains low-residue hydroxy-ethyl-cellulose (HEC) polymer at 80 to 120 lbm/1000 gal and internal breakers to achieve controlled fluid loss and cleanup.

The PROTECTOZONE-VP system is particularly useful in high-permeability formations where excessive losses of heavy brines or linear gels are not acceptable. It can be used in formations ranging from 0.1 to 2 D.

#### **TEMPERATURE**

The PROTECTOZONE-VP system can be used at temperatures ranging from 80 to 290 degF [27 to 143 degC]

#### **APPLICATIONS**

The PROTECTOZONE-VP system can be used as a:

- fluid-loss-control pill during workover operations
- temporary blocking gel for zone isolation

## **TubeCLEAN® Completion Preflush Treatment**

#### **SUMMARY**

TubeCLEAN® treatment is designed to clean the tubulars, limiting the amount of dissolved iron, rust, mill scale, and silt transported into the formation.

The recommended treatment volume should be calculated based on a volume of 100 gal/1000 ft of tubing. If small diameter tubing or CT is used, the treatment volume should be based on a volume of 50 gal/1000 ft.

#### **TEMPERATURE**

TubeClean fluids can be inhibited up to 300 degF [149 degC]

#### **APPLICATIONS**

- Water-wet the tubular goods so that dissolution of iron scale or rust can easily take place
- Suspend silt or other particulate
- Limit corrosion of the metal

## CLEAN SWEEP\* Solvent Systems for Damage Removal

### SUMMARY

CLEAN SWEEP system fluids are designed to remove damage common to oil and gas wells including:

- Emulsions
- Wettability changes
- Mixed deposits
- Scale
- Paraffin and asphaltene deposits
- Water blocks
- Saturation changes

The minimum recommended treatment fluid volume is 150 gal/perforated foot.

CLEAN SWEEP systems can be:

- Xylene-base
- Alcohol-base
- Toluene-base

Each system can be formulated for summer or winter use.

### TEMPERATURE

Applicable temperature up to more than 400 degF [205 degC]

### CLEAN SWEEP I: Xylene-base system

CLEAN SWEEP I system is designed for oil wells requiring a slightly volatile aromatic solvent to remove the damage. This system is used to:

- Remove oil-outside-phase emulsions
- Dissolve paraffin and asphaltene
- Water-wet the formation
- Dissolve calcium carbonate scale
- Dissolve mixed organic/carbonate deposits

### CLEAN SWEEP II: Toluene-base system

CLEAN SWEEP II system is designed for oil wells requiring a highly volatile aromatic solvent to remove the damage. This system is used to:

- Remove oil-outside-phase emulsions
- Dissolve paraffin and asphaltene
- Water-wet the formation
- Dissolve calcium carbonate scale
- Dissolve mixed organic/carbonate deposits

The toluene-base system can be used in paraffinic gas condensate wells because of the solvent properties and volatility.

### CLEAN SWEEP III: Alcohol-base system

CLEAN SWEEP III system is designed primarily for gas wells requiring a highly volatile nonaqueous fluid to remove the damage. This system is used to:

- Remove water-outside-phase emulsions
- Water-wet the formation
- Dissolve calcium carbonate scale

### APPLICATIONS

- Designed for use in either oil or gas wells
- Effective in both low- and high-temperature applications

## OB Mud Removal System

### SUMMARY

OB mud removal system is a water-base system designed to remove oil-base drilling mud damage from a producing formation. It can either be performed as a separate treatment or as a pretreatment prior to a matrix acid or an acid breakdown treatment.

OB mud removal removes the oil-base mud by reducing viscosity, dispersing fines and returning the formation to a water-wet state.

Recommended volumes to use are 100 to 300 gal of total treating fluid per foot of perforated interval. In remedial treatments where damage is further back in the formation, the amount of OB Mud Removal to use should be at least 150 to 600 gal per foot of perforated interval.

### TEMPERATURE

Applicable temperature up to more than 400 degF [205 degC]

### APPLICATIONS

- Removal of oil-base mud
- Breakdown fluid prior to a stimulation treatment
- Perforation cleanup treatment

# Matrix Stimulation Services

## CarboSTIM\* Carbonate Stimulation Service

### SUMMARY

CarboSTIM service is an engineered solution for production enhancement directed at improving production from wells completed in carbonate reservoirs. The CarboSTIM service uses state-of-the-art stimulation engineering software and chemical technology with emphasis on:

- Placement using
  - SDA acid
  - OilSEEKER diverter
  - FoamMAT service
  - VDA\*
  - MaxCO<sub>3</sub> Acid
- Chemistry using
  - SuperX acid emulsion
  - HT emulsion (SXE emulsion - HT)
  - LCA\* leakoff control acids
  - OneSTEP
- Special services
  - MudSOLV\* filtercake removal service
  - ScaleSOLV\* carbonate scale dissolver
  - Scale Blaster\* engineered approach to scale removal service

### CarboSTIM service

- Candidate recognition using treatment design software to select the best candidates for maximum production enhancement
- Develop the optimum stimulation strategy based on economics and treatment design
- Treatment monitoring at the wellsite with data analysis to make necessary job design changes in real-time
- Posttreatment evaluation to better understand treatment results and improve future designs

### Complementary services

- MudSOLV service for effective damage removal.
- Corrosion protection with carbonate scale dissolver.

### APPLICATIONS

- Wells completed in carbonate reservoirs

## MudSOLV\* Filtercake Removal Service

### SUMMARY

MudSOLV service focuses on filtercake removal across the horizontal or vertical, producing or injecting openhole interval. Filtercake removal in openhole reservoirs, when deemed necessary, has been an on-going challenge. MudSOLV service provides an engineering approach to select and optimize solutions.

The MudSOLV service facilitates an integration of cleanup solutions during the drilling and completion design phase. This integrated approach includes solution selection and implementation on a well-by-well basis.

The selection of the least damaging drilling fluid for a reservoir section should be consistent with drilling requirements, removal efficiency, environmental compatibility and cost.

Additionally, the composition of the drilling fluid will dictate the cleanup solution.

### FEATURES

- Synergy among sand control, drilling fluids, and filtercake cleanup design
- Tailored treatment for individual wells
- Low HSE risk
- Long contact times for complete filtercake dissolution
- Choice of enzymes and oxidizers for attacking the starch and polymeric filtercake components
- Choice of nonacid or acid systems for dissolving carbonates
- Fluid compatibility: nonacid carbonate dissolver combine with enzyme breaker
- Good zonal coverage
- Innovative placement techniques including Jet Blaster service or MudSOLV service tool valve

### BENEFITS

- Maximized hydrocarbon production using optimal cleanup solution
- Increased rig time savings
- Reduced risk and uncertainty through engineered solutions
- Minimized corrosion damage to completion equipment
- Simultaneously gravel packing and filtercake removal

### APPLICATIONS

- Sandstone formations with barefoot, screen only or gravel-packed
- Carbonate reservoirs with barefoot or slotted liner completion

## ScaleMAT\* Acid-Compatible Scale Inhibitor

### SUMMARY

ScaleMAT inhibitor integrates scale inhibition with matrix stimulation. Scale is commonly a persistent problem that producing companies have to address on a continuous basis over the economic life of the well. The most widely used method of inhibiting scale deposition is by squeezing liquid scale inhibitors into the near-wellbore matrix, shutting in the well for the inhibitor to adsorb or precipitate onto the matrix, then putting the well back on production where the inhibitor slowly dissolves back in the produced water with time. When all the inhibitor is used up, a new inhibitor squeeze treatment is needed. Frequent well shut-ins for squeeze treatments commonly turn out to be a large economic burden and every effort to reduce the number of required treatments over the life of the well is a goal of the producing company.

The ScaleMAT inhibitor components are candidate selection, treatment design, treatment placement, posttreatment monitoring of the production decline, and the inhibitor return in the produced water. The posttreatment monitoring ensures that the treated well remains protected from scaling and provides timely signals of protection loss so the well can be retreated.

The ScaleMAT inhibitor is one of the ScaleSTIM inhibitor services offered by Schlumberger, which integrate scale inhibition with stimulation. In addition to ScaleMAT inhibitor, the ScaleSTIM inhibitor includes ScaleFRAC service in which scale inhibitors are deployed with the fracturing fluid. ScaleSTIM inhibitor services in general offer mainly workover cost and risk savings to clients, as well as more efficient placement of scale inhibitors in stimulated wells.

### FEATURES AND BENEFITS

- Deployment of treatment at the same time with a matrix stimulation treatment
- Use of an acid-compatible scale inhibitor and eliminates at least one inhibitor squeeze treatment with every acid treatment
- Reduce workover costs risk, especially in typical offshore completions where workover expense and risk is usually significant

### APPLICATIONS

- The ScaleMAT inhibitor can be applied in sandstone and carbonate formations, although the philosophy and detailed design of the treatment vary with the lithology; acid compatible scale inhibitor L066 is the preferred inhibitor for this service and should be recommended whenever possible in the application of a ScaleMAT inhibitor treatment; L066 is a phosphino-polyacrylate that inhibits the deposition of all common carbonate and sulfate scales.
- The L066 scale inhibitor is deployed by batch mixing the inhibitor with the stimulation fluid or by adding the inhibitor on the fly during a conventional matrix treatment; the stimulation fluids containing the inhibitor may be HCl, HF acids<sup>†</sup>, or chelant solutions.

<sup>†</sup>The use of scale inhibitor L066 in acids containing hydrofluoric (HF) acid is restricted and may not be pumped in any acid stage containing HF in: the United States, Great Britain, Australia, Denmark, France, Germany, Ireland, or Norway. In other countries, this restriction does not apply. If in doubt, contact the segment Intellectual Property Group in Sugar Land.

# Schlumberger

## Case Studies

### Volume 2



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# Contents

## Coiled Tubing Case Studies

<b>ACTive Portfolio .....</b>	<b>3</b>
-------------------------------	----------

### **ACTive Tools**

Successful Implementation of ACTive Services Tension-Compression Sub for Lost Tool Retrieval .....	5
--	---

### **ACTive Cleanout**

Live CT Wellbore Fill Removal Service Enables Cost-Effective Sand Removal in the Gulf of Mexico .....	6
Regaining Production from a Sand-Plugged Reservoir in Deepwater Indonesia .....	8
ACTive Cleanout Service Saves Operational Time and Barge Service Time .....	9

### **ACTive Perf**

Accurately Perforate Two Zones in an Underbalanced Condition .....	11
ACTive Perf Service Increases Sand-Free Gas Production in South China Sea .....	13
Real-Time CT-Conveyed Perforating Service Boosts Production in High-Deviation HPHT Gas Well .....	15
Accurately Perforate Zones in an Underbalanced Condition in Saudi Arabia .....	16
ACTive Cleanout Provides DH Access for Perforating Multiple Zones .....	18
ACTive OptiFIRE System Reperforates Critical Producing Interval in Record Time .....	20
ACTive OptiFIRE System Perforates Three Intervals, Increases Well Production 18% in Brownfield Well .....	22

### **ACTive Isolation**

ACTive Isolation Revives Well Production .....	24
Eliminating Water Cut with Water Shutoff Treatment .....	26
ACTive Isolation Revives Well Production .....	28
Eni Deploys Real-Time ACTive Coiled Tubing Services for Workover Operations .....	30
Reviving Production for a Watered-Out Well Through Smart Coiled Tubing Intervention .....	32
ACTive Straddle Inflatable Packer Cleanout Doubles Production in Two Wells .....	34
ACTive Straddle Inflatable Packer Stimulates Multilateral Well in One Run .....	35

### **ACTive Matrix**

Improved Production from Alberta Wells .....	36
Successfully Isolate and Stimulate Wet Wells with ACTive Services .....	38
Improving Foam Quality in Elks Hills Field .....	40
Coiled Tubing Services Enable Real-Time MaxCO <sub>3</sub> Acid System Stimulation Treatment .....	42
CT Stimulation Service Helps Saudi Aramco Double Production in Water-Wet Wells .....	43
Temperature Profiling Optimizes Stimulation Job .....	45

### **ACTive Profiling (PS, DTS, PTA)**

ACTive Matrix Enables Effective Openhole Stimulation in Western Canada .....	47
Integrating Coiled Tubing and Production Logging for ConocoPhillips .....	49
Integrating Production Logging with Coiled Tubing Intervention in Saudi Arabia .....	50
Technique Enables Optimized Remedial Water Shutoff Operations for Saudi Aramco .....	52

ACTive Profiling Service and Pressure Survey Enhance Reservoir Understanding .....	53
Permanent Water Shutoff in Openhole Well .....	55
Successful Profile Diagnosis Maintains Producibility and Prevents Expensive Water-Conformance Treatment .....	57
ACTive Services Enables Real-Time PTA for Stimulation Evaluation .....	58
<b>CT Downhole Technology Case Studies .....</b>	<b>61</b>
Through-Tubing Inflatable Packer Sustains Production More Than Threecold .....	63
Through-Tubing Packer Operation Helps Decrease Water Production in GOM Well from 99% to 13% .....	65
CoilFRAC Stimulation Increases Texaco Hiawatha Field Production by 75% .....	67
Overcoming Severe Drilling Damage in Highly Deviated HPHT K-Gas Well .....	69
Underbalanced Coiled Tubing Drilling Triples Production in Declining UAE Wells .....	71
Exhaustive Dataset Supplied by Multisegment Team .....	73
Protect Fiberglass Lining of Water Disposal Wells .....	74
Four-Well HPHT Intervention Campaign in Hungary .....	76
Rigless Plug-and-Abandonment Campaign Reduces Operating Time by 30% .....	77
Through-Tubing Milling Operations Clear Unexpected Obstructions, Restore Flow in HPHT, Sour Gas Wells .....	79
Back-Pressure Valve Ensures Safer Packer Inflation in Subhydrostatic Wells in Mexico .....	81
HPHT Through-Tubing Packer Achieves Complete Water Shutoff, Saves USD 220,000 .....	82
Complete Zonal Water Shutoff in High-Pressure Well Saves USD 150,000 .....	83
CoilFLATE Inflatable Packer Reduces Water Cut by 70% in North Kuwait .....	84
Reliable Multilateral Entry in Subhydrostatic Conditions in Alaska Results in Successful Cleanout .....	86
Selective Stimulation in Multilateral Middle East Well Reduces Completion Costs .....	88
Discovery MLT Multilateral Tool Increases Production by 500% in One Run in Hole .....	90
ReelCONNECT Technology Enables North Sea Winter CT Operation .....	92
ReelCONNECT Technology Increases Production in an Ula Field, Norway well .....	94
Vantage Modular CT Logging-Head System Saves 75% of Rig-Up Time for Oklahoma Operator .....	96
Vantage Modular CT Logging-Head System Saves USD 10,000 per Day in Operating Costs .....	98
Vantage Modular CT Logging-Head System Reduces Perforating Failure Downtime .....	100
Vantage Modular CT Logging-Head System Saves More Than 1 Day of Operations at USD 250,000/Day in Costs .....	102
Jet Blaster Engineered High-Pressure Service Boosts Oil Production in Indonesia's Duri Field .....	104
Jet Blaster High-Pressure Jetting Service Increases Production from a North Sea Well by 400% .....	105
Jet Blaster High-Pressure Jetting Service Restores Production in Algeria Well to 80% of Original Level .....	107
Jet Blaster Engineered High-Pressure Jetting Service Restores Nonproducing Well and Increases Production .....	109
Jet Blaster High-Pressure Jetting Service Removes CaCO <sub>3</sub> Scale in Single Run .....	111
Jet Blaster Engineered High-Pressure Service Removes Hard Wellbore Deposits Without Damaging Tubulars .....	112
Scale Blaster Service Restores Production to 900 bbl/d in a Middle East Well .....	114
Hard-Scale Milling in Offshore High-Temperature Well .....	115
<b>Stimulation Case Studies .....</b>	<b>117</b>
Significant Oil Production Increase from Horizontal Openhole Lateral in Ecuador .....	119
BG Group Increases Declining Well Production Threecold .....	121
Reducing Multistage Fracturing Time by 15 Days .....	123
Increase Gas Production While Reducing Water Cut .....	125
Increasing Oil Production in Sahara Desert by 160% for Sonatrach .....	127

**Schlumberger**

# **Coiled Tubing Case Studies**

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# ACTive Portfolio

# Successful Implementation of ACTive Services Tension-Compression Sub for Lost Tool Retrieval

World's first fishing operation using Active services tension and compression data for effective indication of downhole weight conditions, offshore ARM

## CHALLENGE

Retrieve wireline tool lost in the well during reverse deployment which was difficult to locate due to its low weight.

## SOLUTION

Use ACTive TC\* live CT tension and compression tool to provide tension compression data to monitor even the small changes in weights downhole.

## RESULTS

Successfully retrieved 45 feet of production logging tool (PLT) string within 36 hours of operation. Saved NPT for the customer as the well was put to production right after the fishing operation.



## Utilizing ACTive TC sub

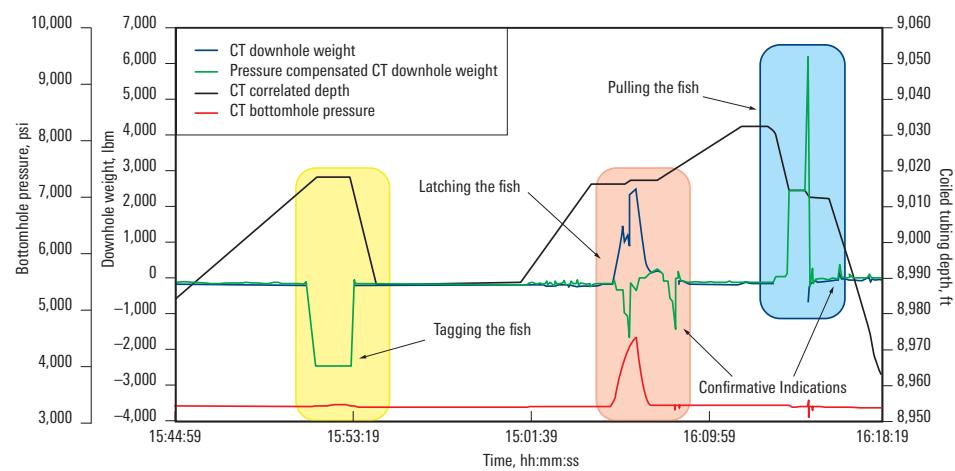
The wireline tool string was lost in a horizontal offshore oil well, and as a result, the client had to stop production. Moreover, the logging schedule had been affected due to the limitation on tools availability. Retrieving the toolstring would have been very difficult without the ACTive\* family of live downhole coiled tubing services, as surface weights are generally poor indicators for manipulation in such cases (weight of the tool string was just 250 lbm).

Utilization of the tension and compression tool enabled us to detect even the smallest of difference in downhole weights. Hence, tagging, latching, and retrieval of the fish were clearly identified during the operation with absolute confidence. The tension, as read, while pulling out the fish when compared to normal pulling tension demonstrated a 270 lbm increase, which could have never been monitored by surface parameters, giving a positive indication of fish being pulled out along with CT.

Manipulating surface weights for predicting downhole conditions may be very inaccurate due to complex well geometries and unknown well parameters, which calls in for utilizing the ACTive TC tool in such cases.



ACTive TC tool.



ACTive services downhole parameters while fishing.

# Live CT Wellbore Fill Removal Service Enables Cost-Effective Sand Removal in the Gulf of Mexico

Performing ACTive Cleanout service on subhydrostatic well saves Mariner Energy Resources more than USD 104,000

## CHALLENGE

Clean out a subhydrostatic well without risking leakoff of expensive foamed fluids.

## SOLUTION

Use ACTive Cleanout\* live CT wellbore fill removal service to determine downhole conditions and to optimize the cleanout process. Avoid originally planned through-tubing gravel-pack job.

## RESULTS

Achieved complete cleanout using a low-cost nitrified fluid rather than a foamed fluid, which saved the client USD 14,000. Saved 5 hours liftboat time and USD 90,000 in wireline/slickline unit standby, mobilization, and demobilization costs.

**ACTive Cleanout service reduces the risk of pipe sticking, prevents unwanted treating fluids entering the formation, and reduces operational time and material usage.**



## Plugged perforations

A subhydrostatic Gulf of Mexico well stopped flowing, and a slickline run tagged high, indicating to the operator, Mariner Energy Resources Inc., that the perforations were covered with sand. The well was completed with 2.44-in ID production tubing in depths to 12,370 ft [3,770 m], which created significant friction pressures in the annulus between the tubing and the 1.5-in coiled tubing (CT) string.

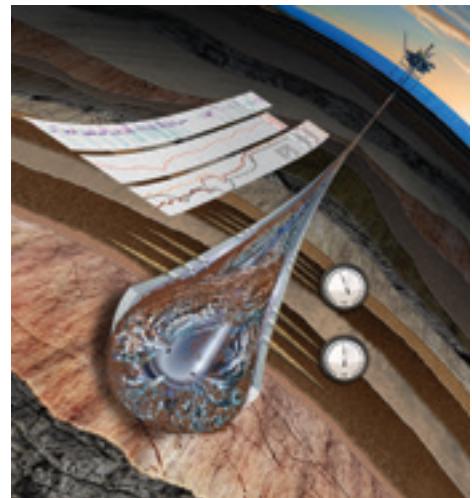
Low bottomhole pressure (BHP)—4,600 psi at 13,100 ft TVD [31.72 MPa at 3,993 m]—and high annular friction pressures imposed significant restrictions on the maximum achievable fluid and N<sub>2</sub> rates for a sand cleanout operation. For this particular well, the fluid and N<sub>2</sub> pump rates were limited to a narrow range for solids transport at an acceptable fluid loss rate.

Cleaning out subhydrostatic wells completed with small production tubing is difficult because of the risk of fluid leakoff into the formation. Foamed fluids are normally used in such wellbore conditions, but they add to the treatment cost.

The well was considered a candidate for a through-tubing gravel-pack installation that required precise depth correlation. However, the CT unit was already mobilized for a cleanout, and its real-time casing collar locator (CCL) capability would eliminate the need for a wireline/slickline unit on the platform.

## Advanced monitoring system

Schlumberger proposed using the ACTive Cleanout service, which uses differential pressure and temperature readings to avoid formation damage, therefore reducing the number of trips and total operating time. The service allows optimizing fluid volume and penetration rate into the fill.



*ACTive Cleanout service optimized sand removal for a subhydrostatic Gulf of Mexico well.*

For Mariner Energy Resources' stopped-up well,

- real-time CCL readings helped verify the well's TD and determine the severity of sand control issues.
- real-time bottomhole pressure (BHP) readings enabled wellbore pressure verification before beginning sand cleanout.
- real-time bottomhole temperature (BHT) readings allowed detection of reservoir fluid flowback in the wellbore long before it could be detected at surface.

The CT operator used the BHT information to change the N<sub>2</sub> injection point downhole to create more drawdown.

With ACTive Cleanout service, the BHP work window can be defined and monitored in real time to maintain desired overbalance, at-balance, and underbalance conditions. This allows both operational-risk and treatment-cost reductions by using conventional cleanout fluid systems instead of fluid systems that are more expensive and more difficult to handle.

The information reduces the risk of pipe sticking, prevents unwanted treating fluids from entering the formation, and reduces operational time and material usage.

#### **Cost-effective cleanout operation**

Job parameters were corrected and the BHP work window was defined and maintained within acceptable overbalance and at-balance conditions. Real-time BHP, BHT, and CCL helped the CT crew make informed decisions while the CT was still in the well. The well cleanout was achieved under extremely low BHP conditions using a low-cost nitrified fluid as opposed to foamed fluid. The job also completed in 5 hours less time than a job using foamed fluids. This represents more than 2 hours of operating time savings for every 100 ft of interval cleaned.

Additionally, the use of nitrified fluid saved USD 14,000 by enabling the crew to pump less nitrogen; it also helped eliminate the need for additional N<sub>2</sub> tanks. If additional N<sub>2</sub> tanks had been required, the job could have been extended even further for logistical reasons.

The solution replaced a through-tubing gravel-packing job, with associated wireline/slickline unit standby, mobilization, and demobilization costs, estimated at USD 90,000. Overall, the ACTive Cleanout service helped achieve the job objective at a minimum cost, saving Mariner Energy Resources a total of USD 104,000.

# Regaining Production from a Sand-Plugged Reservoir in Deepwater Indonesia

Chevron successfully cleans wellbore using real-time data

**CHALLENGE**

Use CT cleanout to restore access to and regain production from a water-sensitive, sand-plugged perforation zone in a deepwater well with low bottomhole pressure (BHP) gradients.

**SOLUTION**

Combine engineered cleanout solution with ACTive\* family of live downhole coiled tubing services for real-time BHP and fluid flow data during the cleanout process.

**RESULTS**

Achieved successful cleanout and regained access to high-producing reservoir.

**High-producing deepwater well**

For a high-producing deepwater well in the West Seno field, Indonesia, Chevron needed to regain access to a perforation zone plugged by sand fill. Initial CT cleanout operations were unsuccessful because of

- large casing—greater than 4.5-in ID
- high deviation angles—greater than 60°
- low BHP gradients—less than 0.3 psi/ft.

The company attempted direct circulation using gas lift, reverse cleanout using fluid, and direct foam circulation. Respectively, these techniques resulted in intermittent returns, a stuck pipe incident, and high cost due to offshore logistical limitations.

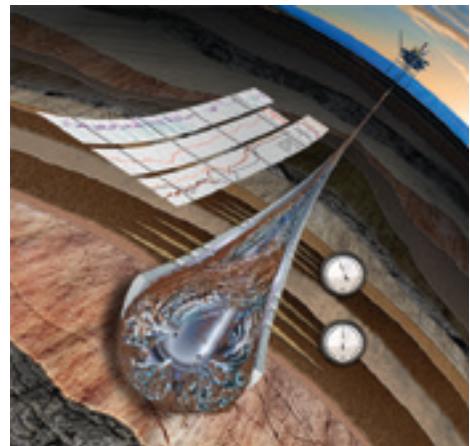
**New cleanout method**

Schlumberger supplied a new cleanout method using an engineered cleanout solution, combined with ACTive services. The gel is a diesel-base solution with a lower density than water-base gel fluids, resulting in a lower hydrostatic fluid column suitable for low-BHP cleanout applications. Core flow tests on the West Seno field showed the gel to be compatible with the water-sensitive formation. They also showed an increase in retained permeability using the gel. Furthermore, because it works in a single phase, the gel proved less complex than foamed fluids, and its high viscosity limited invasion.

The ACTive services provided real-time BHP data that was used with the existing gas lift system to perform the cleanout. Transient effects on the gas lift mandrel could be measured, and operations could be adjusted. The fill-loaded column of fluids was managed with the real-time information, allowing circulation to be maintained at all times. Moreover, the ACTive services' casing collar locator (CCL) depth measurement enabled cleanout to the desired depth by eliminating the errors of surface device measurements.

**Real-time decision making**

The combination of the engineered cleanout solution and ACTive services supplied real-time downhole measurements, which eliminated all assumptions surrounding this cleanout job. Chevron personnel were able to make immediate decisions based on accurate real-time data. The cleanout operation proved successful, and the company regained access to its sand-plugged reservoir.



Used with an engineered cleanout solution, ACTive services provided real-time BHP and depth information that enabled effective cleanout.

# ACTive Cleanout Service Saves Operational Time and Barge Service Time

Real-time downhole measurements verify well cleanout

## CHALLENGE

Achieve efficient and successful wellbore cleanout.

## SOLUTION

Used ACTive Cleanout\* live CT wellbore fill removal service to actively monitor downhole pressure and temperature while accurately correlating the depth measurement.

## RESULTS

Confirmed TD and detected a short casing joint at a known depth, which verified that the well was clean to TD, saving a day of downhole milling and a day of CT barge service.

**Verification that the well was clean to TD saved the operator a day of downhole milling and a day of CT barge service.**



## Depth uncertainties reduce operational efficiencies

During CT operations, differences are commonly observed among the pipe tally depth, the slickline reported depth, and the CT measured depth. In wells with multiple laminated zones, a difference of only 20 ft can create uncertainty and mean the difference between a clean production interval and a sanded-up interval that requires an additional cleanout run. In many cases, using additional cleanout tools—such as acid or solvent pumping, downhole motor runs, tubing end locators, slickline impression blocks, or sample catchers—is necessary to verify the success of the cleanout. However, these operations increase the risk and overall time of the intervention, affecting both the total expenditure and the well's production.

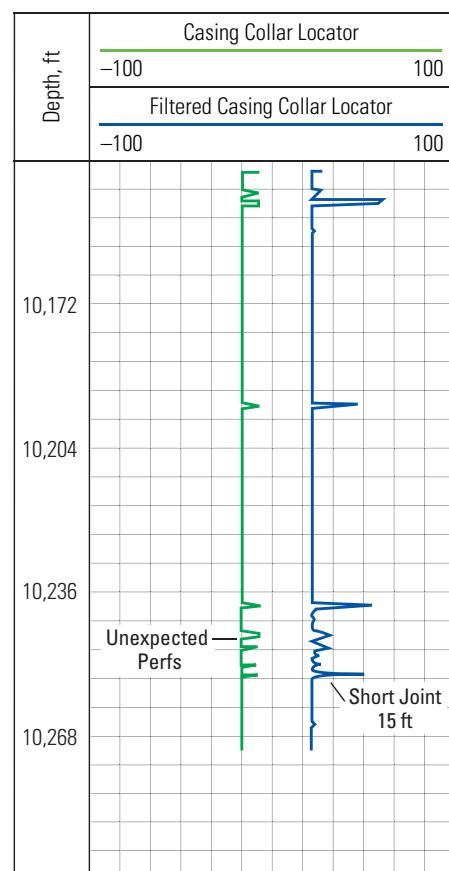
## Real-time data clarifies the situation

An operator in South America selected ACTive Cleanout service for efficient cleanout of a well with multiple laminated zones. The program required a cleanout operation from the last slickline measurement to top-of cement plug. Lost circulation had occurred during the operation along with unexpected casing collar locator (CCL) signals. These CCL signals were correlated to a perforated interval above the top-of-cement plug that started taking fluids when uncovered.

Pressure and temperature data were also acquired during the cleanout job. This information enabled identification of the active gas lift mandrels and provided the well engineer with data to determine if the valves were performing in their expected range.

The tubing and packer integrity was also verified, and while waiting for sand to fall back, the actual static bottomhole pressure was measured.

Pressure and temperature data, which are usually acquired in a separate operation, are potentially valuable during a CT intervention to ensure continuous well circulation, to optimize the use of nitrogen, and to detect and respond to differential sticking incidents.

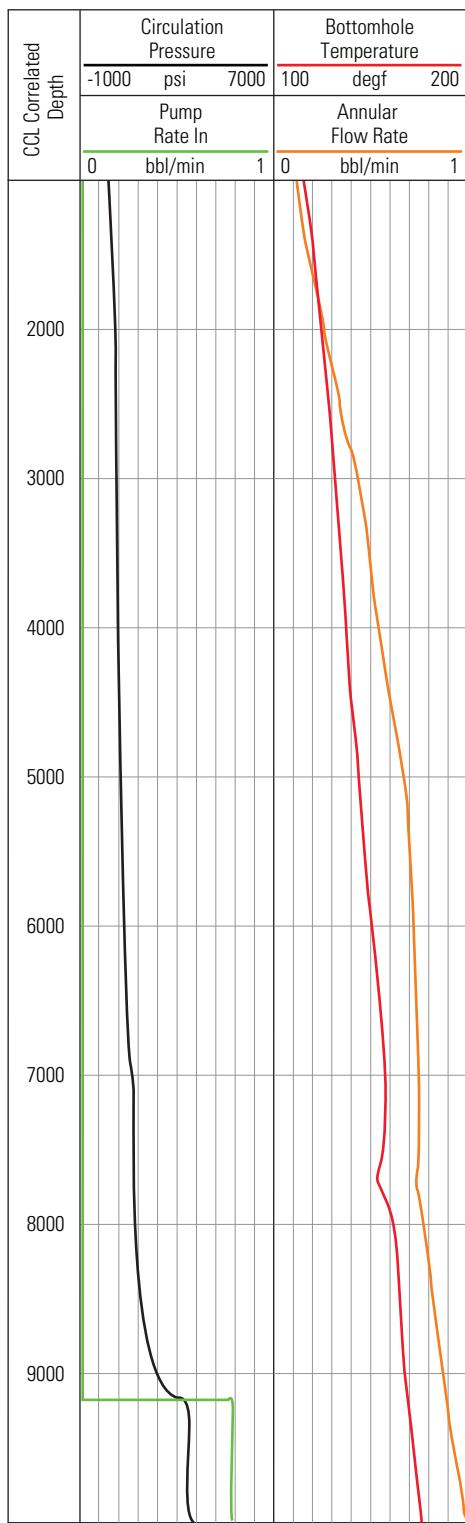


Depth correlation plot obtained using the ACTive Cleanout service.

## Downhole information proves valuable

Using the CT measured depth and assuming there was more than 20 ft to TD, solvent and acid batches were pumped, but with no success or depth gain. The CT measured depth was correlated in real time to the confirmed TD using the ACTive\* service casing collar locator (CCL) and gamma ray/casing collar locator (GR/CCL) slickline log. The operator decided to pull out of hole (POOH) the CT, calling for slickline and a downhole motor run. The next day a sample catcher tagged gun debris at the measured TD, matching the ACTive service real-time correlation. A further review of the well record confirmed the gun debris depth, and the downhole motor run was canceled.

A short casing joint was detected in the well at a known depth, which verified that the well was clean to TD, saving the operator a day of downhole milling and a day of CT barge service.



Pressure and temperature data.

# Accurately Perforate Two Zones in an Underbalanced Condition

Real-time gamma ray for accurate depth control helps save time and money

## CHALLENGE

Minimize CT runs and accurately perforate the well in an underbalanced condition.

## SOLUTION

- Use Jet Blaster\* engineered high-pressure jetting service to clean out, drift, and initiate the required underbalance on the well prior to perforating operation.
- Utilize ACTive\* family of live downhole coiled tubing services—including gamma ray (GR)—combined with the CIRP\* completion insertion and removal under pressure equipment and two CT-deployed perforating systems—the eFire-CT\* electronic firing head system for CT deployment, and the eFire-TCP\* electronic firing head system for tubing-conveyed perforating deployment to accurately perforate the well in an underbalanced condition on the same run.

## RESULTS

Provided precise depth control in real time for accurate gun placement and perforated two zones in one CT run.



## Getting the well ready for intervention

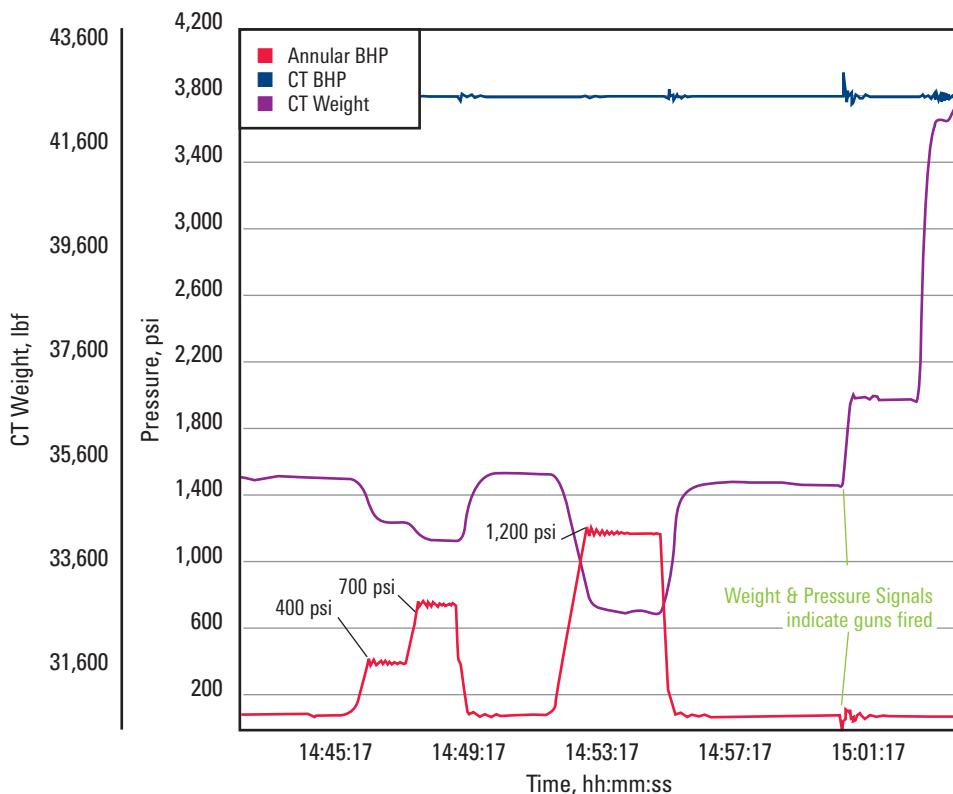
An operator drilled and completed a horizontal cased hole well in the Middle East that had a total measured depth of more than 13,000 ft.

There are two zones of interest—a bottom zone that is 70 ft long and an upper zone that is 80 ft long—that need to be accurately perforated. These zones are 280 ft apart. The solution requires running a wellbore cleanout and drift to ensure that there is no debris left in the completion, followed by setting the well on an underbalanced condition for a smooth perforating operation. An accurate perforating gun placement will be required for the underbalanced perforating technique.

Based on the results of the flowback, the operator considered an additional production log run to optimize the well's production.

## Using real-time gamma ray for accurate gun placement

Operators typically approach a horizontal well perforation using memory logging tools or a wired CT unit, which means that a mobilization of a CT unit and an electric wireline unit is required. Also, a simulation of the CT movement in the well is a critical factor to ensure that the BHA can be deployed all the way to the targeted zones.



The firing sequence of the eFire-TCP perforating deployment, used on the lower zone.

The choice requires precise knowledge of the perforating gun placement and an equally precise pressure reading for creating the underbalanced condition.

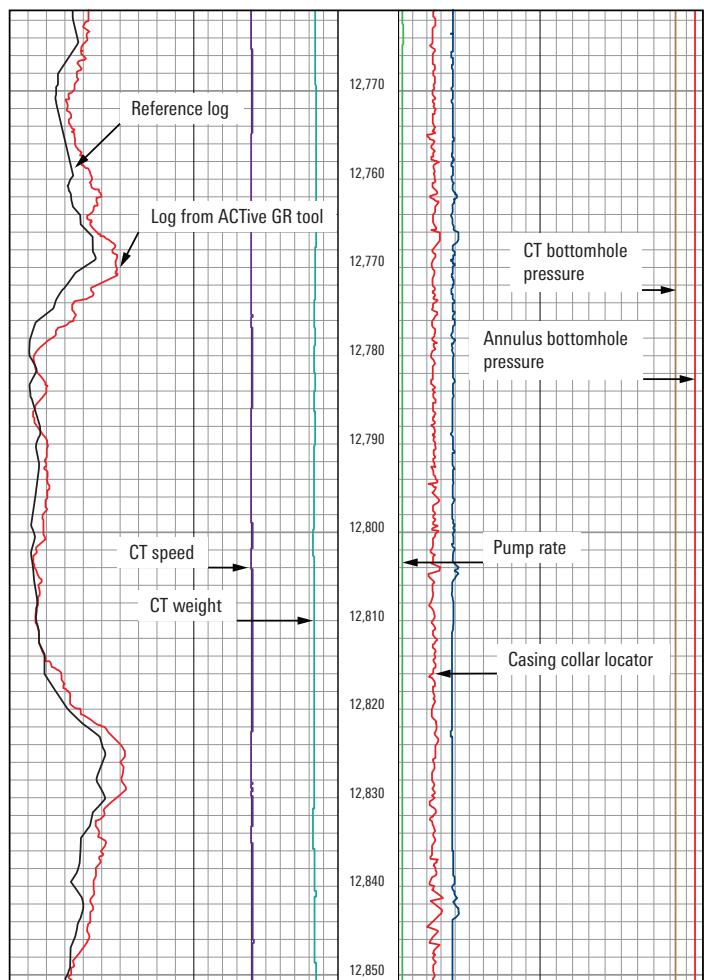
Looking for an efficient and effective solution, the operator elected to use the Schlumberger ACTive services, eFire-CT system, eFire-TCP perforating deployment, and CIRP equipment to efficiently and accurately perforate the well.

For the well, the following sequence of intervention was performed:

1. ACTive services were run with the Jet Blaster service to ensure that the wellbore was clean, drift, and to displace the well to diesel, creating a static underbalanced condition, confirmed by the real-time BHP measurement. Real-time GR was also used for efficiency and depth control confirmation, checked against the baseline log.
2. ACTive services was run with the eFire-CT system, eFire-TCP perforating deployment gun assembly, and GR package. The 250-ft BHA includes the two eFire systems with a total of 150 ft of 2½-in HSD\* high shot density perforating gun system that was deployed using the CIRP equipment. Real-time BHP measurements confirmed the gun detonations.
3. Perforate the lower zone using the eFire-TCP perforating deployment.
4. Perforate the upper zone using the eFire-CT system.

## Efficient perforating

The real-time ability of ACTive services to provide real-time downhole information, combined with the CIRP equipment CT deployment system and the eFire system technology, proved to be a highly advantageous method for underbalanced perforating in a horizontal well. The operator saved time and money using this method instead of the conventional alternative for horizontal well perforating. This resulted in operation efficiency and simplicity.



*Correlation run showing ACTive GR\* live CT gamma ray logging tool correlation against baseline log.*

# ACTive Perf Service Increases Sand-Free Gas Production in South China Sea

Real-time downhole measurement and interpretation optimize reservoir conditions and well performance

## CHALLENGE

Minimize perforation damage while maximizing gas production.

## SOLUTION

Used ACTive Perf\* live CT perforating service to control and accurately place perforating guns while ensuring optimal reservoir conditions.

## RESULTS

Decreased perforation damage which led to sooner-than-expected, higher-than-expected production of 70 MMcf/d of sand-free gas.

**The ability to perforate under optimal reservoir conditions resulted in improved well performance and in higher-than-expected production of 70 MMcf/d of sand-free gas.**



## Perforation damage in South China Sea

Talisman Malaysia Ltd. (TML) operates more than 130 wells in the South China Sea. Many of these wells do not perform to full potential because of perforation damage at suboptimal reservoir conditions.

Initial attempts to solve the damage problem involved using conventional coiled tubing (CT) perforating to complete the well underbalance. The main advantages of using CT were the ability to displace the wellbore fluid with nitrogen to create the underbalanced condition and a lower overall cost when compared to perforating using a rig.

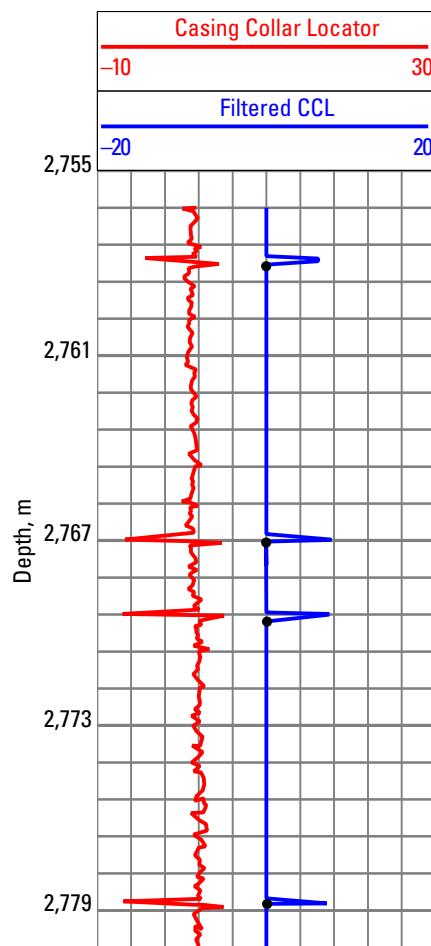
Although conventional methods were deemed efficient in this application, concerns included perforating off depth due to inaccurate depth control, not being able to detect fired guns, and improper balance conditions. Too little pressure could result in ineffective perforation cleanup; too much could cause the guns to be sanded in after firing.

## Downhole data for accurate placement

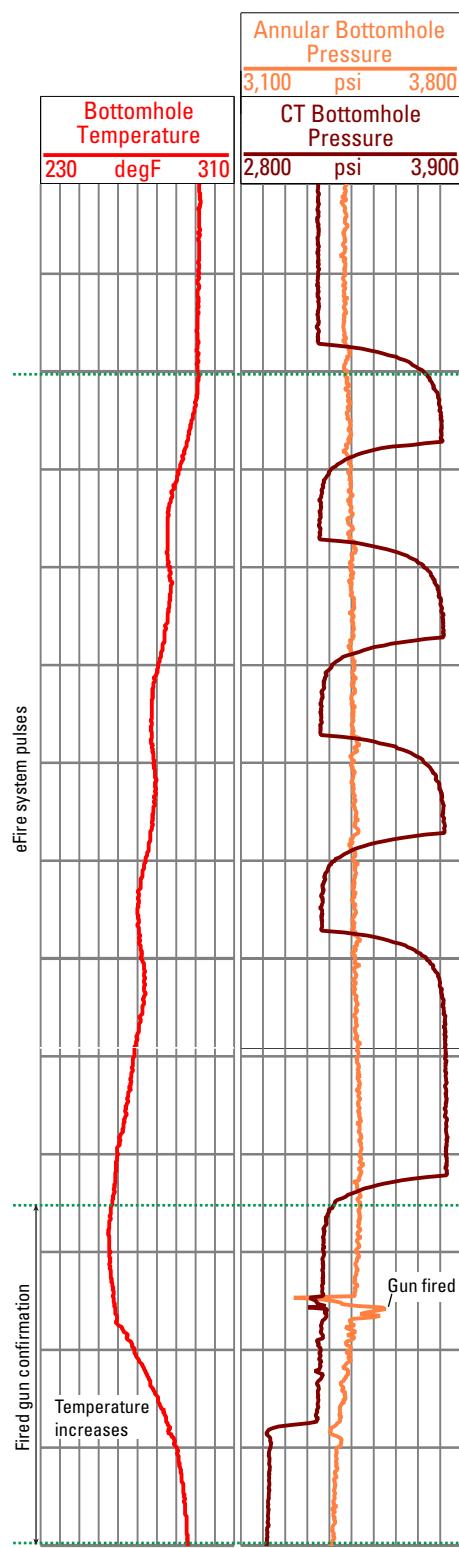
After collaborating with TML, Schlumberger chose to use ACTive Perf service, which provides downhole measurements and downhole tools and techniques to perforate in proper balanced conditions. It also enables

- accurate placement of the guns across the right zone
- tuning the downhole pressure to the optimal underbalanced condition
- controlling when to fire with the eFire\* electronic firing head system
- receiving real-time feedback when the guns fire.

Real-time information was used to complete a TML offshore gas well. The perforating gun was positioned on depth using real-time CCL correlation. Prejob calculations indicated the correct underbalance would be achieved after displacement of wellbore fluid with nitrogen. However, real-time pressure data showed that insufficient underbalance had been achieved. Displacing additional wellbore fluid corrected the underbalance condition.



Depth correlation plot.



Downhole pressure pulses for firing the guns.

Pressure nitrogen pulses down the CT were used to fire the gun. The downhole measurements immediately showed that bottomhole pressure and temperature increased, confirming a successful firing.

### Exceeding expectations

The ability to perforate under optimal reservoir conditions resulted in improved well performance and in higher-than-expected production of 70 MMcf/d of sand-free gas.

# Real-Time CT-Conveyed Perforating Service Boosts Production in High-Deviation HPHT Gas Well

Innovative, integrated approach bypasses near-wellbore damage, improves average pump rate in Saudi Arabia

## CHALLENGE

Bypass scale-induced, near-wellbore damage that was obstructing reservoir connectivity in a HPHT well.

## SOLUTION

Use ACTive Perf\* live CT perforating service with ABRASIJET\* hydraulic pipe-cutting and perforating service to

- cut slots with bigger diameter and tunnel length than possible with gun perforation
- enable real-time depth correlation
- optimize slot diameter and length
- confirm injectivity to perforated intervals.

## RESULTS

Regained wellbore accessibility and improved gas production with and without final acid stimulation.



## Formation damage compromised production

An operator faced major challenges during the perforation of HPHT gas wells in the Khuff reservoir in Saudi Arabia. Because of lost circulation while drilling, the operator applied lost circulation control materials (LCM). However, the high LCM concentrations in the mud led to inorganic scale deposition and irreversible formation damage. The operator was unable to fracture the wells, even after perforation. Several different types of guns were used to perforate the well, but the perforation gun tunnel length could not bypass the high near-wellbore damage, inhibiting production from the well.



*ABRASIJET tool.*

The operator turned to Schlumberger to create a connection between the reservoir and wellbore, which would enable the teams to stimulate the formation and begin producing from the critical well.

## Real-time abrasive perforating technique enhanced fracturing

Schlumberger recommended using ACTive Perf service with ABRASIJET service to create deeper, larger-diameter tunnels than are possible with perforating guns. In addition, this technique would reduce the fracture initiation pressure and allow fractures to extend deeper into the reservoir.

Schlumberger optimized the slot diameter and length by orienting the nozzles to the lower side of the wellbore and maintained slot cutting efficiency with real-time monitoring using ACTive\* family of live downhole coiled tubing services. A total of 12 notches were made due to lower permeability rock adjacent to both the upper and middle zones at 4 stations across a 50-ft interval. There were 16 notches made across a shorter 35-ft interval in the lower 40-ft zone. Injectivity to the perforated intervals was confirmed using ACTive Profiling\* live CT distributed temperature sensing service. The real-time measurements also helped the operator improve depth accuracy and optimize the slot geometry for the fracturing treatment.

## Bypassing formation damage improved production

The well started producing gas during the slot cutting, immediately establishing reservoir connectivity. Schlumberger confirmed injectivity through three zones and improved the injectivity with an acid wash. Crews performed a matrix acid stimulation treatment to help start production and performed the operations at the same average pump rate and pressure as other nondamaged gas wells in the region. ACTive Perf service with ABRASIJET service enabled the effective and efficient bypass of damaged formation zones and established gas production. The operator plans to use this abrasive perforating technique on future wells with similar challenges.

# Accurately Perforate Zones in an Underbalanced Condition in Saudi Arabia

Real-time gamma ray for accurate depth control helped Saudi Aramco save time and money

## CHALLENGE

Minimize the CT run and accurately perforate the well in an underbalanced condition in a Saudi Arabian field.

## SOLUTION

- Use Jet Blaster\* engineered high-pressure jetting service to clean out the well prior to perforating operation.
- Utilize ACTive\* family of live downhole coiled tubing services—including the ACTive PS\* live CT production logging service and ACTive TC\* live CT tension and compression tool and gamma ray (GR)—combined with two CT-deployed perforating systems—the eFire-CT\* coiled tubing electronic head firing, and the tubing-conveyed perforating (TCP) to accurately perforate the well in an underbalanced condition.

## RESULTS

Reduced the numbers of a typical CT run and perforate the well on-depth.



## Getting the well ready for intervention

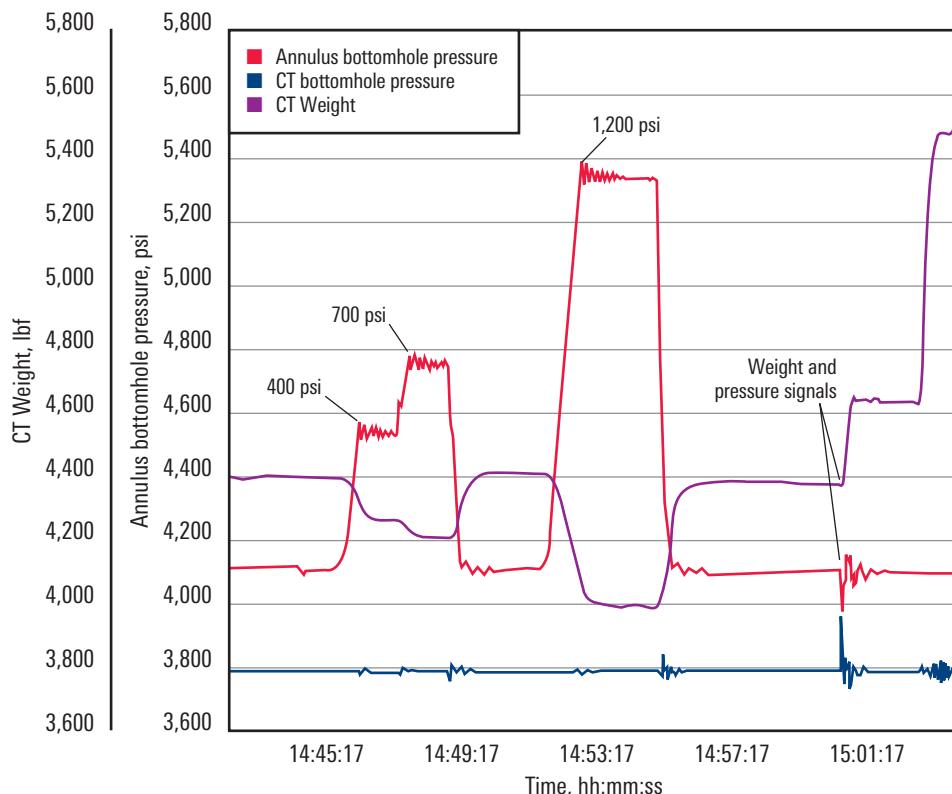
Saudi Aramco's well HWYH-1008 was drilled and completed in April 2010. It is a horizontal cased hole producer across the Khuff-C carbonate formation, with a total measured depth of 13,443 ft.

There are two zones of interest—a bottom zone that is 70 ft long and an upper zone that is 80 ft long—that need to be accurately perforated. These zones are 280 ft apart. The solution requires running a wellbore cleanout to ensure that there is no debris left in the completion for a smooth perforating operation. An accurate perforating gun placement will be required for the underbalanced perforating technique.

Based on the results of the flowback, an additional production log run may be considered to optimize the well's production.

## Using real-time gamma ray for accurate gun placement

Operators typically approach a horizontal well perforation using a wired CT unit, which means that a mobilization of a CT unit and an electric wireline unit is required. Also, a simulation of the CT movement in the well is a critical factor to ensure that the BHA can be deployed all the way to the targeted zones. The choice requires precise knowledge of the perforating gun placement and an equally precise pressure reading for creating the underbalanced condition.



The firing sequence of the eFire-TCP electronic firing head system for tubing-conveyed perforating deployment.

Looking for an efficient and effective solution, Saudi Aramco elected to use the Schlumberger ACTive PS service and eFire-CT system to efficiently and accurately perforate the well.

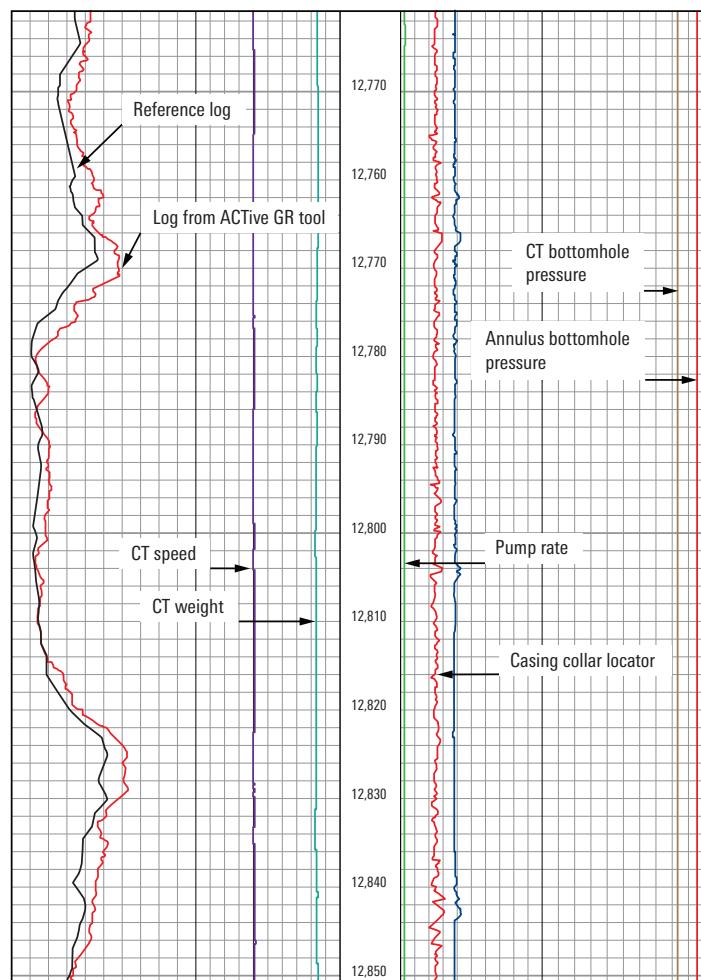
Using the real-time gamma ray (GR) to accurately identify the production zone, the eFire-CT system and eFire TCP\* electronic firing head system for tubing-conveyed perforating deployment were run in hole (RIH). The tension and compression module aided the gun placement, while the real-time pressure information gave an accurate read on the required downhole pressure information for a true underbalanced condition.

For the HWYH-1008 well, the following sequence of intervention was performed:

1. ACTive was run with the Jet Blaster service to ensure that the wellbore was clean and to displace the well to diesel, creating a static underbalanced condition. The tension, compression, and real-time GR was also used for efficiency and depth control confirmation.
2. ACTive PS service was run with the eFire-CT system and eFire-TCP system perforating gun assembly, incorporating the tension, compression, and GR package.
  - Depth was correlated to the first target zone depth and the eFire TCP system was fired.
  - Depth was correlated for the second target zone depth and the eFire-CT system was fired.

### **Efficient perforating**

The real-time ability of ACTive PS service to provide downhole information, coupled with the eFire system, proved to be a highly advantageous method for underbalanced perforating in a horizontal well. Saudi Aramco saved time and money using this method instead of the conventional alternative for horizontal well perforating. The job risks were reduced by using the perforating gun reverse deployment technique. This resulted in operation efficiency and simplicity.



Correlation run showing ACTive PS GR correlation against baseline log.

# ACTive Cleanout Provides DH Access for Perforating Multiple Zones

Real-time downhole measurement and interpretation enable effective sand cleanout in South China Sea

## CHALLENGE

To prevent sand plugging while perforating multiple zones in an injector well.

## SOLUTION

ACTive Cleanout\* live CT wellbore fill removal service to enable effective wellbore access while ensuring accurate placement and optimal well conditions with ACTive Perf\* live CT perforating service.

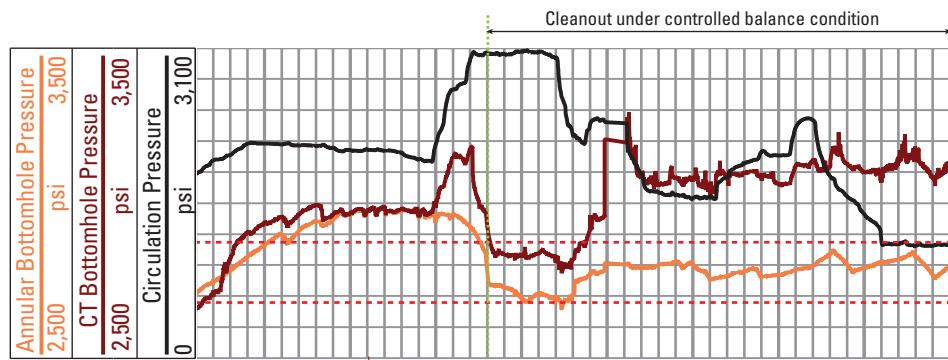
## RESULTS

Effective wellbore cleanout and accurate pressure management resulting in a water injectivity rate of 8,900 bbl/d, confirming that sand plugging was prevented.



## Sand migration after perforation

Talisman Malaysia Ltd. (TML) recently drilled a water injector well in the Malaysian waters of the South China Sea. After the first zone was perforated, sand was produced, plugging the next perforating intervals. Despite efforts to clean out the well using conventional CT methods, the planned intervals could not be accessed. Injecting nitrogen to circulate the fluid and flow the well only produced more sand.



Downhole pressure plots during ACTive cleanout operations.

Most CT activities in this unconsolidated sandstone formation involve the removal of wellbore fill. Formation sand causes wellbore fill or sanding, which is a problem for all operators drilling in this area. Sanding can occur in both newly drilled and mature wells.

## Preventing unconsolidated sand migration

The operator chose ACTive Cleanout service and ACTive Perf service to obtain real-time downhole measurements, which allowed better control of the cleanout and accurate placement of the perforating guns. The existing sand in the wellbore was lifted out by keeping the bottomhole condition at balanced or slightly overbalanced conditions using real-time bottomhole pressure data. The designed pumping schedule was then followed with continuous real-time monitoring of pressure and temperature. Before continuing with the planned perforation run, an injectivity test ensured that the tunnels in the existing perforation interval were open.

The perforating operation was then resumed and the guns were successfully conveyed to the target depth and correlated against base depth log. The real-time bottomhole pressure reading showed proper balance to ensure sand would not be produced. Using the real-time casing collar locator (CCL) correlations, the guns were positioned to perforate the interval. The e-Fire\* electronic firing head system was activated via nitrogen pulses through CT. Bottomhole pressure and bottomhole temperature increased after the guns fired.

**Achieving water injection rates**

These services allowed effective cleanout, accurate placement of the guns across the right zones, tuning the downhole pressure to the correct or slightly overbalanced condition, controlling when to fire the perforating guns with the e-Fire system, and receiving feedback at the surface when the guns were fired.

The final water injectivity rate was 8,900 bbl/d at 700-psi surface pressure, confirming that sand was not introduced into the wellbore after the perforation operations were complete.

# ACTive OptiFIRE System Reperforates Critical Producing Interval in Record Time

First deployment of near-instantaneous coiled tubing technology selectively perforates zone, eliminating deferred production

## CHALLENGE

Selectively perform a perforating intervention on a critical producing interval inaccessible by wireline.

## SOLUTION

Use ACTive OptiFIRE\* CT real-time selective activation system to access the zone, accurately place perforating guns, and confirm downhole detonation in a single run.

## RESULTS

Enhanced intervention safety and efficiency by

- cutting perforating gun detonation time by 75%
- confirming downhole detonation in real time using fiber-optic technology
- cleaning and kicking off the well with the same ACTive\* family of live downhole coiled tubing services CT unit
- avoiding the use of working fluid that could damage the formation, thus mitigating deferred production.



Rigless deployment of the ACTive OptiFIRE system perforating string.

## Deviated, high-clay well prevents conventional reperforation strategy

When a critical interval was not producing as expected, an operator decided to reperforate the zone. However, due to some deployment limitations, this zone was inaccessible by wireline intervention. Like many wells in this area, all efforts were made to avoid killing the well or pumping fluid into the formation, which could delay putting the well back into production.

## Real-time CT technology enables accurate, selective perforating

Schlumberger proposed piloting the ACTive OptiFIRE CT real-time selective activation system, the industry's first coiled tubing technology that allows perforating guns to be selectively activated downhole. Unlike most conventional perforating solutions, the ACTive OptiFIRE system does not require any working fluid for firing head activation. Instead, it relies on real-time fiber-optic technology to detonate the perforating string.

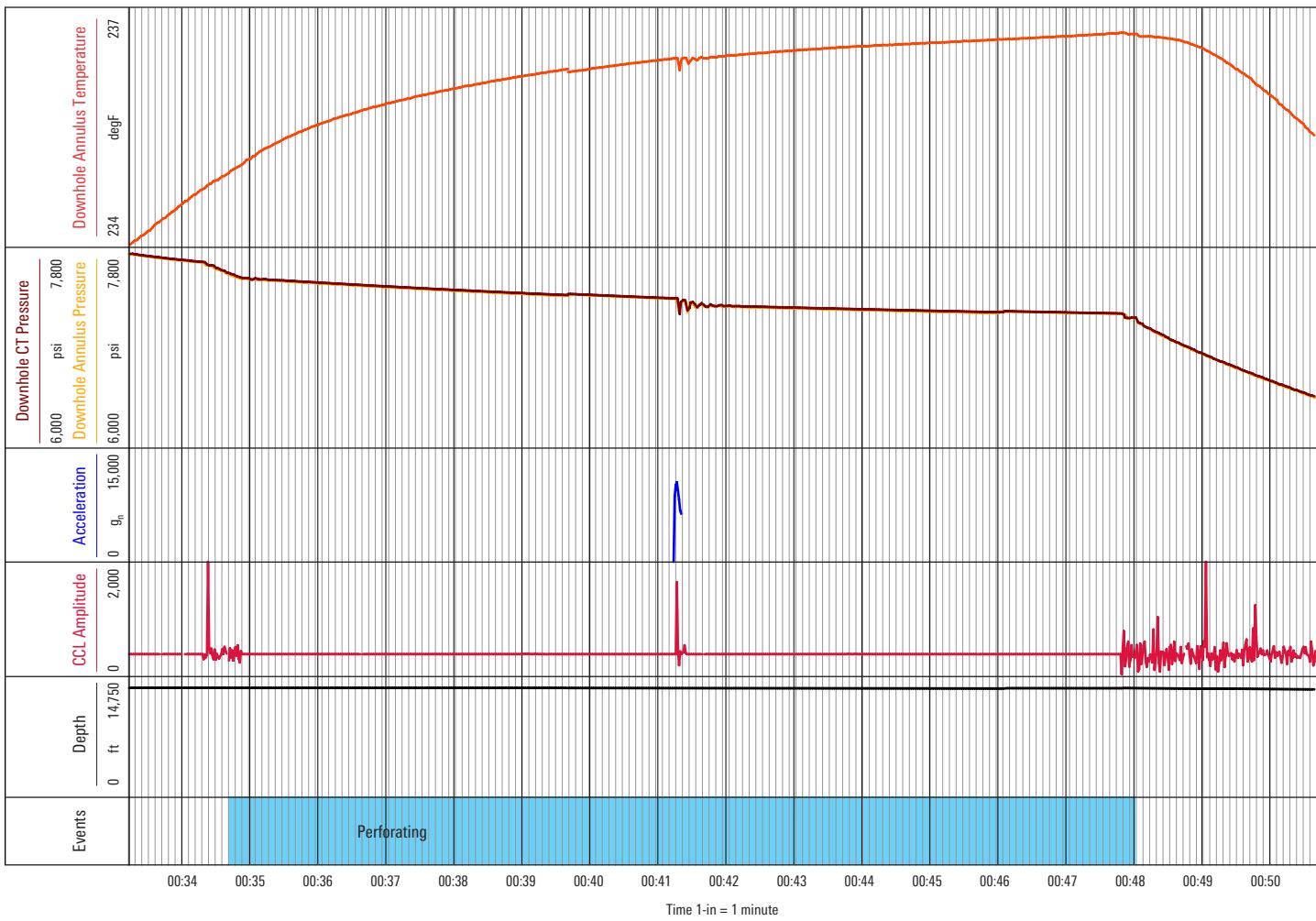
Schlumberger used gamma ray logging tool measurements and the ACTive services' downhole casing collar locator (CCL) module to place the bottomhole assembly (BHA) across the desired zone at 13,327-ft MD [4,062-m MD] and activate the firing head. At the moment of downhole detonation, the ACTive OptiFIRE system sent CCL, pressure, temperature, and accelerometer data to the surface in real time—safely confirming detonation within seconds.

## CT intervention sets record, eliminates deferred production

The operator and Schlumberger used this innovative coiled tubing technology to perforate the well in just 11 hours and monitor downhole conditions in one run—setting a new record in time efficiency. Once the BHA was placed at the target interval, it took only minutes to activate the perforating head and get confirmation of detonation. Hydraulically activated guns would require up to 2 hours to detonate the perforating guns alone. This reduced the time to detonate the perforating string by 75% compared with conventional methods.

Because the ACTive OptiFIRE system did not require any working fluid, the operator mitigated well damage and eliminated deferred production associated with wireline interventions. Following the reperforating treatment, the operator was also able to clean and kick off the well with the same ACTive services unit—avoiding the costs of having additional equipment on site.

Since this successful trial well, the operator has implemented the ACTive OptiFIRE system on three additional wells.



Real-time confirmation of downhole detonation using the response of temperature, pressure, accelerometer, and CCL data.

# ACTive OptiFIRE System Perforates Three Intervals, Increases Well Production 18% in Brownfield Well

Innovative underbalanced perforating technology reduces HSE risk, deferred production, and intervention time

**CHALLENGE**

Perforate two new intervals and reperforate a producing interval in underbalanced conditions without deferring production.

**SOLUTION**

Use ACTive OptiFIRE\* CT real-time selective activation system to perforate the selected zones and confirm downhole detonation instantaneously.

**RESULTS**

Successfully perforated all three intervals, increasing well production by 18%.

**Underbalanced conditions present perforating challenges**

After decades of strong production, a brownfield in Latin America struggled with economic and operational challenges. To enhance declining flow rates, the operator planned to perforate two new intervals and reperforate a critical zone. In an effort to prevent deferred production and remove formation damage, the operator needed Schlumberger to perform the perforating job on a live well during underbalanced conditions.

**ACTive OptiFIRE system accurately perforates and measures in one run**

Schlumberger deployed the ACTive OptiFIRE system, a first-of-its-kind coiled tubing technology that eliminates the need for a ball drop or pressure-pulse system to activate shaped charges. Using advanced fiber-optic technology, Schlumberger accurately placed the perforating guns into the three selected zones and perforated the well. Casing collar locator (CCL), pressure, temperature, and accelerometer data confirmed downhole detonation in real time.

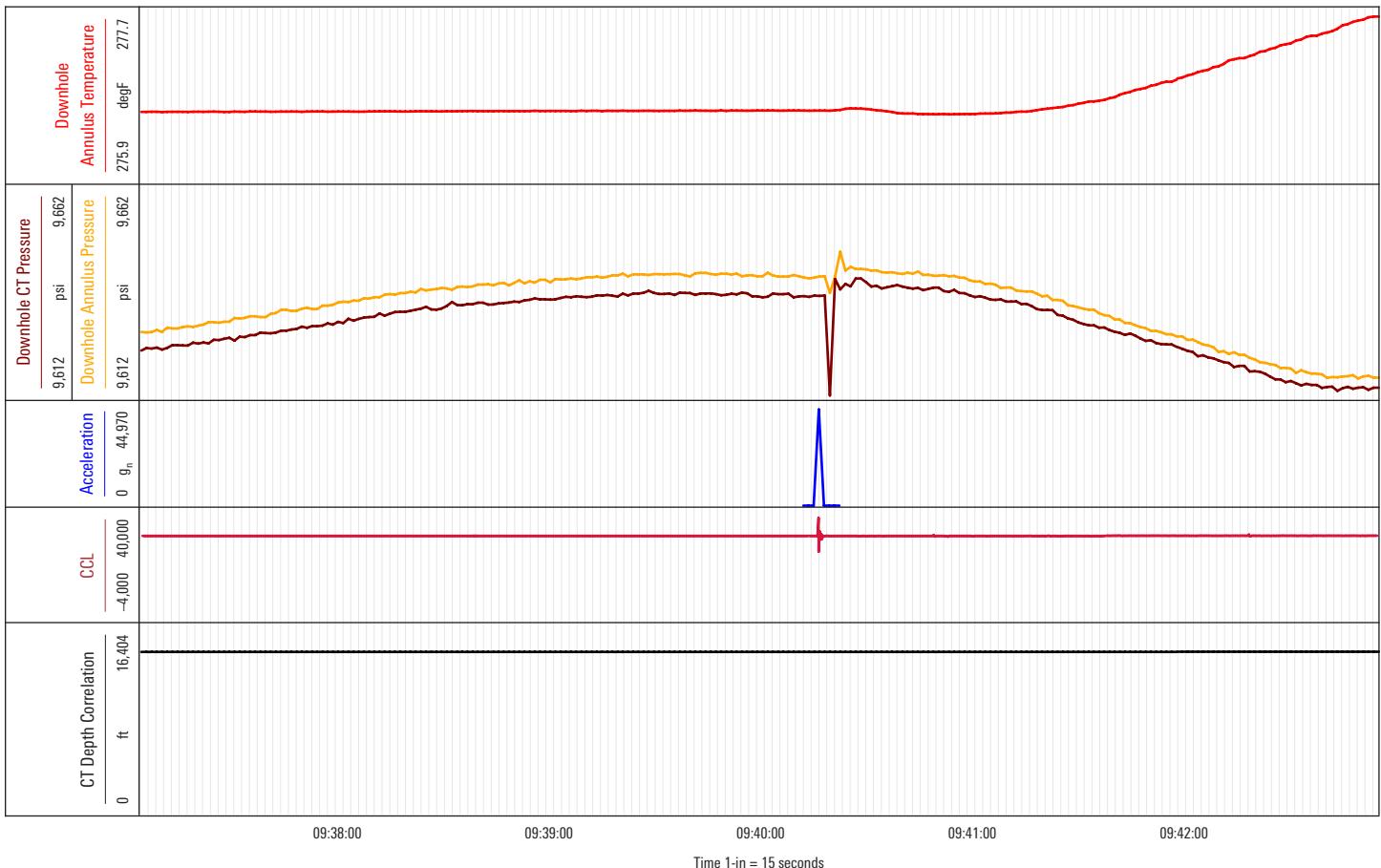
**Live coiled tubing job sets record time while increasing production by 18%**

After the intervention, the operator realized a production increase of 18%, and the ACTive OptiFIRE system reduced perforating gun detonation time by 75%.

The absence of working fluid dramatically reduced HSE risk during the underbalanced perforating intervention, as it eliminated the need to hydrostatically load the well as part of the operation. Because the intervention was performed on a live well, the operator avoided deferred production and nonproductive time associated with conventional perforating methods.



*Initialization of the joint well intervention–wireline rigless deployment of the ACTive OptiFIRE system’s bottomhole assembly.*



Real-time confirmation of downhole detonation using the response of (from top to bottom) temperature, pressure, accelerometer, and CCL data.

# ACTive Isolation Revives Well Production

Rigless shutoff decreases water cut by 50% and increases oil production by 1,000 bbl/d in Saudi Arabia

## CHALLENGE

Improve oil production in a horizontal openhole well experiencing intermittent production caused by increased water cut.

## SOLUTION

Provide better control and accurate placement of high-expansion bridge plugs using ACTive Isolation\* live CT zonal isolation service for real-time downhole measurements.

## RESULTS

- Decreased water cut by 50%.
- Increased oil production by 1,000 bbl/d.
- Reduced completion time by half.
- Eliminated rig intervention costs.



## Water cut stops well production

A new horizontal well in Saudi Arabia was producing oil with a 60% water cut, which was causing the well to stop flowing. Most of the water was coming from the toe of the completion in an open-hole carbonate reservoir. The well was completed as a horizontal openhole well.

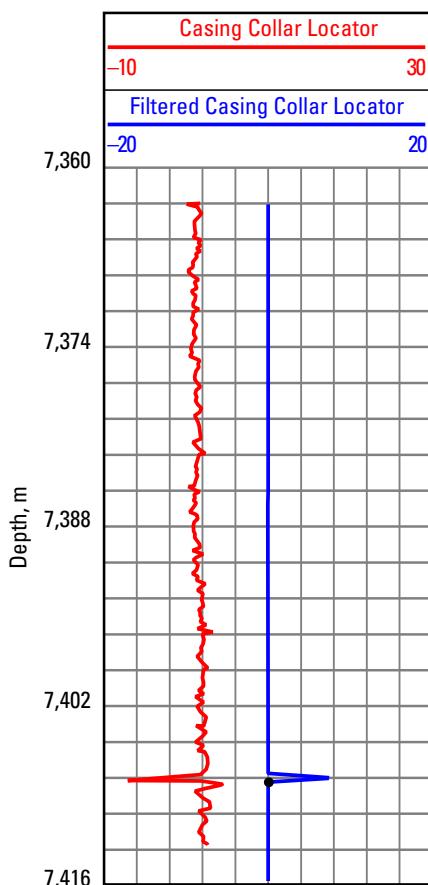
Water shutoff operations in horizontal openhole wells are complicated by lack of information about depth, bottomhole temperature, and bottomhole pressure, which makes isolation difficult. These factors affect the reliability of high-expansion bridge plug operations, cement plug formulation, and proper placement of isolation devices to shut off a water-producing zone.

## Real-time data provides answers

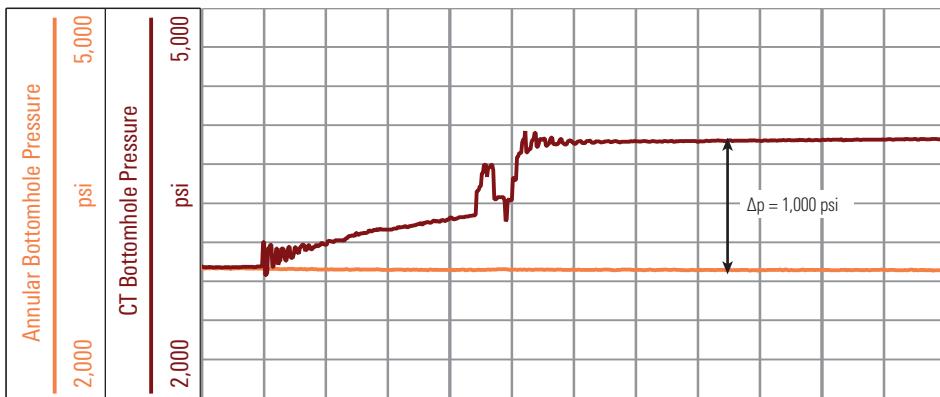
Saudi Aramco chose ACTive Isolation service for an accurate and effective way to isolate the zone, to reduce water cut, and to regain production.

ACTive Isolation service also provided a rigless solution by deploying a through-tubing inflatable packer on CT and a cement plug to isolate the water-producing zone at the toe of the horizontal open hole.

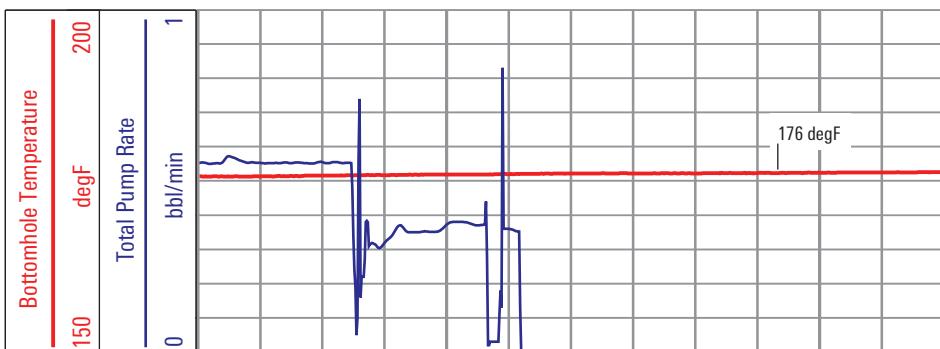
The initial run confirmed well accessibility and downhole temperature for accurate cement slurry design. On the second run, the through-tubing inflatable packer was run to the depth of the oil/water interface. After the depth was confirmed, a ball was dropped in the CT to set the packer. Real-time downhole measurements ensured the packer was properly located and set. On the third run, CT spotted cement on top of the inflatable packer.



Depth correlation at the tubing shoe.



Real-time differential pressure confirming proper packer setting.



Pump rate and real-time downhole temperature during packer setting.

### Oil production revived

The kill fluids were displaced with nitrogen, which was confirmed at surface by monitoring downhole pressure. This rigless solution reduced completion time by half.

With the well back in production, water cut decreased by 50% and oil production increased by 1,000 bbl/d.

# Eliminating Water Cut with Water Shutoff Treatment

CoilFLATE permanent bridge plug and OrganoSEAL gel eliminate water production in the Gulf of Mexico

**CHALLENGE**

Effectively shut off water production in 7-in [177.8-mm] liner.

**SOLUTION**

Set 3-in [76.2-mm] CoilFLATE\* coiled tubing through-tubing inflatable packer as a mechanical isolation device to effectively place OrganoSEAL-F organic crosslinked gel in the water-producing section of the well.

**RESULTS**

Eliminated water production and increased oil production to 1,490 bbl/d.

**Ten days after the water shutoff treatment using ACTive services and OrganoSEAL gel, oil production was at 100%—no water cut.**

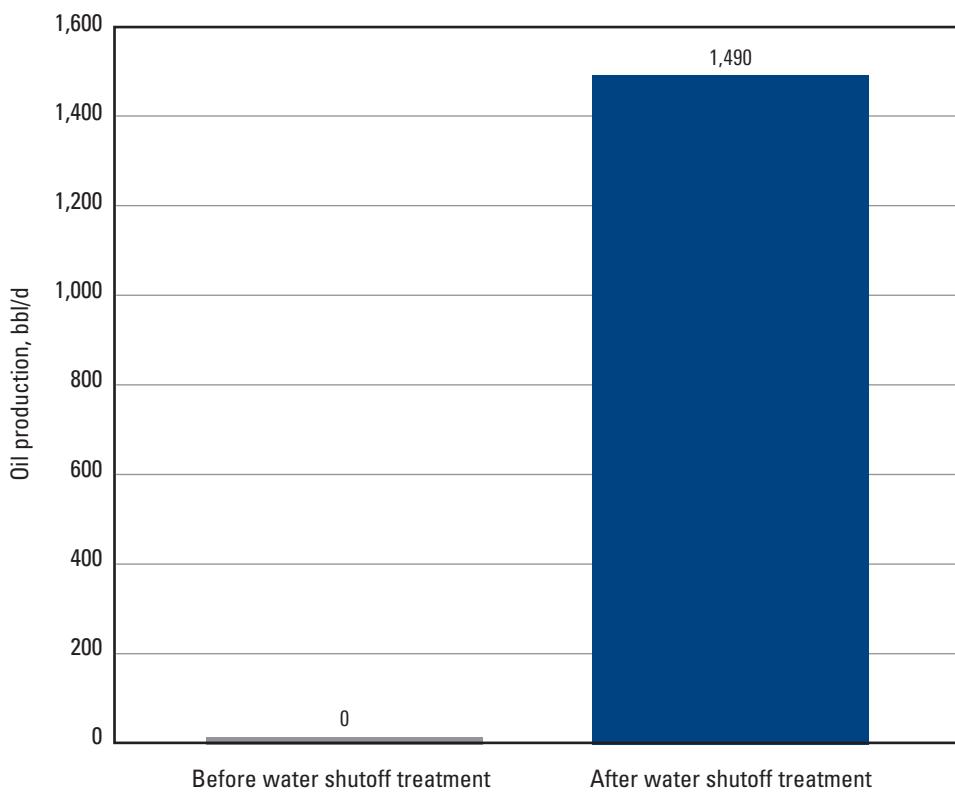
**Water cut causes 54-month shut-in**

A Gulf of Mexico well in the Calcareitas formation was drilled as an oil producer and was completed with a 7-in [177.8-mm] liner. The minimum restriction in the well was 3.675 in [93.345 mm]. The operator had to shut it in for 54 months because of high water cut.

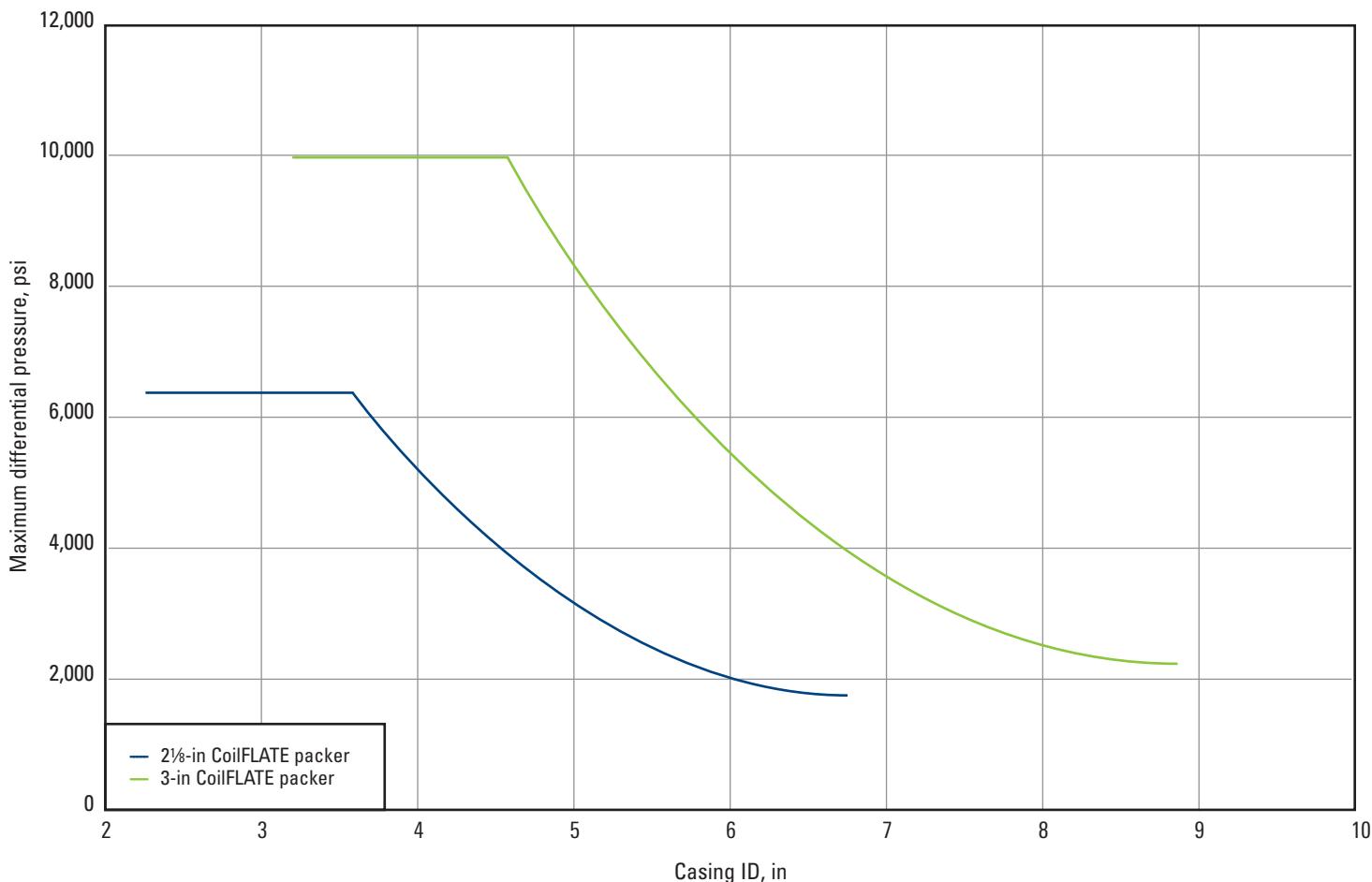
**Operator implements water shutoff treatment**

The operator chose a Schlumberger water shutoff treatment. The project included

- setting a CoilFLATE packer in a 65-ft [19.8-m] window at 10,500 to 10,435 ft [3,200 to 3,180.6 m]
- injecting OrganoSEAL-F gel below the packer
- leaving the packer in the well as a permanent bridge plug
- placing a 30-ft [9-m] cement plug on top of the bridge plug
- perforating a new zone above the packer.



*The Schlumberger water shutoff treatment boosted oil production from 0 to 1,490 bbl/d.*



*The engineered slat design allowed higher differential pressures at varying inflation ratios.*

A dummy run was performed with the Jet Blaster\* engineered high-pressure jetting service and ACTive\* family of live downhole coiled tubing services—an optical fiber pressure, temperature, and casing collar locator (CCL) tool—to correlate depth in real time, clean the ID of the casing at setting depth, and drift the casing. The setting depth had to be accurate to ensure that the top of the cement plug to be placed on the bridge plug was below the new interval to be perforated. The ACTive services tool in the CT string provided accurate real-time transmission of casing collar information from the downhole CCL tool to the surface acquisition system for correlation.

The packer was run in hole and set at 10,480 ft [3,194 m] in the 6.184-in [157.074-mm]-ID liner. After the packer was set, 200 bbl of OrganoSEAL-F gel and 20 bbl of SqueezeCRETE\* remedial cementing solution were injected through the packer to shut off water production from the zone below. The CT was disconnected from the packer, and a 30-ft [9-m] cement plug was placed on it to make the packer a permanent bridge plug.

#### Oil production increases by 100%

New perforations were made from 10,320 to 10,420 ft [3,145 to 3,176 m], and 10 days after the water shutoff treatment, oil production was at 100%—with zero water cut.

# ACTive Isolation Revives Well Production

Rigless shutoff decreases water cut by 50% and increases oil production by 1,000 bbl/d in Saudi Arabia

## CHALLENGE

Increased water cut caused intermittent oil production in a horizontal openhole well.

## SOLUTION

Use ACTive Isolation\* live CT zonal isolation service to provide better control and accurate placement of high-expansion bridge plugs, using real-time downhole measurements.

## RESULTS

Water cut decreased by 50%. Oil production increased by 1,000 bbl/d. Completion time reduced by half. Cost of rig intervention eliminated.



## Water cut stops well production

A new horizontal well in Saudi Arabia was producing oil with a 60% water cut, which was causing the well to stop flowing. Most of the water was coming from the toe of the completion in an openhole carbonate reservoir. The well was completed as a horizontal openhole well.

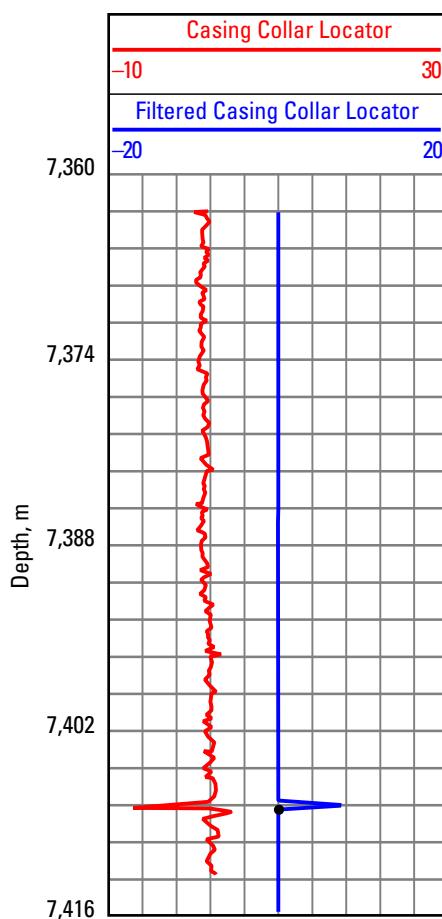
Water shut-off operations in horizontal openhole wells are complicated by lack of information about depth, bottomhole temperature, and bottomhole pressure, which makes isolation difficult. These factors affect the reliability of high-expansion bridge plug operations, cement plug formulation, and proper placement of isolation devices to shut off a water-producing zone.

## Real-time data provides answers

Saudi Aramco chose ACTive Isolation service for an accurate and effective way to isolate the zone, to reduce water cut, and to regain production.

ACTive Isolation service also provided a rigless solution by deploying a through-tubing inflatable packer on CT and a cement plug to isolate the water-producing zone at the toe of the horizontal open hole.

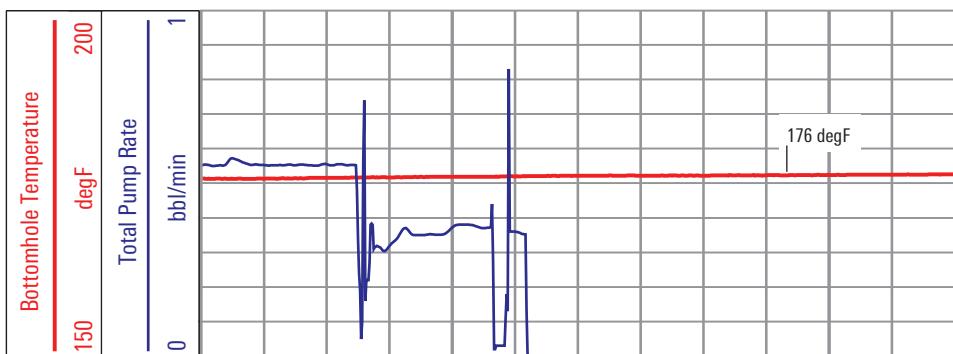
The initial run confirmed well accessibility and downhole temperature for accurate cement slurry design. On the second run, the through-tubing inflatable packer was run to the depth of the oil/water interface. After the depth was confirmed, a ball was dropped in the CT to set the packer. Real-time downhole measurements ensured the packer was properly located and set. On the third run, CT spotted cement on top of the inflatable packer.



Depth correlation at the tubing shoe.



Real-time differential pressure confirming proper packer setting.



Pump rate and real-time downhole temperature during packer setting.

### Oil production revived

The kill fluids were displaced with nitrogen, which was confirmed at surface by monitoring downhole pressure. This rigless solution reduced completion time by half.

With the well back in production, water cut decreased by 50% and oil production increased by 1,000 bbl/d.

# Eni Deploys Real-Time ACTive Coiled Tubing Services for Workover Operations

Deployment of ACTive services, fiber optic–enabled CT technology improves intervention accuracy and efficiency in offshore Egypt wells

## CHALLENGE

Improve workover efficiency in offshore wells plagued by water encroachment, sand production, and aging completions.

## SOLUTION

Use ACTive\* family of live downhole coiled tubing services to provide real-time downhole measurements for casing collar locator (CCL), pressure, temperature, and distributed temperature sensing (DTS).

## RESULTS

Optimized fluid volumes and pumping rates during lifting, cleanout, and stimulation treatments. Blocked water-producing intervals with accurate packer placement.



## Eni needed efficient intervention technique for new workover challenges

Eni, the leading foreign oil operator in Egypt, faced increasingly complex well interventions. Water encroachment, sand production, and aging completions represented a barrier to improving workover efficiency with conventional coiled tubing.

Conventional offshore CT intervention relies heavily on the knowledge and prediction of downhole parameters. In offshore Mediterranean operations, well interventions demand extremely accurate downhole data—including pressure, temperature, and depth measurements—for greater understanding of well challenges and better informed decisions.

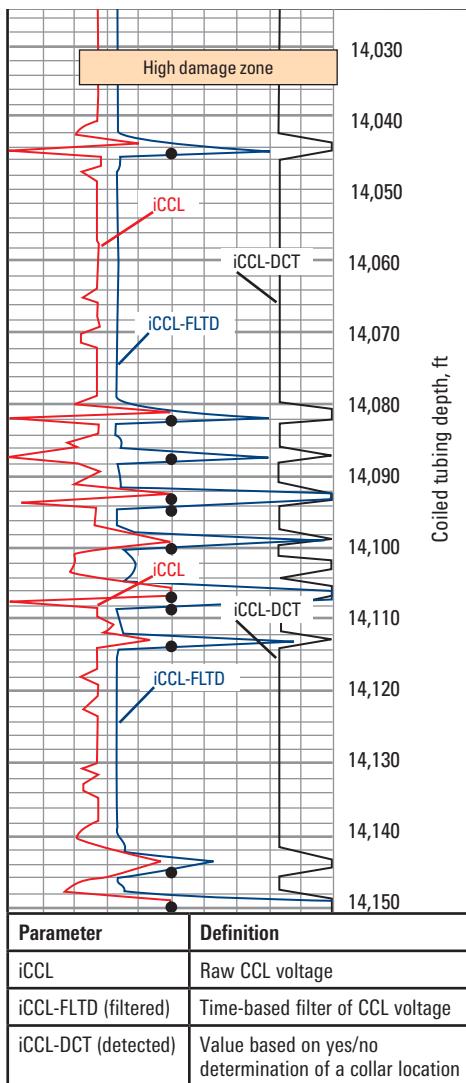
## Live CT services improved data accuracy and intervention efficiency

Schlumberger recommended deploying ACTive services, which would enable Eni to optimize treatments while they were in progress. The precise, real-time measurements obtained using ACTive services helped Eni reduce time and risk by

- acquiring accurate depth correlation, avoiding additional runs
- monitoring packer inflation pressure, minimizing possibility of failure
- controlling underbalance conditions during lifting and cleanout operations
- identifying fluid intake zones by DTS
- protecting completion and formation integrity.



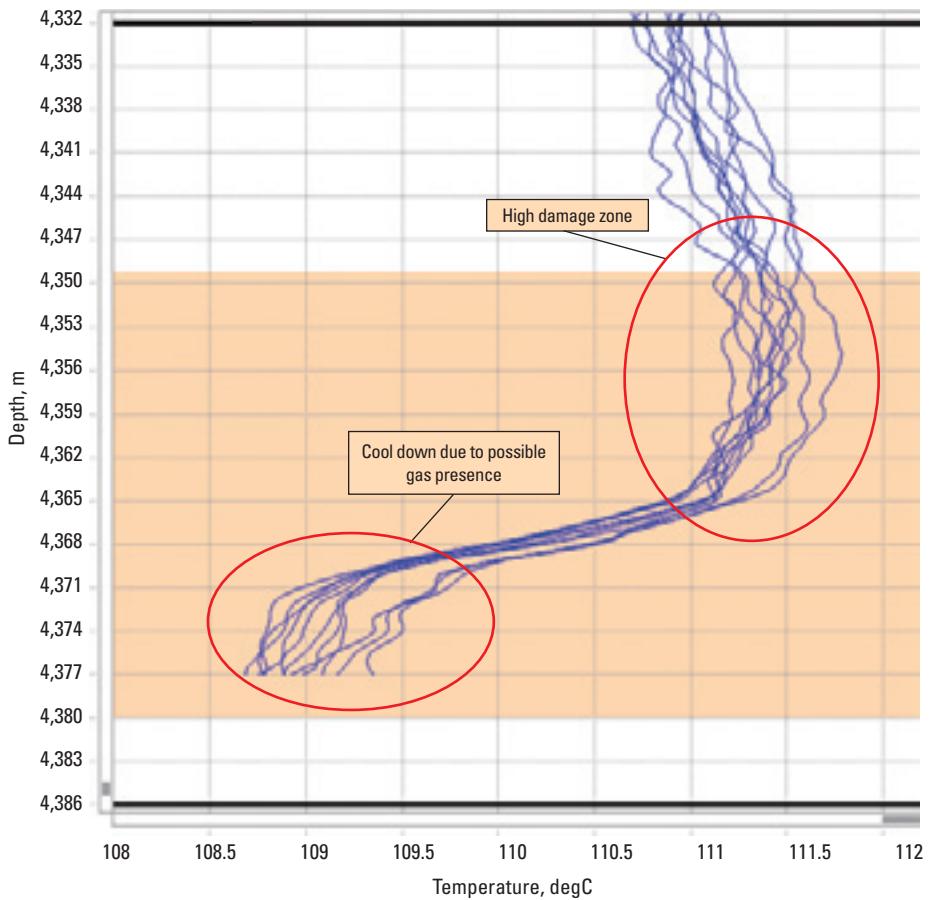
Real-time CT readings enable informed decisions at the customer's office.



Accurate depth correlation with real-time CCL log.

#### Eni improved workover effectiveness and efficiency

ACTive CT services gave Eni a better understanding of well performance. Eni optimized fluid volumes and pumping rates during lifting, cleanouts, and stimulation treatments.



DTS acquisition.

# Reviving Production for a Watered-Out Well Through Smart Coiled Tubing Intervention

Combining ACTive services and CoilFLATE packer technology results in 13,700 bbl/d oil production for Saudi Aramco

## CHALLENGE

Decrease water cut and revive oil production from a dead well.

## SOLUTION

Use ACTive\* family of live downhole coiled tubing services, including ACTive TC\* live CT tension and compression tool and ACTive GR\* live CT gamma ray logging tool, combined with CoilFLATE\* coiled tubing through-tubing inflatable packer, to strategically set the packer and isolate the water zone through cement squeeze.

## RESULTS

Revived well and increased production to 13,700 bbl/d of oil.



## Increasing water production

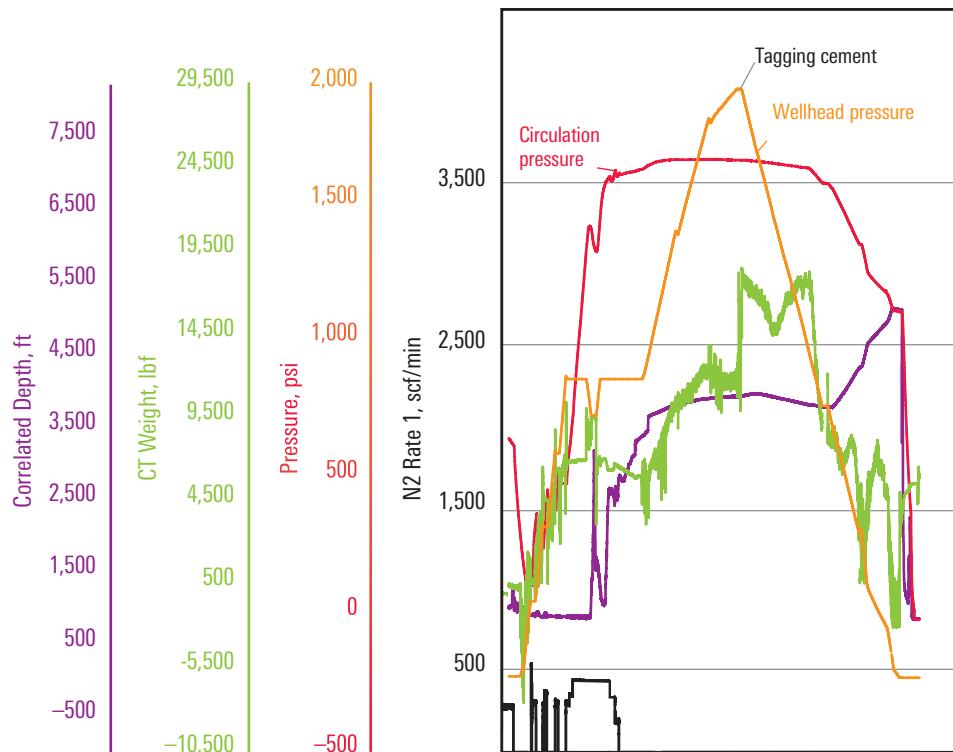
A Saudi Aramco well was drilled and completed in Saudi Arabia in July 2002. The well was a highly slanted openhole producer across the Arab-D formation with a total depth of 9,950 ft.

The operator noticed the well's water production start to increase in early 2004. A Flow Scanner\* horizontal and deviated well production logging system horizontal and deviated well production logging system was run in December 2005 and indicated a 29.6% water cut, with most of the oil production coming from clusters of conductive fractures in the Arab-D zones 2B and 3A. In 2008, the well was producing 80% water and was declared to be noncommercial (dead).

Operators typically approach the water encroachment problem with wellbore isolation, either mechanical or chemical. Both options require precise knowledge of the water production source and an equally precise placement technique to isolate the water production that can result in costly well shut-ins and workover operations.

## Deciding on remedial work

In July 2010, a coiled tubing-deployed slim array induction tool (SAIT) was run on the well to determine its water and oil saturation. Based on the log evaluation, the remedial action for this well was an attempt to isolate the highly water-saturated zones above the fracture clusters. Water shutoff treatment was required to isolate the water-producing zone and enhance oil recovery from the upper section.



The graph above shows N<sub>2</sub> lifting to help bring the well back to life. It also shows tagging cement at 7,923 ft.

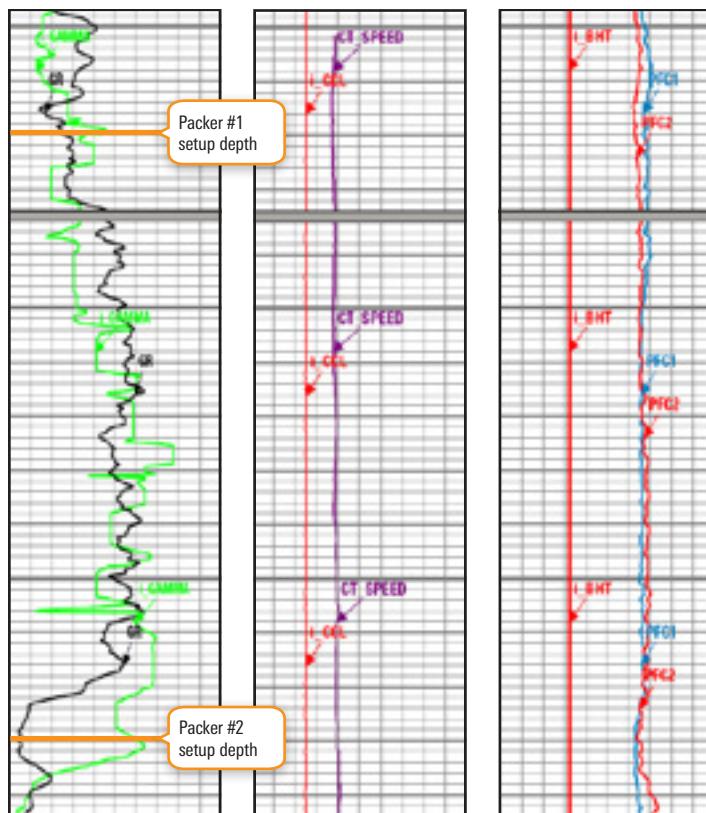
Saudi Aramco selected the ACTive services, incorporating the newly developed TC and GR tools. These services were then combined with the proven CoilFLATE packer to isolate the production zone from the water source and to give a precise cement placement. This was the first time ever that all three of these technologies were run at one site.

For the well, the following sequence of intervention was performed:

1. ACTive services was run with x-y caliper and GR was run to determine the best place to set the isolation packer.
2. A second run of ACTive TC tool and ACTive GR tool package was done to set the CoilFLATE packer.
  - The first 3-in CoilFLATE packer was set to isolate the production zone.
  - A second 3-in CoilFLATE packer was set to place cement to isolate the water zone.

### Back in action

The well was successfully revived for Saudi Aramco. Postjob production rose to 13,700 bbl/d of oil with just 10% water cut on a fully open choke with 620 psi of flowing wellhead pressure.



*Gamma ray correlation run was used for on-depth packer placement.*

# ACTive Straddle Inflatable Packer Cleanout Doubles Production in Two Wells

Kuwait Oil Company isolates and selectively treats plugged inflow control devices in two wells, saving more than one week of rig time and producing 50,000 bbl of oil

## CHALLENGE

Identify and clean specific inflow control devices (ICDs) in wells with dozens of possible areas of interest—even within the same zone.

## SOLUTION

- Use ACTive DTS Inversion\* distributed temperature measurement analysis to discover problem zones.
- Perform a single ACTive Straddle\* CT real-time multiset inflatable packer run to selectively clean out plugged ICDs.
- Monitor real-time downhole pressure to confirm treatment and optimize time efficiency.

## RESULTS

- Increased production from Well A by 150%.
- Increased production from Well B by 171%.
- Saved more than a week of intervention time compared with conventional intervention treatments.



## Plugged ICDs impede well production

Maximizing recovery in extended-reach horizontal wells requires multizone stimulation and advanced reservoir fluids management.

In homogeneous formations, significant pressure drops occur as fluids flow from TD toward the heel of the well, and in many wells, this can prematurely end the well's productive life and leave substantial reserves untouched. Completions using ICDs enable engineers to adjust flow from zones with uneven pressure or early water breakthrough.

Over time, fines migration led to plugged ICDs and diminished production in two of Kuwait Oil Company's wells in the Minagish and Sabriyah fields. With more than 20 ICDs in each well, Kuwait Oil Company needed to identify and selectively clean out the problematic ICDs and restore production with minimal downtime.



*Manipulations of ACTive Straddle Packer are confirmed through real-time measurements displayed in acquisition software at surface.*

## Fiber-optic CT reveals problem zones, enables efficient cleanout

Several isolated zones in the completion had multiple ICDs, making the discovery process especially challenging. Schlumberger ran ACTive DTS Inversion analysis via real-time, fiber-optic coiled tubing to collect continuous temperature profiles along the length of the wellbore. This data helped engineers determine the specific zones that needed treatment.

With the zones identified, Schlumberger performed a single multiset ACTive Straddle packer run to selectively clean out the plugged ICDs in each well—eliminating the need for a workover rig. ACTive Straddle packers were set on the selected ICDs and monitored using the ACTive\* family of live downhole coiled tubing services to clean the devices and confirm treatment in real time.

## Kuwait Oil Company cuts intervention time, doubles oil production

This innovative coiled tubing intervention using ACTive services helped Kuwait Oil Company more than double production in both wells while saving more than a week of intervention time compared with conventional methods. The time saved by using ACTive services instead of conventional treatment resulted in production in Well A increasing by 150% and in Well B increasing by 171%.

# ACTive Straddle Inflatable Packer Stimulates Multilateral Well in One Run

Kuwait Oil Company restores production to 6,300 bbl/d while cutting stimulation time in half

## CHALLENGE

Reduce rig downtime while bullheading stimulation fluid into the target intervals.

## SOLUTION

Use ACTive Straddle\* CT real-time multiset inflatable packer to treat the main wellbore and a lateral in the same run.

## RESULTS

- Restored well production.
- Reduced job length from 4 days to just 2 days.
- Eliminated multiple costly runs associated with conventional bullheading treatments.



## Multilateral well leads to inefficient stimulation treatments

To offset the natural decline in a field discovered in the late 1950s and optimize extraction of oil and gas, Kuwait Oil Company (KOC) had applied many different technologies, including water injection, multilateral wells, and targeted stimulation treatments.

In one multilateral well, KOC needed to isolate and inject stimulation fluids into the main wellbore and the lateral. However, conventional bullheading could result in fluids going into the wrong wellbore. The only way to successfully bullhead both zones would require a series of runs—which could take 4 or more days.

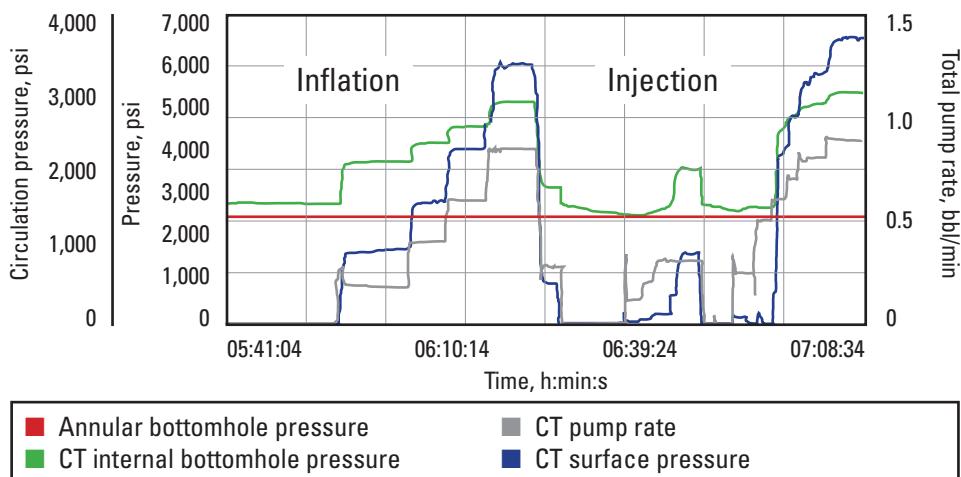
## ACTive Straddle packer eliminates multiple runs

Schlumberger worked closely with KOC to find a way to eliminate multiple runs and the associated time, risk, and costs. Using the ACTive\* family of live downhole coiled tubing services, Schlumberger deployed an ACTive services bottomhole assembly and its integrated casing collar locator (CCL) to set ACTive Straddle packers and treat the well in a single run.

First, the packers were set and inflated at 6,953 ft [2,119 m], just 40 ft above a closed valve in the primary wellbore. ACTive TC\* live CT tension and compression tool provided downhole load measurements, confirming the packers were securely anchored in place before targeted injection. The same packers were placed and inflated across the lateral—with the lower packer at 6,603 ft [2,013 m]. After the second injection treatment, the packers were deflated and the system was pulled to surface and rigged down.

## KOC stimulates multilateral well in one run and in half the time

Schlumberger and KOC successfully restored the well's production while dramatically reducing nonproductive time. ACTive Straddle packers made it possible for KOC to inject stimulation fluids into two separate zones in just one run instead of four. The entire job took less than 2 days—half the time it would have taken with conventional methods—and the ACTive Straddle packer is now deployed in additional wells that face similar challenges.



*ACTive Straddle downhole and surface parameters graphic during inflation and injection. Downhole annular pressure (red line) indicating no variations during injection, demonstrating sealing packer elements.*

# Improved Production from Alberta Wells

ACTive services enables consistent stimulation of long horizontal wells in a carbonate reservoir

## CHALLENGE

Consistently stimulate long horizontal wells in a carbonate reservoir with a dominant thief zone.

## SOLUTION

Use ACTive\* family of live downhole coiled tubing services to identify major intake points and placement by CT of VDA\* viscoelastic diverting acid.

## RESULTS

More consistently stimulated wells for higher production, with treated wells producing 54% more gas than conventionally treated wells.



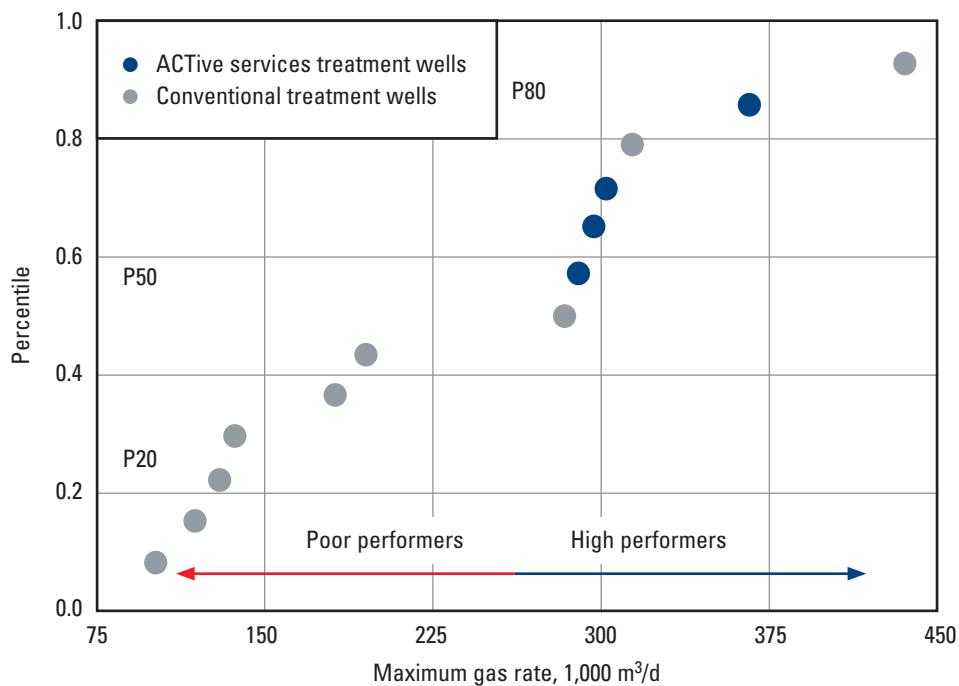
## Openhole section left unstimulated

In gas wells in a carbonate reservoir in Alberta, Canada, one dominant cluster fracture accepted most treatment fluid, leaving the rest of the open hole unstimulated. Inconsistent and erratic production resulted, ranging from extremely prolific wells to very poor producers.

The operator sought more effective matrix stimulation of long horizontal gas wells completed in this carbonate reservoir. Attempts included pumping the main treatment with different diversion stages in a fixed pump schedule, with foam the primary diverting system. This method still did not enable consistent stimulation throughout the well, however, and production results tended to be uneven.

## ACTive services used to identify thief zones

With advice from Schlumberger, the operator selected ACTive services to identify major intake points in the wellbore that act as thief zones. ACTive services, based on fiber-optic telemetry, can identify natural fractures or high-permeability streaks opened by the treatment. It also allows real-time changes in stimulation programs. With these advantages, ACTive services uses downhole measurements and tools and chemical stimulation/diverting fluid systems to ensure stimulation throughout the well.



ACTive services wells produced more gas than conventionally treated wells in this field.

With the better information made possible by using the system, personnel were able to generate a new pump schedule to selectively place VDA viscoelastic diverting acid with CT to redirect subsequent acid volumes to additional reservoir targets. The long horizontal wells were consistently stimulated during the treatment.

**Production increase shown by treated wells**

Wells treated by using ACTive services showed an average 54% production improvement compared with conventionally treated wells. The operator has continued using ACTive services with good results, and wells stimulated with ACTive services are consistently among the best performers in the fields.

# Successfully Isolate and Stimulate Wet Wells with ACTive Services

Production increases by 43% as water cut remains constant

## CHALLENGE

Effectively stimulate wells with high water cut using CT, and eliminate the risk of acidizing high water cut interval during CT matrix stimulation.

## SOLUTION

Use ACTive Matrix\* live CT stimulation and conformance service to optimize CT stimulation through live monitoring of injection rates, diverter efficiency, and downhole pressure and temperature to allow maximum fluid penetration and diversion to optimize treatment volumes.

## RESULTS

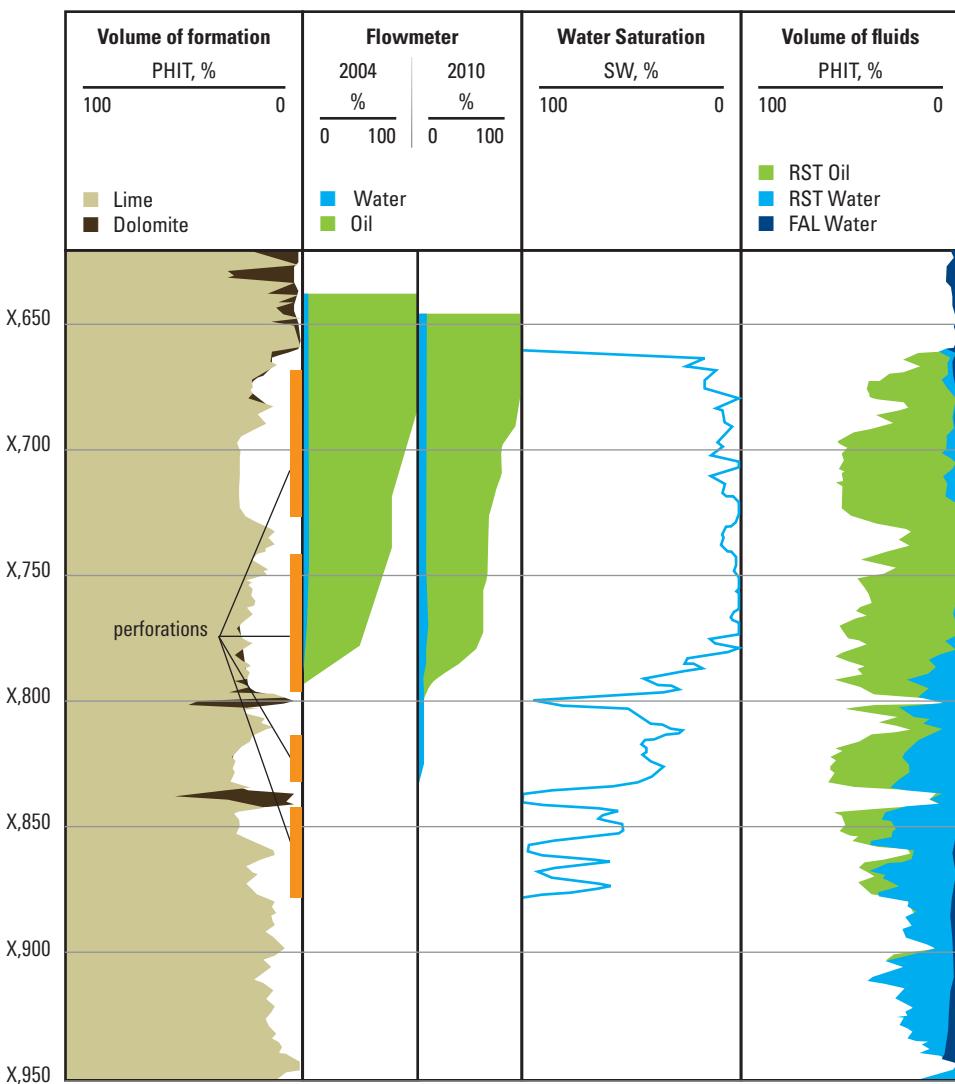
Successfully isolated the water wet zone and stimulated the oil-producing zone. Increased production by 43% without increasing water production.



## Challenged by water cut

Oil-producing wells in some parts of the Middle East often encounter water production, which presents a significant challenge when attempting to stimulate mature reservoirs. Post-acidizing of wells with high water cut could lead to dead wells, or higher water cut, which has an extreme effect on production.

Standard CT stimulations are usually done with no control on acid and diverter placement. Acid volumes are fixed in the designed pumping schedule, regardless of their efficiency, and the stimulation fluids are injected without getting any confirmation that the production zones are treated. The existing water zone often cannot be determined, especially when the information is taken from a production logging tool (PLT) run that was done years ago.



A complete lack of downhole monitoring and control often caused multiple stimulations of oil wells to end up with high water cut.

An operator encountered this problem on a vertical well with four sets of perforations. The well was completed as a perforated cased hole with four sets of perforations and with 4½-in x 3½-in tubing.

The latest production logging tool (PLT) run showed water production from the bottom perforated zones, so temporary isolation was required to stimulate the top oil intervals.

The well was producing 1,400 bbl/d oil and 55% water cut before the stimulation. The operator was facing the challenge of needing a selective stimulation and called on Schlumberger.

### Optimize matrix stimulation

The operator decided to use ACTive Matrix live CT stimulation and conformance service to optimize CT stimulation through live monitoring of injection rates and downhole pressure and temperature to allow maximum fluid penetration and diversion to optimize treatment volumes. These services enable accurate location and placement of downhole tools to control stimulation.

The stimulation program was enhanced by using real-time distributed temperature surveys (DTS). ACTive services stimulation with DTS assists with the real-time control and evaluation of CT matrix stimulation treatments. DTS helps detect the thief zones, determine in real time the diverter efficiency, monitor the stimulation fluids placement, adjust the pumping schedule, and assess the flow contribution during flowback.

The objective of this operation was to acid stimulate the upper zones to remove suspected formation damage and improve well productivity, after isolating the lower zones (water-producing intervals) with a temporary gel plug.

The PROTECTOZONE\* fluid for temporary zone plugging was selected to cover the lower zones, and it was successfully placed with CT at the designed depth.

With the help of the ACTive services CCL depth correlation, the bottom water zone was successfully temporarily isolated to allow the stimulation treatment to be injected in the uppermost zone.

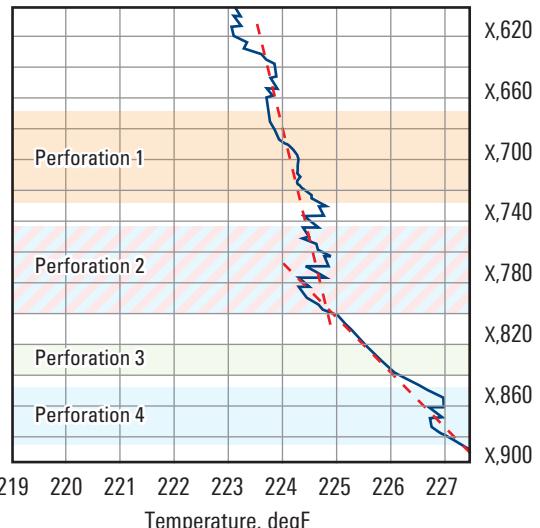
About four hours of wait time was needed for the plug to gel up and isolate the water-producing intervals before pumping stimulation fluids. DTS was recorded while injecting treated water to confirm the efficiency of the chemical isolation.

To stimulate the oil zones, 20% hydrochloric acid (HCl) with required additives (corrosion inhibitor, iron control, and surfactant) was pumped with pre-flush and post-flush containing mutual solvent while reciprocating the CT across the target intervals.

### Production increased

Post-stimulation, well production showed 43% incremental oil production with no increase of water cut. This confirms that the oil-bearing zones were successfully stimulated with sufficient isolation of the water zone.

The operator has the confidence to use this new stimulation technique to acidize their wet wells without risking higher water cut.



Distributed temperature survey across the producing zones.

# Improving Foam Quality in Elks Hills Field

Operator saves more than USD 10,000 using coiled tubing services

## CHALLENGE

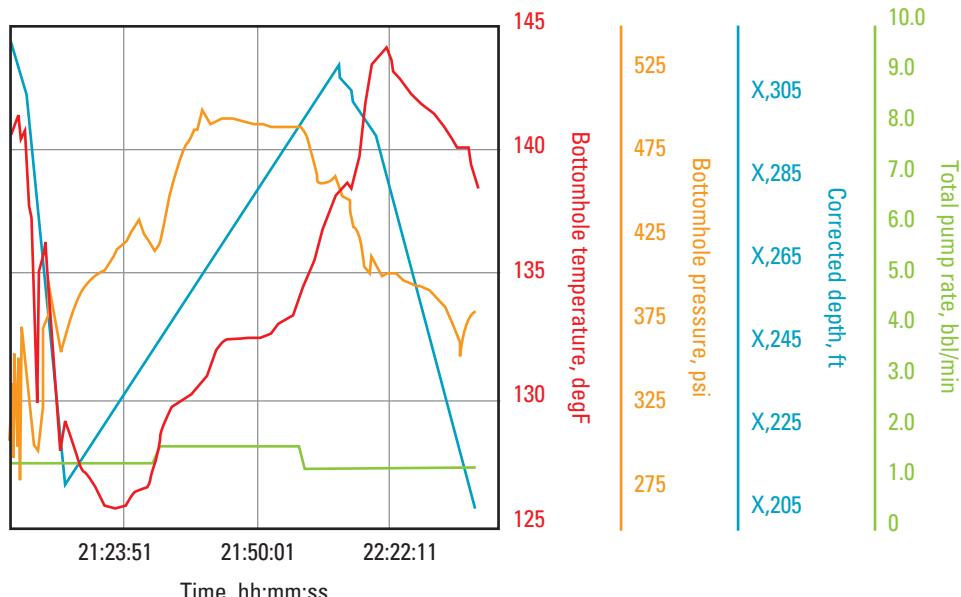
Collect enough downhole information to execute foam diversion according to design during the CT matrix stimulation of an underperforming oil and gas well.

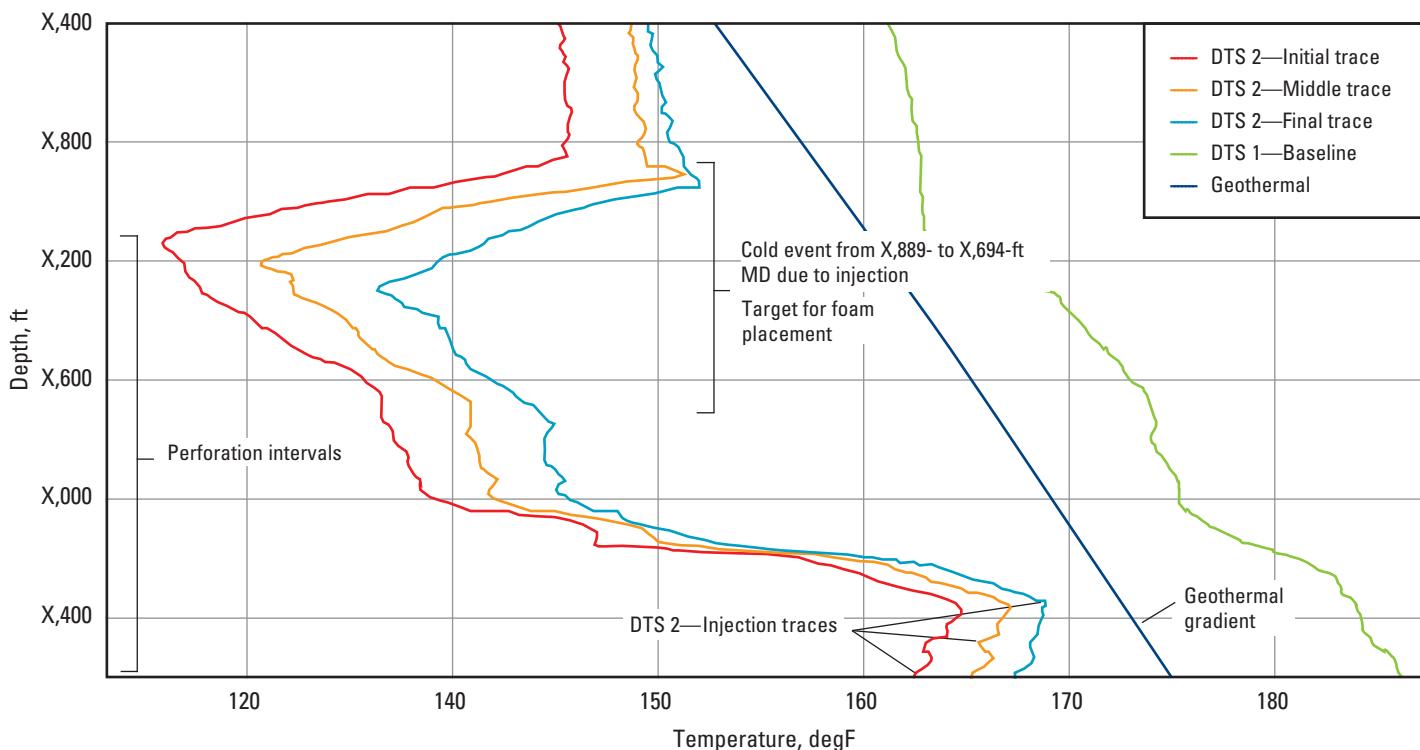
## SOLUTION

Implement ACTive\* family of live downhole coiled tubing services to determine bottomhole pressure (BHP) data, which had been calculated years earlier and was often incorrect.

## RESULTS

- Used real-time data to adjust foam quality (FQ) as needed, resulting in excellent diversion and good stimulation.
- Saved more than USD 10,000 and 5 hours compared with traditional methods.





The accurate DTS data supplied by ACTive services showed a much lower temperature at the perforated interval compared with the geothermal gradient.

### Real-time measurements

Schlumberger proposed the use of ACTive services to solve this problem. ACTive services real-time downhole measurements interpret and optimize treatments while they are still in progress. These real-time CT services allow monitoring and evaluating job progress, optimizing treatment results, and intervening with one trip in hole. The system consists of a BHA, surface electronics, and dynamic interpretation software. It delivers internal and external pressure, temperature, casing collar locator (CCL) depth correlation, and a distributed temperature survey (DTS).

In the Elks Hills well, the ACTive services replaced assumed pressures with real-time data, which allowed adjusting rates to meet the specified FQ percentage. ACTive services data also confirmed that BHP was only 300 psi instead of the anticipated 1,200 psi. This dramatic difference meant reducing nitrogen gas rates to supply the required 70% FQ during the diversion stage. If rates had been pumped as per design, an FQ of approximately 90% would have been pumped. As a result of the lower-than-expected BHP, a planned nitrogen lift was applied in time.

### Less time and cost

The use of the ACTive services saved the operator more than USD 10,000 (US dollar) and 5 hours of time compared with the traditional methods used in the field. In addition, the updated pressure data provided helpful insight for offset well candidate selection.

# Coiled Tubing Services Enable Real-Time MaxCO<sub>3</sub> Acid System Stimulation Treatment

Middle East operator uses ACTive services to achieve uniform diversion, higher production in heterogeneous carbonate reservoir

## CHALLENGE

Enhance well productivity by stimulating higher-permeability intervals in naturally fractured, high-temperature carbonate reservoir.

## SOLUTION

Combine ACTive\* family of live downhole coiled tubing services with Jet Blaster\* engineered high-pressure jetting service and MaxCO<sub>3</sub> Acid\* degradable diversion acid system to optimize stimulation treatment in real time.

## RESULTS

Used real-time monitoring capabilities to optimize diversion and stimulation in a well where diversion treatments were previously impossible.



## Operator needed to enhance stimulation in challenging carbonate wells

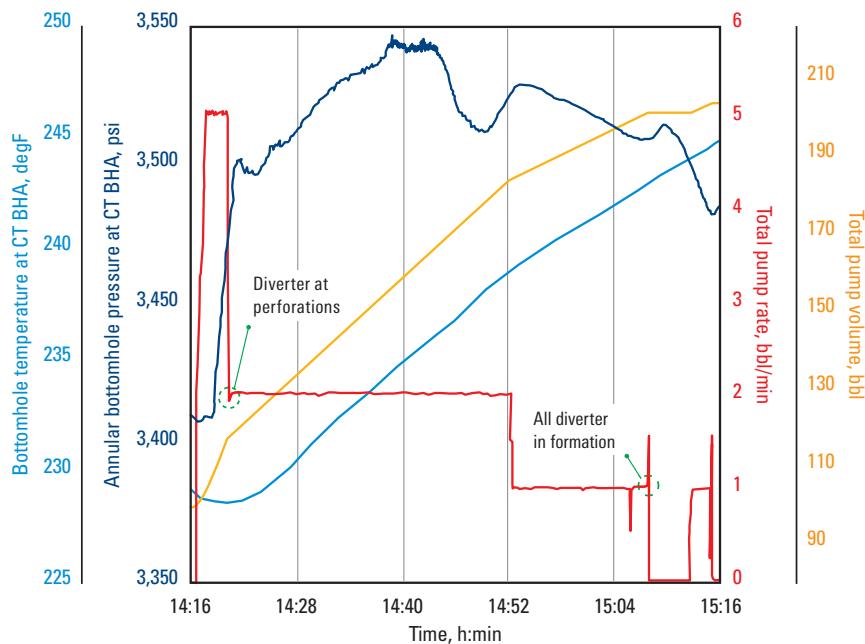
Wells in this Middle East field are prone to high temperature, uneven zone pressures, and scale deposition. In addition, wells are located in highly fractured carbonate reservoirs that require matrix acid stimulation for economic viability. Conventional hydrochloric acid treatments increased productivity, but only marginally. Much of the fluid leaks into massive thief zones instead of creating deep, conductive wormholes. The operator turned to Schlumberger to ensure proper acid placement in difficult-to-reach zones.

## Real-time CT enabled accurate, effective diversion and stimulation

Schlumberger bullheaded fiber-laden MaxCO<sub>3</sub> Acid system through the annulus to form a temporary barrier against tight zones. Hydrochloric acid was pumped through an ACTive services coiled tubing string. Real-time pressure and temperature measurements from the ACTive services enabled the team to monitor job parameters, such as downhole pressure response, and evaluate the effectiveness of the treatment as it was being performed. The Jet Blaster jetting service treated scale buildup and allowed the acid to enter understimulated sections.

## Acid system increased production

When MaxCO<sub>3</sub> Acid system stages reached the formation, bottomhole treating pressure increased, indicating excellent leakoff control and diversion. Production logging showed higher production rates than offset wells stimulated with conventional matrix treatments.



The downhole pressure trace (green) indicates the diversion process occurring in the matrix during acid injection as MaxCO<sub>3</sub> Acid system reaches the perforations. Diverter accumulates in one zone and drops off as another zone breaks down.

# Temperature Profiling Optimizes Stimulation Job

ACTive services performed in single run in Kuwait

## CHALLENGE

Profile a candidate well to optimize stimulation treatment and minimize risk.

## SOLUTION

Performed ACTive\* family of live downhole coiled tubing services in a single run with distributed temperature survey (DTS) capability for profiling and monitoring the well.

## RESULTS

Used real-time information from the profile and the diagnostic acid wash to make informed decisions on fluid placement; saved about 50% fluid volume compared to typical carbonate stimulation treatment.



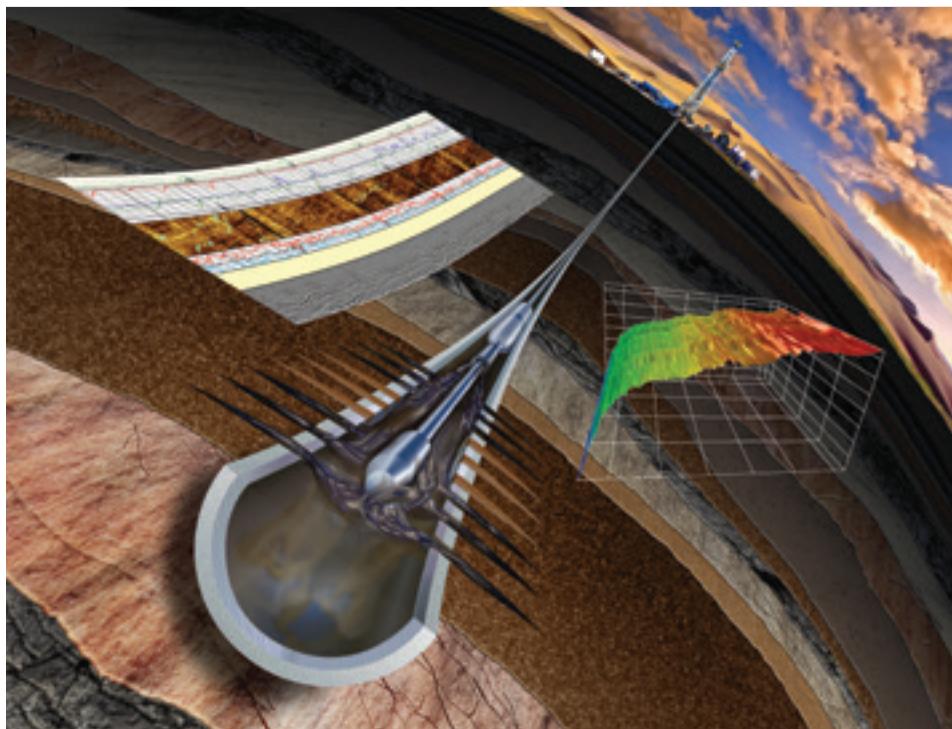
## Watered-out well

The operator of a well in Kuwait observed a sharp production decline and gradual increase in water cut. More information was needed to optimize stimulation. Schlumberger proposed using the ACTive Profiling\* live CT distributed temperature sensing service, which includes DTS. It is a single-run solution for

- diagnosing the well injectivity profile
- establishing a fit-for-well stimulation treatment
- monitoring fluid placement in real time
- evaluating the effect of treatment fluids.

## Successful profiling

During the ACTive Profiling service and ACTive Matrix\* live CT stimulation and conformance service treatment, real-time measurements of bottomhole temperature and pressure were used for real-time optimization and monitoring of fluid placement. Preflush and acid wash DTS measurements indicated a tight zone near the heel of the well, coinciding with a zone of low resistivity according to existing openhole logs. The most permeable zone was identified at the toe of the well.



ACTive Profiling service during an ACTive Matrix service treatment.

Mixing of the treatment fluids was performed on location so that the final treatment volumes could be adjusted according to interpretation of the ACTive Profiling service DTS readings.

Overall, the stimulation treatment was optimized and evaluated in real time, effectively avoiding the need for reentry or repeat runs. The toe section was stimulated with SDA\* self-diverting acid. The target middle openhole section was stimulated with 15% HCl, and the tighter, low-resistivity zone at the heel of the well was avoided.

### **Targeted, optimized stimulation**

The postflush temperature profile after the main treatment confirmed selective fluid placement as designed: diversion at the toe section, stimulation of the middle openhole section, and avoidance of the tight, low-resistivity heel section. Main treatment volumes were reduced by 50% compared to an ordinary carbonate stimulation design.

# ACTive Matrix Enables Effective Openhole Stimulation in Western Canada

Real-time downhole measurements and interpretation increase the stimulation coverage of a multilateral gas well

## CHALLENGE

Effectively stimulate a two branch multilateral openhole completion in a naturally fractured dolomite formation.

## SOLUTION

Deploy ACTive Matrix\* live CT stimulation of conformorance service to enable accurate depth placement of the CT in each lateral using real-time downhole measurements.

## RESULTS

Effectively placed the stimulation and diverting fluid systems and verified treatment and lateral entry results in real time.



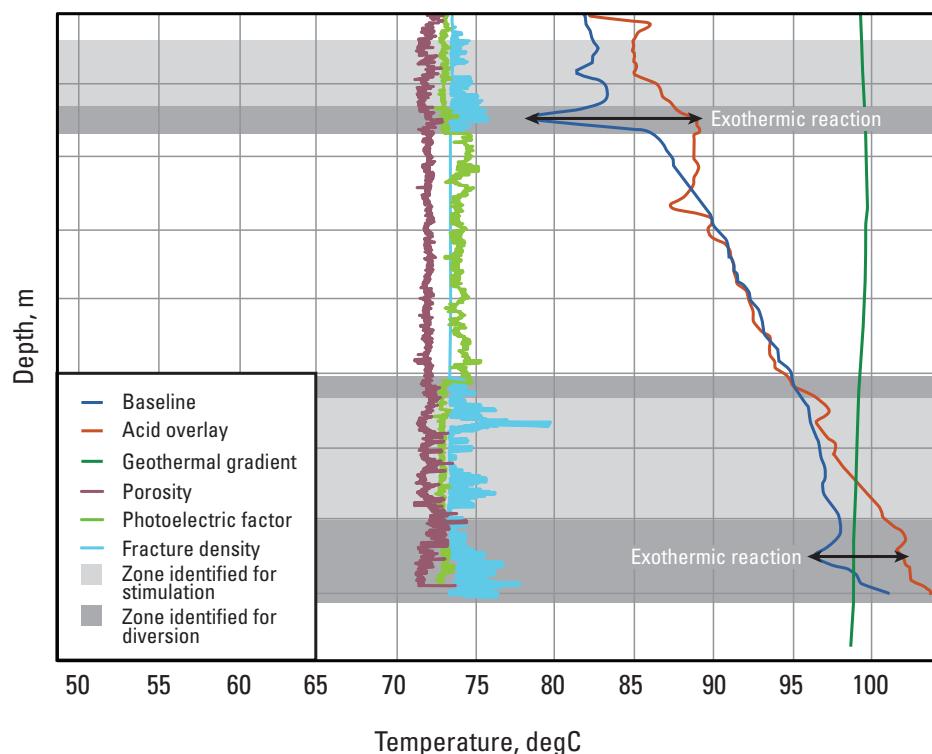
## Costly interventions in Western Canada

An operator needed to increase productivity of two openhole legs in an existing multilateral gas well in a naturally fractured dolomite formation in Western Canada. The well produced 21% H<sub>2</sub>S and 5% CO<sub>2</sub>.

Operators in this area face economic challenges in maximizing reservoir contact in these partially depleted carbonate reservoirs. By using a multilateral completion technique, the operators have been able to achieve greater reservoir contact and access isolated reservoir compartments with a minimal increase in well construction cost or complexity.

Coiled tubing, which has been used to access and treat the multilaterals, presents two challenges:

- ensuring efficient access and treatment of all laterals during intervention
- getting existing downhole tools to operate in a subhydrostatic environment.



*Prestimulation baseline thermal analysis using distributed temperature survey (DTS) data for identifying treatment zones.*

## Accurate depth and placement of downhole tools

ACTive Matrix service uses downhole measurements and tools and chemical stimulation/diverting fluid systems to meet the challenges. These services enable accurate location and placement of downhole tools in the laterals to control stimulation of the individual legs.

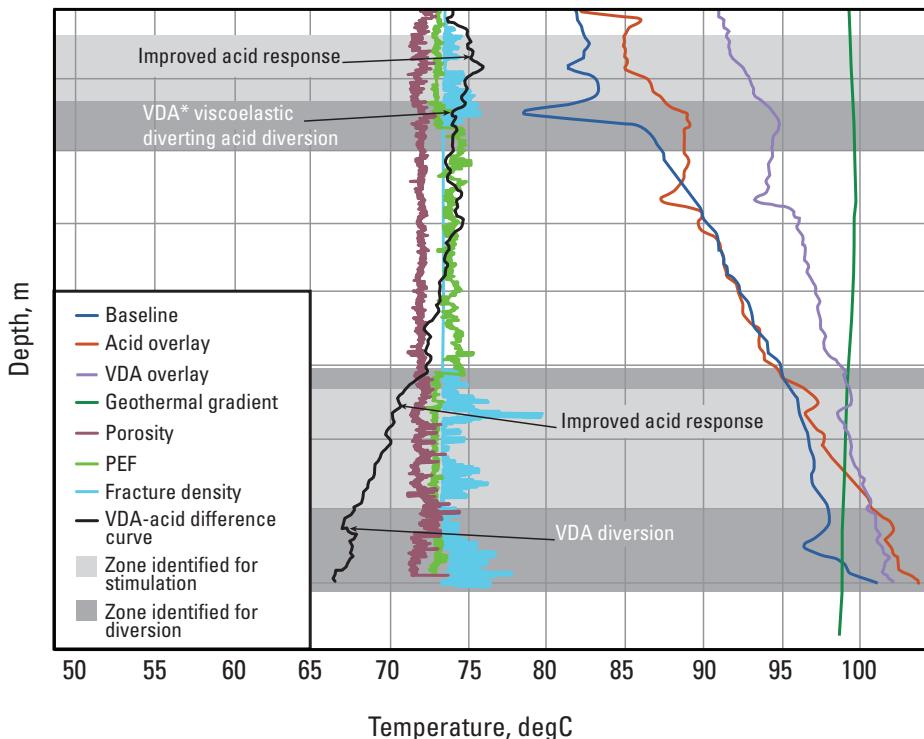
CT was run in the hole to obtain downhole measurements, which were used to stimulate the openhole legs. Acid treatments temporarily diverted and treated the sections of the open hole that otherwise would not have been stimulated. Pre- and posttreatment distributed temperature sensing (DTS) data were used to optimize acid placement.

## Accuracy and effectiveness of acid stimulation confirmed

Using the more reliable real-time bottomhole pressure measurements rather than surface pressure measurements increased the accuracy and effectiveness of the stimulation treatments.

The initial acid treatment was confirmed and injectivity points and other zones to be opened were identified. Thermal analysis results were used to generate a revised pump schedule that provided details of the appropriate diverter and acid stages, which allowed temporary diversion of the initially stimulated zones and better overall treatment of the multilateral leg.

A final DTS confirmed that the treatment successfully diverted the acid and stimulated all the targeted zones.



*Poststimulation thermal analysis showing effective acid treatment.*

# Integrating Coiled Tubing and Production Logging for ConocoPhillips

ACTive PS service uses fiber-optic telemetry for a single-run strategy in the Barnett Shale

## CHALLENGE

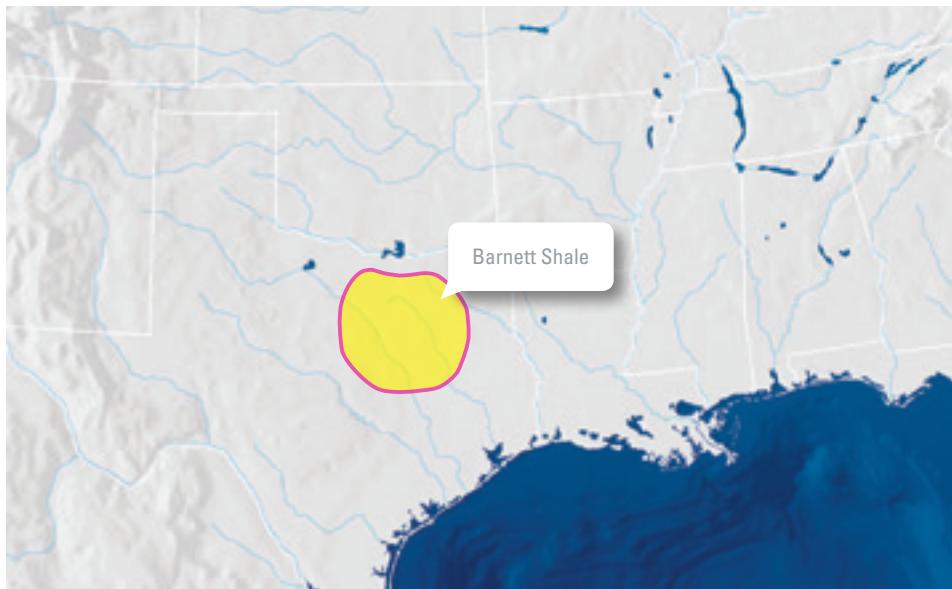
Understand fracture/completion program effectiveness using production logging technologies. Compare production monitoring capabilities of fiber optics in dry gas wells.

## SOLUTION

Use ACTive PS\* live CT production logging service to acquire production logging and distributed temperature survey (DTS) measurements in a single run.

## RESULTS

Validated production monitoring capabilities of fiber optics, with a very strong correlation to wireline production logs. Saved one trip downhole for each well, reducing risk, cost, and time.



The Barnett Shale geological formation is located in the Permian basin.

## Operator seeks long-term monitoring without regular intervention

Operating in the Barnett Shale, ConocoPhillips required long-term production monitoring to analyze completion effectiveness, reservoir depletion, and zonal flow contributions. The conventional approach for horizontal wells required separate production logs over different time periods to evaluate changing well performance.

## Integrated service uses fiber-optic telemetry

ConocoPhillips chose to explore and evaluate the use of fiber optics. An integrated technique was applied to two wells. Rather than validate DTS measurements with separate CT runs (fiber optic-enabled CT for DTS and an electric line inside CT for production logging), the company acquired both DTS and FloScan Imager\* horizontal and deviated well production logging system measurements in one run using the ACTive PS service.

Part of the ACTive\* family of live downhole coiled tubing services, the ACTive PS service uses fiber-optic telemetry and downhole wireline data conversion to deliver high-quality, real-time data for tools conventionally only available in memory mode or with live telemetry via electric line.

## Conventional logging techniques performed with ACTive PS service save time and money

ConocoPhillips required DTS and FloScan Imager system logs, and ACTive PS service enabled real-time telemetry to surface, eliminating the use of wireline logging cable-equipped CT and capturing both logs in a single run. This technique reduced time, risk, and cost and ultimately provided two logs without the additional effects of tripping CT in and out of the well to switch CT strings.

# Integrating Production Logging with Coiled Tubing Intervention in Saudi Arabia

Openhole water injection well achieves first-ever real-time stimulation and production logging operation

## CHALLENGE

Stimulate water injection well using CT, and run a production log to confirm uniform injection profile after the stimulation. Efficiently perform both operations in real time with a single CT unit.

## SOLUTION

Use ACTive PS\* live CT production logging service with CT intervention. Make faster, more-informed decisions with real-time production logging operations.

## RESULTS

Deployed world-record fiber optic–enabled CT string length of 32,175 ft. Efficiently stimulated and logged well using one CT string, saving time and resources.

**Not only is this water injection well the first in the field to undergo real-time production logging, it is the first well in the industry to use fiber-optic CT for production logging telemetry—a technique that saved time and resources.**

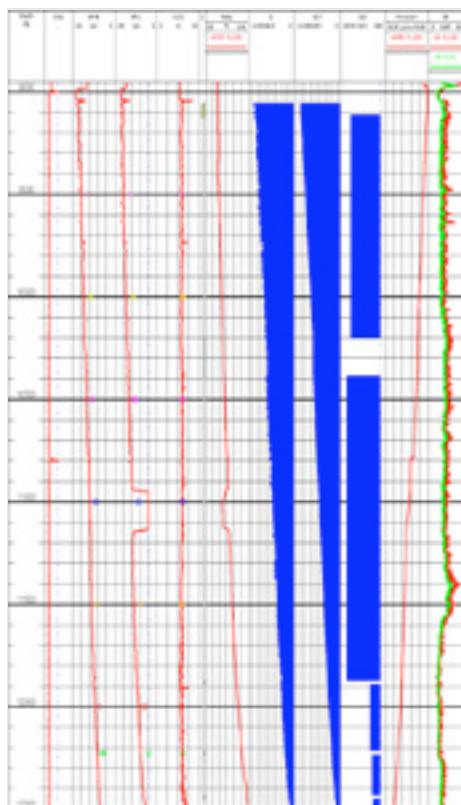


## Formation damage removal needed in water injection well

A water injection well in a horizontal openhole section in a field in Saudi Arabia experienced formation damage during the drilling process. To remove this damage and enhance permeability for better water injection results, the operator required a CT-supported acid stimulation job.

Traditional methods for this type of operation include a post-treatment production logging run to record an injection profile for calibrating the injection model. A logging cable–equipped CT string and a standard logging unit are necessary to convey the production logging data. Among other complications in this process, the cable restricts the flow rate through the CT, a critical component in optimizing injection. Two CT strings were used to perform the job. When this conventional strategy was applied to the field's water injection well, though, a uniform injection profile was not achieved.

The operator then explored the use of memory production logging for this well, hoping to avoid the extra time and cost of using two CT strings. This choice, however, risked low data quality and a potential additional run.



The operator used fiber-optic telemetry to acquire a production log.



ACTive PS service BHA.

**Real-time production logging service successfully acquired**

Schlumberger suggested ACTive PS logging service with CT intervention to enable production logging jobs in real time—using the same string for both stimulation and logging interventions. The system uses a fiber optic-enabled CT string for telemetry and a 11½-in BHA, which powers and communicates with the conventional production logging system. Data is sent wirelessly from the working reel to the acquisition software on surface, so no surface logging unit is needed on location.

The well was stimulated using ACTive Matrix\* live CT stimulation and conformance service and ACTive Profiling\* live CT distributed temperature sensing service first, after which the first-ever real-time production logging job was performed in the field using the ACTive PS service. During the injection of 1,725 bbl of preflush, acid, and VDA\* viscoelastic diverting acid fluids, a distributed temperature survey (DTS) facilitated the understanding of the injection profiles. Consistent acid placement was based on acid reactions in observed high-injection zones.

To measure the well's injection profile following the acid stimulation treatment, water was injected on surface at 7 bbl/min while the up and down logging passes were executed. The ACTive PS service BHA and PS Platform\* production services platform were conveyed to 12,560-ft TD. Measurements included pressure, temperature, casing collar locator (CCL), gamma ray, XY caliper, and inline spinner. The objective was to measure the well's injection flow profile following the acid stimulation treatment.

**Record set for longest fiber optic–enabled coiled tubing string**

Not only is this well the first to undergo real-time production logging in the field, it is the first well in the industry to use fiber optic–enabled CT for production logging telemetry. This operation also achieved a world-record fiber optic–enabled CT string length of 32,175 ft.

The data quality ensured by the ACTive PS service minimized logging misruns, which will prove especially important for future wells in the field. Stimulation was performed with one CT string, allowing the operator to mobilize a reduced amount of equipment just once, logically saving time and resources while improving the safety of operations.

Because of this success, the operator planned remedial action to eliminate water production using the ACTive PS service. This system can also be used to optimize offshore barge use, with the multipurpose CT performing both conventional and real-time horizontal logging operations.

# Technique Enables Optimized Remedial Water Shutoff Operations for Saudi Aramco

ACTive PS service allows production logging and intervention with the same coiled tubing unit

## CHALLENGE

Improve efficiency and effectiveness of remedial water shutoff operations.

## SOLUTION

Run ACTive PS\* live CT production logging service with FloScan Imager horizontal and deviated well production logging system.

## RESULTS

Allowed CT remedial work and production logging to be scheduled with the same unit, maximizing productivity and saving cost for future operations.



## Improve water shutoff strategy

Saudi Aramco worked over and completed a well as a horizontal openhole producer. After initial production, the well started producing with water cut, which increased gradually to 24.1% of 2,400 bbl/d. For wells with this problem, the operator traditionally performed wireline logging cable-equipped CT jobs to understand the well production profile. The logistics for this type of intervention often took several months or even years, making remedial work difficult in the face of changing well conditions. Because logging results were not current, CT interventions needed to be optimized.

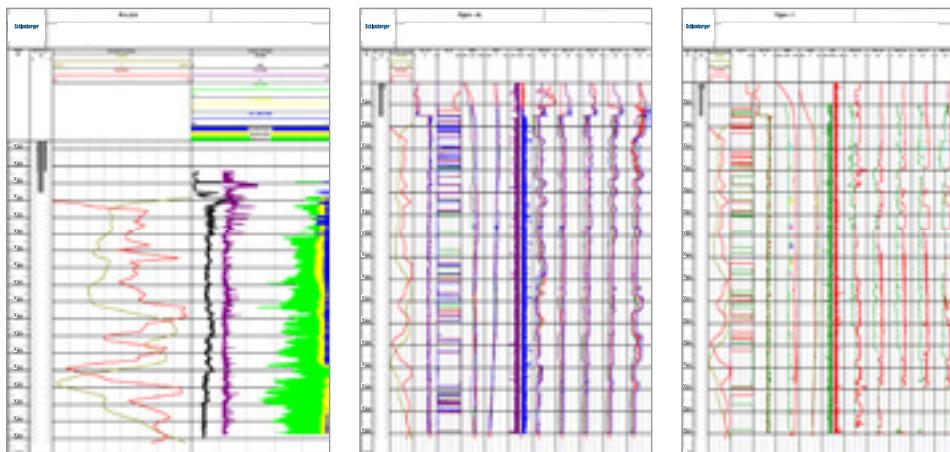
## Combine production logging and intervention

To improve the effectiveness of its remedial work, Saudi Aramco sought a Schlumberger solution because of the company's expertise with fiber optics. ACTive PS service was chosen as a trial for the well. This service enables wireline production logging tools, such as FloScan Imager horizontal and deviated well production logging system, to be run by the optical telemetry of ACTive\* family of live downhole coiled tubing services. With the ACTive PS service, CT intervention and real-time production logging can be performed with the same CT unit.

Saudi Aramco ran the ACTive PS service with the FloScan Imager system for logging. The toolstring comprised several sensors, such as gamma ray, casing collar locator (CCL), pressure, and temperature. It reached a maximum depth of 9,848 ft, with cross sections captured at 6,820 and 9,140 ft. No crossflow was detected during shut-in, and passes were repeated to ensure data quality.

## Optimize remedial operations

Using the ACTive PS system allowed Saudi Aramco to gather high-quality FloScan Imager data, making it possible to schedule and perform production logging and CT remedial jobs together. The acquired data showed clear points of water entry and a multispanner flow profile, proving critical for Saudi Aramco remedial water shutoff jobs to maximize productivity and save cost of water production.



Prejob planning, flowing survey, and shut-in survey logs for Saudi Aramco well.

# ACTive Profiling Service and Pressure Survey Enhance Reservoir Understanding

3D temperature profile combined with pressure survey data reveals reason for well production decline

## CHALLENGE

Understand why postchemical treatment rates were not sustained after the well was shut in.

## SOLUTION

Use pressure survey and ACTive Profiling\* live CT distributed temperature sensing service—3D DTS survey—for the entire wellbore to identify formation characteristics, flow contribution from across the horizontal section, and the condition of the hydrocarbons.

## RESULTS

Determined that minimum pressure support caused gas cap expansion that contributed to the decline in liquid production.

**Using the ACTive Profiling service, TML concluded that excessive gas production from the heel and toe was hindering well productivity.**

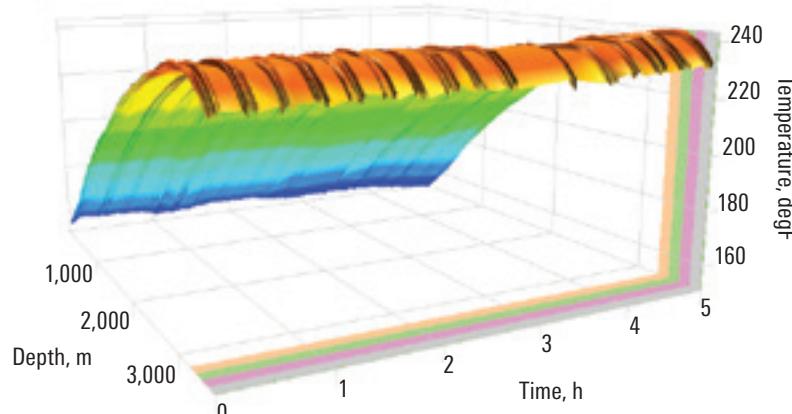


## Chemical treatment to remove emulsion and polymer plugging

When production dropped from a well that was completed using an openhole slotted liner in the Bunga Raya field, the operator—Talisman Malaysia Ltd. (TML)—performed a chemical treatment to remove emulsion and polymers left by the drilling fluid used to drill the well. Immediately after treatment, production increased to 2,000 bbl/d from 500 bbl/d, but within 5 hours, it dropped dramatically and then stabilized at pretreatment rates.

TML suspected that emulsions and asphaltenes had formed in the wellbore during well shut-in while rigging down. However, TML did not have adequate information about the formation characteristics and well trajectory to understand

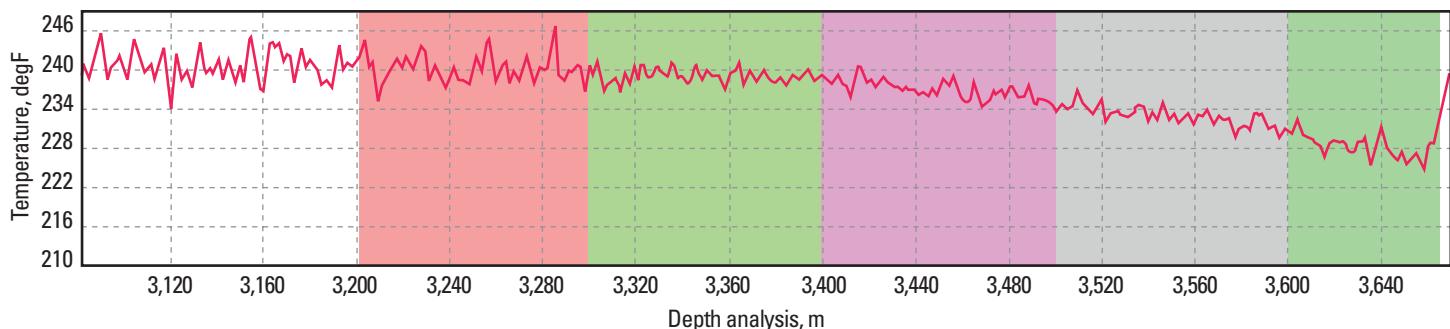
- the cause of the production decline after treatment
- where and how the emulsions and asphaltenes were forming
- how to completely dissolve emulsions and asphaltenes and to prevent them from reforming.



The DTS shows a trend of increasing temperature over a 5-hour period.

## Innovative CT intervention to better understand the well

TML consulted Schlumberger to design a well cleanup, to obtain pressurized bottomhole samples, and to run a DTS. The ACTive Profiling service was chosen to provide a single-point temperature reading at the tool and to provide a temperature reading across the fiber optics inside the coiled tubing. The system uses fiber-optic telemetry conveyed in the coiled tubing to deliver DTS measurements.



The DTS shows that the temperature decreases from 240 degF in the heel to 225 degF in the toe.

The objectives were to

- check for conformance of the first DTS results and interpretation
- use the DTS data to select the location to collect representative bottomhole hydrocarbon samples
- optimize the treatment interval.

### Lessons learned for effective stimulation

The pressure survey and DTS data revealed minimum pressure support from the water injector, which, in turn, caused gas cap expansion. The temperature dropped across the entire interval but was lowest at the toe. The reason for the cooling effect was gas production from the toe and heel sections caused by the gas cap expansion that limited liquid production. The combination of gas rates with oil and water production was also creating tight viscous emulsion, further hindering production performance.

TML concluded that the high gas production from the toe and heel could not be selectively shut off or controlled in the horizontal openhole slotted liner completion to perform an effective stimulation program and treat the tight viscous emulsions.

# Permanent Water Shutoff in Openhole Well

CoilFLATE inflatable openhole packer installed as cement retainer in live well

## CHALLENGE

Permanently shut off 86% water flow in openhole Saudi Arabia horizontal well.

## SOLUTION

Use ACTive\* family of live downhole coiled tubing services to place openhole CoilFLATE\* inflatable packer as a cement retainer to isolate watered-out zones in live wells.

## RESULTS

Shut off flow from target zones with four CT runs and 72 hours of working time versus the cost and time required for a workover rig.



## High water cut

An operator working in Saudi Arabia encountered extremely high—86%—water cut in an openhole slanted horizontal producer. A well log indicated water production came from the lower zone, below 10,600 ft. Water shutoff was required to eliminate the watering interval and to increase the life of this carbonate well. Using only cement to isolate the interval was considered challenging because of the risk of cement leakoff into the natural fracture.

The operator selected Schlumberger to remediate the well because of past experience with Schlumberger tools and the convenience and cost savings of having a single provider for all operations.

## Mechanical wellbore isolation

Mechanical wellbore isolation using fiberoptic telemetry with coiled tubing as the conveyance method was selected as an accurate and effective way to isolate water entry, reduce water cut, and enhance oil production. Schlumberger proposed a rigless through-tubing intervention on the live well that would set a CoilFLATE openhole inflatable packer as a cement retainer and leave it inhole as a permanent bridge plug. Cement would be placed above the packer.



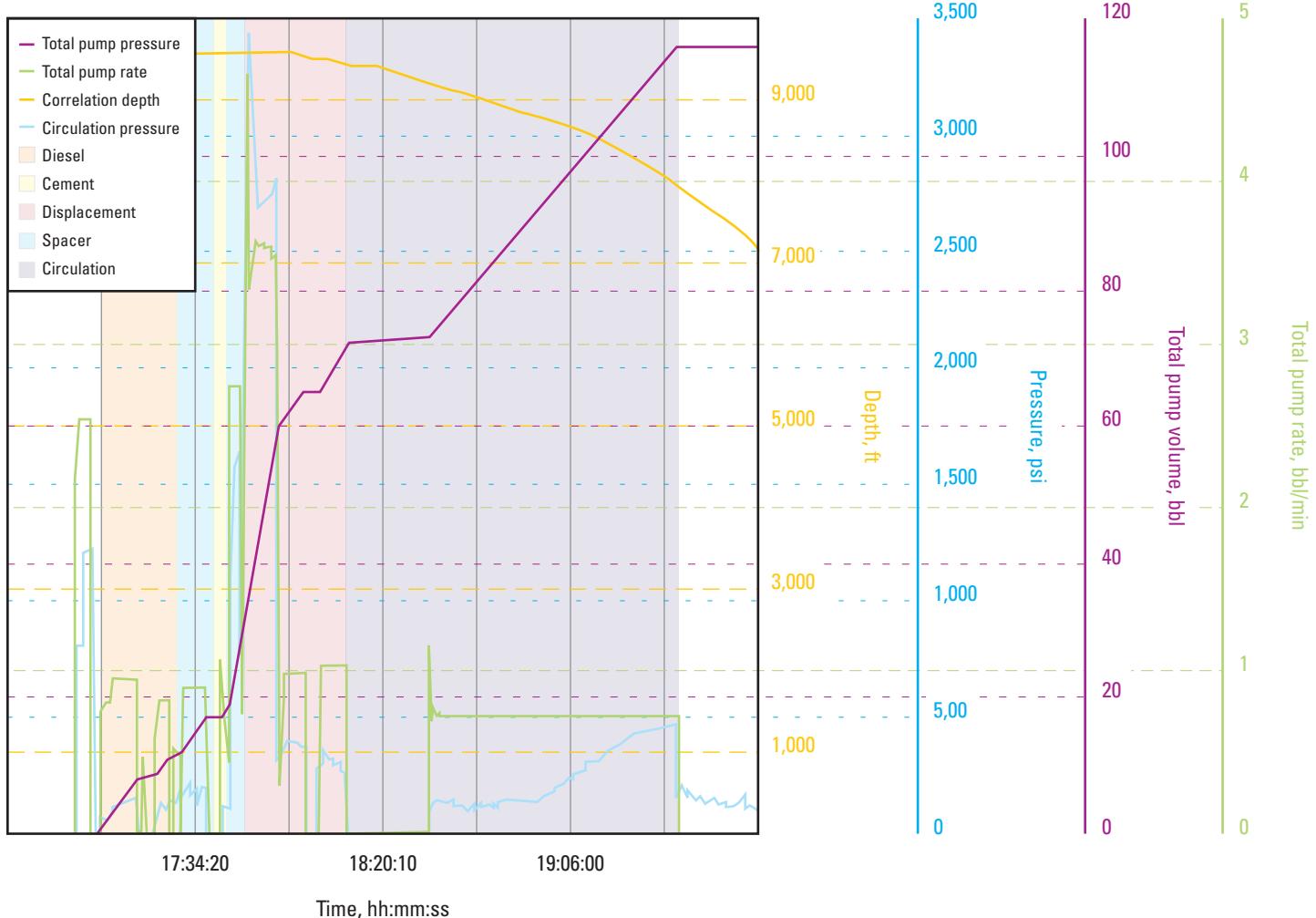
CoilFLATE packer.

During the operation, fiber-optic ACTive services measured casing collar locator, temperature, and differential pressure readings, enabling precision depth measurements for placement of the CoilFLATE packer, controllable inflation of the packer, and optimization of cement design.

The CoilFLATE packer, which offers an expansion ratio of 2:1, withstands high differential pressures as it is installed in a live well. The packer was left downhole to prevent water entry below the cement.

## Fast, effective installation

The whole job, including permanent zonal isolation using a cement plug above the inflatable packer, was achieved with four CT runs in 72 hours. This solution was much more time- and cost-effective than a traditional drilling rig-enabled workover, which could have taken days at a high day rate. CoilFLATE packers also allow water control treatments to be pumped below the plug. The operator was impressed by the value added with the portfolio of ACTive services.



*Treatment log showing the fluid pumping sequence; the color code indicates fluid at the nozzle.*

# Successful Profile Diagnosis Maintains Productivity and Prevents Expensive Water-Conformance Treatment

First-time use of ACTive PS service and Flow Scanner system in the horizontal section of Shishito 11

## CHALLENGE

Make first-time entry to log to total depth inside the horizontal section of well to determine water entries and possibly define water-conformance treatment.

## SOLUTION

Deploy ACTive PS\* live CT production logging service and Flow Scanner\* horizontal and deviated well production logging system to determine the multiphase flow characteristics of the well.

## RESULTS

Acquired quality, real-time data demonstrating various sources of water, including the hydrocarbon-producing well sections. This information helped PEMEX avoid a costly water-conformance treatment while reducing logistics and environmental footprint.



## Production-profile diagnosis and water-cut assessment

PEMEX sought diagnostics and a solution to decrease water cut in its Shishito 11 well—the best oil producer in the Shishito field. The water cut had increased from 20% to 40% in a six month period. Initially, PEMEX attempted to determine the water entry points and possibly define a water-conformance treatment by running a production log on cable. However, the log was dependent on the production log tools' ability to reach beneath the cable under gravity conveyance. Subsequently, it was not possible to run a log in the horizontal section of the well or obtain a production profile of the producing zones.

## Real-time measurements with coiled tubing and production logging

The operator partnered with Schlumberger, the recognized leader in production logging in southern Mexico, to assist with the special needs of this production logging. The operator was specifically impressed with the ACTive PS service and Flow Scanner logging system.

The ACTive PS service uses fiber-optic telemetry and downhole wireline data conversion to run real-time tools conventionally conveyed on wireline. Running the ACTive PS service and Flow Scanner system together would enable PEMEX to gather valuable information about the lateral section—in real time without killing the well. Schlumberger ran the toolstring inside a horizontal, expandable-screen completion that had not been entered since its installation four years earlier.

## Substantial cost savings while maintaining production level

The high-quality, real-time data revealed water sources in various sections of the well, including the hydrocarbon-producing sections. Based on information from the ACTive PS service operation, PEMEX decided not to perform any water-conformance intervention in the short term. Water-conformance treatments can reduce permeability in water-producing zones and decrease the overall productivity of the well. This helped PEMEX avoid the expenses and risks of a water-conformance treatment. PEMEX continued to produce the well in its present state, maintaining hydrocarbon production.



*Coiled tubing crew reviewing operational procedures.*

# ACTive Services Enables Real-Time PTA for Stimulation Evaluation

Live CT services allows stimulation and evaluation in a single run in Saudi Arabia

**CHALLENGE**

Quantitatively estimate of the skin reduction resulting from a matrix treatment job in a mega reach water injector well.

**SOLUTION**

Deploy ACTive\* family of live downhole coiled tubing services and pressure transient analysis (PTA) to measure the pressure transient events before and after the treatment.

**RESULTS**

Estimated formation damage before the job, and improved injectivity by a factor of two; improved effective permeability in the near wellbore area.

**Mega reach injector**

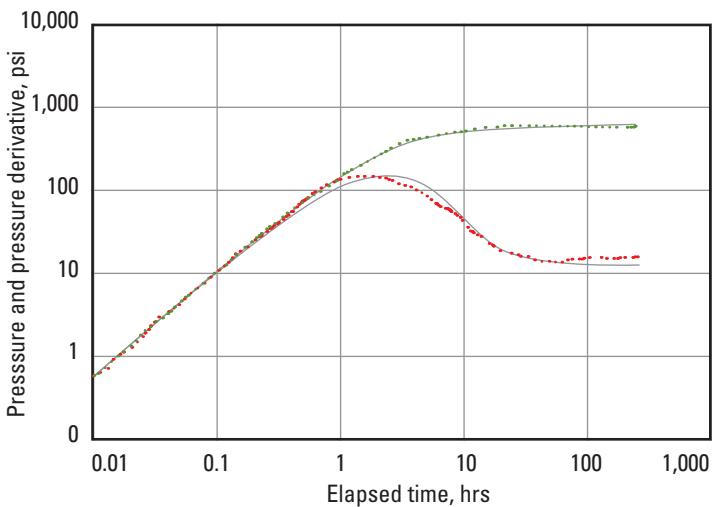
An operator working in Saudi Arabia was stimulating a significant number of mega-reach water injector. The objective of these matrix treatments is to achieve uniform injection profiles across the long horizontal section (> 6,000 ft). ACTive Profiling\* live CT distributed temperature sensing service (DTS) has been deployed to address optimizing the placement of acid. Yet, there was no direct way to measure the impact of a treatment of the formation damage skin.

**ACTive Profiling and PTA introduction**

Schlumberger proposed using the portfolio of ACTive services that is supported by the domain experts and PTA using high resolution real-time PTC (pressure, temperature, CCL) gauges to measure the pressure transient events before and after treatment.

**Improved effective permeability**

ACTive services enabled the operator to optimize the fluid placement through DTS and identify damage improvement through PTA. The operator saved on the cost of additional memory gauges run—up to USD 150,000 total—and eliminated the risk of having noninterpretable data by performing real-time analysis.



Pressure transient analysis using type curve matching.

**Schlumberger**

# CT Downhole Technology Case Studies

# Through-Tubing Inflatable Packer Sustains Production More Than Threefold

Use of CoilFLATE coiled tubing packer in integrated operation saves two runs in Algerian well

## CHALLENGE

Isolate two perforated intervals and stimulate the lower underperforming interval.

## SOLUTION

Combining DepthLOG® CT depth correlation log and CoilFLATE® coiled tubing through-tubing inflatable packer for isolation of the top zone to lift the well on the same run that the packer was set.

## RESULTS

Sustained posttreatment production at more than three times the original production level.

**Depth correlation and nitrogen lift were performed on the same run as setting the packer, saving two runs. Posttreatment production was sustained at more than three times the original production level.**



## Isolation of zones for targeted stimulation

An operator in Algeria required isolation between two perforated intervals. The fractured top interval was highly permeable, but the less-permeable bottom interval, which was the stimulation target zone, was underperforming.

When the two zones were completely isolated, the bottom zone was to be stimulated through CT and below the packer with organic mud acid.

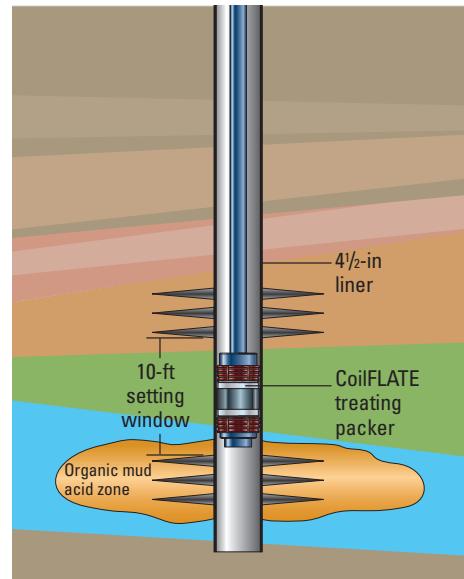
## CoilFLATE isolation and DepthLOG correlation

CoilFLATE inflatable packer was selected because it can operate at up to 375 degF [191 degC] in harsh wellbore conditions.

When setting the packer between perforation zones, job success relies primarily on depth accuracy. Only 10 ft [3 m] of wellbore was available to set the CoilFLATE packer and isolate the top zone (a window at 11,253 to 11,263 ft [3,430 to 3,433 m]).

To aid depth certainty, the DepthLOG CT depth correlation log was employed because it enables depth control through wireless real-time casing collar log correlation for optimum packer positioning. The DepthLOG log and CoilFLATE packer are completely compatible.

The CoilFLATE packer was positioned precisely between the perforated intervals and then inflated. The 120-bbl [19,080-L] organic mud acid treatment was successfully pumped at a maximum differential pressure of 3,500 psi [24 MPa] across the packer.



A multilayer CoilFLATE packer application.



*Components tailored to fit the individual application.*

After the CoilFLATE packer was deflated, nitrogen was pumped to flow back the acid while pulling the CT and bottomhole assembly to surface. Depth correlation and nitrogen lift were performed on the same run as setting the packer, saving two runs.

### Sustainable post-treatment production

A wellbore drift and perforation wash was performed using the Jet Blaster\* engineered high-pressure jetting service prior to the packer run. Depth correlation using the DepthLOG log was performed, and the packer was set the first time at the required setting depth.

The treatment was pumped below the packer at 3,500-psi [24-MPa] differential pressure. Nitrogen was pumped to lift the well while the packer was retrieved. This solution allowed correlating and lifting the well on the same run as setting the packer, saving two runs. Posttreatment production was sustained at more than three times the original production level.

# Through-Tubing Packer Operation Helps Decrease Water Production in GOM Well from 99% to 13%

CoilFLATE packer acts as permanent bridge plug, shuts off water production in offshore horizontal wellbore

## CHALLENGE

Effectively shut off water production in a horizontal wellbore completed with 7-in [177.8-mm] slotted liner producing at 99% water cut.

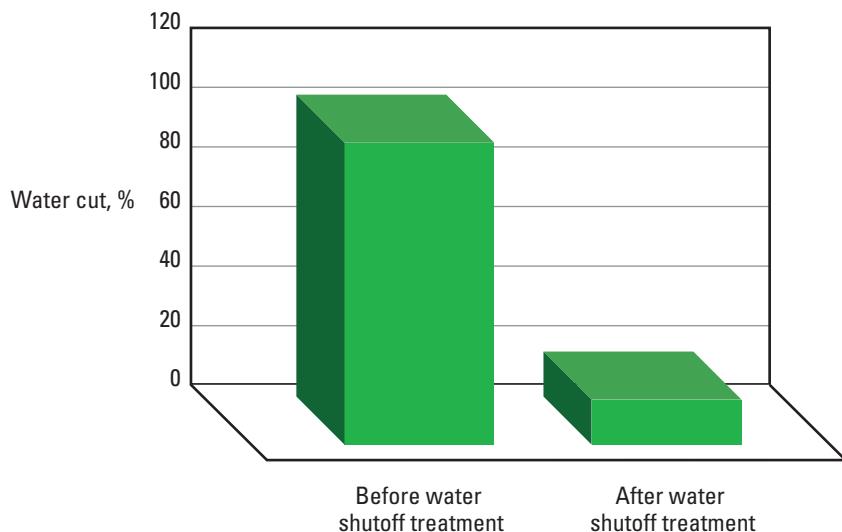
## SOLUTION

Set 3-in [76.2-mm]-OD CoilFLATE\* coiled tubing through-tubing inflatable packer as a cement retainer and leave in the well as a permanent bridge plug.

## RESULTS

Decreased water production from 99% to 13%.

**The well was put on production after 8 days. Water production after the treatment dropped to 13%, compared with 99% before the treatment.**



*Water shutoff treatment reduced water cut from 99% to 13%.*

## Water production in offshore well

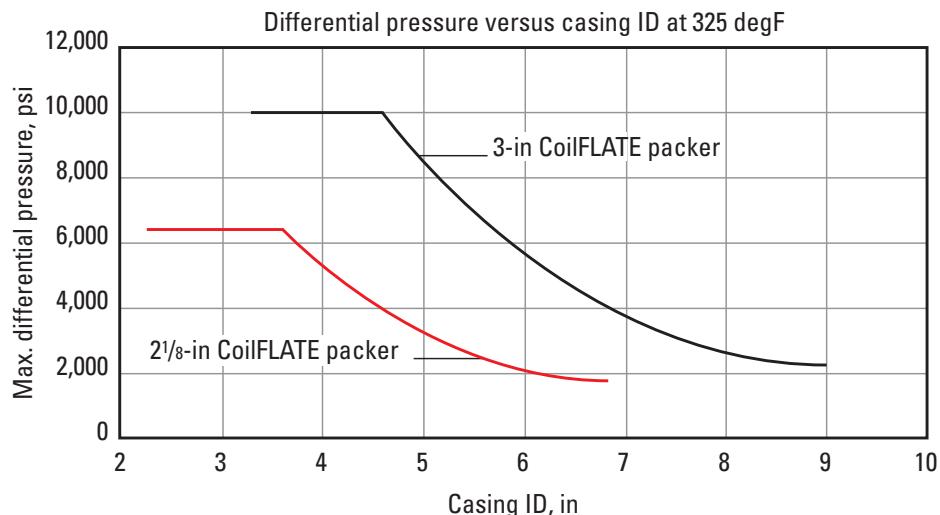
A Gulf of Mexico well in the Cretacico Inferior formation was drilled as an oil producer and completed with a 7-in [177.8-mm] slotted liner. Because it was a horizontal well, a mechanical barrier was required to ensure that the water control treatment fluid was injected into only the toe of the well. Because water production was confirmed as coming from the toe, 420 ft [128 m] needed to be shut off.

A dummy BHA with a maximum OD of 3.5 in [88.9 mm] was deployed on a 1.75-in [44.45-mm]-OD CT to drift the wellbore and confirm that the CoilFLATE packer could be deployed to target depth without obstruction. The packer setting was also simulated on the dummy run to confirm the design software output data for the running tool.

## Water control treatment

The CoilFLATE packer was run through a 4.725-in [120-mm] restriction in the tubing to 13,615 ft [4,149.9 m] and inflated to 2,250 psi [15.5 MPa] in the 7-in [177.8-mm] slotted liner. Before the treatment, nitrogen was pumped into the wellbore above the packer to prevent the treatment fluid from flowing uphole around the slotted liner. A total of 660 bbl of water control treatment fluid was injected below the packer to shut off water production from the lower section of the well.

The release mechanism was activated and, as planned, the packer was left downhole as a permanent bridge plug.



*The engineered slat design allowed higher differential pressures at varying inflation ratios.*

### Decrease in water production

The well was put on production after 8 days. Water production after the treatment dropped to 13%, compared with 99% before the treatment.

CoilFLATE through-tubing inflatable packers can be configured as treatment packers, cement retainers, and bridge plugs for cased hole and openhole applications.

# CoilFrac Stimulation Increases Texaco Hiawatha Field Production by 75%

Effective stimulation of sandstone formation more than doubles production,  
Rocky Mountains

## CHALLENGE

Separately stimulate multiple vertical sand layers with varied fracture gradients in Rocky Mountain well without increasing completion costs.

## SOLUTION

Use CoilFrac\* stimulation through coiled tubing to individually stimulate each layer in one run.

## RESULTS

Increased recoverable reserves per well by more than 75%.

**Based on the results of the four-well test, the most significant impact of the CoilFrac stimulation was that the recoverable reserves per well increased by more than 75%.**



The CoilFrac stimulation crew completed 4 wells and 21 stages in the Hiawatha field for Texaco.

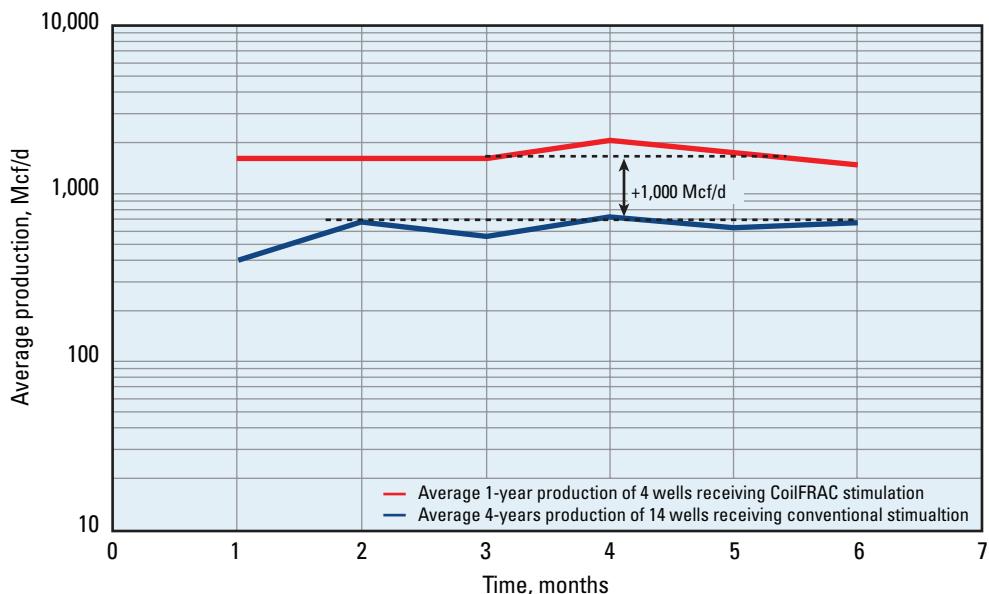
## Vertical sand layers with varied fracture gradients

The Hiawatha field in the Rocky Mountains comprises multiple vertical sand layers that range from 5 to 60 ft thick and are distributed from 2,000 to 5,000 ft. Texaco completed wells in this field primarily with limited entry and with bridge plugs when the distance between layers was significant. However, because of varied fracture gradients for each sand layer, many layers were not being effectively stimulated. In addition, some marginal layers were bypassed because of economic constraints. Texaco was looking for an effective way to stimulate each interval separately without increasing completion costs.

## Effective stimulation in one run

CoilFrac stimulation through coiled tubing was chosen to effectively stimulate each interval separately. In CoilFrac stimulation, all producing layers are conventionally perforated. CT is then deployed into the wellbore with a straddle-tool bottomhole assembly. The bottom layer is straddled, and the fracture stimulation is pumped through the CT.

Residual proppant is then reverse-circulated out of the wellbore, and the straddle tool is moved to the next interval, where the process is repeated. Through this process, each layer is individually stimulated in one run into the wellbore.



Production logs show that new wells stimulated with the CoilFRAC stimulation outperformed conventionally stimulated older wells.

### Increase in recoverable reserves

Based on the results of the four-well test, the most significant impact of CoilFRAC stimulation was that the recoverable reserves per well increased by more than 75%. One well in the field was producing 1.9 MMcf/d from one limited-entry fracture stimulation of multiple layers. Some bypassed layers were perforated, and the entire well was restimulated. Eight consecutive fracture stimulations were performed in 1 day, and the stabilized production from the well was recorded at 5.3 MMcf/d.

In addition to a more effective stimulation on each layer, the treatment took 1 or 2 days, compared with the several weeks that the conventional technique would have taken. The time, cost, and risk of milling composite bridge plugs were also eliminated using CoilFRAC stimulation.

### About the Contact services family

CoilFRAC stimulation is a member of the family of Contact\* staged fracturing and completion services. These technologies maximize reservoir contact by offering the most efficient and effective services for each well. Contact services enable multiple stages to be perforated, jetted, fractured, and isolated in one intervention. Contact services can be enhanced with real-time measurement options.

# Overcoming Severe Drilling Damage in Highly Deviated HPHT K-Gas Well

Using ACTive Perf and ABRASISET service helps achieve production target with thin-zone access and stimulation on CT

## CHALLENGE

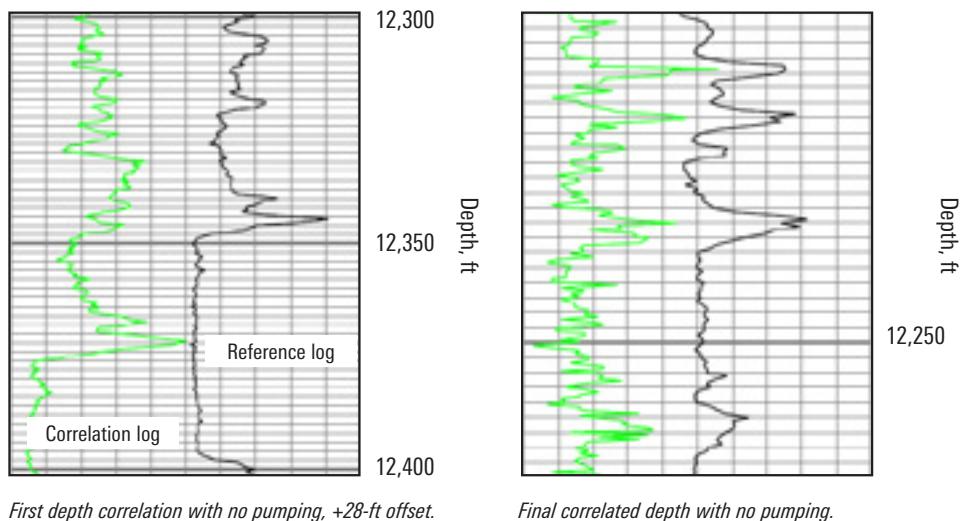
Bypass drilling formation damage to enable stimulation and production of a 70° deviated high-pressure, high-temperature (HPHT) gas well, where conventional perforation techniques had proved ineffective.

## SOLUTION

Use ABRASIJET® hydraulic pipe-cutting and perforating service enhanced with ACTive Perf® live CT perforating service.

## RESULTS

Achieved production target with matrix stimulation enabled by abrasive jet perforating to provide formation access.



*First depth correlation with no pumping, +28-ft offset.*

*Final correlated depth with no pumping.*

## Severe formation damage impedes production

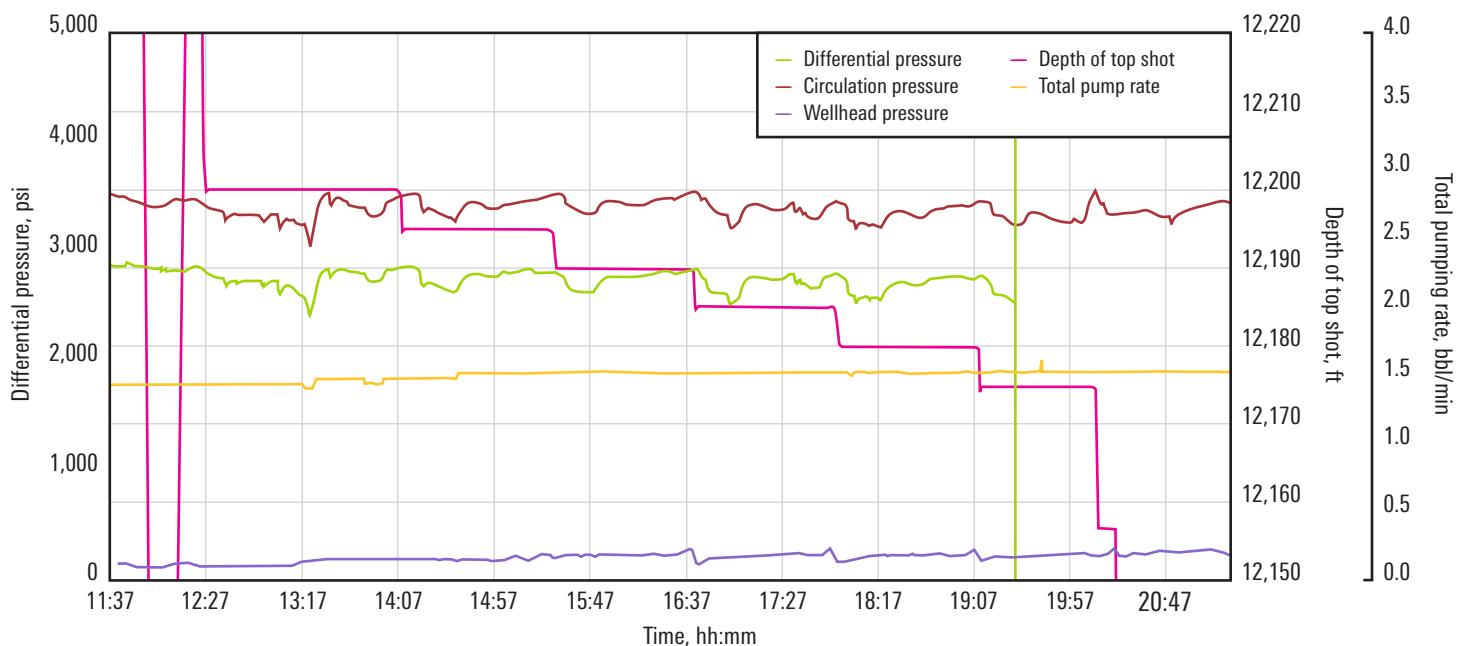
While drilling a K-carbonate gas well in the Middle East, an operator encountered high fluid losses. A special mud with different lost circulation material (LCM) was used to enable drilling the well to 12,600-ft MD with a maximum deviation of 70°.

However, this type of LCM causes severe damage to the near-wellbore formation and has low solubility in acid. The K-wells that were drilled using this mud could not flow after being perforated using conventional techniques. Subsequent matrix stimulation is often not feasible because the short perforation tunnels cannot extend beyond the damaged zone to enable communication with the reservoir.

## Abrasive jet perforating penetrates damaged zone

Creating large-diameter, long cavities (notches) in the formation can potentially reduce the fracture initiation pressure and help extend the fracture deeper into the reservoir. ABRASIJET hydraulic pipe-cutting and perforating service was selected and optimized for the first time in the Middle East by adding ACTive Perf service, which obtained pressure, temperature, casing collar locator (CCL), and gamma ray (GR) measurements in real time—all during the same trip.

The GR and CCL enabled accurate depth correlation for precise placement of the notches in every thin interval with high gas saturation. Forty perforations were made at the best reservoir depths for acid stimulation. By monitoring the pressure inside and outside the CT with the bottomhole pressure measurement, the abrasive-fluid pumping rate was adjusted to maintain a minimum of 2,500-psi differential pressure across the nozzles for efficient perforation. The notch length was further optimized by nitrifying the abrasive sand slurry, increasing the pumping time, and orienting the nozzles to the lower side of the highly deviated borehole to minimize standoff from the liner.



*Real-time downhole data acquired during abrasive slot cutting of lower zone, Stations 1–6.*

### Well exceeds expectations with production similar to offset wells

Unlike wells perforated using conventional techniques, this well showed gas at surface—1,100-psi wellhead pressure—after the first abrasive-jet perforating run, demonstrating successful contact with the reservoir. Injectivity was confirmed and further improved with an acid wash through CT while monitoring the distributed temperature sensing response across the perforated zones for smart fluid placement.

Temperature monitoring continued during subsequent acid fracturing operations, which were conducted at an average pump rate and pressure similar to nondamaged K-carbonate offset gas wells. This brought production online quickly and efficiently to achieve the field's highest postperforating gas flow. The ability of the ACTive Perf service to measure depth, pressure, and temperature in real time was critical to ensuring a successful intervention and increased operator confidence in the outcome.

# Underbalanced Coiled Tubing Drilling Triples Production in Declining UAE Wells

Combined technologies reduce NPT and lower costs per well while reversing production decline for BP Amoco

## CHALLENGE

Increase production by accessing new and bypassed reserves.

## SOLUTION

Combine CT and underbalanced drilling technologies to enter horizontal openhole multilaterals of existing wells.

## RESULTS

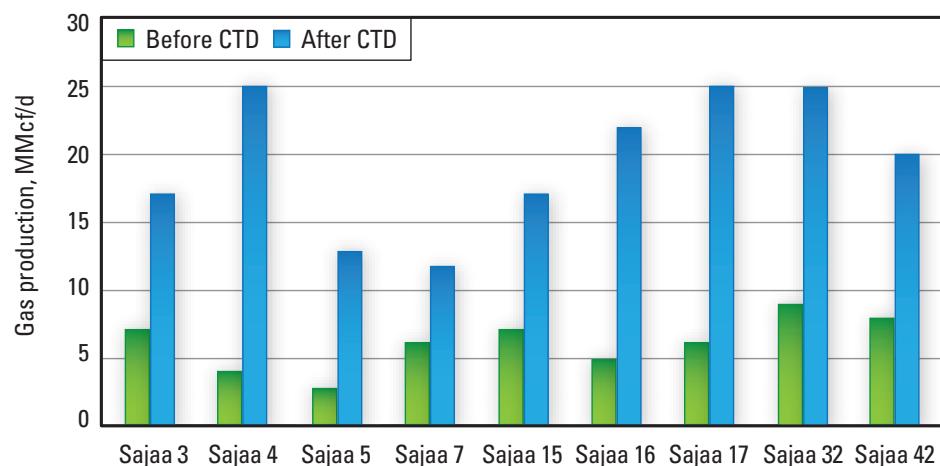
Tripled the average production from 18 wells, reduced NPT to 3%, and lowered costs per well by 35%.

**The project proved the feasibility of underbalanced CT drilling (CTD) to access new and bypassed reserves. Because of this success, BP Amoco extended the contract with Schlumberger for an additional 1½ years.**



## Reentering wells to reach unaccessed reserves

The Sajaa field in the UAE produces from a deep, low-pressure carbonate reservoir. BP Amoco had drilled a number of wells in this prolific gas field, and when production began declining, the company needed to access reserves in areas that were not being effectively drained by the original wellbores. After consulting with Schlumberger and evaluating several methods for reentering wells, the company began drilling multilateral sidetracks from existing wellbores using CT for underbalanced operations.



*Substantial production increase because of the underbalanced CTD campaign in Sajaa field.*

## Using CT for underbalanced reentry drilling

Long strings of relatively small-diameter CT can be quickly mobilized to reenter wells through existing wellbore tubulars. CT provides relatively high load capacities for deeper vertical or extended high-angle reach and for greater overpull downhole. This facilitates both directional and underbalanced drilling, helping to reduce NPT.

In all, 54 laterals, totaling 134,500 ft, were drilled using underbalanced CTD of 3 3/4-in casing-exit sidetracks to access new and bypassed reserves in the Thamama limestone. Drilling was done with underbalanced pressures using nitrogen and freshwater. The project was divided into three phases based on operational and geological complexities. The three phases included 253 pressure deployments and pumping 7 million galUS of liquid nitrogen. In the final phase, 1,394 ft of open hole was drilled in 24 hours, with the average rate of penetration exceeding 58 ft/h.

Strict quality, health, safety, and environmental procedures were followed throughout the 650,000-work-hour project, with no lost-time incidents.



Aerial view of Sajaa underbalanced CTD location.

### Accessing new and bypassed reserves

The project achieved its objectives—arresting declining production in the Sajaa gas field and proving the feasibility of underbalanced CTD to access new and bypassed reserves. In addition, NPT was reduced from 22% in the initial phase to 3% in the final phase, and AFE per well was reduced by 35%.

The average production from 18 wells was tripled by drilling 54 laterals to access new and bypassed reserves. The best CTD run to date was 1,394 ft drilled in 24 hours, shortening time to market. Because of this success, BP Amoco extended the contract with Schlumberger for an additional 1½ years.

# Exhaustive Dataset Supplied by Multisegment Team

Comprehensive CT strategy for North Sea prospect well

## CHALLENGE

Acquire large amount of data for offshore horizontal well with HPHT requirements.

## SOLUTION

Employ a multisegment team with a comprehensive CT strategy, including CoilTOOLS® coiled tubing intervention tools and solutions as well as Vantage® modular CT logging head system.

## RESULTS

- Successfully intervened and safely plugged and abandoned well.
- Retrieved exhaustive dataset for reservoir engineers.



*Operations were based on CT as the first means for intervention.*

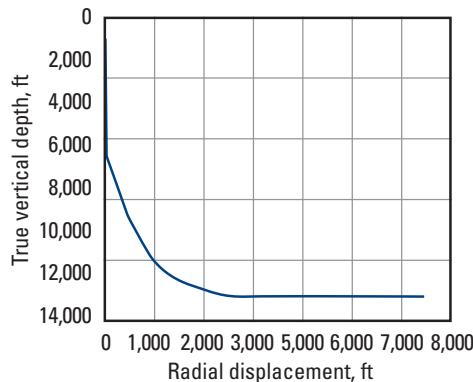
## Large dataset requirement

In the North Sea, an operator needed to test a gascondensate well for prospecting purposes. Testing the well proved problematic because of its high temperature and pressure—298 degF and 11,100 psi, respectively. Furthermore, this offshore horizontal well was in a tight spot and had a multifracture completion with heavy fluid pumping required.

Reservoir engineers at the company needed a maximum amount of data for the well.

## Comprehensive CT strategy

With significant experience in the offshore North Sea environment and in HPHT conditions, Schlumberger was employed to address the company's data needs. With several technologies applied and several situations to be addressed, the team brought together multiple segments, both onshore and offshore.



*The team carefully engineered the CT string to run successfully in the horizontal well.*

Operations were based on CT as the first means for intervention, including

- setting plugs
- running memory tool
- pumping completion sealing fluid
- cleaning out fracturing sand
- milling Packers Plus® ball and seat
- running venturi junk basket
- logging with CT and wireline
- taking downhole samples
- shifting sleeves
- killing the well.

CT string design was carefully engineered, and reliable CoilTOOLS intervention tools and a Vantage modular CT logging head system were applied with a heavy-wall 2-in CT pipe and a robust backup pump. Equipment was rated to 15,000 psi, meeting the high-pressure requirement of the reservoir.

The CT team stayed onboard for nearly 6 months and completed 44 runs, from the postdrilling cleanup of the well to plug and abandonment.

## Superior service

With the comprehensive CT strategy and a CT string carefully designed for success, the team overcame pump reliability issues, finished completion remedial actions, cleaned out the screenout, and safely plugged and abandoned the well. The Vantage logging heads were used for 10 successive days, and heavy fluids were pumped for great lengths of time at high pressures (up to 9,000 psi).

The superior service provided by the Schlumberger team for this well was shown by its knowledgeable personnel, the availability of equipment throughout the operation, and the communication between segments. The one-team concept proved crucial and contributed to a robust dataset provided to the operator.

# Protect Fiberglass Lining of Water Disposal Wells

Drillpipe-conveyed CoilFLATE packer saves 60 hours of rig time per well for KJO

**CHALLENGE**

Need high-expansion retrievable packer that will not damage fiberglass-lined casing of water disposal wells and can be set through the BOP and retrieved through the wellhead.

**SOLUTION**

Use drillpipe-conveyed CoilFLATE\* coiled tubing through-tubing inflatable packer.

**RESULTS**

Saved an average 60 hours of rig time by deploying CoilFLATE packer with drillpipe.



*The CoilFLATE through-tubing inflatable packer distributes the anchoring force over a large surface area. Thus, no damage was done to the fiberglass coating of the well's casing.*

**Avoid damage to casing**

Al-Khafji Joint Operations (KJO), a collaboration between Aramco Gulf Operations Company and Kuwait Gulf Oil Company, encountered a challenge with one of its water disposal wells.

Water disposal wells in Khafji, Saudi Arabia, are completed with fullbore 7-in fiberglass-lined casing.

With kill brine in the well, only one barrier was in place during nippling down the drilling BOP and nippling up the wellhead. However, KJO safety standards dictate that two wellbore barriers are required to perform the operation safely. Thus, KJO needed a high-expansion retrievable packer that

- would not damage the fiberglass coating
- could be set through the BOP and retrieved through the wellhead before putting the well on injection.

**Protect fiberglass lining**

The anchors of standard slip-type packers would likely damage the soft fiberglass lining. The unique slat-design anchoring mechanism of the Schlumberger CoilFLATE through-tubing inflatable packer distributes the anchoring force over a large surface area; therefore, no damage is done to the fiberglass coating of the casing.

Field test results showed that no damage was observed on the fiberglass lining after setting and retrieving the CoilFLATE packer. As a result, the CoilFLATE packer was selected as the best candidate for this application.

CoilFLATE packers are mostly deployed via CT, which allows for accurate surface control of tension and compression forces on the CoilFLATE packer during the inflation and anchoring process. While it is operationally safer, it takes additional time to rig up a CT unit (CTU). Consequently, KJO requested to develop the process and procedures to set CoilFLATE packers on drillpipe.

The risks associated with setting and retrieving the CoilFLATE packer with drillpipe were mitigated, and action plans were executed. A yard test to use a CT BOP to cut the drillpipe was performed, and a rig-up stack on top of the wellhead was provided to enable the retrieval of the CoilFLATE packer with drillpipe, in compliance with KJO safety standards. Later, an optimization of the rig-up procedure was implemented to further reduce rig time.

### **Save rig time**

Four CoilFLATE packer jobs were performed on RKH water disposal wells. A CoilFLATE packer was deployed with CT on two of the wells, RKH-06 and RKH-07. On the other two wells, RKH-08 and RKH-09, a CoilFLATE packer was deployed with drillpipe.

A large amount of savings in rig time was achieved on the wells that deployed the CoilFLATE packer with drillpipe instead of CT. Rig time was reduced from 126 hours on the first well, which used CT, to 17 hours on the fourth well, which used drillpipe. An average 60 hours of rig time was saved per well by using the CoilFLATE packer with drillpipe versus CT.

# Four-Well HPHT Intervention Campaign in Hungary

Comprehensive process and highly rated CT technology complete 36 runs in 5 months

## CHALLENGE

Intervene in four problematic high-pressure, high-temperature (HPHT) wells from post-fracture cleanout to cement plug.

## SOLUTION

Perform peer review and assessment by global experts; mobilize highly rated CT equipment and use TIM\* tubing integrity monitor and CoilLIFE\* coiled tubing life prediction model.

## RESULTS

- Completed 36 runs in 5 months
- Exposed BHA and CT string to high pressures and pump rates without failure



## Intervention impeded by well characteristics

The fields Hódmezővásárhely, Földeák, Gyula, and Mako are located in an HPHT reservoir in Hungary. Intervention was needed for four wells, consisting of

- postfracture cleanout
- gas lift
- memory gauge run
- fishing
- milling
- cement plug.

The following well characteristics caused problems for the intervention operation:

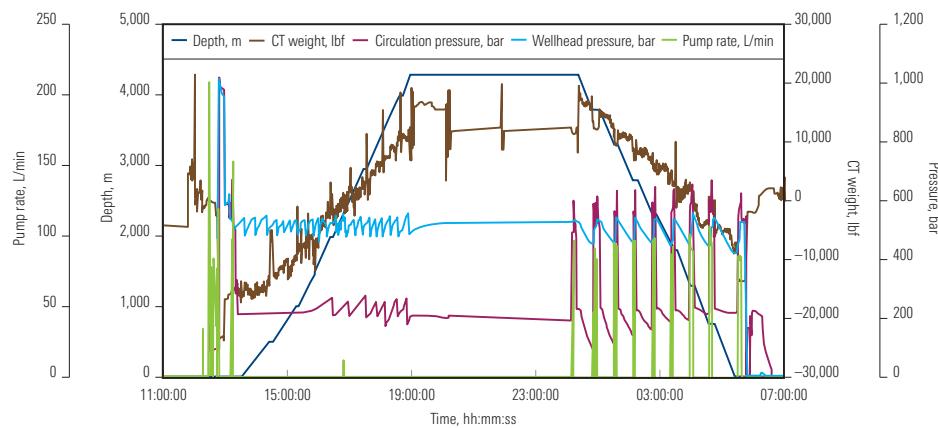
- well depth: 12,500–14,400 ft [3,700–4,400 m]
- bottomhole temperature: 320–350 degF [160–180 degC]
- reservoir pressure: 12,600–13,500 psi [87–92.5 MPa]
- wellhead pressure: 0–8,400 psi [0–57 MPa]
- hydrogen sulfide ( $H_2S$ ) content: 300 ppm.

## Specialized team and equipment mobilized

The operator contacted Schlumberger for this complex intervention project. A rigorous process was followed, including proper string selection, systematic peer review, and a final assessment of the project by global experts. A team of CT personnel with prior HPHT exposure was assigned to the operation, and 15,000-psi [103.4-MPa] equipment was identified and mobilized, including a specially designed 1.5-in [3.8-cm] CT string. Throughout the operations, strings were closely monitored by TIM tubing integrity monitor and CoilLIFE CT life prediction model to ensure tubing geometry was not compromised.

## Successful runs completed without failure

A total of 36 runs were performed without failure in the 5-month campaign, in which the BHAs and CT string were exposed to pressures as high as 13,000 psi [89.6 MPa] and pump rates of 2.5 bbl/min.



*Memory gauge run, while circulating the well, letting in kicks to determine reservoir pressure. Pressure and weight changes correspond to choke adjustments.*

# Rigless Plug-and-Abandonment Campaign Reduces Operating Time by 30%

Optimization helps operator save more than USD 5 million during 60-well campaign

## CHALLENGE

Develop a plan to plug and abandon 60 onshore exploration wells in approximately 40 different fields using a cost-effective, environmentally safe methodology.

## SOLUTION

Use Schlumberger CT units to

- eliminate the need for a rig
- speed up operations and relocation
- reduce costs
- improve environmental safety.

## RESULTS

Conducted the plug-and-abandonment operation in 30% less time compared with previous campaigns using a drilling rig, saving more than USD 5 million.



## Safe, cost-effective method required for abandonment of dozens of wells

An operator planning to plug and abandon 60 exploration wells in Oman needed a safe, cost-effective method that would not only meet technical and safety standards but also ensure long-term environmental protection. The wells, which were located in approximately 40 different oil and gas fields in North and South Oman, varied in depth between 2,200 and 13,450 ft [670 and 4,100 m] and bottomhole temperatures ranged from 107.6 to 210 degF [42 to 99 degC].

The operator quickly realized that the complexity and variety of the abandonment activities required an integrated services approach.



*The mobile plug-and-abandon operation meant that all equipment was on wheels. Schlumberger managed supplies, transport, and subcontractor services, saving time and expense for the operator.*

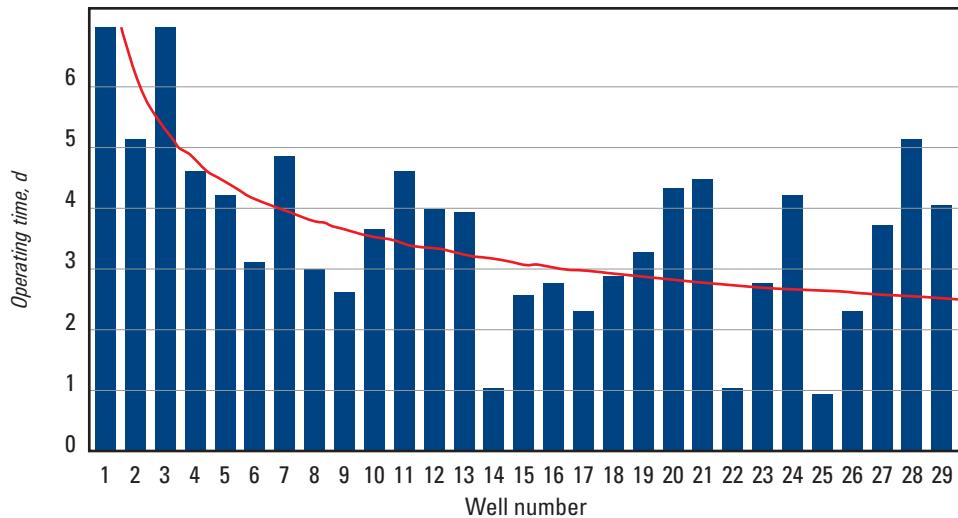
## CT unit eliminated need for rig, improving efficiency and safety

The operator teamed with Schlumberger to develop and execute a plan to permanently plug the wells. Together, the two companies decided that a rigless approach would be the most cost-effective, environmentally responsible plan for plug-and-abandon operations. A CT unit provided faster tripping speeds compared with a rig, resulting in operational savings. A CT unit also enabled precise placement of cement plugs, even in deviated wellbores. CT operations can take place on live wells without removing the production tubing or wellhead, enabling crews to kill the well at the same time.

The team also developed a five-step plan that would be the most optimal and efficient method of plugging and abandoning these wells. The first aspect of the plan was that it needed to be mobile. Crews and equipment would be moved every 4 to 6 days, so all equipment, including the camp, was put on wheels. The second aspect of the plan included a dry location concept. All fluids were stored in tanks instead of being drained at the wellsite, saving cleanup time and protecting the surrounding environment. Each wellsite was only visited once, and the entire job was completed at that time. In addition, Schlumberger took care of nearly all activities, such as supplies, transport, and subcontractor services, saving time and expense for the operator. Schlumberger optimized moves from wellsites to reduce time and minimize safety concerns.

## Rigless approach saved operator more than USD 5 million

Schlumberger completed the abandonment of all 60 wells in just 11 months—a time savings of 30% compared with previous abandonment campaigns with a drilling rig. Overall, this rigless operation saved the operator more than USD 5 million dollars compared with conventional abandonments using a workover or drilling rig. The plan helped minimize abandonment costs, set new standards for rigless abandonment, and helped protect the surrounding environment. The operator was so impressed with this approach that it plans to use it for future campaigns, not only in Oman but in other areas of the world.



*The operating time per well was kept to a minimum to complete the abandonment of 60 wells in just 11 months.*

# Through-Tubing Milling Operations Clear Unexpected Obstructions, Restore Flow in HPHT, Sour Gas Wells

Robust intervention helps KOC safely recover high-risk wells in 24 hours or less

## CHALLENGE

Free unknown obstructions from three deep, HPHT, sour gas wells after conventional methods were ineffective.

## SOLUTION

Perform a detailed risk analysis and determine an engineered milling solution to quickly clear plugged zones with minimal HSE risk.

## RESULTS

- Milled 6,208 ft in Well 1 in less than 24 hours.
- Milled 70 ft of soft fill and a 4-ft hard bridge of Well 2 in under 10 hours.
- Milled a 100-ft hard bridge plug in Well 3 within 8 hours, reestablishing reservoir contact.



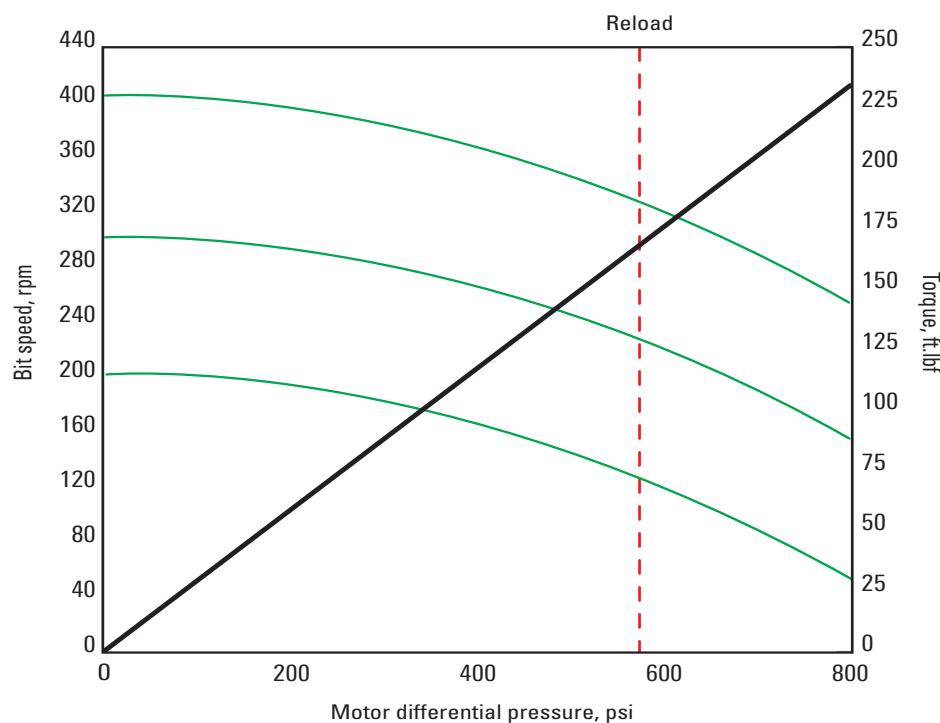
## Unknown obstruction blocked flow from complex wells

Kuwait Oil Company (KOC) is focusing attention on gas exploration and production. However, the reservoirs in northern Kuwait are more complex than most. The fields are deep—typically ranging from 13,000 to 16,000 ft—and prone to HPHT conditions and high hydrogen sulfide content. On average, wells in the area take 200 days to drill, complete, and test. While preparing three wells for the testing phase, the tubing unexpectedly plugged. The lack of flow forced KOC to temporarily abandon the wells. Conventional cleaning methods, including unloading the well, running with a standard BHA, and jetting, were ineffective.

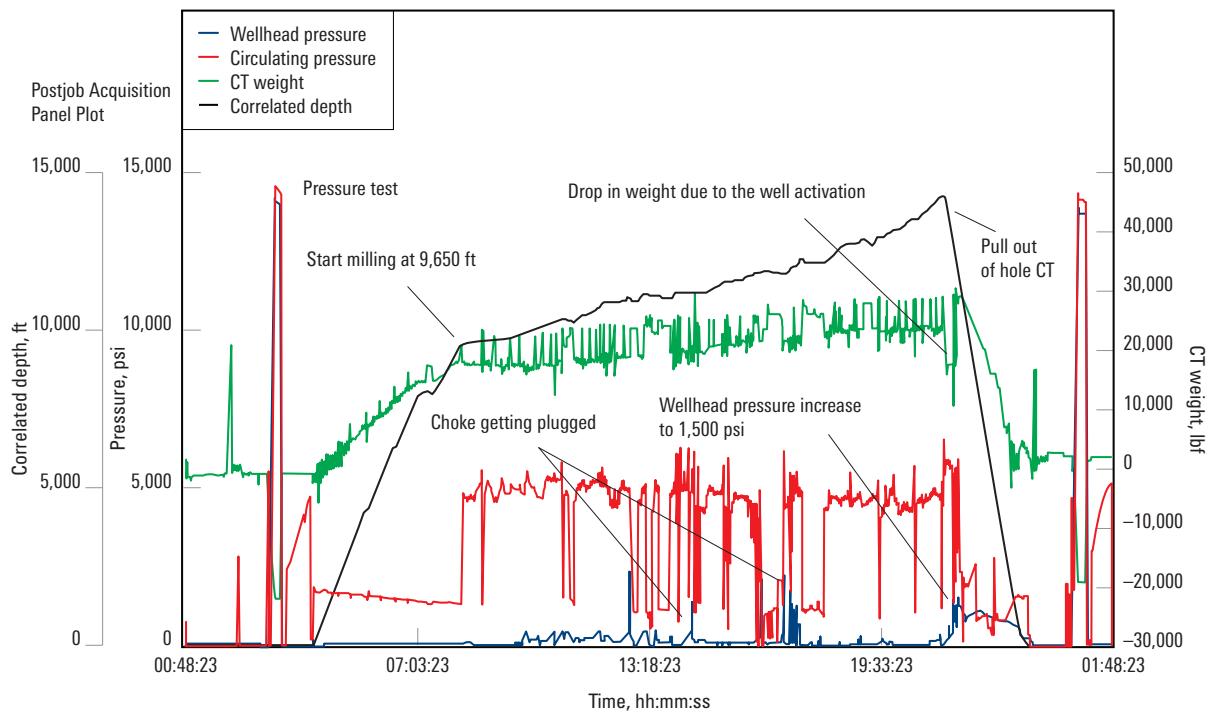
To safely resume operations, Schlumberger performed a detailed risk analysis and proposed an integrated through-tubing milling method using specially selected motors, mills, and fluid systems.

## Comprehensive job design met harsh conditions

Schlumberger selected 15,000-psi CT for durability. To minimize working hours, trips in hole, and tool damage, 2 1/8-in and 1 11/16-in downhole drilling motors were chosen to provide needed torque without excessive pumping rates. The relatively small motor sizes allowed KOC to use less aggressive mills. Lab analysis and simulations by M-I SWACO, a Schlumberger company, helped KOC find the right fluids to mill the wells in an underbalanced condition.



1 1/8-in coiled tubing intervention tools and solutions milling motor job design.



Milling with 1 1/16-in motor and 2-in bit for fourth run.

### KOC resumed production testing on three wells

The first well—a 15,900-ft horizontal openhole well—had stopped during the unloading phase as soon as it began flowing. Schlumberger ran CT to the top of the obstruction and milled 6,208 ft in less than 24 hours. KOC retrieved the downhole test tool and resumed operations on the well.

Well 2, a high-pressure vertical well, suddenly became plugged up to 14,422 ft. After several attempts to remove the obstruction conventionally, Schlumberger recommended the through-tubing milling strategy. In less than 10 hours, including the time to run in hole and pull out of hole, Schlumberger milled 70 ft of soft fill and a hard, 4-ft bridge.

In Well 3, Schlumberger milled a hard bridge plug of 100 ft in just 8 hours. KOC tested the well as soon as the CT returned to surface. The first testing results showed oil production of 2,685 bbl/d with 6 Mcf/d of associated gas at 2,200 psi flowing pressure under a 2 1/64-in choke.



2 1/8-in motor and 2 1/2-in bit.

# Back-Pressure Valve Ensures Safer Packer Inflation in Subhydrostatic Wells in Mexico

Safer packer inflation enables accurate, reliable placement of stimulation treatment

## CHALLENGE

Control fluid placement and chemical diversion in a depleted, low-bottomhole-pressure well.

## SOLUTION

Control fluid flow during operations using the Schlumberger back-pressure valve (BPV); perform mechanical and chemical diversion using CoilFLATE® coiled tubing through-tubing inflatable packer and SDA\* self-diverting acid.

## RESULTS

Enabled safer inflation of the packer for more reliable, accurate placement of the stimulation treatment according to job design.



## Using inflatable packers in subhydrostatic wells

Stimulating targeted zones in subhydrostatic conditions proved ineffective for an operator in Mexico because of the difficulty in controlling fluid displacement inside the CT. Yet, stimulation of the targeted zone, proper zonal coverage, and a good cleanup process are all essential to increasing production after stimulation. This is why mechanical and chemical diversions are used in these conditions. However, controlling hydrostatic pressure balances while performing inflatable packer operations in low-bottomhole-pressure wells still presents challenges.

The low-bottomhole-pressure conditions of these wells limited the use of inflatable packers for high-expansion-ratio applications because of the challenge of ensuring safe use of the packers. Consequently, the operator was restricted to performing conventional bullhead treatments, which are not as effective as a CT matrix treatment with mechanical diversion.

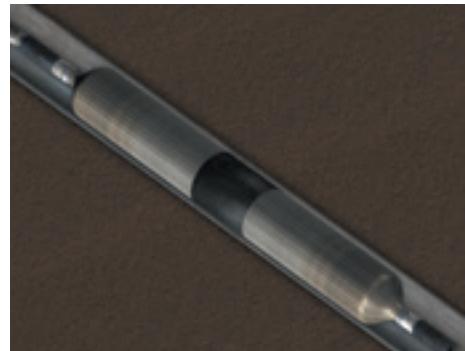
## Ensuring safer use of inflatable packers

The operator chose the CoilFLATE through-tubing packer to provide reliable mechanical diversion and zonal isolation and to guarantee proper fluid placement during the intervention. The BPV was used for the first time in a 2½-in CoilFLATE packer application to ensure safer use of the packer. SDA self-diverting acid for chemical diversion was selected as the optimum solution for treatment diversion.

The CoilFLATE CT through-tubing inflatable packer extended critical zonal isolation to the previously inaccessible, chemically harsh, and high-temperature environment, enabling selective placement of the treating fluid. For more control in low-bottomhole-pressure conditions, the BPV supported a fluid column in the CT string. The setting pressure was adjustable to support the amount of hydrostatic overbalance or pressure differential conditions of the well. Without such a device, critical operation processes are more at risk of failure because of improper control of fluid flow.

## Reducing risk, increasing reliability

By using the CoilFLATE 2½-in cased-hole packer in combination with the BPV and SDA acid, the operator was able to place the stimulation treatment according to the job design. Using the BPV ensured safer inflation of the packer, which avoided a misrun or a CT string stuck in the hole.



*The CoilFLATE 2½-in cased-hole packer used to place the stimulation treatment.*

# HPHT Through-Tubing Packer Achieves Complete Water Shutoff, Saves USD 220,000

In first attempt, CoilFLATE packer enables perforating and producing 30-ft zone, saves workover run in GOM operation

## CHALLENGE

Isolate and seal an existing water-producing zone so that a zone only 30 ft [9 m] above could be perforated and produced.

## SOLUTION

Set the CoilFLATE\* coiled tubing through-tubing inflatable packer at an inflation ratio greater than 3:1 and at the required injection pressure of 1,500 psi [10 MPa].

## RESULTS

Successfully set the packer on the first attempt, eliminating the need for a workover and saving more than USD 220,000.



## Zonal isolation in HPHT well

An operator in the Gulf of Mexico wanted to isolate a water-producing zone while starting production from a zone only 30 ft [9 m] above. The packer solution had to be delivered to the target zone through 2 $\frac{7}{8}$ -in production tubing, which was cased with 7 $\frac{5}{8}$ -in pipe.

## Complete water shutoff

A function test run was carried out on the circulate-inflate orifice tool and the universal valve under downhole conditions. Then a depth-correlation run on 1 $\frac{1}{4}$ -in CT was carried out to ensure depth control and proper packer setting depth.

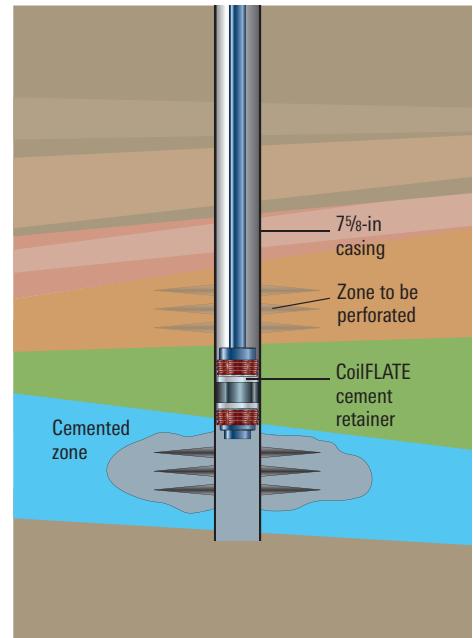
The CoilFLATE packer was set at greater than a 3:1 expansion ratio. While holding 1,500 psi of pressure on the annulus, the required high-differential squeeze pressure of cement slurry was squeezed into the zone below the packer. The CT was disconnected from the CoilFLATE packer and the hole was circulated clean.

## Water-free production

After the lower zone was isolated, the target zone was perforated and produced waterfree, resulting in a savings of more than USD 220,000 because the use of a workover rig was avoided.



Advanced-design components contribute to the performance of the CoilFLATE packer.



CoilFLATE packer in a multilayer application.

# Complete Zonal Water Shutoff in High-Pressure Well Saves USD 150,000

CoilFLATE inflatable packer delivers selective water control in Indonesia

## CHALLENGE

Achieve complete zonal water shutoff in a high-pressure well.

## SOLUTION

Run CoilFLATE\* coiled tubing through-tubing inflatable packer and pump DGS\* delayed gelation system to isolate a zone, reduce water production, and increase productivity.

## RESULTS

Achieved water shutoff and saved approximately USD 150,000 in costs because neither a workover rig nor pulling of production tubing was required.



## Reducing water production in a high-pressure well

The operator of an Indonesian well planned a water shutoff treatment to reduce water production and improve oil production. The high differential pressure of 2,500 psi [24 MPa] from the zone below complicated the treatment. The operator selected the CoilFLATE inflatable packer system because of its unique inflation profile and its reputation for reliability in high-pressure, harsh-environment wells. The DGS delayed gelation system was chosen because it can penetrate deep into the formation where it gels to reduce permeability.

## Shutting off the water zone

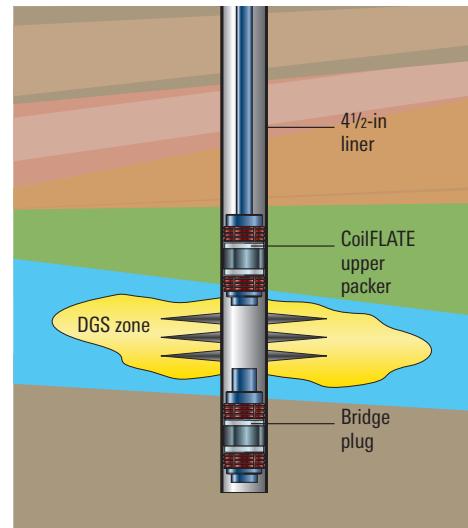
The CoilFLATE packer was run to the setting depth and inflated to 2,500 psi [17 MPa], which was indicated by a pressure drop as the universal valve opened. The packer was confirmed as fully inflated, 129 bbl of DGS system fluid was pumped at approximately 0.8 bbl/min through the coiled tubing and below the CoilFLATE packer. Because of its water-like viscosity, DGS system fluid can be placed in a low-permeability matrix where traditional polymers will not penetrate.

## Saving USD 150,000

After displacement of the treatment fluid with brine, the CoilFLATE packer was retrieved to the surface. The water zone was completely shut off. The CoilFLATE packer was set on depth in the 4½-in tubing on the first attempt, resulting in a savings of approximately USD 150,000 because no workover rig or pulling of production tubing was required.



*Superior components and assembly techniques are key to CoilFLATE packer performance.*



*CoilFLATE packer and DGS achieved middle-zone isolation.*

# CoilFLATE Inflatable Packer Reduces Water Cut by 70% in North Kuwait

Water shutoff treatment saves USD 180,000 for Kuwait Oil Company

## CHALLENGE

Achieve complete zonal isolation in a field where multiple-zone productive intervals and well completions restricted the choice of downhole tools.

## SOLUTION

Use two CoilFLATE\* coiled tubing through-tubing inflatable packers to isolate middle zone the first time.

## RESULTS

Reduced water cut by 70% and saved more than USD 180,000.



## Isolation between multiple oil-producing zones

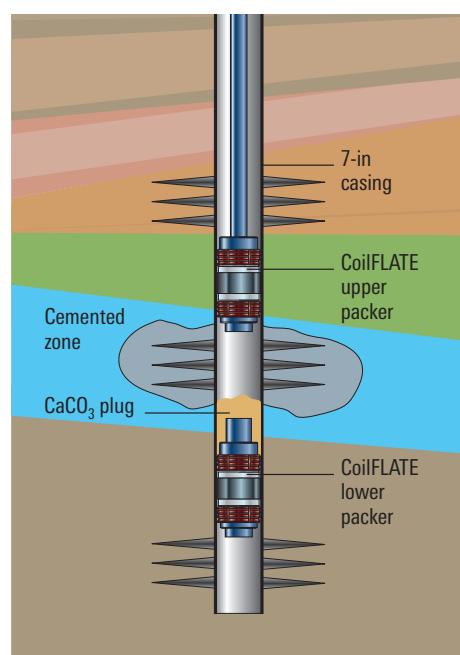
Kuwait Oil Company (KOC) identified an increasing water cut from the SA-098 well in the Sabriyah field, one of the largest oil fields in North Kuwait. The well continued to produce at 2,094 bbl/d [333 m<sup>3</sup>/d], but the water cut steadily increased over a 2-year period to 36% from 10%. KOC decided to remediate using CoilFLATE through-tubing inflatable packers conveyed on coiled tubing (CT) because selective fluid placement was necessary for effective total isolation.

The multiple-zone productive interval and the completion of the well restricted the choice of down-hole tools that could be used in this well. Tool requirements included a

- limited outside diameter because of the production tubing restrictions
- high expansion ratio because of the large inside diameter of the producing casing.

## Successful water shutoff

Because of the nature of the water problem, and because the targeted section was between multiple oil-producing zones, the CoilFLATE HPHT packer offered the best solution to achieve zonal isolation, with the added capability of providing the necessary inflation ratio of greater than 3:1.



Layer-straddling CoilFLATE zonal isolation.

Two CoilFLATE HPHT packers were set successfully on the first attempt in the 7-in casing. SqueezeCRETE\* slurry was pumped at the required high-differential squeeze pressure through and below the CoilFLATE HPHT sealing element. The slurry sealed off the targeted zones and the water shutoff treatment was successful.

#### Water cut reduction

Postjob wireline logs showed a significant—70%—water cut reduction, resulting in a savings of more than USD 180,000 because pulling the production tubing and using a workover rig were avoided.



*The CoilFLATE packer relies on advanced Schlumberger technology, allowing high expansion ratios.*

# Reliable Multilateral Entry in Subhydrostatic Conditions in Alaska Results in Successful Cleanout

Discovery MLT, ACTive services, and back pressure valve enable single-trip intervention in low-bottomhole-pressure conditions

## CHALLENGE

Obtain downhole data to locate, enter, and clean out all laterals in one trip in hole in subhydrostatic conditions.

## SOLUTION

Selected the Discovery MLT\* multilateral tool to access the laterals, the Schlumberger back pressure valve (BPV) to maintain and control the fluid column in the CT string, and ACTive\* family of live downhole coiled tubing services to provide depth correlation, quickly confirm access to the correct lateral, and provide live downhole pressure measurements to optimize fill cleanout.

## RESULTS

Successfully located, entered, and cleaned out all the targeted laterals in a single trip, saving time, conserving fluids, and reducing personnel exposure because of fewer rig-up and rig-down events.

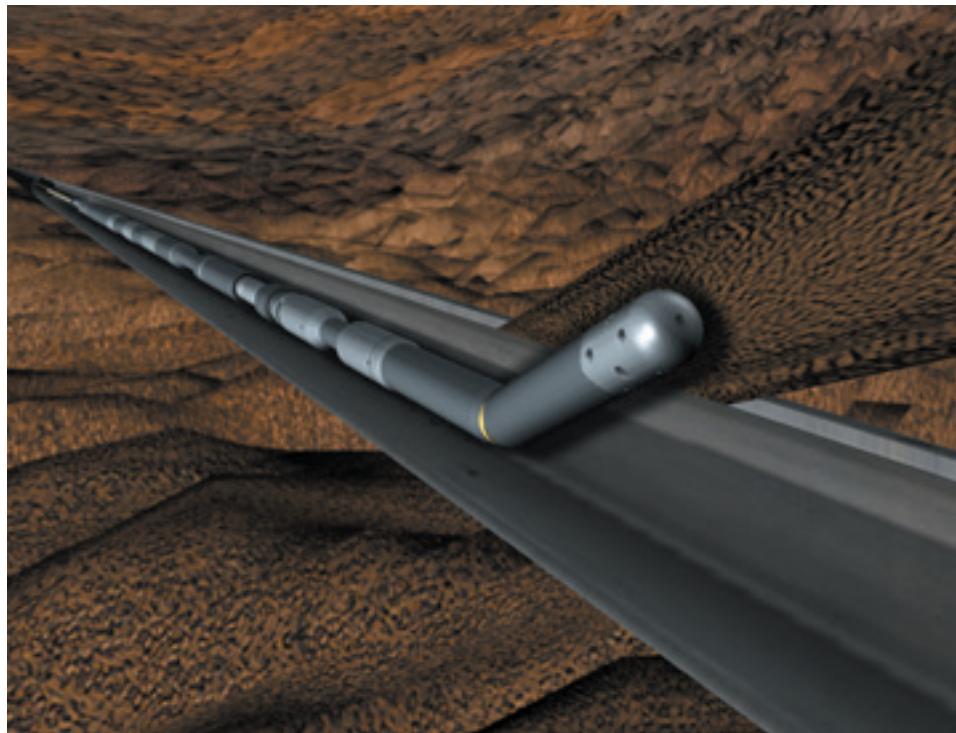


## Subhydrostatic well conditions in Alaska

Well conditions in Alaska present challenges for through-tubing downhole tool technologies capable of lateral entry. Knowing what is happening downhole is key to the success of this type of application because, in the subhydrostatic well conditions in Alaska, the wells will not sustain the column of treatment fluid needed to reflect downhole pressure and tool responses.

An operator in Prudhoe Bay, Alaska, had used conventional lateral entry tools and mechanical diverters in a number of wells. Several attempts to enter all the laterals of a multilateral well with subhydrostatic conditions were unsuccessful. Successful well cleanout and stimulation operations are challenging in multilateral wells with these characteristics. Efficient and effective profiling of lateral windows is essential to gaining access to vital target intervals within each lateral leg of the well.

Because of the historical difficulty in entering all the laterals using conventional methods, the operator contacted Schlumberger for a more effective method to locate, enter, and clean out all the laterals in a single trip in hole.



*Discovery MLT tool shown entering lateral.*

## Efficiency of combined CT services

Schlumberger proposed using

- the Discovery MLT tool to locate and enter the laterals
- ACTive services to provide casing collar depth correlation and pressure monitoring.

This combination enables early identification of the window, improving performance and reducing operational risk. The BPV is used to control fluid flow and hydrostatic pressure, which ensures that the CT remains fluid-packed for signal transmission from the Discovery MLT tool to surface. It also enables controlling displacement of cleanout fluids to further optimize the treatment.

The Discovery MLT tool provides cost-effective, controlled selective entry on CT to all levels of multi-lateral wells. The tool sends a pressure signal to the surface to confirm access to the correct lateral. The ability to adjust the suborientation, or bend, from surface and the real-time feedback to surface of window identification save time by increasing the probability of successful reentry on the first attempt. The BPV mitigates the problem of low bottomhole pressure by providing the ability to reflect tool signals to surface in severely underpressured wells.

## Single-trip intervention

The operator was able to locate and clean out all the targeted laterals in a single trip, saving time during profiling, and reducing the risk of personnel exposure during rig-up and rig-down. In addition, the amount of fluids required—including tripping, profiling, and cleaning fluids—was reduced.

## Fast, effective installation

The whole job, including permanent zonal isolation using a cement plug above the inflatable packer, was achieved with four CT runs in 72 hours. This solution was much more time- and cost-effective than a traditional drilling rig-enabled workover, which could have taken days at a high day rate. CoilFLATE packers also allow water control treatments to be pumped below the plug. The operator was impressed by the value added with the portfolio of ACTive services.

# Selective Stimulation in Multilateral Middle East Well Reduces Completion Costs

Discovery MLT tool pinpoints lateral on first attempt to achieve high-rate selective treatment offshore Abu Dhabi

**CHALLENGE**

Access and treat a specific lateral where the conventionally used bullheading process would not be successful.

**SOLUTION**

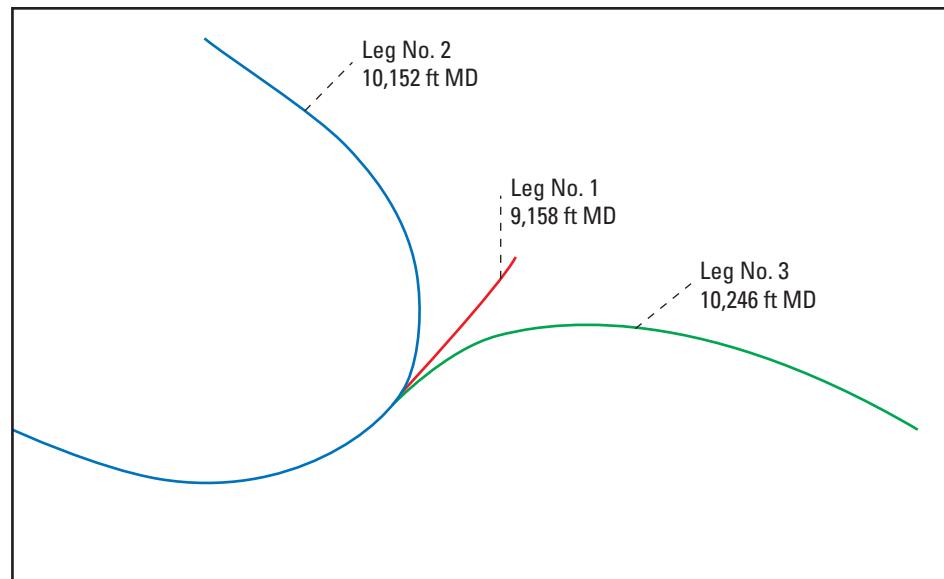
Used Discovery MLT\* multilateral tool, combined with CoilCADE\* coiled tubing design and evaluation software, to access target laterals on first pass.

**RESULTS**

Achieved high-rate selective treatment, saving money over more expensive completion options.

**Selective entry for acid treatments in a multilateral well**

The operator needed to access and treat a specific lateral in a multilateral well offshore Abu Dhabi. The commonly used bullheading process would not allow control over fluid flow and could not provide selective entry for acid treatments.



Multilateral well trajectory.

**Target lateral access on first pass**

The Discovery MLT tool was selected for the CT stimulation treatment because of its simple, one-run operation. The system sends a pressure signal to the surface confirming access to the correct lateral.

CoilCADE software showed that 1½-in CT was required to access the target laterals. The CT BHA included a motorhead assembly with a dual-flapper check valve, a hydraulic release, a drop ball circulating sub, a downhole filter, and the Discovery MLT tool BHA. The maximum outside diameter of the entire tool string was 2.125 in.

To verify access into Legs 2 and 3, a universal tubing length monitor was installed on the reel. On the first pass, the Discovery MLT tool was run straight past the junctions at 2,583 m [8,475 ft] (Leg No. 1) and 2,598 m [8,525 ft] (Leg No. 2).

After confirming that the CT had entered Leg No. 3 (the natural leg), the CT was pulled back to 2,621 m [8,600 ft] to start the profiling procedure. The pump rate was increased to 1.6 bbl/min during profiling of the window, and the pressure response of the tool was monitored in the CT unit using the custom Discovery MLT tool software. The window was located at 2,591 m [8,500 ft].

The CT was then run through the window to the bottom of the well. After entry into Leg No. 2 was confirmed by tagging total depth, the ball was dropped to open the circulating sub and begin the acid treatment.

The leg was stimulated using 57 m<sup>3</sup> [15,000 gal] of hydrochloric acid in conjunction with a drop ball circulating sub with embedded jets. To enhance efficiency, the acid stimulation was combined with a high-pressure acid wash nozzle.

#### **Reduced completion costs**

This operation accessed and treated the lateral of interest as planned. Selective high-rate treatment of one lateral extension was achieved. Because only one run was required to confirm access to the correct lateral, the Discovery MLT tool and CoilCADE software saved time and money for the operator. Efficient acid stimulation was performed through a highpressure wash of acid directly at the pay zone. This technology makes openhole laterals a viable alternative to more expensive completion options.

# Discovery MLT Multilateral Tool Increases Production by 500% in One Run in Hole

Multilateral tool ensures selective reentry for CT acid treatment on dual-lateral well in Alberta, Canada

## CHALLENGE

Ensure selective reentry for a CT acid treatment on a dual-lateral well after a conventional rotating reentry tool failed to provide access for treatment on a nearby well.

## SOLUTION

Deploy the Discovery MLT\* multilateral tool, which allows surface-controlled, selective reentry on CT into all levels of multilateral wells.

## RESULTS

Increased production by 500% in one run in hole.

**Acidizing using the Discovery MLT tool was performed in a single run and increased production by 500%.**



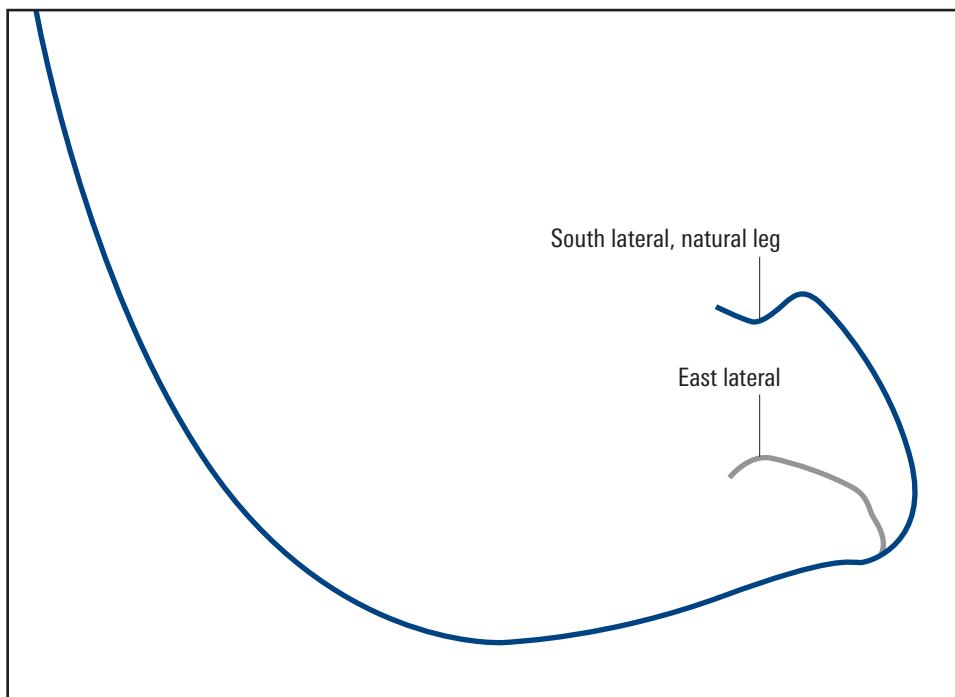
## Selective reentry in a dual-lateral well

An operator drilling in Alberta, Canada, needed to ensure selective reentry for a CT acid treatment on a dual-lateral well. A conventional rotating reentry tool used on a nearby well had failed to provide access for treatment, possibly because of wellbore washouts.

After consulting with Schlumberger, the operator chose the Discovery MLT tool because it allows surface-controlled, selective reentry on CT into all levels of multilateral wells.

## Surface-controlled, selective reentry on CT

A surface test of the BHA was conducted, and the Discovery MLT tool was run straight past the lateral junction at 12,041 ft [3,670 m] into the natural leg. After tagging TD to confirm entry into the south lateral, the CT was pulled back to the lateral window to start the profiling procedure.



Multilateral software monitored pressure responses and, after the profiling procedure was complete, the software memorized the window orientation and monitored the BHA orientation throughout the entire operation. The Discovery MLT tool was oriented toward the lateral exit and the east lateral was entered. Then the pump was stopped and the CT was run to TD of the short leg to confirm that the correct lateral had been entered. The lateral was then acidized according to the well design.

**Production increase of 500%**

The Discovery MLT tool enabled formation wash and stimulation operations in this multilateral well. Furthermore, the high-pressure jetting sub, a modified version of the original circulation sub, proved to be an efficient means to clean drilling mud residues from the wellbores. The acid treatment was performed in a single run, increasing production before stimulation by 500%, to 29 MMcf/d [0.82 million m<sup>3</sup>/d] from 5 MMcf/d [0.14 million m<sup>3</sup>/d].

# ReelCONNECT Technology Enables North Sea Winter CT Operation

StatoilHydro CT operations continue despite crane limitations and winter weather conditions

**CHALLENGE**

Return two wells on a North Sea platform to production despite crane load limitations and weather conditions.

**SOLUTION**

Overcome crane load limitations by using the ReelCONNECT® seamless technology for connecting multiple coiled tubing strings to join two string sections to obtain the required CT string length.

**RESULTS**

Revived nonproducing wells to production without deferring the CT operation.

**A spoolable connector was essential to mobilizing the optimum CT string size for the operation. ReelCONNECT seamless technology for connecting multiple CT strings was selected.**



*ReelCONNECT technology enables joining or repairing at the wellsite without welding or obtaining a hot work permit.*

**Winter conditions in the North Sea**

Winter in the North Sea is considered one of the harshest offshore environments. A challenge for operators is to find windows of time when weather conditions and local regulations will allow simultaneous operation CT interventions on offshore platforms.

A series of CT operations was scheduled on 2 wells in late winter on an installation operated by StatoilHydro. The wells were completed with 7-in casing and 4½-in liner and had not been producing for 9 to 12 months. The objectives of the intervention operation included

- sand cleanout
- plug retrievals
- placement of cement plugs.

In addition to other constraints imposed by winter conditions, the lifting capacity of the platform crane was limited to 28 t [25,400 kg] with 6.6-ft [2-m] heave height—a third of its normal capacity. A 2 $\frac{3}{8}$ -in-OD CT string was selected for the intervention operation.

### **Multiple CT string connections**

A spoolable connector was essential to mobilizing the optimum CT string size for the operation. ReelCONNECT seamless (no welding) technology for connecting multiple CT strings was selected for the operation. The technology enables joining or repairing at the wellsite without welding or obtaining a hot work permit.

The connector is compatible with most CT operations, including standard jar and accelerator combinations in the BHA, and it allows use of the friction and drag reducing tool.

The ReelCONNECT technology has an assembly skid that allows easy manipulation of the CT strings to be joined and safer installation of the spoolable connector(s). The skid provides a well-lit, protected environment for connector installation and enables raising the work platform to an optimum height.

A wireless remote control panel allows the operator to control and guide the two sections of CT pipe into the skid and to secure them from a safe distance.

### **A successful operation**

Sand cleanout, memory production log, and plug retrieval runs were performed in both wells.

The wells were returned to production after 9 to 12 months of no production.

The ReelCONNECT technology was vital to the fast mobilization and deployment of CT in this harsh offshore environment in the Norwegian sector of the North Sea.

Wells returned to production on schedule without waiting for good weather conditions to be able to increase crane capacity. ReelCONNECT technology allowed winter CT operations on the StatoilHydro platforms, where the string weight and crane capacity have limited CT operations in the winter season.

# ReelCONNECT Technology Increases Production in an Ula Field, Norway well

Fill cleanout performed in record time, resulting in a well production rate exceeding 4,500 bbl/d

## CHALLENGE

Remove barite and well formation debris hampering well production from the perforated interval using CT for cleanout to TD.

## SOLUTION

Use ReelCONNECT\* seamless technology for connecting multiple coiled tubing strings and obtain a string length that would reach target depth.

## RESULTS

Removed debris from the wellbore in record time and the well was placed on production at a rate exceeding 4,500 bbl/d.

**The CT strings were connected to achieve the string length needed for the operation, and debris was successfully removed from the wellbore.**



## Water production in offshore well

An operator in Norway had drilled and completed a well in the Ula field, but cleanout to TD was required to return the well to maximum production.

A series of slickline operations confirmed that barite and traces of formation debris in the perforated interval was hampering production, requiring a CT fill cleanout.

The well had been drilled on an installation with a crane that could not lift a single reel of 2%-in CT appropriate for the operation. In addition to the weight limitations, a single CT of sufficient length to reach the required depth would have required 6 months of manufacturing lead time.



*ReelCONNECT technology enables joining CT at the wellsite.*



*CT intervention is now possible on tight, previously inaccessible installations.*

### **ReelCONNECT technology connects CT strings**

ReelCONNECT technology for connecting multiple CT strings was proposed to connect two strings that were lifted separately onto the platform. The ReelCONNECT technology enabled joining or repairing the CT at the wellsite, without requiring welding or a hot work permit required by conventional techniques. The outer profile of the installed connector fit flush with the outside diameter of the CT string, while the internal profile remained compatible with launching operations for standard balls, darts, or pigs. The connector was compatible with standard jar and accelerator combinations in the BHA as well as with the friction and drag-reducing tool.

A connector assembly skid was used to align the CT string sections and assemble the connector. The skid enabled the work platform to be raised to an optimum height and provided a well-lit and protected environment for connector installation. A wireless remote control panel enabled the operator to control and guide the two sections of CT pipe onto the skid while remaining at a safe distance.

### **Fill cleanout enables production rate increase**

The strings were connected to achieve the string length needed for the operation. Debris was successfully removed from the wellbore, and the well was placed on production at a rate in excess of 4,500 bbl/d.

# Vantage Modular CT Logging-Head System Saves 75% of Rig-Up Time for Oklahoma Operator

Modular design and uncomplicated assembly cut hours off job

**CHALLENGE**

Run an efficient, cost-effective, and reliable CT logging operation in El Reno, Oklahoma, field.

**SOLUTION**

Use the Vantage\* modular CT logging-head system for fast rig-up and straightforward operation.

**RESULTS**

Reduced rig-up time from hours to minutes, resulting in a 75% savings in rig-up time.

**The fast rig-up without the need for maintenance or specialized training was completed in minutes rather than hours, resulting in a savings of 75% in rig-up time for the CT e-line head.**

**Logging efficiency in Oklahoma**

To increase CT logging efficiency and reliability, an operator in El Reno, Oklahoma, consulted with Schlumberger for a faster, easier, more reliable solution. The operator decided to use the 1 $\frac{1}{16}$ -in Vantage modular CT logging-head system, which was brought to the well location directly from another job without requiring postjob maintenance.

The Vantage logging-head system is uncomplicated to assemble and simple to use. Because the system enables rapid electric line (e-line) connectivity of the CT string and does not require redressing after each job, it saves rig-up time and allows more operations to be performed within the same time frame.



*The Vantage modular CT logging-head system is highly reliable and requires minimum maintenance.*

**Innovative CT logging assembly**

The Vantage system's modular components are designed to connect via plug-and-play connections that enable rapid interchangeability and reduce nonproductive time. The modular concept also minimizes the length of the cable termination connection so that it can be prewired and run through the CT injector system. In addition, minimal training is required for the crew on location to run the logging operation.

Because the tool can be used on one job after another without redressing, it improves operational efficiency and saves rig-up time. In addition, additional logging operations can be run within the same time frame.



*Because of the plug-and-play connections, the modular Vantage system can be assembled in minutes.*

### **Efficiency and reliability**

Using the Vantage modular CT logging-head system minimized nonproductive time and lessened the chance of malfunctions, which were the main objectives of the operation. The fast rig-up without the need for maintenance or specialized training was completed in minutes rather than hours, resulting in a 75% savings in rig-up time. The operator was pleased with the results from using the Vantage logging head system assembly and decided to use it with the Flow Scanner\* horizontal and deviated well production logging system to log additional wells in the area.

# Vantage Modular CT Logging-Head System Saves USD 10,000 per Day in Operating Costs

Oklahoma operator eliminates more than 4 hours of operating time per job

## CHALLENGE

Improve operating efficiency on a multistage wireline plug setting, perforating, and fracturing job in El Reno, Oklahoma.

## SOLUTION

Use the 1<sup>11</sup>/<sub>16</sub>-in Vantage\* modular CT logging-head system for more reliable and efficient operation.

## RESULTS

Saved USD 10,000 per day in operating costs and more than 4 hours per well in operating time.

**Vantage technology saved more than USD 10,000 per day in operating costs. Each hour allowed for running additional operations, which improved operations efficiency.**



## Conventional CT electric line head tools

A major operator in El Reno, Oklahoma, needed to spread the cost of services over several multistage jobs and optimize operating time. Because traditional CT logging heads require frequent redressing, the operator was looking for a more efficient and reliable way to run multistage wireline plug setting, perforating, and fracturing operations.

After consulting with Schlumberger, the operator selected the 1<sup>11</sup>/<sub>16</sub>-in Vantage modular CT logging-head system to replace the conventional system. Each stage required deploying a wireline plug and perforating an interval, which was followed by a fracturing treatment. With the CT at the surface, the BHA was reassembled for the next run while the fracturing operation was performed. Using a traditional logging tool would have required maintenance on the CT logging head after every third run to minimize logging failure.



*The Vantage modular CT logging-head system enables rapid assembly and replacement of any components.*

## Efficient modular CT logging assembly

The Vantage system tools, which are made up of modular components, are uncomplicated to assemble and simple to operate. Before arriving on location, the CT connector and cable termination are preassembled and tested.

The modular concept allows for minimizing the length of the cable termination connection so that it can be prewired and run through the CT injector system. Each component in the system serves a unique function, and the system as a whole provides

- rapid wired CT connectivity
- flowback protection
- downhole tool disconnection capability
- deployment under pressure.

The Vantage system can be run in hole multiple times without redressing, saving valuable operational time. Minimizing rig-up time, which is a vital part of the operation, reduces the operational costs of equipment and personnel.

#### **Flawless execution**

The Vantage logging-head system was run on 12 stages in three wells with an average depth of 16,800 ft without a complete redress of any of the components. Only the O-rings were replaced before each component was reassembled, saving more than 4 hours of fracturing time per well. During travel from wellsite to wellsite, the termination connection remained assembled on the unit, saving more than 1 hour of time in each rig-up.

Overall, the Vantage system saved more than USD 10,000 per day in operating costs. Each hour saved provided the potential for running more operations, which increased economic feasibility for the operator.



*The Vantage system's plug-and-play capability enables rig-ups to be performed in minutes.*

# Vantage Modular CT Logging-Head System Reduces Perforating Failure Downtime

Rugged, modular system increases logging and perforating reliability in Oman field

**CHALLENGE**

Reduce rig-up time and avoid frequent misruns caused by CT logging head failures when perforating.

**SOLUTION**

Run the Vantage\* modular CT logging-head system for faster, more reliable job completion.

**RESULTS**

Completed a seven-job campaign with no failures.

**The operator was pleased with the reliable performance of the Vantage CT logging-head system. Completing seven logging and perforating jobs with no failures demonstrated that the Vantage system eliminates downtime caused by logging head failure.**



*The Vantage modular CT logging-head system's reliability is critical to avoid multiservice operational cost overruns.*

**Conventional CT logging head operations**

An operator drilling in a carbonate and sandstone reservoir in Oman wanted to minimize the amount of downtime caused by frequent logging head failures during perforating operations. The principal challenge in CT electric-line (e-line) perforating in Oman is frequent logging head failure. Completing a single perforation job requires multiple runs, and every time a head failure occurs, up to 20 hours can be lost as a result of pulling out of the hole, repairing the head, and returning downhole. In addition, when multiple runs are needed, regular maintenance of the assembly is necessary to ensure adequate performance, which increases rig-up time.

Looking for a faster and more reliable way to perform logging and perforating operations, the operator chose the Vantage modular CT logging-head system to minimize BHA failure. Plug-and-play connections enable rapid interchangeability of the Vantage system's modular components and reduce nonproductive time.

**Rugged design concept**

The Vantage system's rugged design increases the reliability and safety of the CT logging head for perforating operations. Hardened replaceable wear rings extend the system's life and protect expensive Inconel® housings from abrasion and wear. High-strength corrosion-resistant alloy materials offer superior performance in the most challenging environments.

Several runs were performed to set wireline plugs and perforate with guns from the PURE\* perforating system for clean perforations. The long BHAs were deployed under pressure without the need for major maintenance. A 3-day Flow Scanner\* horizontal and deviated well production logging system image operation was performed in another run to monitor the well production profile across a 1,100-m interval of a horizontal well, which was one of the longest logging jobs ever performed using the Vantage logging-head system.



*Personnel exposure to suspended loads is minimized by the faster assembly of the modular Vantage system.*

#### **Faster, more reliable completion**

Reducing rig-up and rig-down time by using a modular system resulted in less exposure for the crew while working below the load during tool assembly. In addition, the completion of seven logging and perforating jobs with no failures demonstrated that the Vantage CT logging head eliminates downtime caused by logging head failure.

The design enabled increased flow rates with less pressure loss, allowing faster nitrogen pump rates. Thus, the well could be placed under necessary underbalanced conditions in less time.

An impressive performance during its introduction in the field confirmed the superior design of this new CT logging head. The operator was pleased with the reliable performance provided by the Vantage modular CT logging-head system.

# Vantage Modular CT Logging-Head System Saves More Than 1 Day of Operations at USD 250,000/Day in Costs

Nine ERD wells completed ahead of schedule in Malaysia with zero NPT

**CHALLENGE**

Convey long perforation guns reliably for maximum flow rates and effectively actuate CT logging tractors when required.

**SOLUTION**

Run the 2½-in Vantage\* modular CT logging-head system with its conveyance capability of pumping through at higher rates.

**RESULTS**

Completed nine wells in 15 runs, which was 5 days ahead of schedule, with zero NPT.

**The operator contacted Schlumberger for a robust logging head capable of conveying long perforating guns in a high-pumping-rate environment, and actuating the CT wired-through tractor required in several wells.**



*The Vantage CT modular logging-head system offers a 3.0 bbl/min pump-through rate.*

**Extreme extended-reach wells**

An operator in the Malaysia-Thailand Joint Development Area was attempting to perforate nine wells from a central platform. The wells had a long perforation area that required a long perforation BHA. Successful CT electric line (e-line) operations are difficult because the CT tends to buckle in extreme extended-reach drilling (ERD) wells. Third parties were unable to consistently convey the long guns safely; a third-party contractor lost a BHA in a hole, requiring a 2-day fishing job.

The operator contacted Schlumberger and requested a robust logging head to convey long perforating guns in the high-pumping-rate environment. The operator specified that the head had to be able to actuate the CT wired-through tractor required in several wells.

**Conveyance capability**

Schlumberger recommended the Vantage CT modular logging-head system. This system is able to convey long, heavy perforation guns while permitting fluid to pass through. It is able to easily exceed a pumping rate of 1.8 bbl/min, which is the minimum rate needed to activate the CT logging tractor required by the ERD wells.

The 2½-in Vantage modular CT logging-head system is the only logging head on the market with this flow functionality that enables a more efficient underbalanced perforation. Modular logging head architecture offers faster replacement of any module if required. The cable termination tool can also be preterminated and then stabbed through the injector head and stripper at the wellsite, saving rig-up time. The Vantage logging-head system can perform several runs without needing major maintenance.

The Vantage modular CT logging head system is designed for offshore, land, desert, and arctic environments, for vertical to horizontal wells, and for oil, gas, and injector wells. The system is rated to a maximum temperature of 350 degF and a maximum tensile strength of 58,000 lbm.

The ability to pump completion fluid at a higher rate shortened the operation. The Vantage logging-head system managed a 2.0 bbl/min pump rate, compared with conventional logging heads' typical rate of 0.7 bbl/min. The improved pump rates resulted in a 60% decrease in circulation time. No equipment was lost in the hole, even though the longest gun was 597 ft long and weighed 6,736 lbm. A total of 2,600 ft of 2⅜-in guns was deployed in the campaign.

### **Savings of 27 hours**

The operator completed nine wells in 15 runs, which was 5 days ahead of schedule with zero NPT from the logging operation, and saved 27 hours during the nine-well campaign, more than 1 day of costs for the company.

# Jet Blaster Engineered High-Pressure Service Boosts Oil Production in Indonesia's Duri Field

Screen cleanouts increase revenue by USD 3.36 Million

**CHALLENGE**

Remove scale buildup in liner screens and improve productivity after failure of conventional techniques.

**SOLUTION**

Use the Jet Blaster\* engineered high-pressure jetting service with the Jet Advisor\* scale removal software to remove scale and improve production.

**RESULTS**

Eliminated scale buildup and increased oil production for all 39 treated wells, and achieved an additional USD 3.36 million of revenue in the first 90-day period.



*The Jet Blaster service delivers a high-pressure cleaning solution to remove scale and improve production.*

**Calcium-rich water causes scale**

In Indonesia's Duri field, calcium-rich formation water creates a soluble  $\text{CaCO}_3$  scale buildup in liner screens, causing production to decline. The operator first tried to remove the scale with a conventional hydrochloric acid treatment with foam-diversion, or cup-packer placement, techniques.

**Optimized jetting service removes scale**

Because the conventional technique proved unsatisfactory, the operator selected the Jet Blaster service from Schlumberger to achieve better results. The Jet Blaster engineered high-pressure jetting service, with its focused, high-energy fluid streams, loosened compacted fills reliably. A high rate of fluid allowed the fills to flow out safely. Large engineered high-pressure, long-throw nozzles produced a stable, coherent fluid stream over a large jetting radius.

During a single CT-conveyed cleaning run, the Jet Blaster service delivered a high-pressure sequence of fluid trains while the Jet Advisor scale removal software optimized jetting performance and minimized fluid consumption.

**Production increases**

After treatment, the enhanced production delivered a USD 3.36 million increase in revenue over a 90-day production period. During the first 7 months, production from all 39 treated wells increased and the treatment payback period was only 18 days per well.

# Jet Blaster High-Pressure Jetting Service Increases Production from a North Sea Well by 400%

Successful scale-removal operation eliminates flow restrictions

## CHALLENGE

Reduce scale and increase production from two wells in a mature North Sea field.

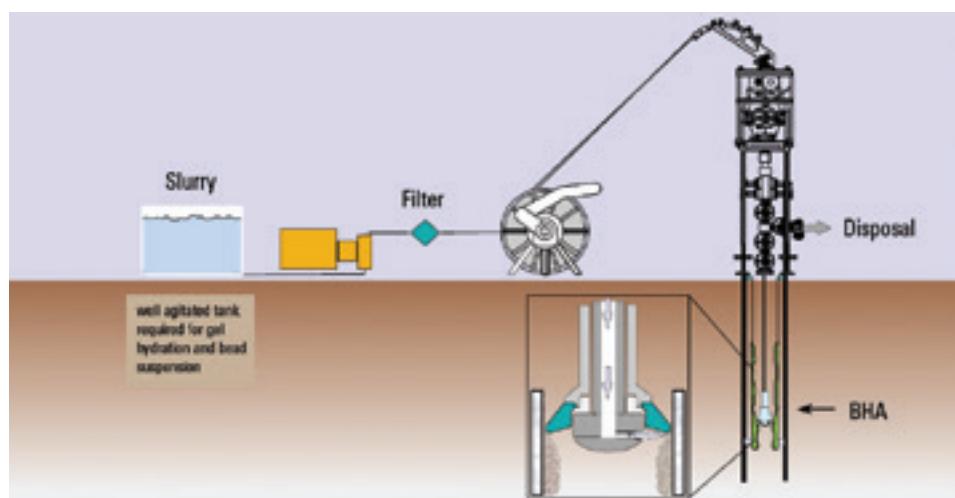
## SOLUTION

Use Jet Blaster\* engineered high-pressure service to remove significant wellbore scale.

## RESULTS

Increased production in one well by 400% and in another well by 500 bbl/d.

**Scale restrictions were removed and well production was restored, with an intervention payout time of only 3 to 4 days.**



An overview of the Jet Blaster system. Inset is a closeup of the drift ring, providing a positive indication of progress and ensuring that cuttings are kept in the jet stream until they are small enough to circulate out of the hole.

## Scale deposition

Many mature fields in the North Sea have scale problems due to the onset of increased water production and injection water breakthrough. Scale growth leads to roughening of the internal surface of the production tubing and increasing friction pressure, which results in a production decrease and mechanical restrictions in the wellbore.

In one of the North Sea fields, the scale was formed largely of barium sulfate. Well A in this field experienced a significant production decline—from 2,600 bbl/d to less than 600 bbl/d—when the well was finally shut in. Water analysis confirmed breakthrough and scale precipitation as major causes of the decrease in productivity. Attempts to remove scale in the well using conventional milling BHAs proved inefficient, with ROPs as low as 3 cm [0.1 ft]/h. Drift runs determined that the length of scaled tubing to be treated was approximately 76 m [250 ft]. There was a consistent buildup of approximately 2.54 cm [1 in] of barium sulfate scale on the tubing walls.

In Well B, formation scaling was suspected because of the commingling of different formation water types. A scale bridge was formed in the casing adjacent to a recently perforated section. The operator chose scale removal to enable access for plugging or reperforating intervals in the well to decrease the scaling tendency and increase the oil production rate.

## State-of-the-art deposit removal technology

To meet these scale-removal challenges, the operator selected the Jet Blaster high-pressure jetting service, which combines a rotating head jetting tool and the Sterling Beads\* safe hard-scale removal system. The focused, high-energy fluid streams loosened compacted fills reliably. A high rate of fluid allowed the fills to flow out safely. Large engineered high-pressure, long-throw nozzles produced a stable, coherent fluid stream over a large, efficient jetting radius. In the jetted fluid, pellets from the Sterling Beads system caused impact fracturing of the brittle scale, leaving the tubing undamaged.

The Jet Advisor\* scale removal software provided guidance as to the optimum head, nozzle size, flow rate, and pressure for each run, maximizing scale removal and wellbore cleanup efficiency.

## **Successful interventions; restored production**

The Well A job took approximately 180 hours of running time spread over 14 days. In all, eight CT runs into the hole with CT were made, with a total of 1,600 bbl of slurry being pumped. The well was reperforated after the intervention; however, before this additional work was performed, the well was already showing an increase of 2,400 bbl/d in production, a 400% increase.

In Well B, the job was performed in a single run over a 4-day period using a 2.125-in jetting head and 3.8-in drift ring. In total, 335 m [1,100 ft] of scaled tubing was successfully cleaned, resulting in a production increase of 500 bbl/d.

Both operations were successful in removing the scale restrictions and restoring well production, with an intervention payout time of only 3 to 4 days, compared with weeks using conventional technology.

# Jet Blaster High-Pressure Jetting Service Restores Production in Algeria Well to 80% of Original Level

Combination of testing and treatment revives Sonatrach wells

## CHALLENGE

Remove barium sulfate ( $\text{BaSO}_4$ ) scale from wells completed with 2½-in production tubing and 7-in liner and 7-in liner.

## SOLUTION

Use the Jet Blaster\* engineered high-pressure jetting service and pump Sterling Beads\* safe hard scale removal system abrasive through a 1½-in rotating-head nozzle.

## RESULTS

Restored production to 80% of the original level in initial test and reduced the workover costs.

**Scale restrictions were removed and well production was restored, with an intervention payout time of only 3 to 4 days.**



Operations in the Zarzatine field in eastern Algeria.

## Heavy scale deposits in Zarzatine field

Removal of  $\text{BaSO}_4$  scale from wells completed with 2½-in production tubing and 7-in liner was a challenge for Sonatrach, operator of the Zarzatine field in eastern Algeria. Heavy scale deposits at perforation depths in the liner were forming bridges that caused numerous wells to be shut in, with a significant loss of revenue. Typically, scale removal using a high-pressure jetting system in a 7-in liner requires a nozzle head with a diameter of 3½-in or more—impossible with a 2½-in tubing completion.

Early in 2000, 15 wells with an average production rate of 630 bbl/d were shut in for more than a year as a result of this problem; deferred production revenue exceeded USD 75 million.

## Alternative treatment method

A project to investigate the  $\text{BaSO}_4$  scale deposition problem began in 1999. Although a few operations had been performed in this field to mill scale from the production tubing, Sonatrach considered the treatments only partially successful because scale still plugged the perforations in the 7-in liners.

Schlumberger and Sonatrach teamed up to develop a solution to this problem. The design process, tool preparation, and surface and laboratory testing were provided by Schlumberger in Hassi-Messaoud.

The 2½-in production tubing used in the Zarzatine field was not large enough to accommodate the 3½-in nozzle heads typically used for scale-removal operations in these liners. As a result, a treatment method using a smaller nozzle head was required. The Jet Advisor\* scale removal software was selected to model surface tests on 7-in tubing, using the Jet Blaster high-pressure jetting scale removal service. The Jet Blaster service tool pumped Sterling Beads scale-removal service abrasive through its 1½-in rotating-head nozzle. The composition of the beads caused impact fracturing of the brittle scale but left the tubing undamaged. As a result, the 1½-in Jet Blaster service nozzle head and Sterling Beads system abrasive were chosen to remove the scale.

In the initial operation performed on Well ZR 217, the Sterling Beads system abrasive was pumped at a rate of 1.2 bbl/min and nitrogen was pumped at 300 ft<sup>3</sup> [8.5 m<sup>3</sup>]/min. Treated (NH<sub>4</sub>Cl) water was then pumped at 1½ bbl/min. In total, 11 passes were pumped across a 167.3-ft [51-m] interval, 8 with Sterling Beads abrasive and 3 with treated water.

The well flowed throughout the operation, carrying the removed scale and the abrasive to the surface. Analysis of returned samples showed that the scale was approximately 80% BaSO<sub>4</sub>. Wireline caliper measurements were made before the treatment to optimize the volume of Sterling Beads system abrasive and again after the treatment to evaluate the performance of the scale removal operation.

## Restored production

This first treatment was successful and production reached approximately 80% of its original level. As a result, Sonatrach initiated Jet Blaster service treatments in additional wells with scale buildup in the Zarzatine field and other fields. The Jet Blaster service project helped to cost-effectively restore production without requiring the pulling of completions.

The success of this operation also reduced workover costs for Sonatrach and reinstated its ability to log the wells to evaluate recompletion needs based on oil saturation. Wells could then be reperforated and treated with ScalePROP® scale-inhibitor-impregnated ceramic proppant to maintain future production.



A sample surface test of tubing before (top) and after (bottom) Jet Blaster service cleaning.

# Jet Blaster Engineered High-Pressure Jetting Service Restores Nonproducing Well and Increases Production

Screen plugging removal restores production and stimulates Gulf of Mexico well

## CHALLENGE

Efficiently clean a screen accidentally plugged by cement to restore well production.

## SOLUTION

Use the Jet Blaster\* engineered high-pressure jetting service with the gelled Sterling Beads\* safe hard scale removal system to efficiently remove screen plugging and restore productivity.

## RESULTS

Stimulated a nonproducing well and restored production to 1,200 bbl/d [191 m<sup>3</sup>/d], an increase over the initial production rate of 1,100 bbl/d [175 m<sup>3</sup>/d].



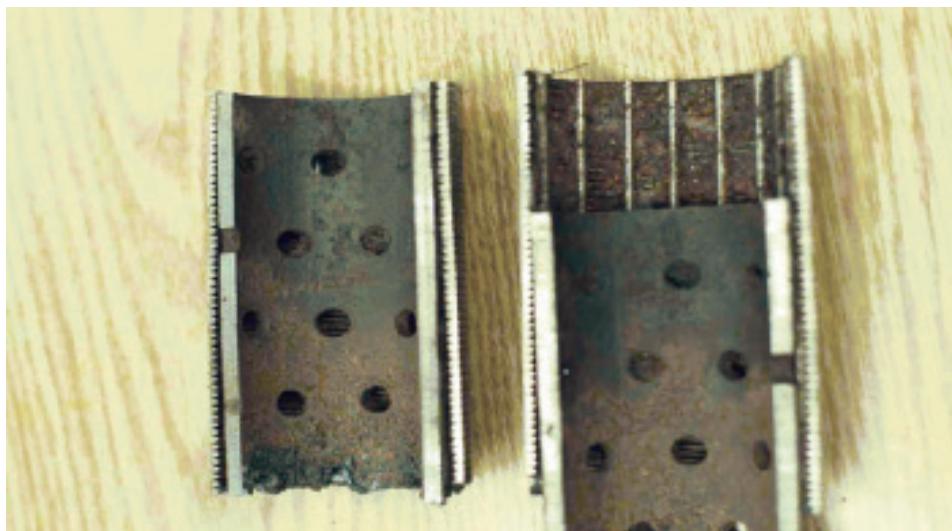
## Cement removal from a cemented screen

When cement was accidentally placed across a wire-wrapped screen of a Gulf of Mexico well that had been producing 1,100 bbl/d [175 m<sup>3</sup>/d], the well stopped producing. The operator performed a bullheaded acid job on the screen, but it had no effect on production. To restore production, the operator contacted Schlumberger for a more effective method of removing the cement from the screen. The Jet Blaster engineered high-pressure jetting service with Sterling Beads system abrasives was selected to effectively remove the cement from the screen.

## Optimized jetting performance

A section of the plugged screen was initially tested using the Jet Blaster system with water, followed by Sterling Beads system abrasives.

To duplicate the downhole conditions, a wire-wrapped section of screen was mounted on a 2 3/8-in perforated basepipe for testing. The Jet Blaster service tool was fitted with a 1.5-in [3.8-cm] head that had two 0.125-in [0.32-cm] nozzles that were flowing water at the rate of 1 bbl/min [0.16 m<sup>3</sup>/min] with a nozzle pressure drop of 2,150 psi [14,824 kPa].



Section of screen showing the high level of plugging between the basepipe and the screen.



*Section of screen cleaned with the water jet showing that the cement had been removed. In the section adjacent to the perforations in the basepipe, the screen was polished by the water jet.*



*Screen cleaned with the Jet Blaster service tool and Sterling Beads system abrasives, showing that the screen had been polished.*

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During the surface tests, 30% to 40% of the fluid flowed out of the top or bottom of the screen with the remainder flushing the screen. Even the material shielded from the jets was washed from the annulus through the adjacent holes in the basepipe. In the sections of the screen exposed to the jets, the screen was polished without any visible damage to the screen.

A second Jet Blaster service test was performed using a concentration of 2.5% Sterling Beads system abrasives to evaluate whether the beads had damaged the screen. During this test, the Jet Blaster service tool was held stationary for 4 minutes. After the screen was sectioned, the beads were found to have cleaned corrosion from the basepipe as well as the screen. The scouring action of the abrasives moving in the annulus behind the basepipe had also cleaned in front of the holes in the pipe.

### **Restored and increased production**

After the screen tests were completed on the surface, the jetting operation performed on the plugged screen increased the well's production rate to 1,200 bbl/d [191 m<sup>3</sup>/d] from the earlier 1,100 bbl/d [175 m<sup>3</sup>/d] production level. Not only had jetting the acid cleaned the screen, it had stimulated the well and restored production.

# Jet Blaster High-Pressure Jetting Service Removes CaCO<sub>3</sub> Scale in Single Run

Efficient scale cleanout removes perforating gun restrictions and improves operational efficiency in Thailand wells

## CHALLENGE

Efficiently remove calcium carbonate (CaCO<sub>3</sub>) scale and allow perforating guns to reach zones of interest.

## SOLUTION

Use the Jet Blaster\* engineered high-pressure jetting service to clean out CaCO<sub>3</sub> scale and allow the perforating guns to run to depth without requiring a drift run with slickline to verify clearance.

## RESULTS

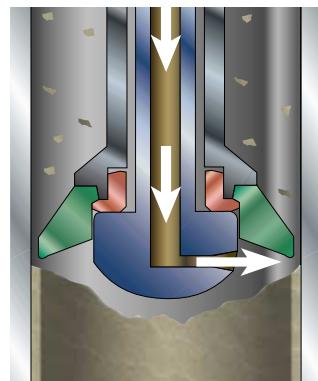
Successfully removed the CaCO<sub>3</sub> scale in a single run, allowing the perforating guns to reach the zones of interest, resulting in improved operational efficiency and cost savings.



## Scale buildup in tubing

An operator in Thailand routinely reperforated its gas wells in the Platong field to enable producing from low-pressure sands as other intervals began to deplete. However, CaCO<sub>3</sub> scales formed in the tubing above the nipples, preventing the perforating guns from reaching the zones of interest.

The operator's early attempts to dissolve the CaCO<sub>3</sub> scale involved using CT to place hydrochloric acid (HCl) downhole. This technique often had to be applied several times to completely dissolve the scale, and then a drift run had to be made to confirm adequate clearance for the perforating guns.



*Rotating head nozzles increase efficiency while the drift ring provides surface indication of scale removal.*

## Efficient single-trip scale removal

Looking for a more effective scale removal alternative, the operator selected the Jet Blaster high-pressure jetting service to remove the scale before running the perforating guns. Jet Advisor\* scale removal software was used to configure the Jet Blaster service tool for maximum jetting efficiency and to take into account all of the relative completion design parameters.

The operation called for using 4,145 m [13,600 ft] of 3.8-cm [1.5-in] CT. Based on the Jet Advisor software results, the Jet Blaster service tool was configured with a 3.8-cm [1.5-in] nozzle head with two 3.175-mm [0.125-in] radial nozzles and a 2.362-mm [0.093-in] downjet. A drift ring was used to provide an indication at the surface that enough scale had been removed to allow passage of the perforating guns.

The Jet Blaster tool was deployed to a depth of 2,100 m [6,891 ft], where the drift ring tagged scale. A total of 1.59 m<sup>3</sup> [10 bbl] of HCl was then pumped downhole, which was approximately one-third the volume typically used with the spot-and-soak method to achieve the same results. The Jet Blaster service tool was run in hole with no indication of tagging scale.

## Operational efficiency and cost savings

Following the scale removal operation, the perforating guns were successfully run to depth without the need for a slickline run to verify the drift. The Jet Blaster high-pressure jetting service removed the CaCO<sub>3</sub> scale in a single run, which was a significant improvement over the previous technique. As a result, the operator began using the Jet Blaster service as the standard scale removal method to achieve its reperforating objectives in the Platong field.

# Jet Blaster Engineered High-Pressure Service Removes Hard Wellbore Deposits Without Damaging Tubulars

Technology removes 10,390 ft of iron sulfide from eight Canadian wells with 32.5 hours of jetting time

## CHALLENGE

Remove hard wellbore deposits from eight wells in Canada without damaging the wellbore tubulars.

## SOLUTION

Determine ID of deposits on sample wells from prejob gauge runs and extrapolate for remaining wells. Then use the Jet Blaster\* engineered high-pressure jetting scale removal service to remove the deposits.

## RESULTS

Successfully removed 10,390 ft of iron sulfide from eight wells in 32.5 hours of jetting time without jeopardizing wellbore tubular integrity.



## Iron sulfide deposits in Canadian wells

The accumulation of iron sulfide deposits on metal completion tubulars and components in the wellbore was a problem for an operator in the South Kaybob region of Alberta, Canada. With sufficient salinity, pressure, and hydrogen sulfide concentration, iron sulfide precipitates on metal completion tubulars and components. These deposits can significantly lower production rates. Excessive accumulation over time can completely obstruct production and access to the lower wellbore area.

Eight of the operator's gas-producing wells in the Beaver Hill Lake formation were plagued with iron sulfide deposits. The production tubing had an OD of 2.87 in [73 mm] and an ID of 2.44 in [62 mm]. The operator had used three conventional methods to remove the deposits, including

- HCl and xylene jetting treatment
- changeover of production completion tubulars and components
- milling.

Each method had an inconsistent record of success. When the operator contacted Schlumberger for a more reliable, cost-effective method to remove the scale deposits, the Jet Blaster high-pressure jetting service was selected for the treatment.

## An engineered approach to scale removal

Prejob gauge runs in three wells showed that the inner diameter of the deposits was 40 mm. This information was helpful in selecting drift ring size and the tool, bridge, or bead to run. The remaining wells were assumed to have similar configurations without measuring the drift. Treatment was implemented using the following materials and equipment:

- CT string: 13,287 ft [4,050 m] of 1.5-in [38.1-mm] HS 80 CM, 0.11-in [2.77-mm] wall thickness
- slurry: gelled water containing 30 lbm/1,000 galUS [9.5 L/m<sup>3</sup>] of xanthan and 2.5% of Sterling Beads\* safe hard scale removal system abrasive
- Jet Blaster\* service: CT connector, double-flapper check valve, disconnect, dual circulating sub, downhole filter, swivel, gauge ring, and rotating head with nozzles
- Bridge Blaster\* bridge and scale removal service: CT connector, double-flapper check valve, disconnect, dual circulating sub, downhole filter, positive displacement motor, drift ring, mill/bit
- CoilLIMIT\* coiled tubing pressure and tension limit model.

**Removal of scale deposits with no damage**

The Jet Blaster service tool removed deposits that were not bridged off. In two instances, the Bridge Blaster service was used to combat bridged areas. The tools were in good condition following the treatments.

Overall, 10,390 ft [3,167 m] of iron sulfide deposit were successfully removed from eight wells within a cumulative period of 32.5 hours of jetting time. The Jet Blaster technology proved to be a viable solution for removing iron sulfide without jeopardizing wellbore tubular integrity.

**Review of Well Treatments**

Well	Blaster System	Time, h	Length of Scale Removed, ft [m]	Tool Drift OD, in [mm]
Well No. 1	Jet Blaster service	1.5	3,356 [1,023]	0.213 [54]
Well No. 2	Jet Blaster service	1	148 [45]	0.184 [46.7]
Well No. 3	Jet Blaster service or Bridge Blaster services	13	531 [162]	0.184 [46.7]
Well No. 4	Jet Blaster service	4	3,635 [1,108]	0.184 [46.7]
Well No. 5	Jet Blaster service	2.5	92 [28]	0.213 [54]
Well No. 6	Jet Blaster service or Bridge Blaster services	7	886 [270]	0.213 [54] (Jet Blaster service) or 0.177 [45] (Bridge Blaster service)
Well No. 7	Jet Blaster service	2	1,677 [511]	0.213 [54]
Well No. 8	Jet Blaster service	1.5	660 [20]	0.184 [46.7]

# Scale Blaster Service Restores Production to 900 bbl/d in a Middle East Well

Wellbore cleanout operation removes deposits from 230 ft of tubing

**CHALLENGE**

Remove scale deposits from blocked well and return the well to production.

**SOLUTION**

Deploy the Scale Blaster\* engineered approach to scale removal service for single-pass cleaning of the wellbore tubular.

**RESULTS**

Cleaned 230 ft of tubing and restored production rate to 900 bbl/d.

**Solid deposits in Middle East well**

An oil well in the Middle East stopped flowing because of blockage caused by solid deposits in the wellbore tubular. These deposits interfered with the operation of downhole tools and equipment, restricting reservoir monitoring and production planning. Scale deposits on the subsurface and surface safety valves also prevented proper functioning of safety equipment. A wireline survey showed obstructive material at 5,330 ft, and a retrieved sample analysis indicated iron sulfide, corrosion products, calcium carbonate ( $\text{CaCO}_3$ ), and other scale deposits. To continue production and monitoring, the operator chose to remove the scale rather than pull the tubing.

**Single-pass scale cleaning**

The Schlumberger Scale Blaster service—an engineered approach to scale removal—was selected to remove the hard deposits in the tubular. The treatment fluid design, scale type and physical properties, and obstruction location were carefully studied to ensure a successful treatment strategy. Assuming the worst case—that the entire tubing was plugged from 5,330 ft to tubing end at 5,560 ft—the treatment was optimized using job design software for best pump rate, ROP, and size of drift ring and nozzle head.

The Scale Blaster scale removal service was used to remove the hard deposits. Two nozzles on a continuously rotating, speed-controlled head maximized the jet velocity, cutting range, and wellbore coverage. The cleaning was achieved in one pass, minimizing CT fatigue. A drift ring prevented penetration of the head until the deposit was removed to the diameter of the ring.

**Restored production**

The Scale Blaster service well intervention operation cleaned the wellbore and eliminated the need to rerun 230 ft of tubing. Production testing confirmed the results, and well productivity was restored to its original rate of 900 bbl/d.



Before



After

*Wellbore tubular comparison before and after Scale Blaster technology removed the deposits.*

# Hard-Scale Milling in Offshore High-Temperature Well

Coiled tubing—conveyed downhole turbine motor helps reach target interval, North Sea

## CHALLENGE

Remove hard wellbore deposits to gain access to a new perforating interval in a high-temperature well.

## SOLUTION

Run the TT Turbomill\* thru-tubing turbomill to reduce the size of the deposits, allowing for efficiently cleaning out the wellbore without using chemicals.

## RESULTS

Successfully reached target depth and confirmed the efficiency of diamond turbine mills.



## Hard wellbore deposits obstruct perforating interval

An operator in the Norwegian sector of the North Sea performed bailing operations followed by scale milling using wireline to clean out wellbore deposits and gain access to a new interval.

Limited progress was achieved due to the hardness of the deposit, high temperature 324 degF [162 degC] and asphaltenes causing wireline tools to stick. The maximum depth reached was not considered sufficient to proceed and perforate the intervals that were originally planned.

## Downhole turbine motor solution in HT well

To gain access to the intervals for perforating,  $\frac{2}{3}$ -in CT was used to mill hard barium sulfate ( $\text{BaSO}_4$ ) scale.

First Run:

- Ran the TT Turbomill mill in 3.625-in-OD tubing.
- Slowly milled down from 14,700 ft to 14,727 ft [4,483 m to 4,489 m] but could go no deeper.
- Noted that carbide mill cutters were heavily worn on outside third of face, which confirmed very hard and massive scaling deposits.



TT Turbomill mill before and after the first run.

Second Run:

- Ran the MDX Diamond mill in 3.5-in-OD tubing
- Milled down from 14,730 to 15,062 ft [4,490 to 4,521 m] and reached TD.
- Noted very little wear on mill and cutting face still intact.



MDX Diamond mill before and after the second run.

## A successful operation

Because of the nature of the deposit and the high temperature, the CT intervention that used the downhole turbine motor and diamond mill offered the best solution to reach target depth.

**Schlumberger**

# **Stimulation Case Studies**

# Significant Oil Production Increase from Horizontal Openhole Lateral in Ecuador

Combination of organic clay acid and OilMAX matrix acidizing diverter increases production more than tenfold while reducing water cut

## CHALLENGE

Stimulate an openhole horizontal lateral with high water cut to increase oil production without increasing water cut.

## SOLUTION

Use CT and a Jet Blaster\* engineered high-pressure jetting service to pump OilMAX\* matrix acidizing diverter and OCA\* organic clay acid stimulation fluid to remove the damage and stabilize fines.

## RESULTS

Increased production tenfold, from 12 bbl/d to a stabilized 140 bbl/d of oil and reduced water cut.



## Addressing low production due to fines migration and water

An operator in Ecuador wanted to stimulate a horizontal well with declining oil production and 95% water cut. The well, located in the Napo U formation, is at 7,000-ft TVD and has 75 ft of open hole completed with wire-wrapped screens. Permeability ranges from 300 to 500 mD. Production had been decreasing in the well because of

- fines migration caused by high kaolinite concentration in the formation
- the rapid onset of formation water.

Fines migration is a common problem in Ecuador. In addition, the intervals of the openhole where water had broken through were not known.

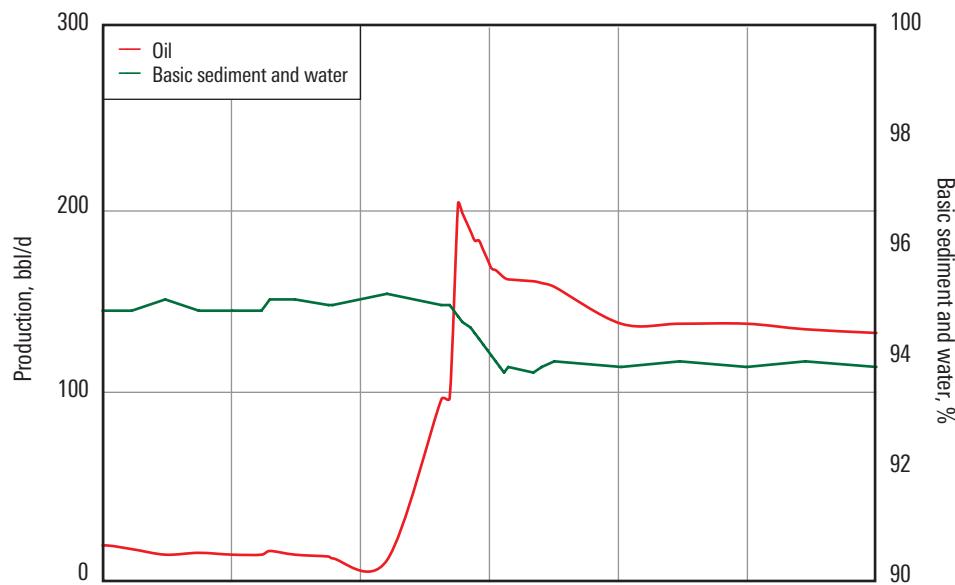
## Combining organic clay acid and matrix acidizing diverter

A treatment was needed to increase oil production, which had declined to 12 bbl/d, without increasing water cut. Because it was not known where the water had broken through in the horizontal section, the treatment design with OilMAX diverter helped to selectively divert the subsequent OCA organic clay acid stimulation fluid away from the high-water-cut intervals to avoid stimulating them.

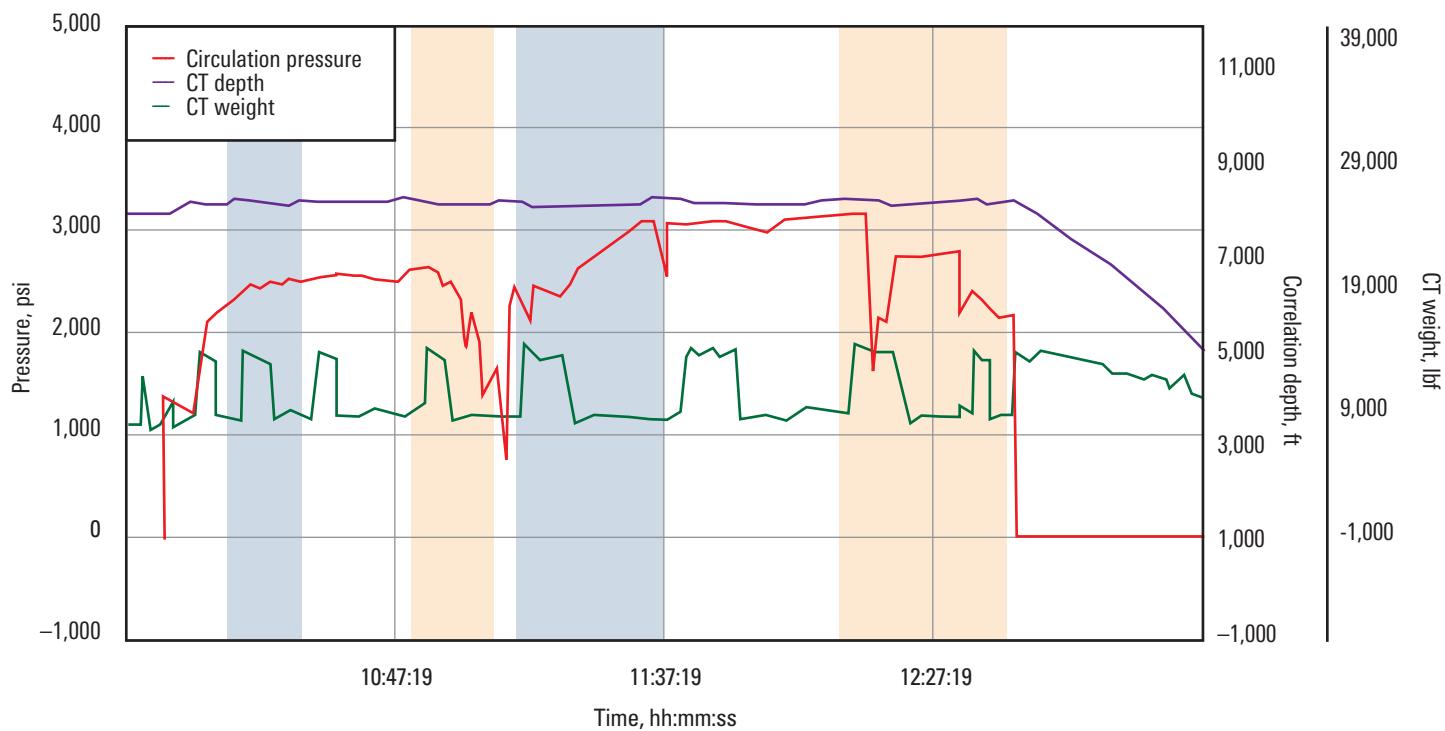
The treatment was pumped through CT using the Jet Blaster service because the well was completed with an ESP and a Y-tool. The CT was cycled up and down the openhole section during each stage.

## Increasing production tenfold

The OilMAX diverter and OCA fluid helped the operator increase oil production to 200 bbl/d and decreased water production from 95 to 94%. Oil production stabilized at 140 bbl/d.



OilMAX diverter and OCA fluid helped to increase oil production from 12 to 200 bbl/d and decreased basic sediment and water (BSW) production from 95 to 94%. Oil production stabilized at 140 bbl/d.



The treatment was pumped through CT using the Jet Blaster service and was cycled up and down the openhole section during each stage.

# BG Group Increases Declining Well Production Threefold

First-ever catenary CT application with Jet Blaster service resolves critical production loss

## CHALLENGE

Explain and resolve rapid production decline from a critical well. Operate totally from a platform with crane, loading, fluid-handling, and HSE limitations.

## SOLUTION

Investigate well for cause with scale samples and tubing pictures. Apply first-ever catenary CT system with Jet Blaster\* engineered high-pressure jetting service. Manage production facilities using innovative equipment layout for filtering solids.

## RESULTS

Resolved the cause of production decline, removed 1 ton/UK of calcium carbonate, and put the well back on production with a threefold production increase.

**"This world-first operation got it right the first time at every stage of the process. Schlumberger personnel displayed not only a highly professional, but a proactive attitude that resulted in top performance. Considering the complexity of operation, it is hard to see any other service company delivering the technical outcomes achieved by the on- and offshore teams."**

David Donaldson

Vice President of Development  
BG Group



*Communication and visibility between the boat and platform were maintained by live-feed cameras at each location.*

## Rapid production loss in critical field

Following sociopolitical turmoil in Tunisia, BG Group faced rapid production decline in its A14 well in Miskar field. Miskar field represents more than 50% of Tunisia's gas production, meaning production decline from any of its wells could become a matter of national importance. Thus, the company sought a fast, comprehensive solution for A14, a high-temperature well (approximately 175-degC bottomhole temperature) with a 25° deviated well profile, high hydrogen sulfide and carbon dioxide levels, and an abrasive chrome completion.

The task proved difficult because all operations had to be performed from the Miskar platform, meaning limitations on crane capacity and platform deck loading, as well as HSE limits on operating time because of swell, wave height, and wind speeds that could push the dynamic positioning vessel out of its holding position capacity—all in the wake of a national revolution. Cleanout operations could also suffer because of an insufficient fluid-handling capacity (0.4 bbl/min) of the offshore platform process facilities.

## Integrated strategy for investigation, CT operation, and cleanup

To explain and resolve the rapid production decline of Well A14, BG Group called on Schlumberger because of its reputation for thoroughness, accuracy, and efficiency. Because of the hydrogen sulfide and carbon dioxide content, well deviation, and bottomhole temperature, the team decided to convey the sample bailer on slickline. For evidence film, a new camera was designed to be run in the hostile environment and produce pictures from before and after the cleanup intervention. After collecting scale samples, determining the holdup depth, and obtaining pictures of the tubing, the team determined the cause of production decline to be severe tubing obstruction by calcium carbonate scaling.

After rigorous, extended preparation, Schlumberger began a CT intervention accounting for every operational, quality, and logistical challenge posed by the project. The CT intervention became the first-ever catenary CT system application located on a dynamic maritime vessel stationed alongside a platform. This arrangement avoided the high cost of a workover rig or barge and respected the loading restrictions of the platform.



The specially engineered strategy included:

- 2½-in downhole motors and 2-in coil for better hydraulic performance
- Jet Blaster service for a high washing effect
- platform equipment layout tailored to the Miskar deck load capacity of 2.9 tonUK/m<sup>2</sup>
- Black Eagle hose with a hose hanger specifically designed to project specifications
- maximum nitrogen tanks on the vessel for maximum pumping time.

To ensure safety, visibility, and communication, Schlumberger performed detailed sea trials of the disconnect system in case of bad weather, fastened live-feed cameras to the platform and boat, rigged up the whole system in the onshore yard with quality inspections witnessed by BG Group, and inspected the dynamic positioning vessel for Schlumberger QHSE standards regarding the CT reel and pumping equipment.

The CT BHA scraped the scale off the tubing and brought through nitrogen before lifting the scale and debris back to surface. There, Schlumberger protected the production facilities by taking over the additional liquid returns and by filtering solids content (scale and debris) before it reached the production filters. The team applied an innovative solution, using only a cyclonic desander, sand filter, choke manifold, and safety system; surge tanks and test separators were not used because of weight and space requirements. The entire equipment layout considered platform weight capacity, crane capability, and shared deck space—while leaving enough space for manageable working conditions and personnel escape routes.

### **Threefold production increase**

The comprehensive, integrated strategy efficiently solved A14's production decline. With extensive preparation, attention to detail, and a cooperative partnership with BG Group, the team quickly identified the cause of production decline, took over the production facilities, resolved the 0.4-bbl/min limitation, applied a cleanup solution that eliminated flaring, and overcame parameters that pushed equipment to its technical specification limits for flow, volume, and pressure.

This technically and logically demanding operation at Miskar field was completed successfully with a high regard for safety and the environment, removing 1 tonUK of calcium carbonate and putting Well A14 back into production with a threefold increase in production.

# Reducing Multistage Fracturing Time by 15 Days

AbrasiFRAC service more than doubles gas production in Texas

## CHALLENGE

Improve multistage fracturing efficiency where conventional techniques would require an average of 18 days.

## SOLUTION

Run the AbrasiFRAC\* abrasive perforating and fracturing service to perforate and stimulate multiple intervals in a single field operation.

## RESULTS

Completed a five-stage fracturing operation in 3 days, resulting in stabilized gas production after 30 days that was 150% greater than offset wells.

**"The Houston Exploration Company was pleased with the overall performance of this stimulation. It takes a lot of detailed planning and coordination to make a complicated job like this run on schedule, and your team pulled it off. Congratulations on a job well done!"**

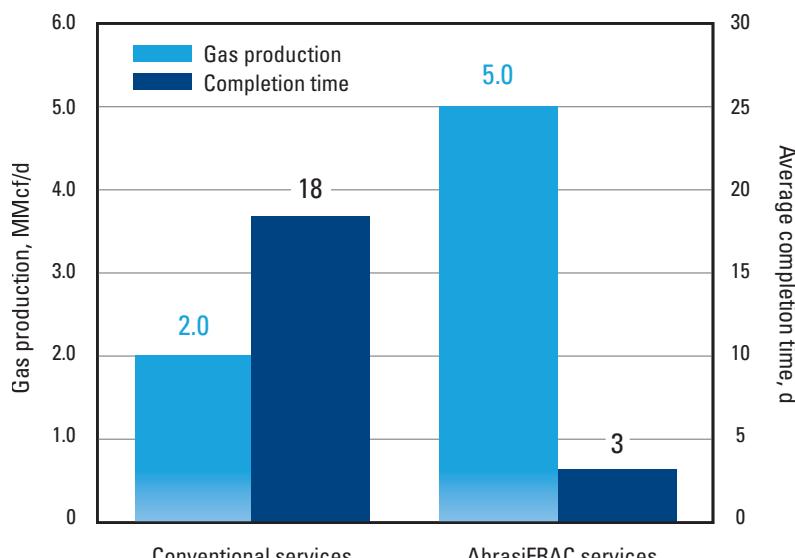
Allen Dutt  
Production Engineer  
The Houston  
Exploration Company



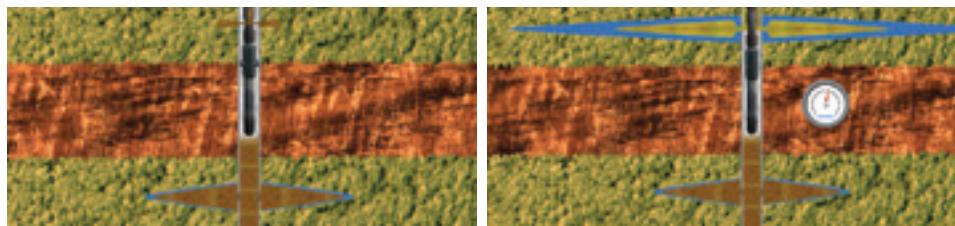
## Challenging time constraints

In the Vicksburg field in south Texas, the Houston Exploration Company was conducting a multistage hydraulic fracturing operation. The conventional process for stimulation requires repeatedly perforating, setting plugs, and stimulating for each stage of the operation. The process takes an average of 18 days and can be costly. Houston Exploration wanted to complete the stimulation job more efficiently while improving productivity.

The company selected the AbrasiFRAC service, which perforates and stimulates multiple intervals in a well in a single field operation, offering better access in less time. The multistage or multilayer fracturing technique enables accurate placement of fracturing treatments down the casing or the CT-casing annulus.



*The AbrasiFRAC service allowed Houston Exploration to reduce completion time by 15 days while more than doubling production.*



The AbrasiFRAC service allows perforation and stimulation in one field operation.

Slurry containing abrasive solids is pumped at a high differential pressure through a specially designed jet gun conveyed on a CT workstring. The resulting high-velocity fluid stream perforates tubulars and the surrounding cement sheath. The AbrasiFRAC service can also be used in openhole applications.

For multiple-stage treatments, sand plugs or bridge plugs can be used for zonal isolation between the fracturing treatment stages. The AbrasiFRAC service process is more cost-efficient than traditional methods because it requires lower breakdown pressure, which reduces equipment horsepower requirements.

The Houston Exploration multistage fracturing operation was completed in 3 days, an 80% efficiency increase compared to the usual time required using conventional fracturing operations. Well productivity increased because the AbrasiFRAC service permitted accurate placement of stimulation. The well's stabilized production rate after 30 days was 5.0 MMcf/d, compared with 2.0 MMcf/d in typical offset wells.

## About the Contact family

AbrasiFRAC technology is part of the intervention category of the Contact\* staged fracturing and completion services. These technologies maximize reservoir contact by offering the most efficient and effective services for each well. The Contact intervention category enables multiple stages to be perforated/jetted, fractured, and isolated in one intervention. Contact services can be enhanced with real-time measurement options.

# Increase Gas Production While Reducing Water Cut

AbrasiFRAC service efficiently stimulates highly laminated sands for EOG Resources

## CHALLENGE

Efficiently stimulate highly laminated sands while avoiding fracture growth into water-bearing zones.

## SOLUTION

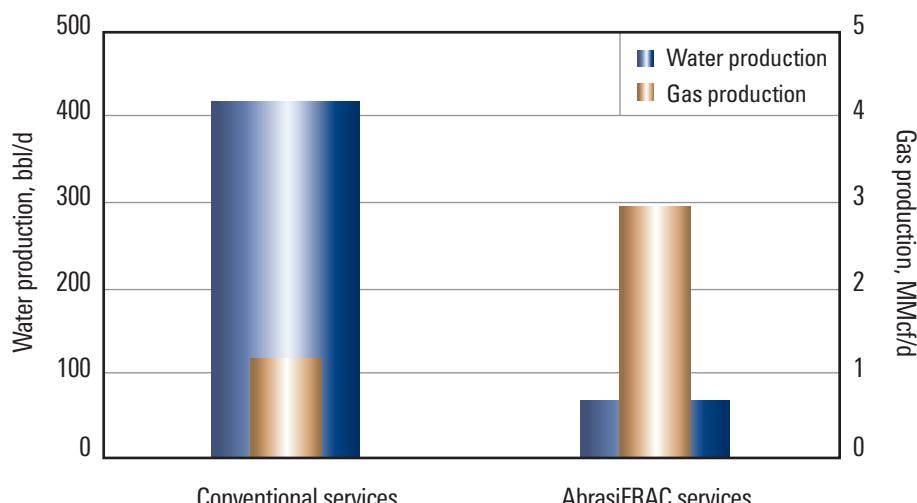
Run the AbrasiFRAC\* abrasive perforating and fracturing service for accurate placement of fracturing treatments.

## RESULTS

Successfully stimulated up to nine stages in a single AbrasiFRAC service, reducing water production by 85% and more than doubling gas production.

**"Lowering the completion costs and reducing water production, the AbrasiFRAC technology is the perfect solution for the challenges encountered in this field."**

Charly Miklaski  
Production Engineer  
EOG Resources



The AbrasiFRAC service reduced water production by 85% while more than doubling gas production.

## Thin gas sands

The Hosston sands in Sligo field, northern Louisiana, are highly laminated. They contain many thin, gas-bearing sands, alternating with water-bearing sands with varying levels of depletion.

Conventional completion designs for these wells typically call for multistage stimulation treatments with energized fracturing fluids and use of bridge plugs for isolation between the stages. To improve both cost and time efficiencies, EOG Resources field-tested an alternative completion method.

## Stimulation of individual sands

The AbrasiFRAC service, which stimulates multiple intervals of a well in a single field operation, proved to be the most efficient multistage fracturing service for this application. The AbrasiFRAC service allowed EOG Resources to more effectively and efficiently stimulate the individual sands, with the treatment varying from four to nine stages using CO<sub>2</sub>-energized fracturing fluids.



*AbrasiFRAC service allows perforating and fracturing operations in a single field operation to reduce cycle time.*

## **Increased production**

The AbrasiFRAC service allowed for a more accurate treatment placement and avoided fracture growth into water-bearing sands, reducing water production in one particular case by 85% while increasing gas production to almost 3 MMcf/d from its previous 1.2 MMcf/d.

Additionally, the use of AbrasiFRAC service resulted in a major completion-cost reduction compared with conventional techniques.

## **About the Contact family**

The AbrasiFRAC service is part of the intervention category of the Contact\* staged fracturing and completion services. These technologies maximize reservoir contact by offering the most efficient and effective services for each well. The Contact services intervention category enables multiple stages to be perforated/jetted, fractured, and isolated in one intervention. Contact services can be enhanced with real-time measurement options.

# Increasing Oil Production in Sahara Desert by 160% for Sonatrach

CoilFRAC stimulation intervention enables stimulation while protecting wellbore tubulars from high-pressure pumping

## CHALLENGE

Stimulate single or multiple zones of a well while protecting damaged tubulars.

## SOLUTION

Use CoilFRAC\* stimulation through coiled tubing to perform high-pressure pumping operations until a workover rig becomes available.

## RESULTS

Boosted well production to 2,160 bbl/d from 820 [343 m<sup>3</sup>/d from 130], an increase of 160% and a payout time of 39 days for the job.



## Damaged tubulars and delayed remediation

In the Hassi Messaoud field of Algeria, many Sonatrach wells with good production potential contained tubulars that are damaged as a result of age-related corrosion or fluid communication. The typical remediation method in the wells involved pulling and repairing the completions; however, the wait time for a workover rig in the Sahara Desert routinely exceeded one year.

## Stimulation through CT

Because the long wait time is an ever-present problem, Sonatrach chose CoilFRAC stimulation, which enables stimulation of single or multiple zones through CT. CoilFRAC stimulation was used to refracture previously completed zones. In this application, low-pressure and suspect casing could be protected from the treatment fluids and pressure caused by the CT string. Compared with a conventional workover rig, the CoilFRAC stimulation process was faster, and it minimized fluid damage to existing layers because the well did not have to be killed.

Both tubing and casing were damaged in Well OMP 843, the initial candidate for CoilFRAC stimulation. The job was designed to bypass skin, and operations were conducted at a measured depth of 10,660 ft [3,249 m]. By using CT intervention, wellbore tubulars were protected from high-pressure pumping operations until a workover rig became available.

## Sustained increase in oil production

The CoilFRAC fracture treatment was successful, resulting in a sustained oil production increase of more than 160%. After the intervention to fracture the formation, well production increased to an average of 2,160 bbl/d from 820 [343 m<sup>3</sup>/d from 130]. The payout time for the job was 39 days, including all the associated work performed on the well before and after the CoilFRAC stimulation intervention. This additional production at best would have been deferred for more than a year and, at worst, would have been lost completely if CoilFRAC stimulation had not been available.

## DataFRAC\* Fracture Data Determination

Midperforation depth, ft [m]	11,181 [3,408]
Fracture gradient (FG) pumping, psi/ft [kPa/m]	0.84 [19.0]
FG instant shut-in pressure, psi/ft [kPa/m]	0.57 [12.89]
Gel volume, galUS [ $m^3$ ]	10,063 [38.1]
Closure pressure, psi [MPa] (FG = 13.35 kPa/m [0.59 psi/ft])	6,550 [45.2]
Efficiency, %	3

## Main Fracture Treatment

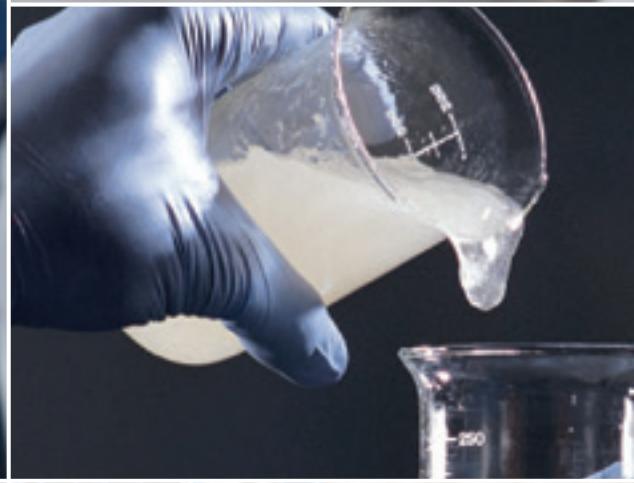
	Design After DataFRAC Analysis	Actual Executed
Rate, bbl/min	8.0	8.4, 8.9, 7.9, 7.5
Pad volume, galUS [ $m^3$ ]	20,000 [75.7]	20,026 [75.8]
Proppant-laden fluid, galUS [ $m^3$ ]	14,213 [53.8]	10,248 [38.8]
Crosslinked gel, galUS [ $m^3$ ]	33,000 [124.9]	29,461 [111.5]
Proppant, lbm [kg]	33,000 [14,968.5]	22,019 [9,987.6]
Proppant placed, lbm [kg]	32,546 [14,762.6]	21,464 [9,735.9]
Bottomhole proppant concentration, lbm [kg]	3.0 [1.36]	3.1 [1.41]
Propped half-length, ft [m]	99 [30.2]	121 [36.9]
Propped height at wellbore, ft [m]	25.9 [85]	73 [22.3]
Fluid efficiency, %	2	13
Average propped width, in [mm]	0.202 [5.13]	0.081 [2.06]

*DataFRAC fracture data determination service was used to determine the in situ parameters that were critical to optimizing the fracture treatment design and making the CoilFRAC treatment more effective and accurate.*

# Schlumberger

## Matrix Stimulation

Volume 3



Schlumberger  
3750 Briarpark Drive  
Houston, Texas 77042

[www.slb.com](http://www.slb.com)

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# Contents

13. Introduction to Matrix Treatments .....	1
13-1. Introduction .....	1
13-1.1. Candidate selection .....	1
13-1.2. Formation damage characterization .....	3
13-1.3. Stimulation technique determination .....	3
13-1.4. Fluid and additive selection .....	3
13-1.5. Pumping schedule generation and simulation .....	3
13-1.6. Economic evaluation .....	4
13-1.7. Execution .....	4
13-1.8. Evaluation .....	4
13-2. Candidate selection .....	4
13-2.2. Impact of formation damage on productivity .....	6
13-2.3. Preliminary economic evaluation .....	7
13-3. Formation damage characterization .....	8
13-4. Stimulation technique determination .....	10
13-5. Treatment design .....	11
13-5.2. Treatment fluid selection .....	12
13-5.3. Pumping schedule generation and simulation .....	19
13-6. Final economic evaluation .....	32
13-7. Execution .....	32
13-7.1. Quality control .....	32
13-7.2. Data collection .....	34
13-8. Treatment evaluation .....	36
13-8.2. Real-time evaluation .....	36
13-8.3. Post-treatment evaluation .....	37
14. Formation Damage: Origin, Diagnosis, and Treatment .....	39
14-1. Introduction .....	39
14-2. Damage characterization .....	39
14-2.1. Pseudodamage .....	40
14-2.2. Pseudoskin effects and well completion and configuration .....	40
14-3. Formation damage descriptions .....	42

14-3.1. Fines migration .....	42
14-3.2. Swelling clays .....	43
14-3.3. Scales.....	44
14-3.4. Organic deposits.....	45
14-3.5. Mixed deposits .....	46
14-3.6. Emulsions .....	46
14-3.7. Induced particle plugging.....	47
14-3.8. Wettability alteration .....	47
14-3.9. Acid reactions and acid reaction by-products .....	48
14-3.10. Bacteria .....	48
14-3.11. Water blocks .....	49
14-3.12. Oil-base drilling fluids .....	49
14-4. Origins of formation damage .....	50
14-4.1. Drilling .....	50
14-4.2. Cementing.....	57
14-4.3. Perforating .....	58
14-4.4. Gravel packing .....	58
14-4.5. Workovers .....	59
14-4.6. Stimulation and remedial treatments .....	59
14-4.7. Normal production or injection operations.....	60
14-5. Laboratory identification and treatment selection .....	62
14-5.1. Damage identification.....	62
14-5.2. Treatment selection .....	64
14-6. Treatment strategies and concerns .....	68
14-6.1. Fines and clays .....	69
14-6.2. Scales.....	70
14-6.3. Organic deposits.....	70
14-6.4. Mixed deposits .....	71
14-6.5. Emulsions .....	71
14-6.6. Bacteria .....	71
14-6.7. Induced particle plugging.....	71
14-6.8. Oil-base drilling fluids.....	72
14-6.9. Water blocks.....	73
14-6.10. Wettability alteration .....	73
14-6.11. Wellbore damage.....	73
14-7. Conclusions .....	74
15. Additives in Acidizing Fluids .....	75
15-1. Introduction .....	75
15-2. Corrosion inhibitors .....	76

15-2.1. Corrosion of metals.....	76
15-2.2. Acid corrosion on steel.....	76
15-2.3. Pitting types of acid corrosion .....	77
15-2.4. Hydrogen embrittlement.....	77
15-2.5. Corrosion by different acid types .....	77
15-2.6. Inhibitor types.....	78
15-2.7. Compatibility with other additives.....	78
15-2.8. Laboratory evaluation of inhibitors.....	79
15-2.9. Suggestions for inhibitor selection.....	79
15-3. Surfactants .....	79
15-3.1. Anionic surfactants.....	80
15-3.2. Cationic surfactants.....	80
15-3.3. Nonionic surfactants .....	80
15-3.4. Amphoteric surfactants .....	81
15-3.5. Fluorocarbon surfactants .....	81
15-3.6. Properties affected by surfactants .....	81
15-3.7. Applications and types of surfactants.....	83
15-4. Clay stabilizers .....	85
15-4.1. Highly charged cations.....	85
15-4.2. Quaternary surfactants.....	85
15-4.3. Polyamines .....	86
15-4.4. Polyquaternary amines.....	86
15-4.5. Organosilane .....	86
15-5. Mutual solvents.....	87
15-5.1. Adsorption of mutual solvents .....	87
15-5.2. Chlorination of mutual solvents.....	87
15-6. Iron control additives .....	88
15-6.2. Methods of iron control .....	88
15-7. Alcohols.....	90
15-8. Acetic acid.....	91
15-9. Organic dispersants .....	91
15-10. Organic solvents.....	91
15-11. Diversion .....	92
15-12. Additive compatibility.....	92
15-13. Facility upsets following acid stimulation .....	92
15-13.2. Prevention of facility upsets .....	93

16. Fundamentals of Acid Stimulation .....	95
16-1. Introduction .....	95
16-2. Acid-mineral interactions .....	96
16-2.2. Acid-mineral reaction kinetics .....	98
16-2.3. Precipitation of reaction products .....	104
16-3. Sandstone acidizing .....	107
16-3.2. Acid selection .....	107
16-3.3. Sandstone acidizing models .....	107
16-3.4. Permeability response .....	113
16-4. Carbonate acidizing .....	113
16-4.2. Wormholes .....	114
16-4.3. Initiation of wormholes .....	115
16-4.4. Acidizing experiments .....	117
16-4.5. Propagation of wormholes .....	121
16. Appendix: Advances in Understanding and Predicting Wormhole Formation .....	123
Introduction .....	123
Carbonate dissolution .....	123
Generalized description of carbonate dissolution .....	126
Wormhole formation .....	126
Dissolution structures .....	127
Optimum injection rate .....	128
Fundamentals of wormhole formation .....	128
Dependence on the Damköhler number .....	129
Optimum Damköhler number .....	130
Wormhole formation modeling .....	131
Prediction of optimum field conditions .....	132
Significance of the Damköhler number .....	132
Application of the optimum Damköhler number .....	135
Optimum injection strategies .....	135
Conclusions .....	138
17. Carbonate Acidizing Design .....	139
17-1. Introduction .....	139
17-2. Rock and damage characteristics in carbonate formations .....	139
17-2.2. Damage characteristics .....	140
17-3. Carbonate acidizing with hydrochloric acid .....	140
17-3.2. Historical background .....	140

17-3.3. Reactivity of carbonate minerals with hydrochloric acid .....	141
17-3.4. Acidizing physics .....	141
17-3.5. Application to field design .....	145
17-4. Other formulations .....	146
17-4.2. Gelled acids .....	147
17-4.3. Emulsions .....	148
17-4.4. Microemulsions .....	148
17-4.5. Special treatments .....	149
17-4.6. Self-diverting acid .....	149
17-5. Treatment design .....	151
17-5.2. Pumping schedule .....	151
17-5.3. Additives .....	151
17-5.4. Placement .....	151
17-6. Conclusions .....	152
Acknowledgments .....	152
18. Sandstone Acidizing .....	153
18-1. Introduction .....	153
18-2. Treating fluids .....	153
18-2.2. Chemistry of hydrofluoric acid systems .....	154
18-3. Solubility of by-products .....	156
18-3.1. Calcium fluoride .....	157
18-3.2. Alkali fluosilicates and fluoaluminates .....	157
18-3.3. Aluminum fluoride and hydroxide .....	157
18-3.4. Ferric complexes .....	157
18-4. Kinetics: factors affecting reaction rates .....	157
18-4.1. Hydrofluoric acid concentration .....	158
18-4.2. Hydrochloric acid concentration .....	158
18-4.3. Temperature .....	158
18-4.4. Mineralogical composition and accessible surface area .....	159
18-4.5. Pressure .....	159
18-5. Hydrofluoric acid reaction modeling .....	159
18-6. Other acidizing formulations .....	160
18-6.1. Fluoboric acid .....	160
18-6.2. Sequential mud acid .....	162
18-6.3. Alcoholic mud acid .....	163
18-6.4. Mud acid plus aluminum chloride for retardation .....	163
18-6.5. Organic mud acid .....	163
18-6.6. Self-generating mud acid systems .....	163
18-6.7 Buffer-regulated hydrofluoric acid systems .....	164

18-7. Damage removal mechanisms.....	164
18-7.1. Formation response to acid .....	164
18-7.2. Formation properties.....	164
18-7.3. Formation brine compatibility.....	165
18-7.4. Crude oil compatibility.....	165
18-7.5. Formation mineral compatibility with fluid systems .....	165
18-7.6. Acid type and concentration .....	167
18-8. Methods of controlling precipitates.....	169
18-8.1. Preflush .....	169
18-8.2. Mud acid volume and concentration.....	169
18-8.3. Postflush or overflush .....	169
18-9. Acid treatment design considerations .....	170
18-9.1. Selection of fluid sequence stages .....	170
18-9.2. Typical sandstone acid job stages.....	170
18-9.3. Tubing pickle .....	170
18-9.4. Preflushes .....	171
18-9.5. Main fluid stage .....	172
18-9.6. Overflush stage.....	172
18-9.7. Diversion techniques.....	172
18-9.8. Typical sandstone acid job stages.....	172
18-10. Matrix acidizing design guidelines.....	174
18-10.1. Calculations .....	174
18-10.2. Flowback and cleanup techniques.....	175
18-11. Acid treatment evaluation .....	176
18-12. Conclusions .....	177
19. Fluid Placement and Pumping Strategy .....	179
19-1. Introduction .....	179
19-2. Choice of pumping strategy .....	179
19-2.2. Comparison of diversion methods .....	180
19-2.3. Fluid placement versus injection rate .....	181
19-2.4. MAPDIR method .....	181
19-3. Chemical diverter techniques .....	181
19-3.1. Historical background .....	181
19-3.2. Diverting agent properties .....	182
19-3.3. Classification of diverting agents .....	182
19-3.4. Potential problems during diversion treatment .....	183
19-3.5. Laboratory characterization .....	183
19-3.6. Modeling diverter effects .....	184
19-3.7. Field design .....	187

19-4. Foam diversion .....	187
19-4.2. Foam mechanisms .....	188
19-4.3. Foam behavior in porous media .....	189
19-4.4. Foam diversion experiments .....	191
19-4.5. Modeling and predicting foam diversion.....	191
19-4.6. Application to field design .....	193
19-5. Ball sealers .....	195
19-6. Mechanical tools .....	196
19-7. Horizontal wells .....	197
19-7.2. Placement techniques .....	198
19-8. Conclusions.....	200
Acknowledgments.....	200
20. Matrix Stimulation Treatment Evaluation .....	201
20-1. Introduction.....	201
20-2. Derivation of bottomhole parameters from wellhead measurements .....	201
20-3. Monitoring skin effect evolution during treatment.....	201
20-3.1. McLeod and Coulter technique .....	201
20-3.2. Paccaloni technique.....	202
20-4. Prouvost and Economides method .....	204
20-4.1. Deriving skin effect during treatment .....	204
20-4.2. Determining reservoir characteristics before treatment.....	204
20-5. Behenna method .....	205
20-6. Inverse injectivity diagnostic plot.....	205
20-7. Limitations of matrix treatment evaluation techniques.....	208
20-8. Treatment response diagnosis .....	208
20-9. Post-treatment evaluation .....	211
20-9.1. Return fluid analysis .....	211
20-9.2. Tracer surveys.....	211
20-10. Conclusions .....	213
Reservoir Stimulation References.....	215
Reservoir Stimulation Nomenclature .....	237
Symbols.....	247
Matrix Stimulation .....	251
Introduction.....	251
Basic Concepts in Fluid Selection .....	253

Fluid Selection and Damage Identification .....	255
Introduction .....	255
Hurdles to accurate damage identification .....	255
Damage identification .....	256
Types of damage .....	256
Fines migration .....	257
Clay swelling .....	257
Scales .....	257
Organic deposits .....	259
Mixed deposits .....	259
Induced particle plugging .....	259
Wettability change .....	260
Emulsions .....	260
Acid reactions, precipitates and sludges .....	261
Bacteria .....	261
Water block .....	262
Sandstone Reservoirs .....	263
Introduction .....	263
Formation mineralogy .....	263
Sandstone petrography .....	263
Rock structure .....	264
Clays .....	264
Chemistry of sandstone acidizing .....	265
Primary reactions .....	265
Secondary reactions .....	266
Tertiary reactions .....	266
Other reactions .....	266
Reaction front .....	267
Sandstone treatment design .....	267
Preflush .....	267
Main fluid .....	268
Overflush .....	269
Sandstone treatment fluid selection .....	269
Brine preflush or overflush .....	269
Acid preflush or overflush .....	270
Main treatment fluid .....	270
Organic clay acid .....	273
Mud and silt remover .....	273
Dynamic acid dispersion .....	273

NARS fluid .....	273
Non-acid treatments .....	274
Carbonate Reservoirs.....	275
Carbonate Treatment Fluid Selection .....	280
Selection Criteria .....	280
Pumping Rate (flow velocity).....	280
Fluid type .....	280
Selection Guidelines .....	281
Injection Strategy .....	281
Fluid Loss .....	281
Fluid Type.....	282
Temperature .....	282
Specialty Acids .....	283
SXE Acid .....	283
NARS.....	284
DAD .....	284
Acid plus alcohol (alcoholic acids).....	284
Nonacid Treatments .....	284
Additives for Matrix Treatments .....	285
Introduction.....	285
Major additives.....	285
Surfactants.....	286
Mutual solvents .....	286
Iron control .....	286
Minor additives.....	287
Organic dispersants.....	287
Friction reducers .....	287
Scale inhibitors .....	288
Specialty additives .....	288
Antifoamer .....	288
Formation cleaner .....	288
Emulsifiers .....	288
Diverting agents .....	288
Laboratory Studies for Designing a Matrix Treatment.....	291
Objectives of laboratory experiments .....	291
Core analysis .....	291
Solubility tests.....	291

Petrographic study.....	293
Sedimentary rocks.....	293
Petrographic techniques.....	294
Thin section analysis.....	294
X-ray diffraction.....	294
Scanning electron microscopy.....	294
Computed tomography.....	295
Magnetic resonance imaging.....	295
Petrophysics.....	295
Porosity .....	295
Permeability .....	296
Fluid analyses.....	298
Acid and oil compatibility .....	298
Damage identification .....	299
Water analysis.....	299
Paraffin and asphaltene content .....	300
Solids analysis.....	300
Using lab data in fluid selection .....	300
Fluid Selection Guide References.....	303

# 13. Introduction to Matrix Treatments

*R. L. Thomas, Schlumberger Dowell  
L. N. Morgenthaler, Shell E&P Technology Company*

This chapter is dedicated to Alfred R. (Al) Hendrickson, the father of modern-day acidizing. Al made numerous unique discoveries during his career and is best known for his work in sandstone acidizing. The knowledge he offered the industry is the cornerstone of acidizing technology today. His energetic personality and technical contributions will forever be appreciated.

## 13-1. Introduction

Matrix stimulation is a technique that has been used extensively since the 1930s to improve production from oil and gas wells and to improve injection into injection wells. Sidebar 13A discusses the history of matrix stimulation. Matrix stimulation is accomplished by injecting a fluid (e.g., acid or solvent) to dissolve and/or disperse materials that impair well production in sandstones or to create new, unimpaired flow channels between the wellbore and a carbonate formation. In matrix stimulation, fluids are injected below the fracturing pressure of the formation (McLeod, 1984). At the time of this writing, it is estimated that matrix treatments constitute 75% to 80% of all stimulation treatments (matrix and fracturing) worldwide, but the total expenditure for matrix treatments is only 20% to 25% of the total for all stimulation treatments. However, because the payout time for matrix treatments is normally days rather than months as it is for conventional fracturing treatments, engineers should master this technique. Many operators around the world have indicated that an average of 40% to 50% of their wells have significant damage, but routinely only 1% to 2% of their wells are treated every year.

Substantial production improvements can be achieved with matrix stimulation if treatments are engineered properly. A success rate greater than 90% is reasonable. The systematic approach to stimulation treatments consists of candidate selection, formation damage characterization, stimulation technique determination, treatment design, job execution and treatment evaluation. Although many matrix stimulation treatments are performed in an unsystematic manner, the success of matrix stimulation

can be enhanced when each of these activities is performed properly. Proper performance of these steps requires the interaction of numerous individuals with expertise in geoscience, engineering and operations. The remaining chapters in this volume provide detailed discussions of the state of the art in matrix stimulation. The purpose of this chapter is to provide an integrated overview of the process of engineering successful matrix stimulation treatments.

Engineering a matrix treatment includes many tasks and a methodology that are accomplished on the basis of the best available data and knowledge at hand, which is usually incomplete. This does not mean a treatment will be unsuccessful. The process is a continuous cycle, starting with the diagnostic phase of the design process and progressing through the execution and evaluation phases to develop improvements. In addition, computer systems with "advisors" are available to assist the process. Advisors are expert systems with a knowledge base derived from current technology.

### 13-1.1. Candidate selection

Candidate selection for matrix stimulation is based on finding wells with impaired productivity and diagnosing the cause of the impairment. Failure of a well to obtain economic objectives alone is not evidence of impaired productivity. Failure to achieve economic objectives may be the result of limitations of the reservoir (e.g., pressure, permeability) or wellbore (e.g., artificial lift, inadequate tubing size). Matrix stimulation cannot solve these problems.

Candidate selection requires an accurate assessment of what a well can produce without impairment and the current productivity of the well. Techniques for making these assessments rely heavily on knowledge of the formation geology and reservoir properties. Methods for assessment of production system performance have been developed and are in wide use. Methods for pressure transient testing of reservoirs and well performance analysis have been published (Earlougher, 1977). These methods enable the engineer to quantify the extent of formation damage and the potential for productivity improvement.

## 13A. The history of matrix stimulation

"The results gained by the use of acid to increase oil and gas production are no longer hypothetical. Wherever production comes from essentially limestone reservoirs, its use is indicated and recommended." This quote is from "The Value of Repeated Acid Treatments" by P. E. Fitzgerald of Dowell Inc. in 1934. Fitzgerald went on to write, "It is recognized now that every well is a problem in itself, and must be analyzed individually in order to obtain the best results." It is interesting to note that the forefathers of matrix stimulation realized the importance of proper well diagnosis for treatment success, because it is a key step in the matrix stimulation engineering process used today. In addition, it is interesting that the "acidizing era" began more than 30 years following development of the concept. It took that long to develop the technology required to overcome the fundamental problem of acid corrosion of the tubing and casing. As history indicates, a chemical company with a need to stimulate brine wells developed the solution of an acid corrosion inhibitor. With this key invention the matrix stimulation era began in full force.

The history of acidizing dates back to 1895, when the Ohio Oil Company acidized both oil and gas wells with significant increases in production; however, the casing was severely corroded and the process became unpopular. One year later, a patent was issued to Herman Frasch of Standard Oil Company. His patent described the use of hydrochloric acid (HCl) in wells with limestone pay formations but did not address the corrosion problem.

Not until 1928 was the use of acid again attempted. This was when the problem of brine disposal, as well as increased production of natural brine, became important. Dr. Herbert Dow, early in his career, lowered bottles of acid into brine wells for the purpose of increasing their production. However, the results were not satisfactory, largely on account of the corrosion incurred and the expensive materials required to protect the metal equipment. Thus, the Dow Chemical Company initiated a project to develop the first acid corrosion inhibitor.

In 1931, Dr. John Grebe of Dow discovered that arsenic acid acted as a corrosion inhibitor. Later, copper salts were used with arsenic to avoid the formation of calcium arsenate precipitate, and soon organic inhibitors were found to be far superior. Soon after the discovery of the arsenic inhibitor, it was applied in the field by Dow and Pure Oil Company to successfully treat the latter's Fox No. 6 well in the Greendale Pool, Michigan, in February 1932. Five hundred gallons of HCl were siphoned into the well, resulting in a previously "dead" well flowing 16 BOPD. Thus, acidizing was reborn, and Dow formed the Dow Well Services Group that soon evolved into Dowell. Three years later, the small company Halliburton Oil Well Cementing Co. in Duncan, Oklahoma, began commercial acidizing service.

In 1935 Drs. Grebe and Stoesser of Dowell wrote, "Commercial acidization of oil and gas wells—although nonexistent four years ago, now is practiced over the entire country. Approximately 6000 oil and gas wells have been treated by Dowell Incorporated, to give an average increase in production of 412 percent. In central Michigan alone, one-sixth of the total oil production is the result of acid treatments, thus indicating a net gain of \$5,000,000 to the oil companies."

When this was published in *World Petroleum* the price of oil was \$1.00 per barrel and acidizing was directed at limestone formations. Since then acidizing technology has expanded, driven by oil and gas discoveries in a variety of formations, all with unique problems.

Sandstone acidizing with hydrofluoric acid (HF) was practiced in Texas in 1933 following the issuance of a patent to the Standard Oil Company; however, the field tests were not successful because of plugging of the formation. Commercial application of HF acidizing of sandstones occurred in the Gulf Coast of Mexico in 1940 when Dowell introduced mud acid, a mixture of HCl and HF. Dowell research indicated that the HCl helped maintain a low pH and decreased the precipitation of damaging precipitates. Following this event, the application of sandstone acidizing grew rapidly.

As the application of acidizing expanded, several chemical and mechanical problems were addressed. Numerous acid additives and systems were developed to solve the problems of acid sludging, acid-induced emulsions, spent acid cleanup, live acid penetration and fines migration. Parallel to this development was the development of methods to improve zone coverage during acidizing.

Acidizing has progressed through the following eras:

- 1950s and 1960s—Emphasis was on the development of additives to address emulsions, sludge, spent acid return and zone coverage. In addition, work on the physics of acidizing in limestones and the secondary reactions of sandstone acidizing was performed. The emphasis for clay problems shifted from clay swelling to clay migration, and numerous clay control agents were developed. Oil-soluble resins were introduced as diverting agents for improved zone coverage.
- 1970s—A need for deeper penetration of live HF acid was addressed with various systems, including alternating stages of HCl and HF, fluoboric acid and a mixture of methyformate and HF.
- 1980s—Foam diversion and coiled tubing placement were introduced to improve zone coverage. Production system analysis became a common tool of the design engineer. Computers were used to assist in all phases of the matrix process, including candidate selection, treatment design, monitoring of execution (real-time evaluation of skin effect evolution) and post-treatment evaluation.
- 1990s—Computers continued to evolve to faster and more user-friendly programs that incorporate improved production prediction capability, economics software, geochemical models and on-site evaluation techniques. Environmentally friendly additives were introduced to meet government regulations along with the development of a better understanding of sandstone acidizing chemistry. Emphasis was placed on the entire matrix process through matrix stimulation engineering.

Great advances have been made since the first acidizing treatment was performed. As wells become deeper, with higher temperatures and harsher conditions along with longer zones as in horizontal wells, matrix technology will expand to meet operators' needs. Matrix stimulation will continue to be a useful, economical tool for production enhancement in the years to come.

### **13-1.2. Formation damage characterization**

Once it has been established that a well is producing below its potential, an assessment of the cause and location of the impairment must be made (Krueger, 1986, 1988). Diagnosis can be based on a review of the well and field history, samples of plugging material recovered from the field and analyzed, knowledge of formation mineral and fluid (e.g., water and oil) properties, as well as pressure testing and logging evaluation. The process of searching and sifting through the mass of data that may provide clues to the problem of a particular well is facilitated by databases and expert systems. In the end, the ingenuity and training of the person analyzing the data and the application of engineering tools are critical to a successful diagnosis. The challenge is to recognize the cause of the well impairment from the information available. In many cases, it is not possible to characterize the formation damage completely. If the diagnosis is uncertain, it is recommended to prioritize the probable causes and design a treatment for the most probable scenarios. Thus, multiple damage types may be suspected, and all should be considered in designing the treatment.

### **13-1.3. Stimulation technique determination**

Selection of the stimulation technique is based on the productivity target, lithology, operational limitations and various other considerations. Normally the productivity target dictates the stimulation technique. For example, if a 90% reduction in skin effect in a sandstone yields the target production, then matrix stimulation will probably be the most cost-effective technique. If matrix stimulation cannot be accomplished, then the feasibility of using propped fracturing should be evaluated.

In carbonates, acid fracturing, propped fracturing and matrix acidizing techniques are applicable. However, if matrix acidizing yields a final skin effect of -2 to -3, it will probably be the most cost-effective technique.

### **13-1.4. Fluid and additive selection**

Identification of the cause and location of the well impairment drives the treatment design process. The chemistry of the stimulation fluids is chosen either to dissolve or disperse the impairment or in the case of carbonate reservoirs to create high-permeability channels through the damage zone. The treating fluid system is selected on the basis of field experience and laboratory testing and can be derived from an expert system.

In cases where it is impossible to remove or bypass damage chemically, a small-volume fracturing treatment may be indicated (Fletcher *et al.*, 1995). This is particularly true today, with the tip-screenout (TSO) technique applied to high-permeability reservoirs. Chemical additives, as well as pre- and postflushes, are selected to enhance the action of the main stimulation fluid, prevent acid corrosion or prevent productivity impairment from by-products of the stimulation process (see Chapter 15).

### **13-1.5. Pumping schedule generation and simulation**

The volume of each material pumped is based on an assessment of the amount of damage or the required depth of treatment and must address the potential inefficiency of the placement process. The location of the damage dictates the placement technique. Both mechanical methods using tools and fluid mechanical methods (e.g., particulate suspensions and foams) can be used to ensure that the stimulation fluids contact the formation damage.

Once the volume, composition and sequence of a treatment are established, a treating schedule can be designed on the basis of the well and reservoir properties. However, the effect of acidizing on formation strength may impose an upper limit on the acid strength and volume in wells that are not gravel packed. The pumping schedule includes the treating fluid and diverter sequence and injection rate for each stage. It can be generated using empirical rules based on previous field experience. In addition, the schedule can be optimized to meet specific objectives for each fluid type by using a single-phase reservoir model (Perthuis *et al.*, 1989).

A field-validated stimulation simulator should be used for the systematic engineering of matrix stimulation treatments. A numerical simulator can be a valuable tool for predicting damage removal and evaluating skin effect evolution, flow profile and wellhead and bottomhole pressures versus injection rate for the proposed pumping schedule. The simulator should take into consideration both the chemistry and damage removal along with the placement strategy, which is another important part of the design process. This step allows the design engineer to fine tune or optimize the schedule to obtain the desired results in the most cost-effective manner. Because many key parameters in the simulation may not be accurately assessed in the laboratory, the simulator is most useful for predicting trends. Comparison to field data is critical to fully validate the simulation model for future design work (Bartko *et al.*, 1996).

### **13-1.6. Economic evaluation**

Although a preliminary economic analysis is performed during the candidate selection process, the final analysis should be conducted once the treatment design is finalized. Production performance is predicted by using a production forecast module and is based on initial and/or final skin effect calculations. Payout time, net present value (NPV), cash flow or other financial indicators may be determined to evaluate economic justifications (Bartko *et al.*, 1996).

### **13-1.7. Execution**

Execution of the treatment is an often neglected step by the design engineer but is obviously critical to the process. Materials must be monitored to ensure that they meet the specifications of the design, equipment must be maintained to perform properly, and personnel on site must understand and execute their assigned roles. Quality control (QC) testing and training should be documented as standard practices (Brannon *et al.*, 1987). Modern data acquisition and communication equipment make it possible to obtain and analyze detailed data during the well treatment, on and off the wellsite.

### **13-1.8. Evaluation**

Treatment evaluation consists of pretreatment, real-time and post-treatment phases. Each is an important link to treatment success and the economic impact of the stimulation treatment. In addition, technical evaluation is required to validate and calibrate the models and assumptions used in candidate selection, treatment design and execution. Treatment evaluation uses the same well evaluation tools and knowledge of potential well productivity as candidate selection. Consistently following the engineering concepts outlined here makes stimulation a learning process and drives improvement in production performance in the field.

## **13-2. Candidate selection**

### **13-2.1. Identifying low-productivity wells and stimulation candidates**

The process of candidate selection consists of identifying wells with low productivity relative to what they are capable of producing and then evaluating possible mechanical problems in these wells (Thomas and Milne, 1995).

Geology, petrophysics and reservoir engineering play important roles in quantifying the productive potential of a given well. Ideally, a thorough understanding of the reservoir geology and reservoir drive mechanics is required to quantify production potential. In many cases such data are incomplete, and the engineer must rely on comparison to similar wells or the field history to identify performance norms. The productivity of each well can be mapped using a three-dimensional (3D) surface graph to assist the identification of underproducers (i.e., candidates). For oil wells, the productivity index (PI), productivity index per net pay thickness  $PI/h$ , production rate in barrels of oil per day (BOPD), production rate per reservoir porosity thickness product (BOPD/porosity-ft) or skin effect can be plotted for each location. The variable selected is a function of the data available. For example, if limited data are available (e.g., permeability-height  $kh$  is unknown) BOPD/porosity-ft or  $h$  can be plotted. This process allows the engineer to pinpoint likely underproducers and determine their relationship with other wells in the field.

Once the production potential of a well is established (to the highest certainty possible with the available data), it can be compared with the actual production. This is a deceptively simple statement because it hides the difficulty in measuring actual production in some cases. A facility's engineers and operations staff can help ensure that an accurate assessment of current well performance is obtained.

Once a well is diagnosed as underperforming, the reason or reasons must be determined. Appropriate remedial action must be taken, including the determination of whether artificial lift is required or if the existing lift is adequate and functioning properly. In some cases, production is constrained by tubing size, downhole equipment restrictions or other mechanical reasons. Stimulation will not help in these cases. Once mechanical reasons are eliminated as a potential cause of poor production, the remaining wells become stimulation candidates.

Well screening should be based on the potential production increase and incremental economics. Obviously, wells with the greatest potential should be selected as candidates. This process should include determination of the maximum allowable drawdown pressure before formation or sand production occurs (i.e., critical drawdown). The critical drawdown is used to predict expected production and is important in evaluating the economic potential of the treatment (Weingarten and Perkins, 1992).

An expert system can be used to screen potential candidate wells. Its knowledge base uses a series of rules to determine the suitability of a well for matrix stimulation. The determination is based on the results of pressure transient analysis (PTA) of the well or on the ratio of actual to theoretical flow rates. Consideration of possible mechanical problems is also built into the rules. Alternatively, a systems analysis can be used to determine the production potential of a well immediately following treatment. Matrix acidizing simulators and field experience indicate that a 90% reduction in skin effect in sandstones and skin effect values of -2 in carbonates are conservative assumptions for a properly designed and executed treatment unless local experience indicates otherwise.

In Fig. 13-1, the knowledge base uses a simplified method to estimate the theoretical reservoir flow (i.e., no systems analysis). Comparison of the actual rate to the computed theoretical rate is made. The engineer then determines whether further evaluation is warranted. One

rule-of-thumb cutoff suggests that the well should be stimulated if the actual rate is less than 75% of the theoretical. This cutoff should be used as a gross indicator only because the theoretical rate does not include effects resulting from production tubulars or separation equipment. By using this process to screen several wells, the engineer can identify underproducers, followed by refinement using systems analysis.

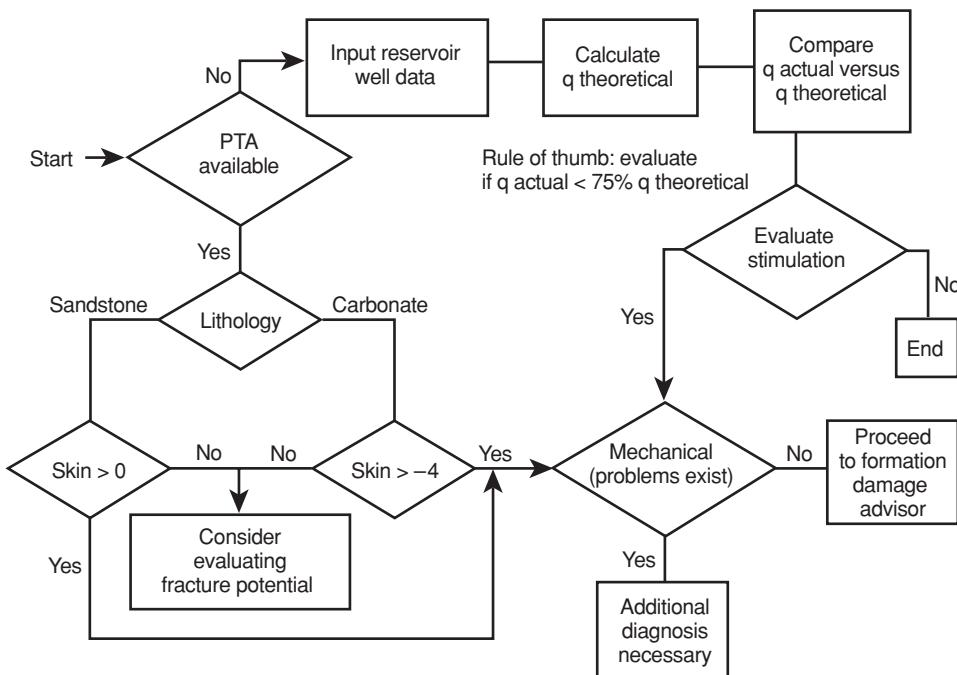
Once the analysis has been completed, wells with low permeability or pressure can be identified. In these cases, matrix stimulation will not provide an economic improvement in performance, but fracture stimulation may be appropriate. Sidebar 13B discusses the candidate selection process applied to a highly damaged well located in the Gulf of Mexico.

A useful and quick indicator of well performance is the productivity index:

$$PI = \frac{q}{\bar{p}_r - p_{wf}}, \quad (13-1)$$

where  $q$  is the flow rate in BOPD,  $\bar{p}_r$  is the average reservoir pressure in psi, and  $p_{wf}$  is the bottomhole flowing pressure in psi.

The variable  $PI/h$  takes into account the effect of drawdown on the production rate. The key parameters required (and not always well known) are  $\bar{p}_r$  and  $p_{wf}$ . Although  $q$  is not always accurately known, it is usually an accessible number. Pressure testing and surveys are required to measure the two pressures accurately. These can also provide data on near-wellbore damage, as



**Figure 13-1.** Candidate selection advisor (CSA) flowchart.

### 13B. Candidate selection field case history

Schiale *et al.* (1986) reported the identification and successful removal of severe damage in a newly completed oil well.

Well logs and completion records documented that a uniform sandstone with 71 ft of net pay was completed using an inside-casing gravel pack. All wells on the platform were producing from a similar zone.

Mapping indicated that the wells on the platform completed in this formation had similar production with the exception of the new well. A knowledge-base expert system indicated that the well was producing at less than 5% of its theoretical flow rate and should have a skin effect of more than 200 on the basis of the following equations. Assumptions were made for  $k$  from previous well test results on offset wells, and the calculation did not consider tubing or completion pressure drops (i.e., systems analysis).

The following equations incorporate assumptions for certain variables.

For oil:

$$q = \frac{7.082 \times 10^{-3} kh(p_r - p_{wf})}{\mu(7.5 + s)}, \quad (13B-1)$$

where  $k$  is the permeability in md,  $h$  is the net pay in ft,  $p_r$  is the reservoir pressure in psi,  $p_{wf}$  is the flowing pressure in psi,  $\mu$  is the viscosity in cp,  $B_o$  is the formation volume factor for oil (default value of 1),  $\ln(r_e/r_w)$  is the ratio of the radial distance to the external reservoir boundary to the radius of the wellbore (estimated value of 7.5), and  $s$  is the skin effect.

For gas:

$$q = \frac{5.39 \times 10^{-2} kh(p_r^2 - p_{wf}^2)}{(7.5 + s)}, \quad (13B-2)$$

where the variables are as described for oil, with default values of viscosity  $\mu = 0.02$  cp, standard pressure  $p_{sc} = 14.5$  psi, standard temperature  $T_{sc} = 487.3^\circ\text{R}$  and flowing temperature  $T_f = 620^\circ\text{R}$ .

On the basis of this information, a well test was performed to determine the permeability and skin effect. As suspected, the pressure transient test indicated that the well had a significant skin effect of 209 and permeability of 526 md. The time to pseudosteady state was 9 hr. Production system analysis indicated that the well could increase from 1,200 to 5,000 BOPD at a skin effect of 20 and 1450-psi wellhead pressure. In addition, the well was tubing limited, and the 34,479-BOPD rate predicted by the knowledge-base expert system was not possible through the 3½-in. tubing. Because all wells completed in this zone were unconsolidated and gravel packed, a critical computer-aided analysis of drawdown was not performed. Other considerations were that the well was located in an easily accessible area with good chemical supplies, availability of service companies and no environmental hazards.

A preliminary economic evaluation based on an estimate for the entire treatment and a 90% reduction in skin effect yielded excellent economics. Assuming a net gain of 3,800 BOPD at \$15 per barrel net yielded \$57,000 revenue per day. Payout for the treatment and associated costs would be less than a week, with an NPV of several million dollars in 3 to 4 months.

discussed in the following. An ideal PI can be calculated from reservoir data by using the equations described in Chapter 1<sup>†</sup>. The ratio of the actual PI to the ideal PI can be used as an indicator of well performance.

Well tests are required to quantify permeability and current reservoir pressure, but usually they are not available. When this is the case, systems analysis can be performed to match current production or bottomhole flowing pressure and calibrate the reservoir net pay, permeability, average reservoir pressure, skin effect, etc., for an underproducer. The key is to calibrate the system to forecast production on the basis of various stimulation scenarios.

#### 13-2.2. Impact of formation damage on productivity

Matrix stimulation is successful because the near-wellbore region controls well productivity. Damage in this area can significantly decrease production by restricting flow in the formation (Krueger, 1986, 1988).

A knowledge of the inflow relationship and Hawkin's equation is essential to understand the effects of near-wellbore formation damage on well production. The steady-state equation for an oil well is:

$$q = \frac{kh(p_e - p_{wf})}{141.2 B \mu \left( \ln \frac{r_e}{r_w} + s \right)}, \quad (13-2)$$

where  $k$  is the permeability in mD,  $h$  is the reservoir thickness in ft,  $p_e$  is the constant outer reservoir pressure in psi,  $p_{wf}$  is the bottomhole flowing pressure in psi,  $B$  is the formation volume factor in RB/STB,  $\mu$  is the viscosity in cp,  $r_e$  is the drainage radius in ft,  $r_w$  is the wellbore radius in ft, and  $s$  is the skin effect.

The total skin effect  $s$  is a dimensionless term used to account for the additional pressure drop in the wellbore area that results from formation damage and other factors (e.g., inadequate perforations, partial completion). Skin effect values, determined from PTA, typically range from 0 to more than 100. Skin effect is positive if an additional pressure drop is present and negative if the actual  $p_{wf}$  is lower than the ideal  $p_{wf}$ . For example, natural fissures in a reservoir or a deviated well contribute a negative skin effect to the total skin effect.

For a given well, Eq. 13-2 can be simplified to

$$\frac{q}{q_o} = \frac{7.5 + s_o}{7.5 + s}, \quad (13-3)$$

where  $q$  and  $q_o$  are the final and initial flow rates, respectively, in BOPD, and  $s$  and  $s_o$  are the final and initial skin effects, respectively.

<sup>†</sup>See *Reservoir Stimulation Third Edition* (SMP-7075)  
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A realistic value for  $\ln r_e/r_w$  is 7.5 because this term is relatively insensitive to the actual values of  $r_e$  and  $r_w$  for oil-field conditions. Thus, for a well with total and damage skin effects equal to 100, a reduction to 10 can exhibit a sixfold increase in productivity. A skin effect reduction from 100 to 0 leads to a 14-fold increase in productivity. Although reduction to 0 is usually unrealistic in a sandstone, reduction to values less than 10 is a reasonable expectation. The actual value would have to be quantified using a valid systems analysis to consider tubing flow, etc. In the same well, a reduction of skin effect from 10 to 0 would yield a 2.3-fold increase in production. Chapter 1<sup>†</sup> provides the productivity equations for gas wells and horizontal wells.

Hawkin's equation relates permeability and the thickness of the damaged zone to the skin effect for vertical wells:

$$s = \left( \frac{k}{k_s} - 1 \right) \ln \frac{r_s}{r_w}, \quad (13-4)$$

where  $k_s$  is the damaged permeability in mD and  $r_s$  is the damage penetration beyond the wellbore in ft, and for horizontal wells:

$$s = \left( \frac{\sqrt{k_H k_V}}{\sqrt{k_{Hs} k_{Vs}}} - 1 \right) \ln \frac{r_s}{r_w}, \quad (13-5)$$

where  $k_H$  is the horizontal permeability,  $k_V$  is the vertical permeability,  $k_{Hs}$  is the horizontal damaged permeability, and  $k_{Vs}$  is the vertical damaged permeability, with all the permeabilities in mD.

Hawkin's equation can be used to determine the skin effect when assumptions are made for the damage radius and permeability. These variables cannot be absolutely quantified, but in combination with well analysis data and/or bottomhole treating pressure response they may indicate trends and define limits.

Combining Eqs. 13-2 and 13-4 yields

$$\frac{PI_s}{PI} = \frac{\frac{k_s}{k} \log \frac{r_e}{r_w}}{\log \frac{r_s}{r_w} + \frac{k_s}{k} + \log \frac{r_e}{r_s}}. \quad (13-6)$$

Figure 13-2 shows the productivity index ratio  $PI_s/PI$  versus the permeability ratio  $k_s/k$ , where the subscript  $s$  indicates damage.  $PI$  and  $k$  represent the nondamaged (ideal) well productivity and reservoir permeability, respectively (Muskat, 1949).

$PI_s/PI$  is equal to  $q_s/q$  for a constant-pressure drawdown. If all damage is removed (i.e., the natural permeability is restored), the well will produce at its natural flow capacity. A 90% permeability reduction extending radially 0.25 and 1.0 ft from the wellbore can decrease production by 35% and 50%, respectively (Fig. 13-2). However, a 90% permeability increase that extends less than 2 ft has little

impact on productivity. Unlike in carbonates, in sandstones it is difficult to increase the permeability above the natural state because of reaction kinetics limitations, reaction stoichiometry and economics.

At this point in the candidate selection process, the engineer knows how the productivity of the candidate well compares with what it would be if the well were undamaged and if artificial lift, tubing restriction, etc., are not the problem. An estimate of the skin effect may be available from production system analysis, or the skin effect may have been determined directly by PTA. If the skin effect is greater than zero, there is potential benefit from matrix stimulation.

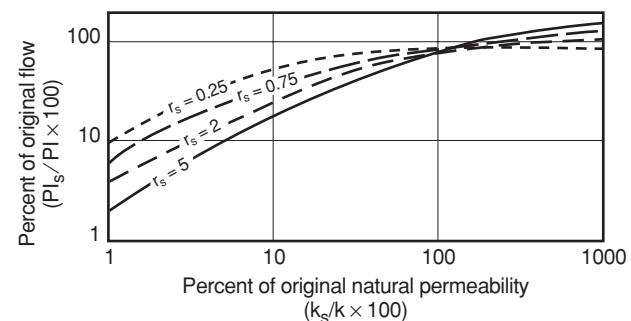


Figure 13-2. Matrix productivity improvement.

### 13-2.3. Preliminary economic evaluation

Having established the production potential of the well as a function of the skin effect and what it is actually producing, the engineer can evaluate the economic value of improved production and the required investment in well work. Economic evaluation requires a good production forecast for the current well condition and a forecast for the stimulated well, possibly as a function of how successful the stimulation is (e.g., post-treatment skin effect). A brief discussion of the methodology follows.

The preliminary economic evaluation requires a model for production (revenue) and job cost (expense) as a function of skin effect. The engineer must determine the effect of the treatment on well economics on the basis of the net gain in cumulative oil or gas over a given period of time and the cost associated with the treatment. The production prediction model should include material balance, allow analysis under different outer boundary conditions (infinite acting, no flow and constant pressure) and forecast on the basis of constant sandface (bottomhole pressure or constant wellhead pressure). The sensitivity of economic performance to skin effect is quantified with this model. The range of skin effects input should be based on the analysis of current (presumably damaged) performance and expected post-stimulation behavior. Post-stimulation skin effect expectations and job costs can be based on field experience or analysis from a numerical stimulation

<sup>†</sup> See *Reservoir Stimulation Third Edition* (SMP-7075)  
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simulator. The numerical stimulation simulator can be used to evaluate potential skin effect removal as a function of job design (e.g., volume pumped).

The economics portion of the model must enable the evaluation of cost versus expected revenue. Estimated costs should include treatment cost, operation costs, cost of money, applicable taxes and any auxiliary costs. Produced product price, price adjustment factors and treatment chance (risk) factors should be included to compute various financial indicators such as the rate of return (ROR), return on investment (ROI), NPV, payout (days) for investment only, payout (days) for investment plus interest and unit cost (investment divided by incremental production).

Several important decisions can be made at this point. For example, if the skin effect required to provide an acceptable return is greater than 0 in a sandstone or  $-4$  in a carbonate, then matrix stimulation is practical; i.e., fracture stimulation is not required.

In conclusion, from a knowledge of the reservoir and well history coupled with the use of diagnostic tools, the engineer should select candidate wells with low risk and significant potential for economic return. This requires the evaluation of numerous wells and is an important link to matrix stimulation success.

### 13-3. Formation damage characterization

Damage characterization is the next step in the matrix stimulation engineering process. It is an essential task prior to treating fluid selection and treatment design. Damage is characterized using laboratory tests, logging techniques and well history. Detailed study is necessary to develop a list of suspected damages from the available data. Multiple types of damage are normally suspected and are all considered when designing the treatment. Tables 14-3 through 14-5 list damage types, diagnostic clues and remedial recommendations for comparison to the condition and characteristics of the candidate well.

The following sections focus on problems that commonly occur in the field and discuss how expert systems can guide an engineer through the damage characterization process. Expert and advisor systems have proved especially useful in the damage characterization process (Krueger, 1988).

All available information on the well such as well logs and records, reservoir characteristics and information on the completion and previous workovers should be collected.

Samples of produced fluids and any solid materials from the well should be analyzed. In some cases, it may be useful to conduct laboratory compatibility tests of the completion or drilling fluids and the formation fluid or rocks. Such tests can help in developing understanding of the problem in the current well and lead to corrective action.

Chemical analysis of solid and liquid samples retrieved from the well can provide valuable insights into damage mechanisms and characteristics. Field testing can quantify certain species (e.g., carbonates and oxides are soluble in hydrochloric acid [HCl], paraffins and asphaltenes float in water, an oil-external-phase emulsion disperses in diesel). Water analyses are commonly performed to assist the determination of scaling potential. The ionic composition of one or two samples can be used to calculate potential scales based on a minimum Gibb's free energy or a Stiff-Davis calculation. In addition, gamma logs can be run to complement the water analyses and detect barium and strontium sulfate scale buildups. Because of trace amounts of the naturally occurring radioactive materials (NORM) radon and radium, barium and strontium sulfate deposits may exhibit an abnormally high gamma count.

The history of the well should be evaluated in detail to assist damage characterization. All phases of well operations—including drilling, cementing, perforating, gravel packing, workover operations, stimulation operations and production or injection—are potential originators of damage (Krueger, 1986).

Expert and advisor systems have been developed to assist damage characterization (Bartko *et al.*, 1996). They provide a guide through a series of questions directed at relating the type of damage to the well behavior and available data. They can pinpoint key gaps in the available data and recommend additional required diagnostics. A brief discussion of the most common questions the engineer should ask in using an advisor are in Sidebar 13C.

Production logs can be run to quantify the flow per layer. This information is input into computer programs to determine the formation damage skin effect per layer. The use of a production log is reviewed in the field case history in Sidebar 13D.

Damage characterization is the basis of treatment design. Chemicals will be selected to remove the suspect cause or causes of damage. Treating procedures will be designed to access the suspected damage with adequate amounts of chemicals to remove enough damage to achieve the well productivity goals. Correct damage characterization is critical to matrix stimulation success.

### **13C. Formation damage characterization field case history**

Schiale *et al.* (1986) performed a detailed laboratory and field study to characterize formation damage. Some of the questions and answers resulting from the study follow.

#### **Well history**

- Is the well newly completed, an old well, huff and puff, a recent workover and/or a recent stimulation treatment? This is a newly completed gravel-packed well that has been tested.
- Is it an oil, gas or water producer or injector with water or hydrogen sulfide ( $H_2S$ ) production? This oil well produces 29.5°API gravity crude.
- Was the well perforated under- or overbalance? The well was perforated underbalance at 12 shots per foot (spf).
- What type of completion fluid was used? Filtered calcium chloride and potassium chloride completion fluids were used to provide temporary clay control.
- Was the well produced at high drawdown rates? Although newly completed, the well was produced at high drawdown rates during the well test.
- Has the well responded to previous treatments? No previous treatments were performed on this well, but offset wells have responded to mud acid treatments.
- Did the production decline slowly or rapidly? Not applicable
- Did the well respond positively to a pump-in test? A pump-in test was not performed because of the associated cost and availability of other data (see "Laboratory and field testing" section).
- Was there excessive drilling mud loss to the pay zone? No unusual loss of drilling mud occurred when drilling through the pay zone.
- Is there fill in the wellbore, produced solids or solids in surface equipment? (Obviously, this would be a major problem indicative of gravel-pack failure.) There is no water production to create scale or solids.

#### **Well logging and testing**

- Are the results of a pressure transient test available? High skin effect values indicate there is severe formation damage.
- Does a production log show nonuniform production rates? Although the porosity logs indicate that the pay zone is a homogeneous sandstone, it is not damaged uniformly.
- Is there fill, a reduction of tubing inner diameter or an increase in gamma count? There is no indication of any of these.
- Is there water production from a specific zone? There is no water production.

#### **Laboratory and field testing**

- What is the mineralogy of the pay zone? Laboratory core testing indicates that the formation is composed of approximately 75% quartz, 10% feldspar and 10% clay with kaolinite, illite, chlorite and illite-smectite present with a 4% to 5% HCl solubility.
- Was a water analysis performed? No, because the well did not produce water.
- What is the composition of samples from the well? No samples other than cores and oil were retrieved from the well.
- Is the salinity of the completion fluid lower than that of the formation water? Not applicable
- Does the oil have an emulsion or sludging tendency? Laboratory testing indicates that the crude will not form an emulsion or sludge.
- Do core tests using the completion or stimulation fluids indicate damage? Laboratory testing indicates that the 2% KCl fluid used during gravel packing created a 62% reduction in permeability to oil (101 md damaged to 45 mD).
- Do core flow tests using stimulation fluids improve the permeability? Core testing using fluoboric acid stimulation fluid indicates that the formation damage can be removed, with 280% of the initial permeability to oil obtained.

### 13D. Fluid and additive selection field case history

The well was severely damaged by the completion fluid (clay swelling in mixed-layer clays) and had possible fines migration during the well test. Production could potentially increase from 1,200 to 5,000 BOPD. Schiable *et al.* (1986) reported the laboratory testing performed to quantify the fluid and additive selection.

- Mineralogy

X-ray diffraction and scanning electron microscopy of formation cores indicated that the formation contained 8% to 11% clay and 8% to 12% feldspar. The clay was composed of 7% to 31% kaolinite, 9% to 18% chlorite, 37% to 46% illite and 22% to 29% mixed-layer clays.

- Petrophysics

The 71-ft zone was not fissured and consisted of a relatively homogeneous sandstone with approximately 29% porosity and 526-mD permeability.

The formation was borderline, between the first two classes of the mud acid fluid selection guide in Table 18-7. Assuming that the sandstone was less than 10% silt and less than 10% clay, a 12% HCl–3% HF system would be used, whereas a sandstone with high clay (greater than 10%) and low silt (less than 10%) would require a 12% HCl–2% HF system. Because the 12% HCl–3% HF sys-

tem had been previously used successfully in the formation, laboratory core tests were performed to determine the damage removal efficiency of the system. A 101-md core was damaged with completion fluid by flowing 20 pore volumes of water containing 2% KCl to yield 45.6-mD permeability to oil. The core was then treated with a 7.5% HCl preflush followed by 12% HCl–3% HF mud acid overflushed with fluoroboric acid. The fluoroboric acid was used to decrease silt and clay migration. The resulting final permeability to oil was 284 mD (>500% increase). On the basis of laboratory results, the mud acid–fluoroboric acid system was selected to restore permeability in the damaged well.

- Treating and reservoir fluid compatibility

The 29.5°API gravity crude did not exhibit sludging or emulsion tendencies in laboratory testing.

- Damage and permeability profiles

A log recorded by the PLT\* Production Logging Tool indicated that the homogeneous sand was not damaged uniformly. The skin effect per layer based on the production per layer and completion are listed in Table 13D-1.

An oil-soluble diverter was selected to provide uniform flow per layer (i.e., uniform volume of each fluid per foot of zone). Other additives to the acids were an iron control agent, acid corrosion inhibitor and surfactant. An ammonium chloride flush with a mutual solvent ahead of the HCl preflush was recommended to remove oil from the wellbore area.

Table 13D-1. Skin effect per layer based on production per layer and completion.

Layer	Skin Effect		Damage	Total	Production (%)	Porosity (%)
	Development and Partial Completion	Perforation and Gravel Pack				
1	0	0.1	48.5	48.6	50	29
2	0	0.1	277.4	277.5	10	29
3	0	0.1	75.0	75.1	35	29
4	11.5	0.3	2534.2	2546.0	5	29

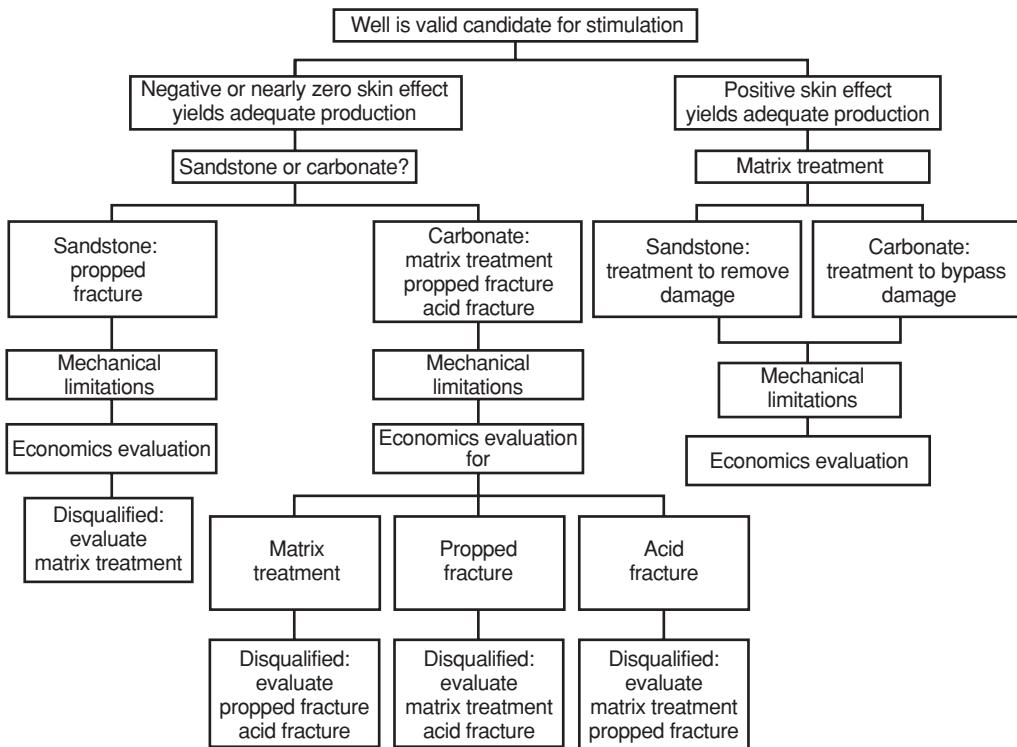
### 13-4. Stimulation technique determination

At this point, the well has been identified as an underperformer. The monetary value of improving well productivity and the possible cause or causes of formation damage have been determined. Next, the engineer must determine the remedial action.

The entire production system must be considered in making this decision. If the problem is in the well design or operation (e.g., tubing size or artificial lift), then stimulation is not indicated and the equipment should be upgraded or repaired. The target well performance must be balanced; i.e., there is no need to produce more than the tubing or lift will transport or than the facilities will process. This may affect the economics of incremental improvements in skin effect. The impact of skin effect on the economic limit and reserve recovery must also be considered.

Figure 13-3 is a decision tree to help the process of candidate selection and stimulation technique. This type of flowchart can be incorporated into computer software. As shown in the figure, the productivity target dictates the stimulation technique.

If the productivity target can be reached with a skin effect of 10% of the original damage skin effect in sandstones and –2 to –3 in carbonates, matrix stimulation will be adequate and probably cost effective. In sandstone reservoirs the only stimulation alternative is hydraulic fracturing. In carbonate reservoirs (limestones or dolomites) acid fracturing can be a cost-effective way to increase productivity. In both cases, a hydraulic fracture is induced in the reservoir. In conventional fracturing, the conductivity of the fracture is maintained by propping it with high-permeability proppant. In acid fracturing, conductivity is created by differential (nonuniform) etching of the rock surface.



**Figure 13-3.** Stimulation decision tree.

Other factors may influence selection of the stimulation technique. In unconsolidated or friable sands, it is advisable to examine the maximum pressure drawdown allowed before formation (sand) production. This drawdown limit may lead to the selection of fracture stimulation to allow obtaining target rates at a lower drawdown. On the other hand, concern about zonal isolation may preclude fracture stimulation. If vertical fracture growth into an aquifer or gas cap cannot be controlled, matrix stimulation may be indicated.

The engineer must also make some decisions about data collection before designing the treatment. As discussed in the following, many technologies are available to improve job monitoring and evaluation. Among the options to be considered are real-time data acquisition, use of downhole pressure gauges (memory or surface readout) and use of wireline surveys and tracers to determine treatment placement. For some wireline evaluations, baseline surveys must be run prior to the treatment.

## 13-5. Treatment design

### 13-5.1. Matrix stimulation techniques

Two types of nonfracture treatments are used to improve production in oil and gas wells. Wellbore cleanup uses chemical and/or mechanical methods to clean the wellbore. For matrix stimulation, fluids are injected into the formation to treat the near-wellbore region.

- Wellbore cleanup

Wellbore cleanup is commonly used to remove scale, paraffin, bacteria or other materials from the tubing, casing or gravel-pack screen. These treatments normally use acid or solvent systems that are placed in the wellbore area to soak. Key parameters in treatment design are the placement technique, chemical selection and soak time.

Mechanical assemblies such as packers, bridge plugs, spring-loaded “spot control” valves and coiled tubing can be used to ensure proper placement. This is critical

in minimizing the volume of treating fluid. Density differences between treating fluids and displacement or well control fluids must also be considered when designing a treatment that will stay in contact with the damage for the required soak time. The well cannot be assumed to remain static (no cross flow) during the soak time.

Chemicals should be selected on the basis of their effectiveness at dissolving the suspected damage. Laboratory tests at bottomhole temperature and, if possible, pressure are desirable to determine necessary soak times. Because of the small surface area of the exposed damage, the soak time can be hours to days depending on the type of damage, temperature and damage removal fluid. Agitation or jetting with coiled tubing can accelerate damage removal. In low-pressure wells, nitrogen ( $N_2$ ) is recommended to assist the removal of reacted treating fluid.

#### ■ Matrix stimulation

Matrix stimulation treatments injected below fracturing pressure down tubing, drillpipe or coiled tubing usually include a sequence of several fluids, referred to as stages. A minimal treatment consists of a pre-flush stage with a nondamaging, nonreactive fluid to establish an injection rate, a stage of the main treating fluid and an overflush stage to clear the main treatment fluid out of the tubing and displace it into the near-wellbore area. In most treatments, other auxiliary stages are included to enhance the effectiveness of the treatment. The selection of chemicals for the stages and the design of the treating sequence (pumping schedule) are reviewed in the following sections.

### 13-5.2. Treatment fluid selection

Treatment fluid selection is an important step in the engineering process. Multiple fluids (fluid systems), composed of base fluids and additives, are selected on the basis of lithology, damage mechanism and well condition. Each fluid in the treating schedule serves a special purpose. Although the process of fluid selection is complex because many parameters are involved (e.g., damage type, mineralogy), guidelines have been developed to simplify the process and improve treatment success.

#### ■ Main treating fluid selection

The main treating fluid is selected to dissolve or disperse the principal damage in sandstone formations and to allow soluble products or solids to flow out of the well (Smith and Hendrickson, 1965). In the case of carbonate formations, the goal is to bypass the damage with acid

or dissolve the damage with solvents (Hendrickson *et al.*, 1960). The main treating chemicals fall into the following categories:

- solvents to remove organic deposits (such as paraffin)
- oxidizers to remove damage from polymers
- scale removers to remove sulfate or oxide scales
- acids to remove carbonate and oxide scales, break polymer residues or stimulate carbonate formations
- hydrofluoric acid (HF) to remove aluminosilicate damage (primarily clays) from sandstone formations.

The main treating fluid is chosen to bypass, dissolve or remove the main damage. If multiple damages are suspected, it may be necessary to use several main fluids or to combine the listed functions into a single fluid; however, in combining fluids and functions, care must be taken to maintain the effectiveness of each and avoid incompatibilities.

Solvents are selected when organic deposits are suspected. If possible, the solvent should be evaluated in the laboratory with samples of the deposit. Various oxidizers have been reported for use in well stimulation. Because the polymer is usually introduced into the wellbore during drilling or completion operations, its identity is well known. An effective oxidizer can be evaluated in the laboratory using this knowledge. In addition, the effect of other fluid components, well materials and formation minerals on the oxidizer must be assessed. Scale removers can likewise be evaluated in the laboratory with samples of scale deposits. Soak time and chemical concentration can be optimized with these tests. One drawback to these forms of stimulation is that they are effective against a limited range of damage materials. If the damage diagnosis is uncertain, a more broad-spectrum treatment may be indicated.

Acid stimulation is performed to remove or bypass a variety of damages. When used to remove carbonate scale or polymer residues, acids act similarly to the treating chemicals discussed previously. Acids are also used to stimulate the near-wellbore region of the reservoir. In carbonates, HCl or organic acids (formic or acetic) are used to etch conductive paths between the wellbore and the formation. In sandstones, mixtures of HCl and HF (mud acids) are used to remove drilling mud, formation fines, fines generated during drilling and perforating residue. These materials are usually more difficult to define or sample than other forms of damage.

Because acids are effective against several types of damage and are inexpensive, they are used in the vast majority of matrix stimulations. As a result, more effort has been expended in the engineering of acid treatments. In the remainder of this chapter, the focus is on engineering matrix acidizing treatments, but the concepts discussed apply to all types of matrix stimulation.

#### ■ Fluid formulation for matrix acid stimulation

Formulating fluids for matrix acid stimulation includes selection of the main acid and identification of the need for preflushes and overflushes. Figure 13-4 shows a decision tree for fluid selection in sandstones and carbonates. Fluid selection depends on the damage type, lithology, mineralogy and type of well. It is also based on field and laboratory experience and can be derived from an expert system (Perthuis *et al.*, 1989). Oil wells are more difficult to treat than gas wells because of potential emulsion, sludging and wettability problems. To remove damage, the treating fluid must be in intimate contact with the damage. This requires a water-wet formation and oil displacement from the pore throats. Thus, preflushes used in oil wells may include an organ-

ic solvent or ammonium chloride with surfactants and/or a mutual solvent to remove heavy hydrocarbons from the wellbore area and ensure a water-wet environment.

The main acid formulation is based on the type of formation to be stimulated. Formulation guidelines are based on studies of acid-mineral reaction chemistry. A brief review of the main considerations in acid formulations follows.

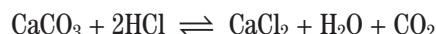
#### ■ Fundamentals of acid-rock chemistry

Chapter 16 presents a detailed discussion of the chemistry and physics associated with acidizing. An appreciation of the key points in the chapter is necessary to understand the fluid selection process.

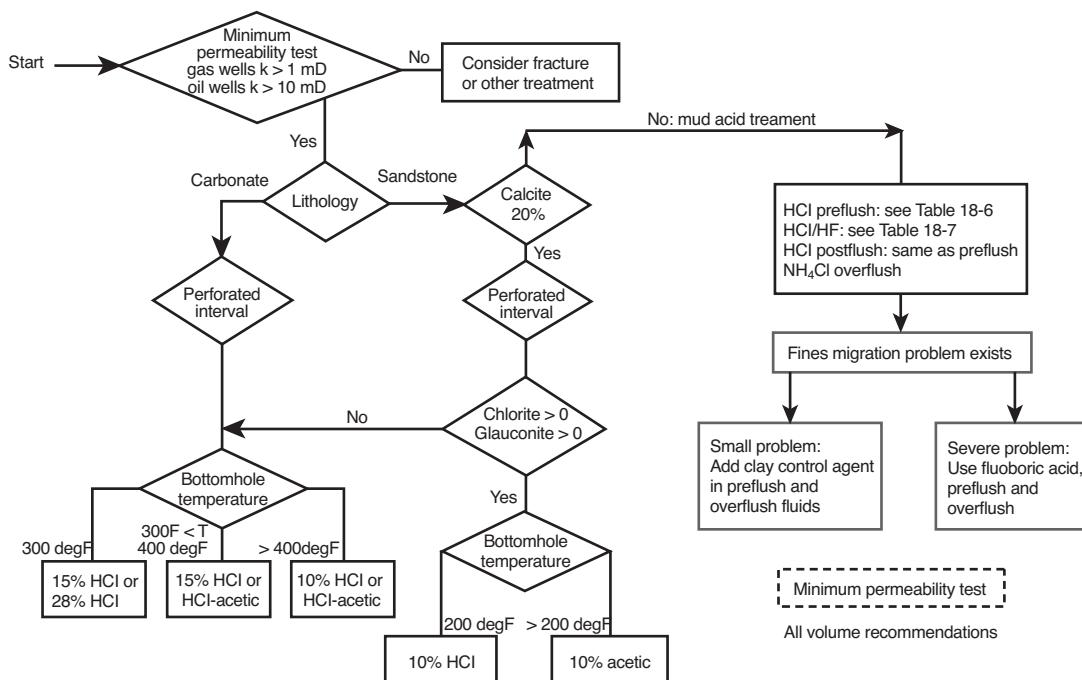
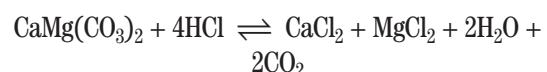
##### – Acid types and kinetics for carbonates

HCl is used for carbonate acidizing because it readily dissolves calcite and dolomite.

The reaction of limestone (calcium carbonate, or  $\text{CaCO}_3$ ) with HCl is



For dolomite, the reaction becomes



**Figure 13-4.** Fluid selection flowchart.

Normally, formation damage is not dissolved but rather bypassed to yield new flow channels (wormholes) and/or an etched surface on fissures, resulting in a reduced pressure drop (decrease in skin effect). The wormhole pattern is created because the highly reactive acid enters the largest pore throats, vugs and/or fissures and essentially enlarges them. The number of wormholes is a function of the pore-size distribution (Schechter and Gidley, 1969).

Acid reaction with carbonate reservoirs is governed by three mechanisms: wormholing, compact dissolution and radial flow. Each mode occurs under certain conditions. For example, at low injection rates, compact dissolution occurs when the formation face is dissolved to enlarge the wellbore. If the flow rate is increased to where the Peclet number (a function of injection rate, acid concentration and diffusion rate) is approximately 1, then wormholing initiates. If the rate is increased significantly, radial flow dominates in a manner similar to sandstones. Wormholing probably occurs in most treatments owing to the heterogeneous nature of carbonates; i.e., normally there are thief pores where wormholing initiates.

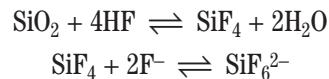
In cases where the temperature exceeds 400 degF [205 degC] (where corrosion inhibitors are ineffective in HCl), organic acids (acetic or formic acid) are used.

The reaction of HCl with calcite is diffusion limited (i.e., mass-transport limited). The limiting step in the dissolution reaction is the diffusion of acid (hydronium ion,  $H_3O^+$ ) to the surface of the calcite. Once the  $H_3O^+$  contacts the surface of the calcite, the reaction occurs very fast. The reaction of HCl with dolomite is diffusion limited at temperatures greater than 150 degF [65 degC] and limited by the surface reaction rate (i.e., diffusion is not the slowest step) below this temperature. Thus, because of the diffusion-limited kinetics of HCl on calcite, wormholes can normally be easily formed through the damaged zone (2 to 3 ft radially).

#### – Acid types and kinetics for sandstones

Mud acid mixtures of HF and HCl are used for sandstone acidizing. Unlike carbonate acidizing, wormholes are not created in sandstones. In a typical sandstone, 80% of the radial flow can be through 20% of the pores (the larger pores). The damage is removed from the larger pores, resulting in a skin effect reduction but possibly not restoration of the natural permeability of the formation.

The primary reaction of HF with quartz grains (pure silica) is expressed in the two following equilibria:

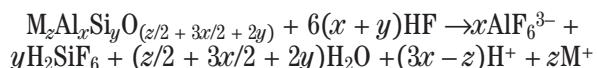


In the latter, silicon tetrafluoride combines with fluoride to produce silicon hexafluoride.

The conventional mud acid formulations (12% HCl–3% HF and 6% HCl–1% HF) used in matrix acidizing dissolve little quartz. The intent of sandstone matrix acidizing is to dissolve clays and other damaging materials, leaving the sandstone matrix undisturbed.

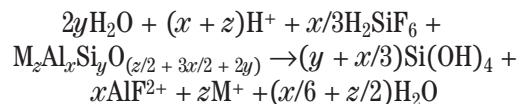
Although the primary reaction of HF with silica is simple, the reaction with silt and clay is more complex.

For aluminosilicates (clays and feldspars), the primary reaction is



where M is a metal atom (e.g., Na or K).

The reaction products  $AlF_6^{3-}$  and  $H_2SiF_6$  continue to react with the aluminosilicates to form silica gel on the surface of the clay (Crowe, 1986). An example of such a secondary reaction is



Theoretically, other secondary reactions can produce aluminum fluorosilicate solids, which may be damaging. Thus, there is a potential for the generation of damaging reaction products, although the effects are normally minimal.

Although HCl accelerates the reaction of HF with siliceous minerals (silt and clay) the reaction is far slower compared with that of HCl reacting with calcite. The reaction is reaction rate limited (i.e., numerous collisions of  $F^-$  with the surface of the mineral must occur before a reaction occurs) and yet results in most of the HF reacting within the first foot of the wellbore. This occurs because of the large surface area of the silt and clay. (Five grams of smectite clay has the surface area of a basketball court.) Retarded acids have been developed to yield deeper acid penetration (Thomas and Crowe, 1981).

- Acid and formation compatibility

- Iron hydroxide

Precipitation of iron (ferric,  $\text{Fe}^{3+}$ ) hydroxide ( $\text{Fe}(\text{OH})_3$ ) can occur during sandstone and carbonate acidizing when the pH value is greater than 2.2. Sources of iron in the formation and tubulars are chlorite, siderite, hematite and rust. Ferrous iron ( $\text{Fe}^{2+}$ ) is not a problem in sandstone acidizing because ferrous hydroxide does not precipitate until the pH value exceeds 7.7. Although fluoride complexation of iron increases the pH required for precipitation, iron control agents are recommended in all acid stages during sandstone and carbonate acidizing (Crowe, 1985).

Iron also increases the tendency of oil to form rigid films and emulsions with acids. These problems can result in formation damage and facility upsets when producing wells after acidizing.

Live acid or partially to completely spent acid occasionally forms an emulsion with crude oil or condensate, resulting in two-phase flow and a production decrease. In addition, sludging can occur because of the coagulation of asphaltenes plugging pore throats. Both emulsions and sludging can be avoided by adding the appropriate chemical determined from laboratory testing. In severe cases, organic acids replace mineral acids to decrease emulsion and sludging tendencies. Preflushes of solvents or potassium or ammonium chloride with mutual solvents are used to separate the crude oil from the acidic fluids.

- Carbonates

Formulating acids for carbonates is relatively simple because the majority of the reaction products is simply calcium chloride, water and carbon dioxide, which do not undergo further reactions. However, there are numerous minerals (silt and clay) in most carbonates that are insoluble in HCl. The insoluble material normally flows back through large wormholes or fissures and is not a problem.

In addition, acids selected for carbonate acidizing must be compatible with the formation fluids. Ensuring oil-acid compatibility is discussed later and in Chapter 15.

- Sandstones

The sensitivity of a sandstone formation to a matrix treatment fluid depends on the mineralogy of the formation, damage type, reaction products, temperature and permeability. As a rule of thumb, the more silt, feldspar and clay and the lower the permeability, the greater the sensitivity of the formation. The amount of precipitate formed is proportional to the amount of rapidly HF-soluble material present, and the impact of the precipitate on plugging is greater at lower permeability. In addition, fines migration and the formation of precipitates during a treatment create more problems in low-permeability formations. Thus, sensitivity is related to chemical and mechanical problems in sandstones.

Although sensitivity cannot be eliminated completely, the goal is to minimize it by selecting fluids with the greatest possible compatibility with the formation. The mineralogy of the formation plays a large role in formation sensitivity and fluid selection. The solubility of the minerals in a sandstone depends on their location. Authigenic clays are pore lining and come into contact with the treating fluid, whereas detrital clays were deposited with the original sand and are not completely exposed to the treating fluids. A discussion of the most important reactive minerals in a sandstone follows.

The solubility of the formation in HCl is normally considered to represent the carbonate content of the sandstone. This assumption is incorrect where other acid-soluble species are present (e.g., chlorite, zeolites, oxides and sulfides). If the acid solubility is greater than 20%, HF is not recommended. Excessive carbonate can react with the HF to precipitate calcium fluoride, and spent HF can react to form calcium hexafluosilicate. Chlorite clay and some zeolites (hydrous calcium/sodium/potassium aluminum silicates) are partially soluble in HCl and can cause severe plugging from the migration of their residue. Special precautions must be taken when treating formations with these minerals (see Chapter 18). Thus, in sandstone acidizing, an HCl (or organic acid) preflush is used ahead of the mud acid.

The silt and clay content can be determined in the laboratory by dissolving a core sample in mud acid. The difference between the mud acid and HCl solubilities is the approximate silt and clay content. Although it is important to know the amount and type of silt, feldspar and clay present, it may be equally important to know their position in the formation.

Secondary reactions can occur to form precipitates in the sandstone if precautions are not taken (see the “Design types” discussion in Section 13-5.3). Potential precipitates are as follows.

Fluosilicates ( $\text{SiF}_6^{2-}$ ) are the most detrimental precipitates produced in sandstone matrix acidizing. Sodium, potassium and calcium fluosilicates ( $\text{Na}_2\text{SiF}_6^{2-}$ ,  $\text{K}_2\text{SiF}_6^{2-}$  and  $\text{CaSiF}_6^{2-}$ , respectively) are extremely insoluble and form when formation water or any sodium/potassium/calcium brine contacts spent mud acid. They are avoided by pre-flushing with a compatible fluid such as ammonium chloride or HCl and then overflushing.

Calcium fluoride forms from the reaction of HF with calcite if adequate HCl (or organic acid) is not injected ahead of the mud acid. It is not necessary to dissolve all the calcite. As reported by Walsh *et al.* (1982), as much as 6% calcite can remain and not cause the precipitation of calcium fluoride or aluminum fluoride.

Precipitation of the aluminum salts aluminum fluoride ( $\text{AlF}_3$ ) and aluminum hydroxide ( $\text{Al}(\text{OH})_3$ ) (Walsh *et al.*, 1982) can be avoided by maintaining a low pH (less than 2). In addition, the tertiary reaction of aluminum bifluoride cations with silt and clay can occur very slowly at temperatures greater than 200 degF [95 degC] or with retarded mud acid formulations containing  $\text{AlCl}_3$ . The addition of more Al to the mud acid formulation results in Al saturation and precipitation. This process consumes acid, resulting in a pH increase and the precipitation of aluminum silicate and/or fluoride species. Citric acetic acid has been used successfully in treatments to complex aluminum and buffer the pH below 2, thus avoiding precipitation (Rogers *et al.*, 1998).

Hydrated silica precipitate forms in all mud acid treatments but is normally not a problem because it occurs during the topochemical reaction of spent mud acid with the surface of the silt and clay. The precipitate is not mobile like other precipitates. However, adequate HCl must be present to account for this process because it consumes acid that may result in the precipitation of other species.

#### ■ Acid selection guidelines for carbonates

– Temperature—Acid selection depends greatly on temperature because of corrosion inhibition limitations. For example, at temperatures greater than 300 degF [150 degC], 28% HCl cannot be used because of excessive corrosion whereas 15% HCl can be used. Above 400 degF, organic acid or fluids containing ethylenediaminetetraacetic acid (EDTA, a non-acid-reactive solvent) can be used. In addition, emulsified acid or HCl with a retarder is used to increase penetration.

– Mineralogy—Calcite and dolomite react differently with acids. Acid formulation should be optimized to achieve the desired reaction and penetration characteristics in each formation. Carbonates commonly contain insoluble minerals (silt and clay) that are released during acidizing. When this occurs, a silt-suspending agent is required along with  $\text{N}_2$  in wells where spent acid will not flow back naturally (less than 0.46 psi/ft pressure gradient).

– Petrophysics—Acid penetration and the amount of damage depend on the type and distribution of porosity. For example, a highly vugular, high-permeability or fissured carbonate usually is damaged severely during drilling and completion because of solids. Attempts to obtain deep penetration (greater than 5 ft) may be difficult, with short but wide wormholes formed. An emulsified, retarded or foamed acid is required to achieve deep penetration. Because much of the porosity (hydrocarbons in place) is located in the vugular or fissure network, it is essential to remove the damage and restore communication with the wellbore. As stated previously, a silt-suspending agent in a gelled or nongelled acid and  $\text{N}_2$  are recommended to remove drilling mud and completion solids.

#### ■ Acid selection guidelines for sandstones

– Temperature—Acid selection depends only slightly on temperature because lower acid concentrations are normally used (i.e., corrosion is not a major issue). The sensitivity of a sandstone formation increases with temperature because of the rapid spending of HCl and mud acid and generation of mobile fines in the spent acid; however, the sensitivity resulting from precipitation reaction products decreases with temperature because of their increased solubility. These processes tend to counterbalance one another, resulting in little temperature dependence.

- Mineralogy—Sandstone mineralogy is the most important factor to consider in fluid selection because of the potential formation of precipitates. Because of the large surface area of silts and clays, most mud acid reacts rapidly to generate a complex mixture of compounds. Numerous guidelines have been developed from field experience and laboratory data (Fogler *et al.*, 1976; Walsh *et al.*, 1982; McLeod, 1984; Ayorinde *et al.*, 1992; Gdanski, 1996), and their use has improved field results. In addition, acid penetration is highly dependent on mineralogy because of the large surface area of silts and clays.
- Petrophysics—As in carbonates, acid penetration and the amount of damage depend on the type and distribution of porosity. Fissured sandstones are not common in most matrix candidates but can be present in basement formations and geothermal areas. A silt-suspending agent in acid and N<sub>2</sub> are recommended to remove drilling mud and completion solids. Although HCl can be used exclusively in this operation, mud acid is recommended to assist damage removal and dispersion.

The sensitivity of a sandstone depends on the permeability of the formation. Because permeability is a function of pore size, low-permeability sandstones are more sensitive than high-permeability sandstones for a given mineralogy. Thus, the permeability must be considered in fluid selection. Guidelines for mud acid selection and HCl selection are in Chapter 18 (Ayorinde *et al.*, 1992). Although they provide useful general guidance, acid formulations should be optimized on the basis of a detailed formation evaluation (Davies *et al.*, 1992; Nitters and Hagelaars, 1990).

#### ■ Preflush fluid selection

The preflush has three important functions. A preflush of a nonreactive fluid is pumped initially to ensure that injection can occur at an acceptable rate and pressure. In some oil wells, it is advisable to inject a preflush formulated to remove oil from the near-wellbore region and leave the minerals and damage in a water-wet condition. This enhances the rate of acid attack. A solvent or solutions containing mutual solvents can be injected for this purpose. Gidley *et al.* (1996) advocated using carbon dioxide as a preflush in oil wells to remove oil and increase acid effectiveness. When acidizing with mud acid, an acid (HCl or organic acid) preflush is used to remove calcium carbonate and iron carbonate or oxide from the near-wellbore region. This helps to eliminate calcium fluoride—and

iron-related impairment problems. Once injection is acceptable and the formation is in the proper condition, the main treating fluid can be injected. The main treating fluid normally contains HF and is displaced into the reservoir by an overflush fluid.

#### ■ Diverting agent selection

Nonuniform damage and permeability heterogeneity in targeted zones cause treating fluids to preferentially enter thief zones. The result is nonuniform damage removal and economic failure in most cases. Chapter 19 addresses treating fluid placement (diversion) in detail. Numerical simulators can model this process and assist treatment optimization (Bartko *et al.*, 1996). The heterogeneity of pay zones requires that the diversion and treating fluids must be compatible with the chemical systems used in the process.

Diverters are used to help control the distribution of acid in the wellbore. The four general types are bridging agents (60 mm), particulates (4 to 60 mm), viscous solutions (gels) and foams. Bridging agents are relatively large particles that are used to bridge at the face of fissures in carbonate formations; particulates are smaller particles that are used in sandstones. For particulates, size and composition are the key parameters (Crowe and Cryar, 1975). Particulates should be sized to form an external filter cake on the formation and should be soluble in the produced fluids (King and Hollingsworth, 1979). Viscosifiers should be stable enough to provide significant resistance to flow, but they must degrade fast and completely so that they do not impede production. Viscosifiers are normally used in carbonate formations. Foams are made by adding a foaming surfactant to the acid or brine and mixing it with N<sub>2</sub>. The foaming material should be stable in the fluid it is mixed in, and sufficient N<sub>2</sub> should be available to ensure a foam with a 65% to 70% (gas volume) quality downhole (Thomas *et al.*, 1998).

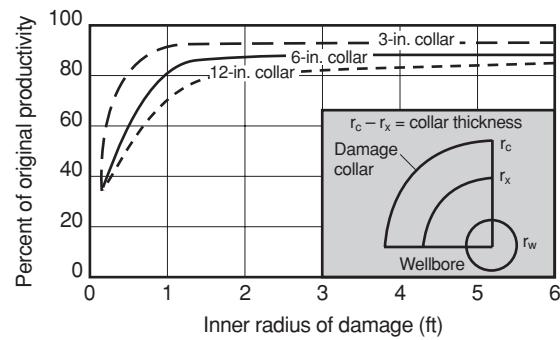
All types of diverters can be injected continuously with the acid or staged in discrete segments of the injection sequence. The concentration can also be varied as required. Experience can provide guidance as to which approach works best, or a numerical model can be used to optimize the diversion process.

#### ■ Postflush fluid selection

A postflush is almost always used to remove the reactive (and corrosive) fluid from the tubing and maximize the contact of main fluid with the near-wellbore area. The decision to inject a postflush fluid depends on the type of stimulation. If the dissolved or dispersed damage has

the potential to damage the formation if displaced radially into the formation, injection into the reservoir must be avoided (e.g., paraffin solvent, mud/silt dispersant fluids would not be overflushed). At the other extreme is sandstone HF acidizing in which the overflush is essential to ensure that secondary precipitation occurs deep in the reservoir, where the impact on productivity is greatly reduced. Damage in the near-wellbore area can significantly decrease production by restricting flow in the formation; however, a 6-in. collar with 80% damage will reduce production by only 10% from ideal if located more than 3 ft radially from the wellbore (Fig. 13-5).

An overflush is also commonly used to displace HCl into a carbonate formation to improve the live acid penetration. Following the treatment, the well is cleaned up by flowing the reacted fluids to the surface along with the undissolved damage (i.e., drilling fluid, scale, paraffin and asphaltenes).



**Figure 13-5.** The effect of shifting an 80% damage collar.

#### ■ Matrix treatment fluid additives

Chapter 15 provides a detailed discussion of the additives required in matrix fluids. Additives are mixed with the treating fluid to modify a property (e.g., corrosion, precipitation, emulsification, sludging, scaling, fines migration, clay swelling tendency, surface tension, flow per layer, friction pressure). The brief discussion that follows emphasizes the optimization of treatment results. Most additives do not depend on the formation type but rather on the reservoir conditions (i.e., hydrocarbon type and temperature).

All additives should be tested for compatibility to ensure that they are chemically compatible with the other additives used in a particular fluid stage. In addition, stages that will be in contact with each other in the wellbore should be tested for compatibility. Compatible spacer stages can be used if incompatible fluids must be pumped, but eliminating incompatibilities is preferred if possible.

Additive types are as follows:

- Acid corrosion inhibitors—Different corrosion inhibitors are required for all inorganic and organic acids. In selecting an inhibitor and concentration level, it is important to realize that partially spent HF may still be highly corrosive. Recommended practices for testing acid corrosion inhibitors and methods for handling returned acid production have been published (NACE International, 1995).
- Solvents—General purpose aromatic solvents based on xylene are used widely as preflushes. In some cases, treating data show a significant reduction in injection pressure with the use of a solvent. Solvent preflushes may also help to prevent interaction with the formation oil by separating the crude oil and aqueous treating fluids.
- Iron stabilizers—Additives to control iron are required in all acid treatments. They can be grouped in three categories: buffers keep the pH value less than 2.2, and the most common buffer is acetic acid, which helps suppress oxide precipitation at temperatures less than 125 degF [50 degC]; chelating or complexing agents bond to the iron and suppress other reactions and are used to prevent precipitation and sludging (Crowe, 1985); and reducing agents prevent oxidation of the iron from ferrous to ferric (Crowe, 1985). Ferrous iron is less likely to precipitate and form sludges.
- Surfactants—Surfactants are used to reduce oil/water surface tension, ensure water wetness, prevent sludge and stabilize foams. They are recommended in most acid treatments to solve one or more potential problems. Small concentrations (e.g., 0.2% to 1%) of surfactants are sufficient. Surfactants are also used as dispersants to keep materials (oil or solids) dispersed in the stimulation fluid and as nonemulsifiers to help prevent emulsions from oil-acid interaction.
- Mutual solvents—Mutual solvents are used to ensure that the formation remains water-wet and to lower surface/interfacial tension. They are recommended in most acid treatments.
- Diverters—Diversion is recommended for all matrix treatments. The bridging agents benzoic acid and rock salt are used to bridge in perforations and/or fissures in carbonate formations and injection wells. Oil-soluble resins (OSRs) sized to form an external filter cake on the formation face are typically used as particulate diverters. Small benzoic acid particles can be used in injection wells completed in sandstone

and nonfissured carbonate reservoirs. Water-soluble polymers used as gel diverters must be carefully chosen to have the right combination of stability during the treatment yet break sufficiently to prevent formation damage. They should not be used in sandstones. Foams are formulated with surfactants and a gas phase (usually N<sub>2</sub>). Surfactants must be compatible with other additives included in the foaming solution (Zerhboub *et al.*, 1991).

- Scale inhibitors—Scale inhibitors are materials that suppress the precipitation of inorganic scales from produced fluids. In general, they are retained on the formation and are more effective at neutral pH values. They are normally applied as an overflush to an acid treatment or mixed with a brine (with or without N<sub>2</sub>) and displaced into the reservoir when scale formation is a problem.
- Clay stabilizers—in treatments of clay-bearing sand formations, these polymeric cationic materials decrease clay migration. They are temporarily effective at low concentrations. Clay stabilizers do not prevent silt (e.g., feldspar, mica, chert) migration (Ezeukwu *et al.*, 1998). They are available in different molecular weight ranges for higher and lower permeability formations, and they must be tailored to the formation to avoid causing damage from the physical plugging of pore throats. Clay stabilizers are recommended where experience indicates that clay migration is a problem.
- Aluminum stabilizer—This class of chemicals was introduced in recognition of the role of fluoroaluminates in secondary precipitation in wells at temperatures above 200 degF in sandstones (Gdanski, 1996). Although new chemicals have been introduced to address this problem, citric acid works well and is economical (Rogers *et al.*, 1998).
- Retarders—Numerous systems for delaying acid reaction in carbonates and allowing deeper penetration into the reservoir have been developed. Simulations should be performed to quantify their benefit.
- Nitrogen—N<sub>2</sub> is commonly added to treating fluids in low-pressure wells to assist in cleanup or to create a foam diverter.

Once the proper treating fluid formulations have been selected, the pumping schedule must be designed.

### 13-5.3. Pumping schedule generation and simulation

The pumping schedule includes the treating fluid and diverter sequence and the injection rate of each stage. It is generated using empirical rules based on previous field experience or computers.

A numerical simulator can be used to simulate damage removal and evaluate skin effect evolution, flow profile and wellhead or bottomhole pressure versus injection rate for the proposed pumping schedule. The simulator takes into consideration the placement strategy, an important part of the design process. The schedule can be optimized using a single-phase reservoir model to meet specific objectives for each fluid type (Bartko *et al.*, 1996). This step allows the design engineer to optimize the schedule to obtain the desired results in the most cost-effective manner. A treatment design is not systematically engineered until it is run using a field-validated simulator. Most treatments are currently based on empirical rules of thumb.

The matrix treatment design process includes several steps. The manual process that is discussed in detail in Chapters 17 through 19 should be understood before using computer-aided design programs. This section focuses on computer-generated design, with emphasis on the required input and interpretation of the output. A field case history for a sandstone is used to illustrate the utility of the procedure.

#### ■ Design types

The four levels of matrix design are photocopy design, advisor design, empirical/kinetic-based design and geochemical-based design. The first two are used for 98% of all matrix treatments. The high failure rate is partially attributed to this nonengineered approach. A discussion of each follows.

##### – Photocopy design

A photocopy design is based on a previous treatment pulled from the well file or an offset well file. The well name and date are changed, and the treatment is submitted for approval or simply processed and pumped.

##### – Advisor design

An advisor treatment design is developed on the basis of guidelines (rules of thumb) or experience. The design may be a refinement over the photocopy design, or it may be similar to it. Obviously, because a treatment design should be reservoir- and formation-damage specific, application of the advisor design is usually not optimum, as shown for the sandstone case history.

Sandstone field case history—The well was previously selected as a matrix stimulation candidate, with clay swelling and/or fines migration damage. Laboratory testing indicated that the well should be treated with mud acid and overflushed with fluoboric acid. Following the guidelines in Fig. 13-4, 50 gal/ft of HCl and 75 gal/ft of mud acid were recommended. Normally, the fluoboric volume is equal to the mud acid volume. Thus, the pumping schedule in Table 13-1 was developed.

Simulation of the advisor design using the kinetic-based numerical simulator described subsequently yielded a decrease in the damage skin effect from 206 to 37. Figure 13-6 shows adequate skin effect evolution in all layers except layer 4. Based on the negative slope of skin effect evolution in layers 2 and 4, it appears that more mud acid should be pumped.

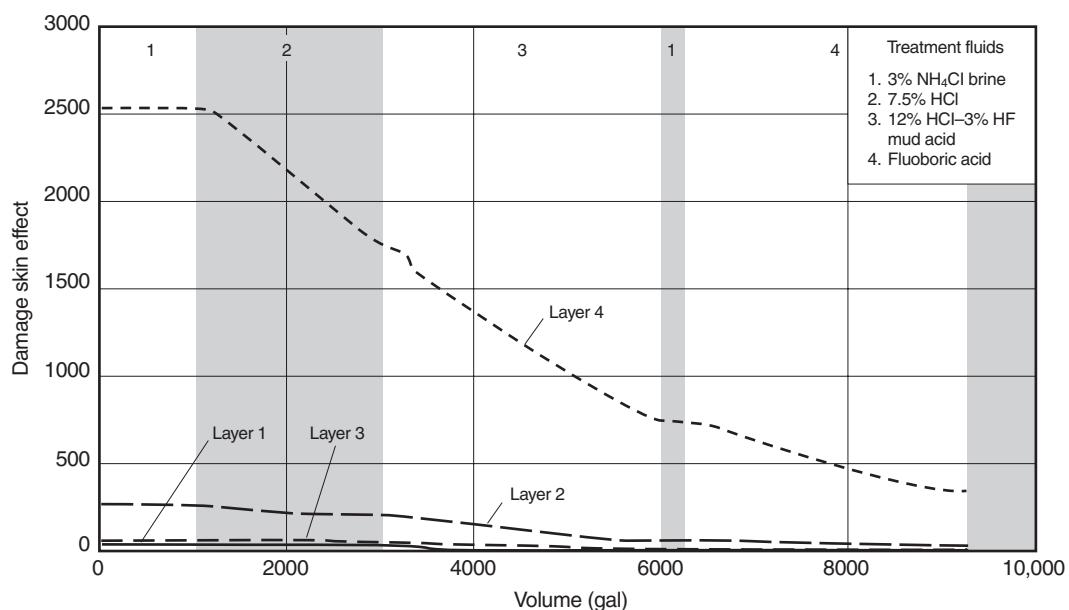
**Table 13-1. Advisor design for sandstone field case.**

Fluid Stage	Description (bbl/min)	Rate (gal)	Volume
Preflush	3% NH <sub>4</sub> Cl brine	1.0	1000
Preflush	7.5% HCl	1.0	2000
Main fluid	12% HCl–3000	3% HF mud	1.0
Overflush	3% NH <sub>4</sub> Cl brine	1.0	250
Main fluid	Fluoboric acid	1.0	3000

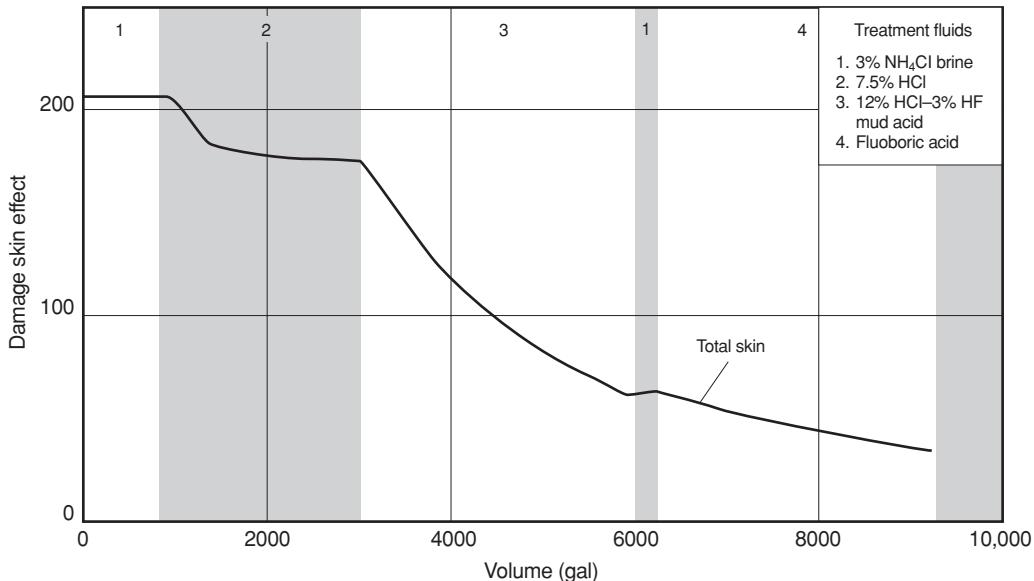
The total damage skin effect versus volume for the same treatment is shown in Fig. 13-7. The change in slope during the mud acid and fluoboric acid stages is attributed to retardation of the fluoboric acid and the change in available HF. The fluoboric acid generates 2.2% HF whereas the mud acid contains 3% free HF (Thomas and Crowe, 1981).

#### – Empirical/kinetic-based design

An empirical/kinetic-based design is produced using a numerical simulator. At a minimum, the simulator should be a two-dimensional (2D), two-phase, finite-difference simulator that allows a multilayer configuration for computing pressure and skin effect evolution during the matrix acidizing of sandstones and carbonates. Mineral dissolution should be simulated using the most common minerals and acids along with the appropriate reaction kinetics (reaction rate limited in sandstones and mass-transfer limited in carbonates with wormholing). This type of simulator correlates the local porosity change during acidizing to a local permeability modification and finally to an overall damage skin effect evolution per layer. Currently, precipitation is not considered in the empirical/kinetic-based simulator; however, if the acids are formulated properly this should not affect treatment results.



**Figure 13-6.** Acid placement: skin effect versus volume by layer (advisor design).



**Figure 13-7.** Acid placement: skin effect versus volume (advisor design).

The empirical/kinetic-based simulator can model damage removal and evaluate skin effect evolution, flow profile and wellhead or bottomhole pressure versus injection rate for the proposed pumping schedule. This step allows the design engineer to fine tune or optimize the schedule to obtain the desired results in the most cost-effective manner. The simulator should be validated using field data to remove uncertainties in the design parameters (Bartko *et al.*, 1996; Thomas *et al.*, 1998).

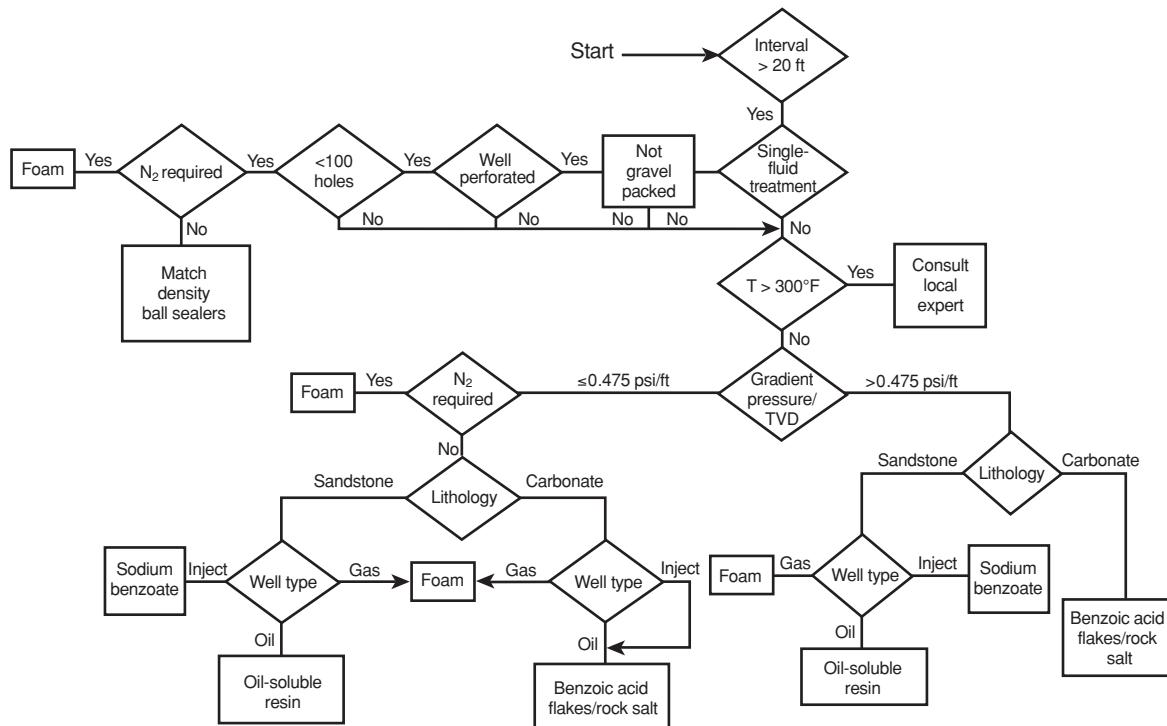
Before using an empirical/kinetic-based simulator, a preliminary pumping schedule should be generated with a numerical simulator for matrix sandstone and carbonate acidizing. This advisor recommends treatment volumes based on the damage penetration. The flowchart in Fig. 13-8 is incorporated in the expert system to assist diversion selection. The pumping schedule includes the treating fluid and diverter sequence and injection rate of each stage. It is generated using empirical rules based on previous field experience or computers.

The schedule can be optimized with a single-phase reservoir model to meet specific objectives for each fluid type (Perthuis *et al.*, 1989).

Sandstone field case history—The pumping schedule shown in Table 13-2 was generated using the numerical simulator described in this section. The objective input to the model was a target damage skin effect per layer of approximately 10% of the original for the mud acid system. This design is approximately twice the volume of the preceding advisor design.

The empirical/kinetic-based numerical simulation pumping schedule yields a total damage skin effect of 16.6 (8% of the original damage skin effect) with good skin effect evolution in layer 4 (Fig. 13-9).

The bottomhole pressure and pumping rate are shown in Fig. 13-10. The overall increase in pressure during the treatment results from diverter deposition. This especially dominates in the stages with the least amount of damage removal (i.e., HCl and fluoboric acid stages).



**Figure 13-8.** Diversion selection flowchart.

**Table 13-2. Pumping schedule generated by simulator for sandstone field case.**

Fluid Stage	Description	Rate (bbl/min)	Volume (gal)
Preflush	3% $\text{NH}_4\text{Cl}$ brine	1.0	1500
Preflush	7.5% HCl	1.0	5350
Main fluid	12% HCl–3% HF mud	1.0	6660
Overflush	3% $\text{NH}_4\text{Cl}$ brine	0.8	840
Main fluid	Fluoboric acid	0.8	5050

To check the validity of the simulator, the actual treatment performed on the well was simulated. The actual pumping schedule is shown in Table 13-3. The empirical/kinetic-based simulator yielded a final damage skin effect of 14.2; the actual damage skin effect was 11.4 from a post-treatment pressure transient test. Thus, the simulator predicted a 93% reduction in damage skin effect whereas the actual skin effect reduction was 94%, indicative of model validation. The good agreement of the simulated skin effect evolution of the treatment with the actual pressure transient test results is shown in Fig. 13-11. Figure 13-12 shows the excellent skin effect evolution in each layer for the actual

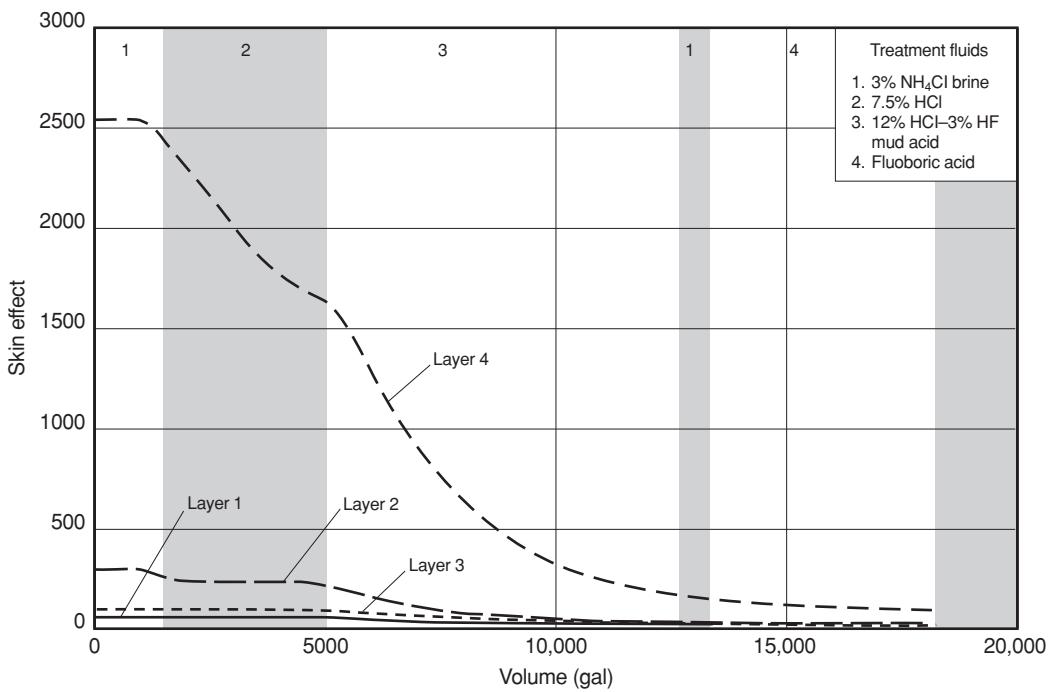
**Table 13-3. Actual pumping schedule for sandstone field case.**

Fluid Stage	Description (bbl/min)	Rate (gal)	Volume
Preflush	7.5% HCl	1.0	4000
Main fluid	12% HCl–3% HF mud	1.0	8000
Overflush	3% $\text{NH}_4\text{Cl}$ brine	1.0	500
Main fluid	Fluoboric acid	1.0	5000

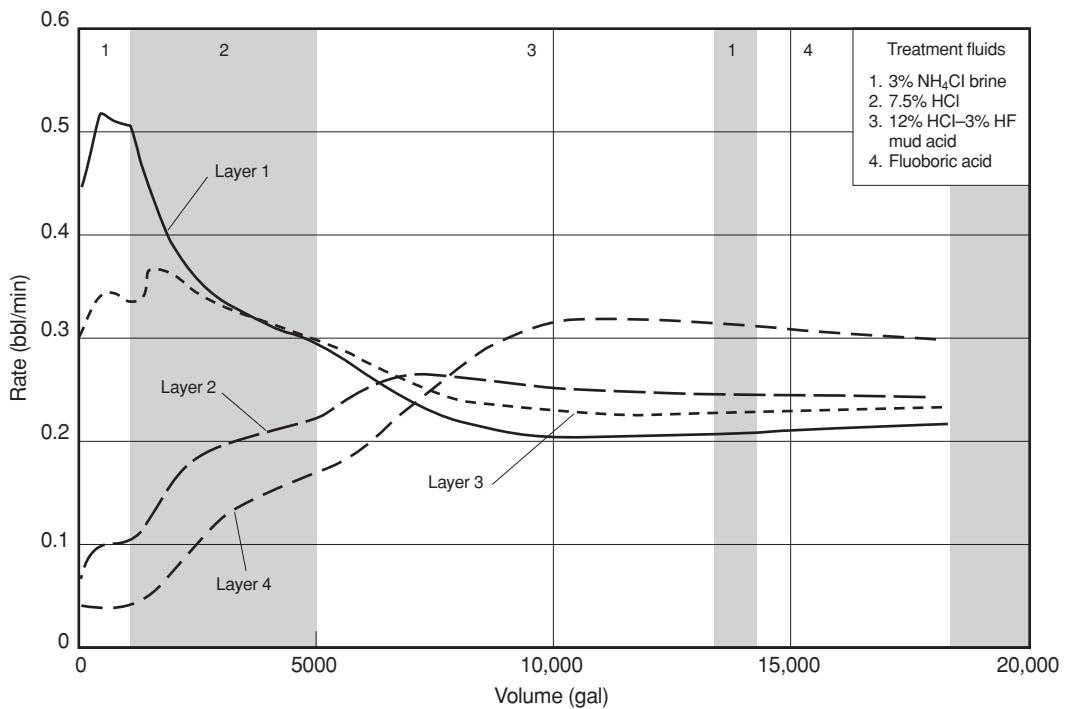
treatment. Figure 13-13 shows the flow rate into each layer versus the volume injected. The flow rate into all layers changed during the treatment; i.e., the rate into the thief zones decreased whereas the rate into the highly damaged zones increased.

#### – Geochemical-based design

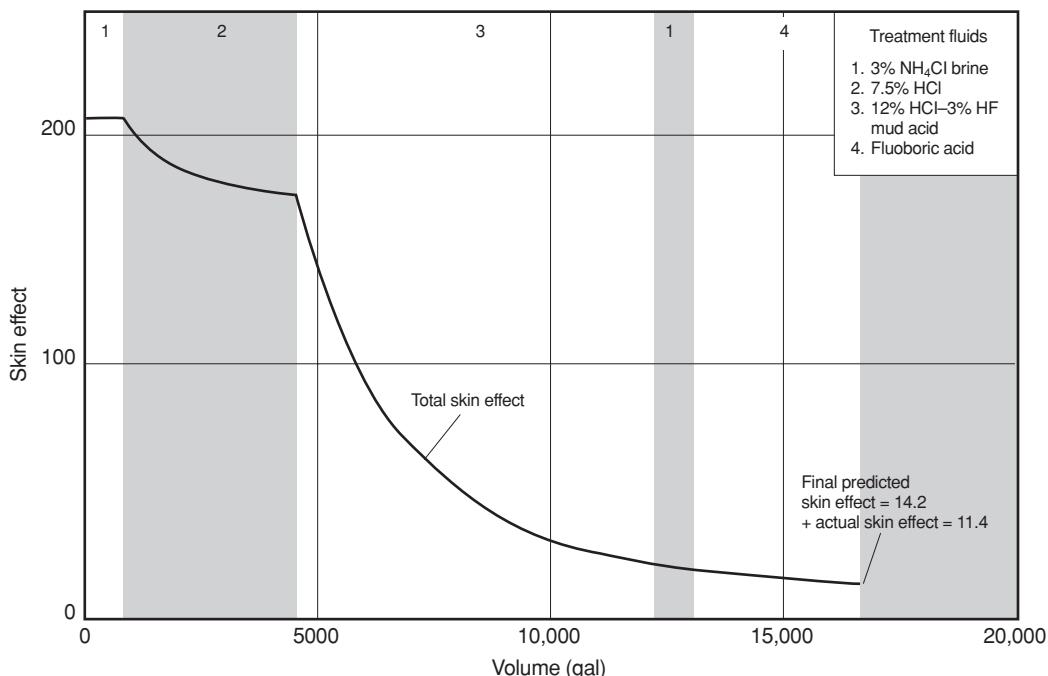
A numerical simulator similar to that discussed for the empirical/kinetic-based design is used for the geochemical-based design; however, the precipitation of reaction products is considered and reported. This is accomplished by incorporating acidizing equilibrium chemistry for up to 14 elements and 100 reaction products.



**Figure 13-9.** Acid placement: skin effect versus volume (empirical/kinetic-based design).



**Figure 13-10.** Bottomhole pressure and pumping rate versus volume (empirical/kinetic-based design).



**Figure 13-11.** Skin evolution of the simulation of the actual treatment.

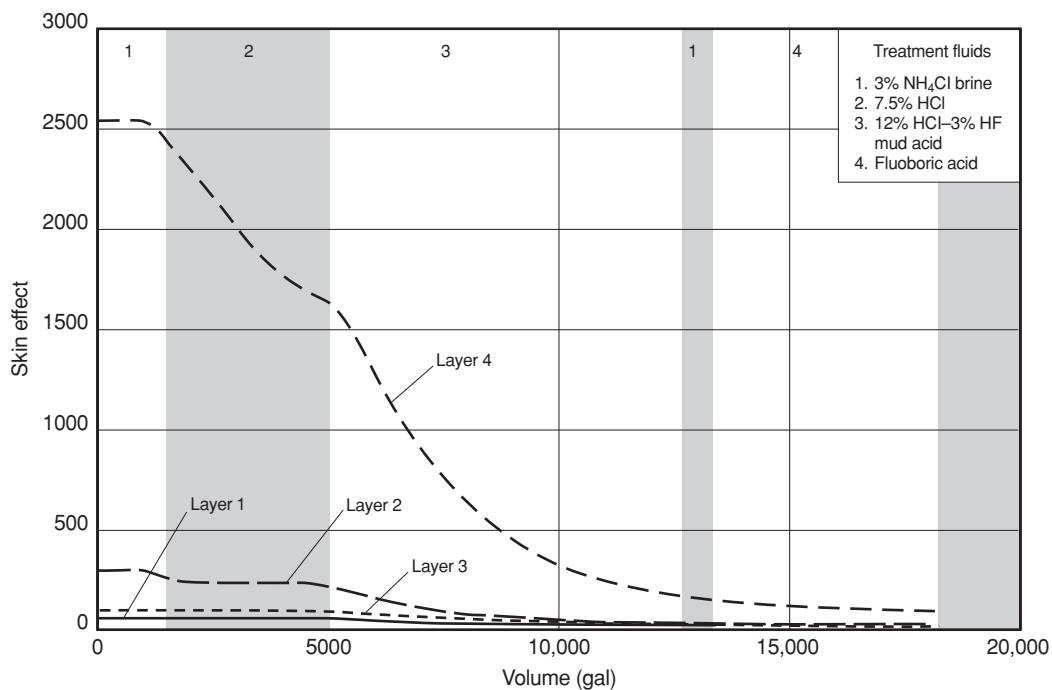
#### ■ Calculations

Equations to calculate the maximum surface treating pressure and injection rate are provided in Chapter 16 for vertical and horizontal wells. The maximum injection rate in a horizontal well usually exceeds the available pumping equipment capability; however, many jobs pumped into horizontal wells employ coiled tubing, which limits the rate far below that necessary to fracture.

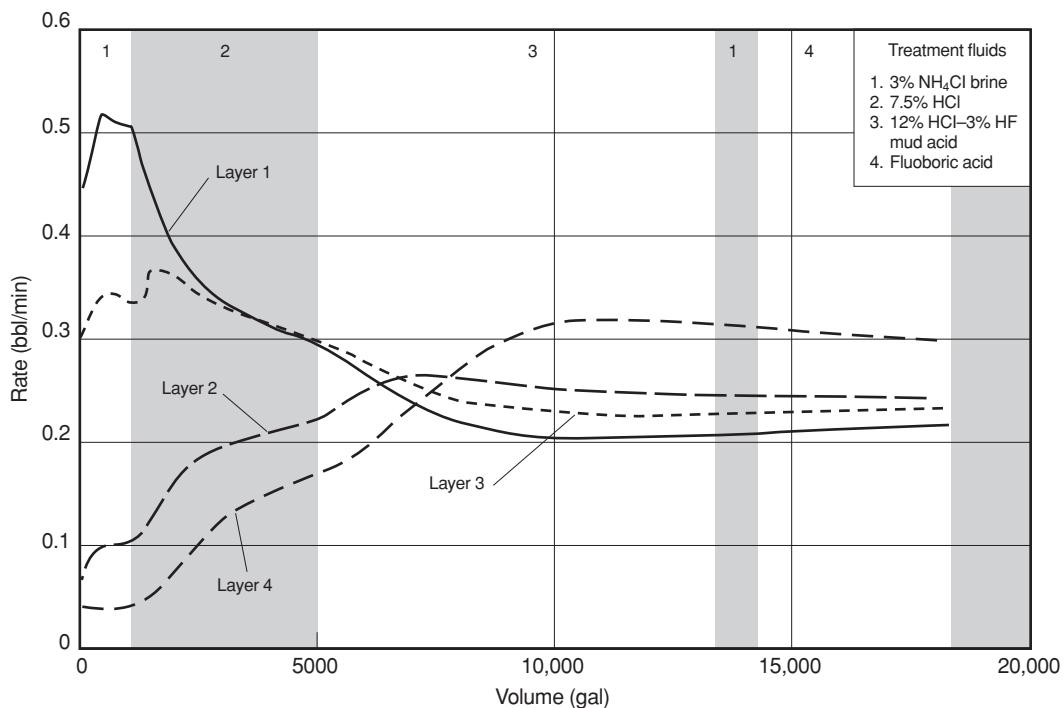
#### ■ Placement strategy

Placement strategy is an important step in the design of a matrix treatment (see Chapter 19). The goal is how to obtain uniform penetration of the treating fluid throughout the entire section and/or into each natural fracture system. If complete zone coverage is not achieved, full production potential cannot be realized.

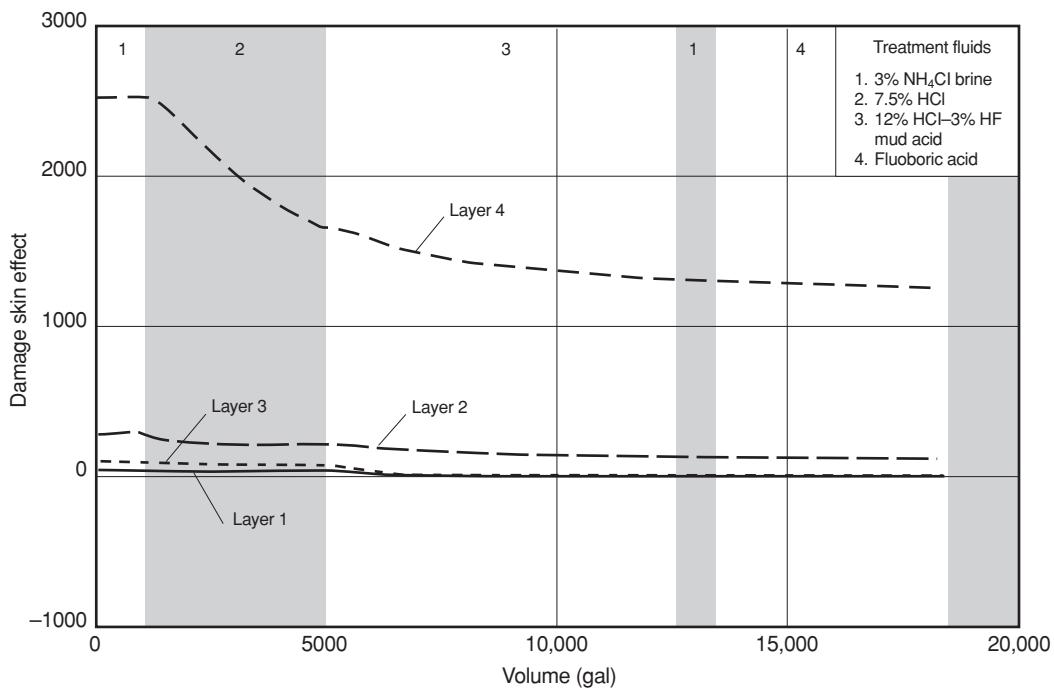
Simulation of the actual sandstone design without a diverter indicates that layers 1 and 3 remain thief zones throughout the entire treatment (Fig. 13-14). In addition, skin effect values for the severely damaged bottom layer reduce to 75 for treatments with diverter and 1,250 for treatments without diverter (Figs. 13-12 and 13-14, respectively). The poor fluid distribution can result in an excessive acid volume per foot of layer in the case without a diverter and inefficient formation damage removal. Figure 13-15 shows that the final damage skin effect is 20 in the case without a diverter. Although this represents a 90% reduction in skin effect and would yield approximately 4,000 BOPD, the actual treatment with a particulate diverter yielded a 93% reduction in skin effect and more than 5,000 BOPD. Thus, the small amount of diverter added to the treating fluids improved the efficiency of the acid and the resulting well performance (i.e., added approximately 1,000 BOPD).



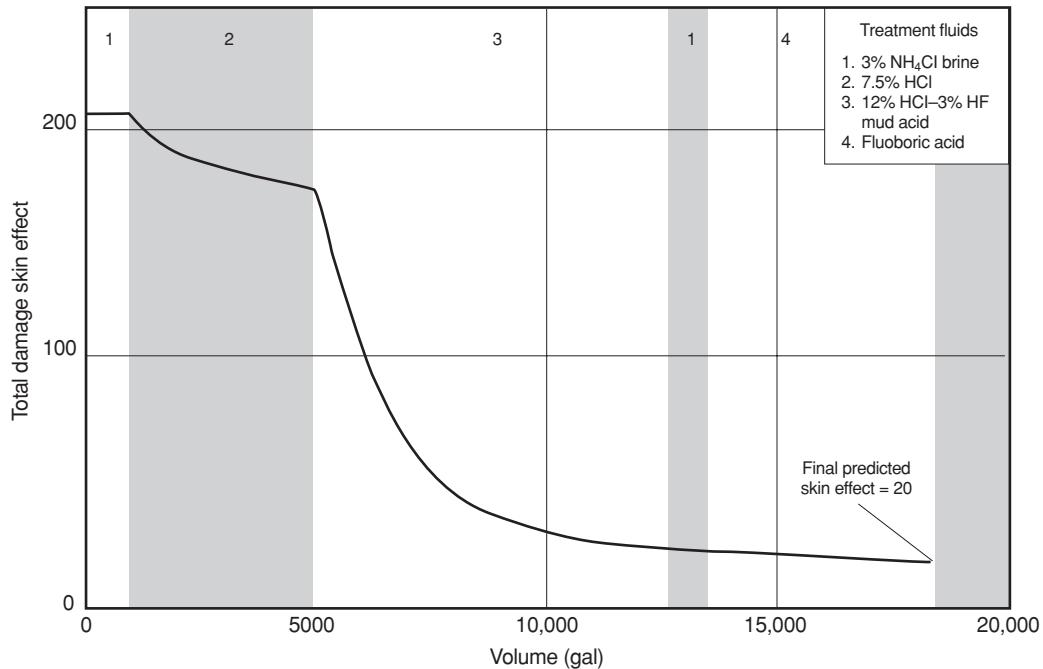
**Figure 13-12.** Skin effect evolution per layer for the actual treatment.



**Figure 13-13.** Flow rate into each layer versus volume injected.



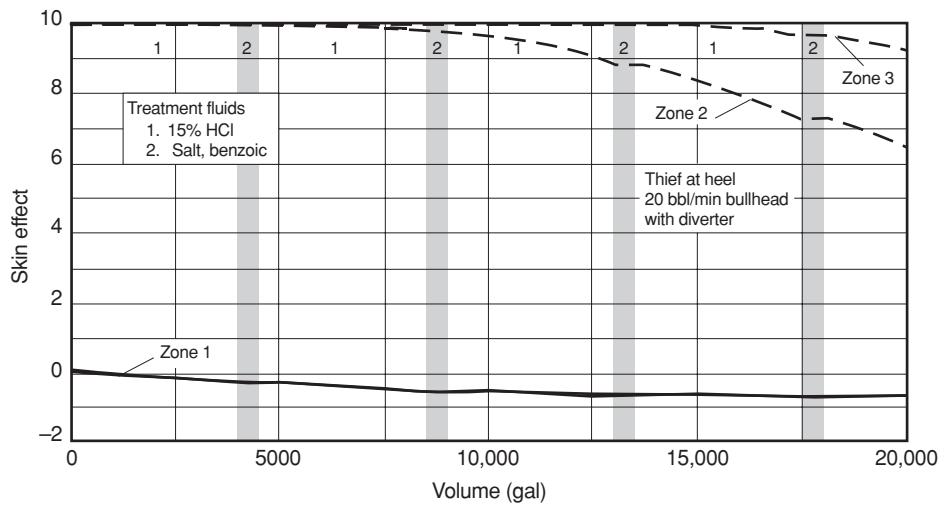
**Figure 13-14.** Damage skin effect per layer versus volume for a treatment incorporating the actual treatment volume without a diverter.



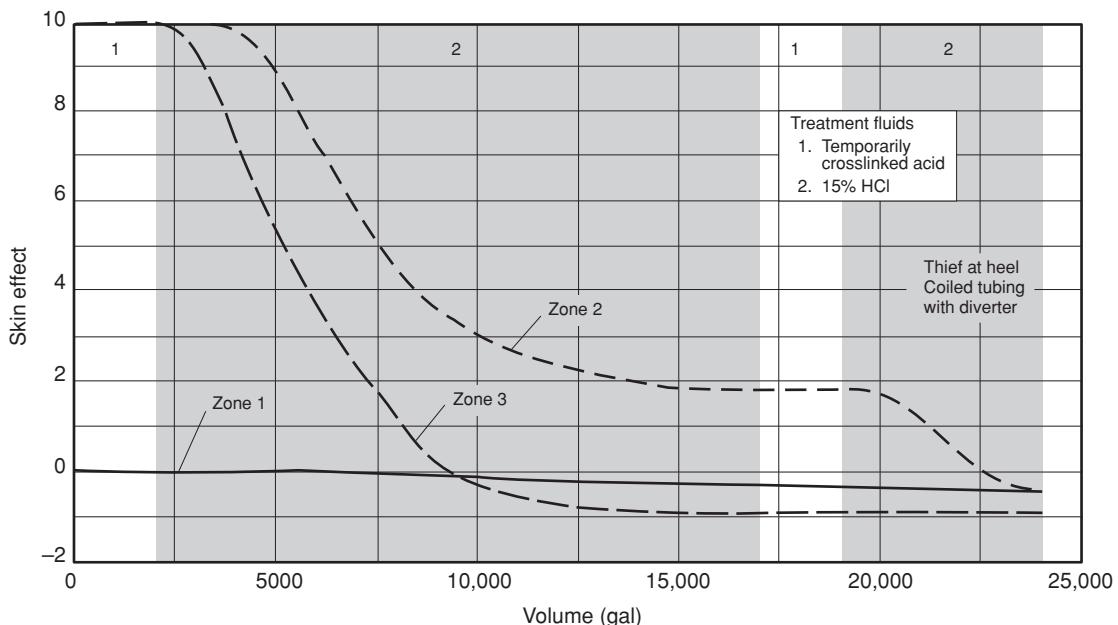
**Figure 13-15.** Total damage skin effect evolution versus volume.

The importance of the placement strategy is magnified in a horizontal well because of the long interval. The placement strategy must address the type of tubing used to inject the fluid and diversion of the fluid from thief zones to the damaged sections. (The term zone is used here to describe longitudinal sections of a horizontal well, from the heel to the toe.) Although conventional tubing or casing can be used to place the treating fluid, this process can be time consuming or inefficient (Fig. 13-16).

Coiled tubing is generally used to overcome these problems. Unlike conventional tubing, coiled tubing can easily be run in and out of the hole, and treating fluid and diverters can be injected during movement (Thomas and Milne, 1995.) Figure 13-17 shows the good skin effect evolution obtained with this technique. Injection down the annulus of the coiled tubing and tubing may be required to optimize fluid diversion and should be modeled during simulations.



**Figure 13-16.** Skin effect evolution in a horizontal well treated using the bullhead technique.



**Figure 13-17.** Skin effect evolution in a horizontal well treated using a coiled tubing placement technique with a temporarily crosslinked acid diverter.

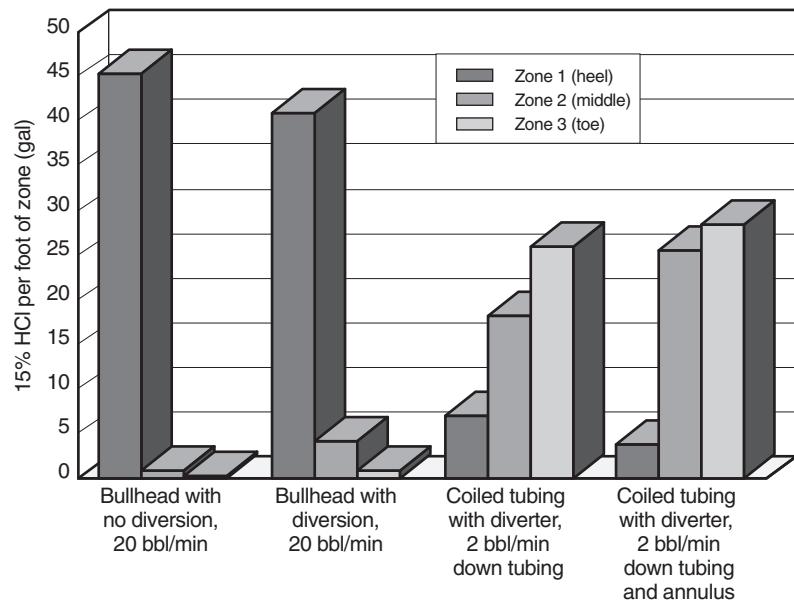
The placement technique is based on the information available for the well. For example, if a production log or spinner survey, mud logs or a log to locate fissures is available, this information can be used to aid the treatment design. If a spinner survey indicates that a thief zone exists in the center of the horizontal length, the coiled tubing can be run to that depth, followed by injection of a diverter slug. The diverter does not completely plug the thief zone but greatly decreases fluid flow into the zone. This process can be repeated as required on the basis of information from production and fissure location logs. The coiled tubing can subsequently be run to total depth to start the treatment. Drilling breaks and mud logs can be used for the same purpose. If the data are inadequate, the entire section is normally treated by alternating acid and diverter stages as the coiled tubing is retrieved.

Diversion must be achieved to ensure that the treating fluid is continuously removing damage rather than simply being injected into a thief zone. Mechanical techniques (straddle packers or ball sealers) are not practical in many wells because they are completed openhole, with slotted liners or gravel packed. In cased hole completions, a straddle packer can be used to selectively place the treating fluid. In carbonate reservoirs, a chemical diverter (i.e., benzoic acid, rock salt, polymer systems, wax beads) can be used.

OSR or foam is normally used in sandstone formations for diversion. Solid diverting agents such as benzoic acid flakes have been used for decades but sometimes do not clean up well following the treatment. This especially occurs in carbonates, where large quantities of inefficient diverters are commonly required to create an increase in bottomhole pressure, resulting in diversion. Although OSRs perform well in sandstones, numerous operators use foam diversion techniques to avoid any chance of plugging by the diverter. A special

application of foam diversion is in high-water-cut wells, where the foam preferentially plugs the water zone, allowing acid to flow into the damaged oil zones (Zerhboub *et al.*, 1991). Similarly, the use of solids for diversion in carbonates has decreased in favor of foam and temporarily crosslinked polymer (Saxon *et al.*, 1997). This approach eliminates the slow cleanup experienced following conventional treatments and results in good zone coverage in vertical and horizontal wells.

Modeling of matrix acidizing of a horizontal well with the 2D simulator previously discussed (Thomas and Milne, 1995; Jones and Davies, 1996) indicates that bullheading matrix treatments in high-permeability or highly fractured limestones may be inefficient. Bullheading acid with a diverter normally results in poor coverage beyond 200 to 300 ft. Apparently the acid rapidly creates a thief zone at the entrance to the zone, and conventional chemical diversion techniques are ineffective (Fig. 13-16). If coiled tubing is used, a diverter can be placed across a known thief zone followed by running the coiled tubing to total depth. Acid is then pumped as the coiled tubing is withdrawn, and a diverter slug is injected every 100–200 ft as required. The result is uniform penetration over the damaged sections with a small amount of acid injection into the thief zone located at the heel. Figure 13-17 shows the results of a numerical simulation, indicating diversion from the heel (i.e., the thief zone) is accomplished using coiled tubing and a diverter. Improved diversion is achieved when annular flow is optimized during the coiled tubing treatment. Figure 13-18 shows a poor distribution of acid per zone when the bullheading technique is used, whereas the treatment goal is achieved when coiled tubing placement is used (i.e., proper stimulation of damaged zones 2 and 3). The case histories reported in Sidebar 13E support the results of the simulations.



**Figure 13-18.** Simulation of acidizing a horizontal well with a thief zone at the heel.

### 13E. Placement study case histories

The following placement studies are the results of work reported by Thomas and Milne (1995).

#### Horizontal oil Well 1: bullhead technique

Horizontal injection Well 1 was completed in a limestone formation with 1800 ft of 5½-in. slotted liner inside an 8½-in. openhole. The well initially accepted 1000 BWPD. Because drilling mud damage was suspected, the well was acidized with 90,000 gal of 15% HCl at 25 bbl/min using the bullhead technique. Diversion was not used in the treatment. After the treatment, injection increased to 16,000 BWPD. The post-treatment PLT log indicated that 80% of the flow was into the first 100 ft below the casing shoe (Fig. 13E-1).

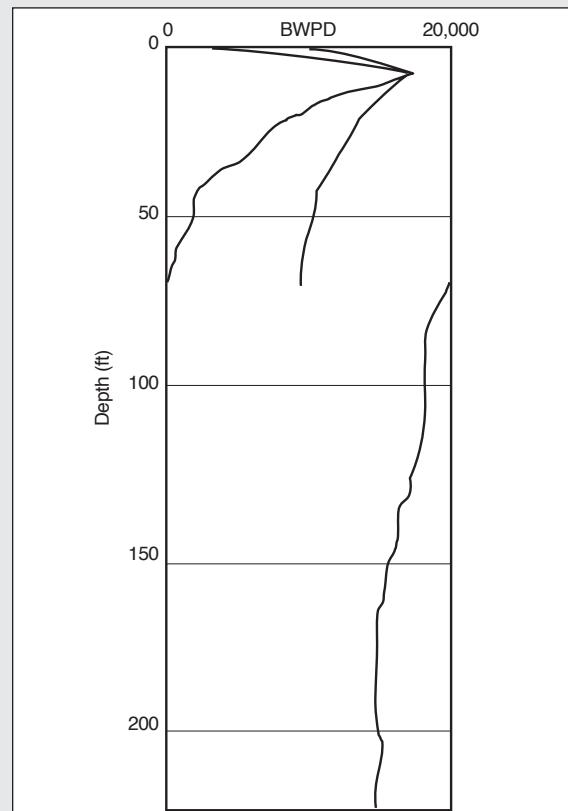
Although no diverter was used in this treatment, the addition of conventional benzoic acid or rock salt diverters was predicted to not improve zone coverage significantly. This was based on similar results observed in vertical wells completed in long limestone zones acidized using a bullhead technique with diverter. Thus, the acidizing treatment using the bullheading technique was not effective in obtaining zonal coverage as predicted by the modeling work.

Injectivity into Well 1 declined over the following 2-month period to 12,000 BWPD. The well was subsequently treated with 26,000 gal of HCl (15 gal/ft) using coiled tubing without a diverter, and injection was restored to 15,000 BWPD. Although injection was not restored to the original level, it was maintained for 1 year, which was indicative of a larger surface area accepting fluid.

#### Horizontal oil Well 2: coiled tubing with foam diversion

Well 2 was completed with a 4½-in. slotted liner in two sections of the Arab D limestone to yield 2378 ft of horizontal hole. The upper section was approximately 1500 ft long with a 100-ft barrier leading down to the lower Arab D limestone with approximately 780 ft of hole. The well was acidized using 25 and 20 gal/ft of 15% HCl in the upper and lower sections, respectively. The larger volume in the upper section was used because of the extended exposure time to drilling mud and suspected higher damage.

The treatment was performed by running 1½-in. coiled tubing in the hole to total depth, followed by loading the hole with diesel. HCl



**Figure 13E-1.** Post-treatment injection log of a horizontal well acidized using the bullhead technique.

### 13E. Placement study case histories (continued)

was then injected at 2.5 bbl/min while the coiled tubing was withdrawn to yield the appropriate gallons per foot. A pressure of 1200 psi was maintained on the coiled tubing annulus to minimize acid flow up the backside. After it was pulled 50 ft, the coiled tubing was stopped and 65% quality foam was injected as a diverter. This sequence was repeated 15 times. Subsequently, the barrier section was loaded with 65% quality foam.

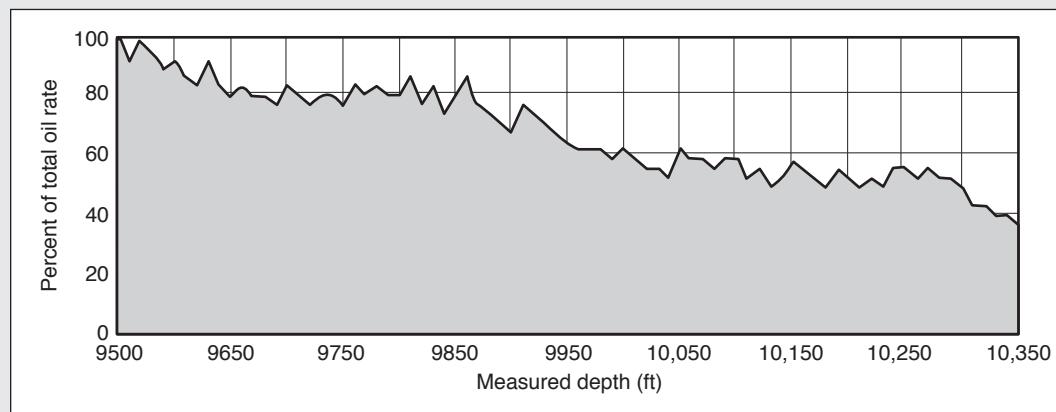
Once the coiled tubing was in the upper section of the Arab D limestone, it was acidized in 30 stages using the same process of alternating stages of acid and foam. Following the last acid stage, the coiled tubing was run to total depth and the horizontal section was displaced with diesel.

Prior to acidizing the well would not flow, yet post-treatment production was 2484 BOPD at 1318-psi flowing tubing pressure. Post-treatment production from the well is more than that from similar horizontal wells treated with up to 4 times more acid (100 gal of 15% HCl per foot of the horizontal section). The key to successful horizontal well acidizing was apparently not the volume of acid but the placement and diversion techniques.

#### Horizontal oil Well 3: coiled tubing with temporarily crosslinked acid diversion

Well 3 was completed openhole in the Arab D limestone with 1000 ft of horizontal hole. Upon initial completion a bullhead acid treatment was performed to remove drilling mud and cuttings damage. However, the results were unsatisfactory. The goal of the treatment was to provide uniform injection along the entire wellbore. Subsequently, the well was acidized using coiled tubing placement to inject 10 gal/ft of 15% HCl with silt dispersants and 4 gal/ft of temporarily crosslinked HCl (Saxon *et al.*, 1997). The treatment was performed by running coiled tubing in the hole to total depth and then injecting 6.3 gal/ft of HCl while withdrawing the coiled tubing from 10,553 to 10,353 ft. This process was repeated while running to total depth (10,553 ft). Next a temporarily crosslinked HCl diverter was injected while pulling out of the hole to 10,353 ft, which was then repeated 3 times to obtain good coverage. Once the coiled tubing reached 9753 ft, it was withdrawn while injecting HCl.

The post-treatment production log in Fig. 13E-2 shows an 800-ft section from the heel with significant flow near the toe of the well. (The production logging tool could not go beyond 800 ft.) This favorable flow profile is completely opposite that of Fig. 13E-1, showing a majority of the flow coming from near the heel of the well. Coiled tubing placement complemented by a temporarily crosslinked acid diverter apparently yielded improved coverage.



**Figure 13E-2.**  
Post-treatment production log of a horizontal well acidized using coiled tubing and temporarily crosslinked HCl diversion.

#### Horizontal oil Wells 4, 5 and 6: coiled tubing with temporarily crosslinked acid diversion

Wells 4, 5 and 6 were treated similarly to Well 3 with coiled tubing and a temporarily crosslinked HCl diverter. Eight to 15 gal of HCl with mud dispersants per foot of the horizontal zone was used in combination with 4 to 5 gal/ft of temporarily crosslinked HCl diverter.

The treatment was performed by running coiled tubing in the hole to total depth and subsequently reciprocating across a 100- to 500-ft section while pumping HCl. Next the coiled tubing was withdrawn while the diverter was injected. This process was repeated as required to obtain coverage over the entire horizontal section. The horizontal length, permeability and production results for the wells are summarized in Table 13E-1. In all cases, production increased significantly, with treatment payout in less than a month. The average increase in production was 1630 BOPD.

#### Vertical wells: bullhead technique

Long (150- to 200-ft) vertical openhole sections of the Arab D formation were historically treated with large volumes of HCl using the bullhead technique. Normally, 100 gal/ft of 15% HCl was injected down the tubing with diverter stages consisting of rock salt and benzoic acid flakes. As reported in the preceding horizontal well case histories, the authors observed that the acid went primarily into the high-permeability zones and the upper sections. This observation is based on the evaluation of pre- and post-treatment flowmeter injection surveys, which indicated a highly nonuniform injection profile.

Laboratory tests indicated that the diverter system was inefficient. Although a low-permeability filter cake was formed with the diverter, it was readily penetrated and destroyed by live acid. This situation explained the poor injection profile following the bullhead technique.

### 13E. Placement study case histories (continued)

**Table 13E-1. Production in horizontal oil Wells 4, 5 and 6 increased 440, 1750 and 2700 BOPD, respectively, following HCl treatment placed with coiled tubing and diverted with temporarily crosslinked HCl.**

Well	Horizontal Length (ft)	$k_H$ (md)	$k_V$ (md)	$p_e$ (psi)	Pretreatment		Post-Treatment	
					Wellhead Pressure (psi)	$q$ (STB/D)	Wellhead Pressure (psi)	$q$ (STB/D)
4	3600	6	3	2089	500	970	600	1410
5	1500	10	3	2950	750	950	875	2700
6	2000	25	12	2800	320	1000	260	3700

As indicated in Table 13E-2, the injectivity index increased although injection into the lower permeability zones in the six studied wells was not achieved. The average post-treatment injectivity index was 61 BWPD/psi.

**Table 13E-2. Pre- and post-treatment injectivity index of vertical wells acidized using the bullhead technique.**

Well	Pretreatment Injection Rate (BWPD)	Pretreatment Injection Pressure (psig)	Post-Treatment Injection Rate (BWPD)	Post-Treatment Injection Pressure (psig)	Pretreatment Injectivity Index (BWPD/psi)	Post-Treatment Injectivity Index (BWPD/psi)
A	21,200	1950	12,000	550	24	65
B	41,700	2750	55,300	2200	20	48
C	27,700	2950	52,800	2100	21	70
D	44,200	2800	44,800	1950	30	72
E	33,600	2900	25,700	1200	20	62
F	33,500	2200	41,600	1815	32	47

Average injectivity index = 61 BWPD/psi

#### Vertical wells: coiled tubing with foam diversion

Five wells were completed in the same field and formation as the six vertical wells discussed previously. Coiled tubing and foam diverter stages were used to improve placement of the acid. The goal was to improve the injection profile by effectively acidizing both the high- and low-permeability zones in each well.

Approximately 50 gal/ft of 15% HCl was injected via coiled tubing at 1 to 1.5 bbl/min in stages. The coiled tubing was run to total depth as the foam was injected. Once at total depth, the coiled tubing was withdrawn as acid was pumped to yield 50 gal/ft. After withdrawing 20 to 50 ft, the coiled tubing was stopped and a stabilized foam was pumped. This viscous foam was designed to fill the wormholes created by the previous acid stage to yield improved zone coverage. The staging process was repeated until the top of the zone was reached.

From Table 13E-3, the average injectivity index for the studied wells was 120 BWPD/psi, nearly double that obtained with the bullhead technique. Injection surveys also show that the coiled tubing and foam diversion treatment yielded a more uniform injection profile, indicating that both the high- and low-permeability zones were acidized. This placement technique resulted in excellent overall results and cost 20% less than the conventional bullhead technique.

### 13E. Placement study case histories (continued)

**Table 13E-3. Pre- and post-treatment injectivity index of vertical wells acidized using the foam diversion technique.**

Well	Pretreatment Injection Rate (BWPD)	Pretreatment Injection Pressure (psig)	Post-Treatment Injection Rate (BWPD)	Post-Treatment Injection Pressure (psig)	Pretreatment Injectivity Index (BWPD/psi)	Post-Treatment Injectivity Index (BWPD/psi)
G	5,000	1,300	67,800	1240	4	119
H	26,200	1,550	42,400	1200	26	112
I	10,000	24,000	59,000	1100	5	139
J	0		38,500	934		65
K	5,000	2,000	73,000	1200	3	165

Average injectivity index = 120 BWPD/psi, a 97% increase over the results obtained with the bullhead technique

#### Summary

These case histories illustrate that the key to successful matrix acidizing in carbonate reservoirs is not the amount of acid injected but how it is injected. This is also true for sandstone reservoirs. Coiled tubing placement in combination with foam diversion in sandstones or carbonates appears to be an improved technique. Chapter 17 discusses the self-diverting acid system, which has been used successfully in long carbonate sections, including horizontal wells. This system is advantageous over foam diversion because it does not require nitrogen.

## 13-6. Final economic evaluation

As discussed for the preliminary economic evaluation in Section 13-2.3, an economic analysis is important. A final economic evaluation should be made on the basis of various treatment scenarios (i.e., advisor-based and empirical/kinetic-based designs). An evaluation of the sandstone field case history designs in the previous section follows.

#### ■ Sandstone field case history

The advisor-based design decreased the skin effect from 206 to 37 (Fig. 13-7), but the empirical/kinetic-based design decreased the skin effect from 206 to 16.6 (Fig. 13-9) to yield an additional 1373 BOPD (3406 versus 4779) and nearly \$1.9 million in NPV (almost \$2.7 million versus \$4.5 million). The actual treatment resulted in more than 5000 BOPD at a lower drawdown, with more than 3 million bbl of oil produced over the life of the well. Figures 3-19 and 3-20 show the economic indicators for the advisor- and empirical/kinetic-based designs, respectively.

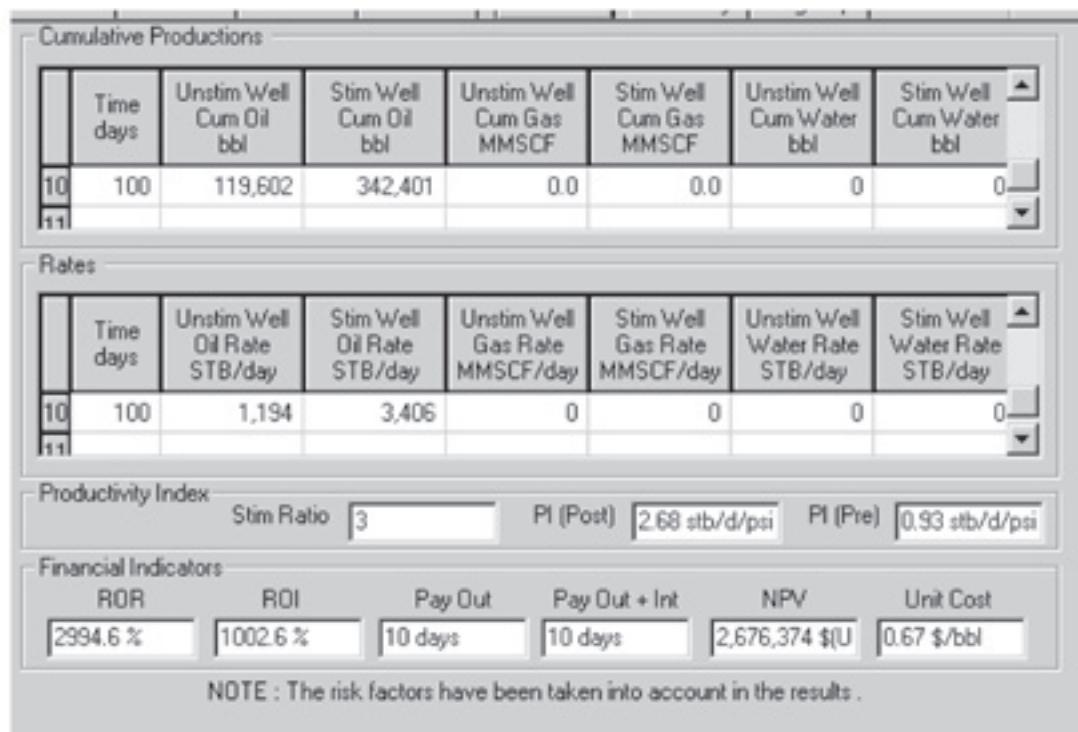
## 13-7. Execution

The execution (pumping operation) must be performed as specified by the treatment schedule or operator on location. During this process, QC and data collection are important. The operational objective is defined by the design. QC is the process of ensuring that the materials and equipment meet specifications and are delivered in proper condition to the wellsite.

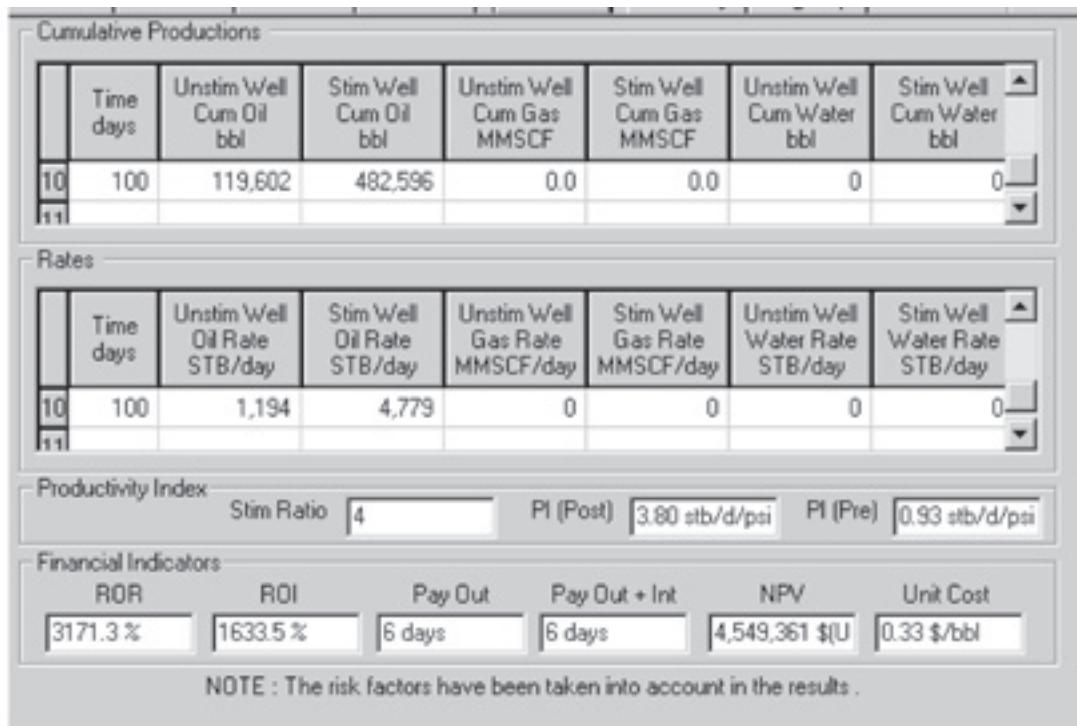
Properly trained personnel are the key to success. The wellsite personnel must understand the fundamentals of the stimulation techniques that will be used and must know how to use the equipment, software and techniques.

### 13-7.1. Quality control

Two keys to effective QC are communication and documentation. The designer must communicate the design expectations to the material suppliers. Because these expectations must be consistent with the supplier or manufacturer's specifications, the specifications should be available to the designer. The designer should request and receive test data on the performance of materials



**Figure 13-19.** Economic indicators for the advisor design sandstone case history. Skin effect decreased from 206 to 37.



**Figure 13-20.** Economic indicators for the empirical/kinetic-based design sandstone case history. Skin effect decreased from 206 to 16.6.

(e.g., corrosion inhibitors) as necessary to ensure that the materials will perform adequately. Numerous standardized test methods developed by the American Petroleum Institute (API), American Institute of Mechanical Engineers (AIME) and National Association of Corrosion Engineers (NACE) can be used to evaluate materials. Additional specialized testing may also be required in critical applications.

QC documentation should follow materials throughout their life cycle and be available if needed by the designer and operating personnel. Suppliers and vendors should ensure that materials shipped to the wellsite meet specifications. Given the time, distance and expense of delivering materials to the wellsite, nobody benefits if materials not meeting specifications arrive on location. In many cases, a material passes through several hands before being delivered to the wellsite. The QC testing routine and required documentation should be agreed on by vendors and customers as part of the commercial arrangement under which services are supplied. Testing should be sufficient to ensure that materials will perform their required functions in the field. Chronic failures in testing are a sign that a more reliable material or better handling procedures are required. Testing methods and options are discussed in Chapter 14.

The degree of attention paid to QC will vary with the critical nature of the operation. For stimulation operations, useful QC measures include

- on-site titration of acids to verify concentration
- regular QC testing of each batch or lot of corrosion inhibitors by the service company
- verification that surface-active agents are supplied in the specified concentration
- on-site testing of gel viscosity for diverters (carbonates)
- regular testing of particle size and solubility of particulate diverters
- sampling of fluids pumped during stimulation treatments, with the samples retained until the treatment has been evaluated.

The equipment must be able to execute the design required. The designer and operations personnel must review procedures in detail to ensure that the available equipment is capable of conducting all required operations. All equipment to be used in stimulation operations should be properly maintained to perform reliably and accurately. As discussed in Section 13-5 for treatment design, adherence to the design is required to increase the chance of success.

Calibration of all measuring devices, such as transducers and flowmeters, should be a regular part of maintenance procedures. Calibration conditions should mimic operating conditions to the extent required to properly calibrate the equipment. Sufficient inventories of spare parts should be available to make maintenance repairs quickly. Calibration tests should be conducted routinely and the results documented.

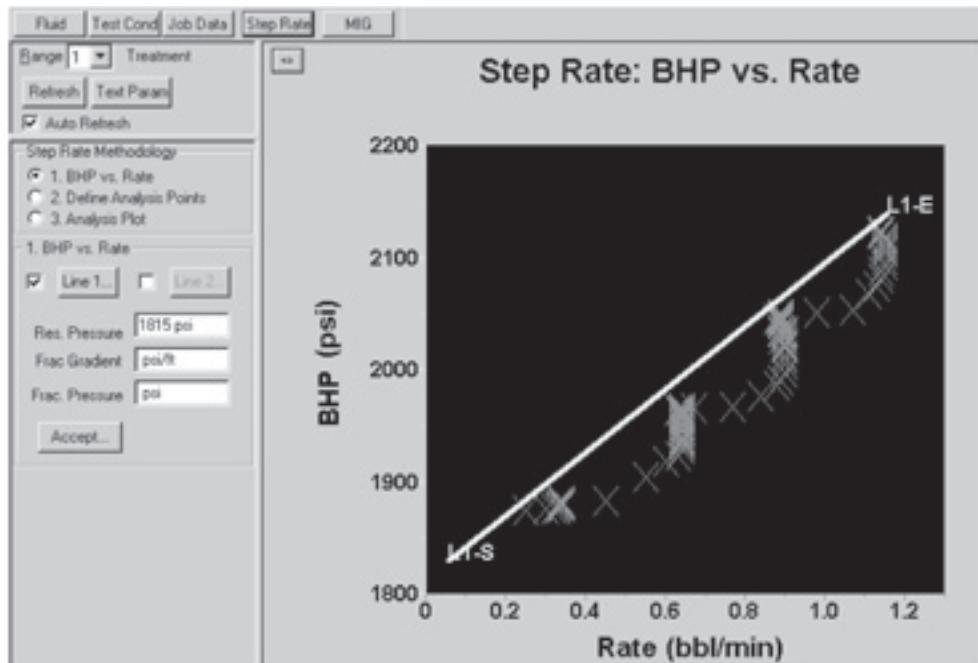
### 13-7.2. Data collection

Careful recording of events during the treatment should be made, including records of unusual observations by operations personnel (McLeod and Coulter, 1969). Over the past decade, the emphasis on improved monitoring and recording equipment and QC rather than pumping and mixing equipment has resulted in better records for postjob treatment evaluation and improved matrix success.

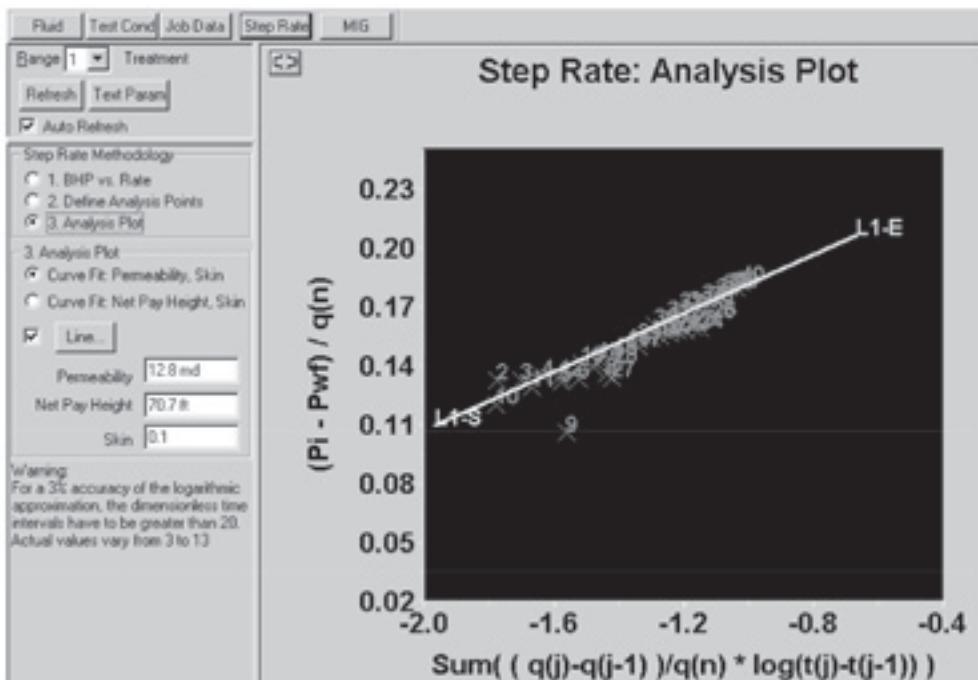
The basic information available from a stimulation treatment minimally consists of a record of pressure and rate and a log of operations prepared by operations personnel. All pressure charts can be analyzed; however, their usefulness may be limited by their imprecision (e.g., pressure gauge accuracy may be  $\pm 150$  psi) and the difficulty and time required to put the data in a more useable form.

The modern approach is to provide continuous digital monitoring of the surface rate and pressure with either an on-site computer or digital data logger. Combined with a detailed log of operations, this information can be analyzed in real time or processed after the procedure with the same type of software. The key advantages of continuous monitoring are higher precision of the data and easier manipulation of the digital data files using computers. The chief drawback is that bottomhole treating pressure must be calculated from surface treating pressure. Reliable means for this calculation are available for Newtonian fluids (e.g., brines and acids), but the calculation for complex fluids (e.g., gels, slurries, foams) is not always reliable.

A relatively simple solution to this problem is to allow pressure communication between the injected fluid column and a static fluid column if the reservoir pressure is greater than the hydrostatic pressure resulting from a column of fluid. The surface pressure of the static fluid is measured, and the bottomhole treating pressure is obtained by subtracting the hydrostatic pressure of the static fluid column. The static column is normally an annulus, either tubing/casing or coiled tubing/tubing. Packer assemblies can be modified to allow pressure communication. The main operational drawback is that stimulation fluids may leak into the tubing casing annulus, which necessitates additional operations to remove them.



**Figure 13-21.** Determination of reservoir pressure from a step rate test.



**Figure 13-22.** Pressure transient analysis from a step rate test.

Memory gauges can also be run on treating strings to record the bottomhole temperature and pressure during treatment. They are retrieved after the treatment and analyzed directly. Their obvious drawback is that real-time analysis is not possible. In running memory gauges, it is critical to select a sufficiently long time interval to record the operation. If similar treatments using gel, foam or slurry diverters are to be performed on a series of wells, a memory gauge can be run on the first one and the data used to develop a friction pressure correlation for the diverters. Surface pressure can then be used with acceptable accuracy on subsequent treatments.

Surface-readout bottomhole pressure recording devices are also available. In general, the devices are expensive and the additional operational difficulties associated with running them further increase their cost. However, they are invaluable for stimulation evaluation and also for reservoir evaluation and management.

In addition, where coiled tubing is run, sensor packages to monitor pressure and temperature are used to determine bottomhole treating pressure for calculation of the skin effect. The temperature profile is determined prior to a treatment following injection of an inert fluid (e.g., water containing ammonium chloride) to estimate the flow profile. Another temperature profile can be run after the treatment to quantify zone coverage.

Technology exists to transmit the job data to the office from most locations. This efficient technique allows an engineer to monitor numerous jobs, participate in decision making and direct operations from off site.

## 13-8. Treatment evaluation

### 13-8.1. Pretreatment evaluation

A step-rate test can be performed prior to the stimulation treatment to quantify reservoir pressure, permeability and skin effect. The benefit to the operator is improved real-time evaluation. The test requires injection of an inert fluid into the zone of interest and bottomhole pressure calculation and recording. The first diagnostic performed determines the reservoir pressure using a plot of the bottomhole pressure versus rate. Theoretically, the y-axis intercept at zero rate is the reservoir pressure (1815 psi in Fig. 13-21).

The second diagnostic incorporates PTA of the data using the Odeh-Jones methodology. Figure 13-22 shows the analysis plot used in the process. This water injection well exhibits permeability of approximately 12.8 mD and

skin effect of 0.1. The permeability and reservoir pressure determined from the step rate test should be used in the subsequent real-time evaluation.

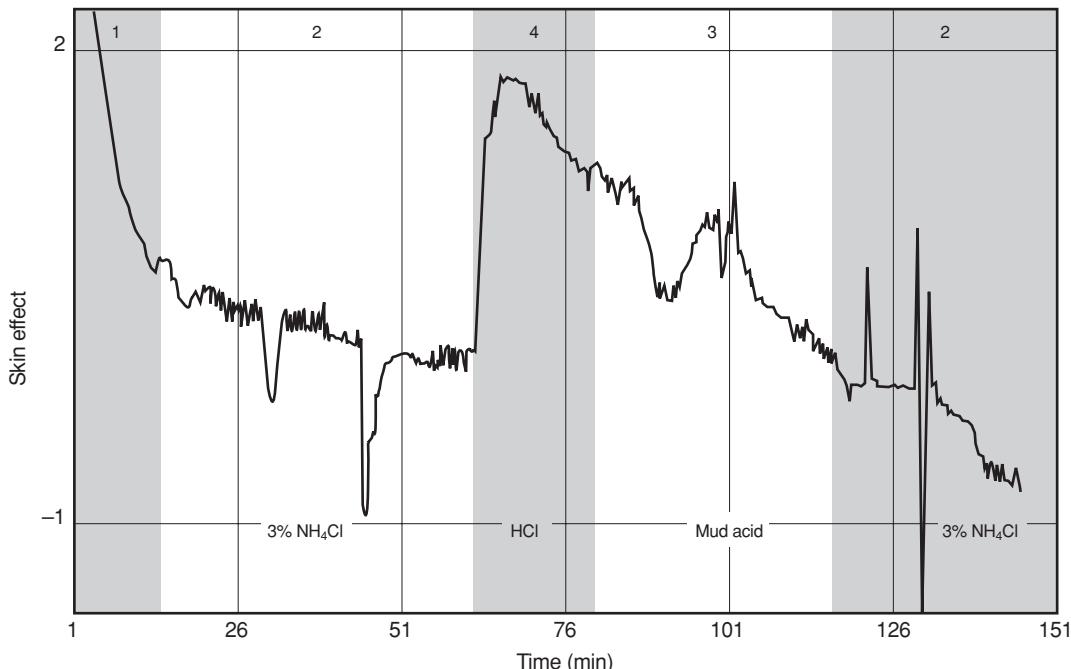
### 13-8.2. Real-time evaluation

In recent years, technology to determine real-time skin effect evolution during a treatment has been developed. Although this technology is not practiced routinely, it can be a useful diagnostic tool (see Chapter 20). For example, if the skin effect is decreasing during an HCl stage, an acid-soluble species (e.g., calcium carbonate/oxide, iron carbonate/oxide) created damage. This information should be complemented by the well history, laboratory testing, etc., to improve understanding of the present problem and assist future work.

One method available to the industry is based on the steady-state design and evaluation method developed by Paccaloni (1979b). Data can be displayed on a graph of the bottomhole pressure versus injection rate. Comparison is made with standard curves calculated for fixed values of skin effect to evaluate skin effect evolution.

More advanced programs calculate skin effect evolution in real time, taking into account transient effects (Prouvost and Economides, 1989). The reservoir pressure response during pumping is computed assuming zero constant skin effect. One value of skin effect is provided, combining the effects of damage, completion and diverters. Using these tools, a more quantitative assessment of each component of the stimulation design can be made.

Figure 13-23 shows the real-time skin effect evolution of the injection well analyzed in the step rate test. The initial skin effect observed when water containing ammonium chloride was injected is close to the skin effect obtained in the previous step rate test. The increase in skin effect when HCl was injected into the formation indicates that the HCl was incompatible with the formation or was incompatible with something that was injected in the leading portion of the acid. In this example, the latter is suspected because the tubing was not cleaned (pickled) prior to the injection of acid down the pipe. The initial acid dissolved magnetite and/or rust on the walls of the tubing and precipitated ferric oxide before the acid reached the zone. Thus, the pressure increased when the solid material (ferric oxide) filtered out on the formation face with an increase in skin effect to approximately 2. As shown in Fig. 13-23, unspent acid removed the damage and the skin effect decreased to a value of approximately 1.



**Figure 13-23.** Real-time skin effect evolution in the injection well analyzed in the step rate test

### 13-8.3. Post-treatment evaluation

The evaluation of stimulation effectiveness is a process similar to well performance evaluation. In this section, the process is applied to returning wells to production following stimulation. Details on the techniques are provided elsewhere in this volume.

Careful recording should be made while bringing a well on production following stimulation. Early indications of success can be found in the ease of initiating production and higher flow rates and flowing tubing pressures. Return fluids should also be sampled. Early production problems may indicate an incompatibility between treating fluids and the produced oil. The analysis of water samples may indicate other problems with the treating fluid selection (e.g., precipitation problems with HF acidizing).

Wells should be subjected to pressure buildup and PTA following a stimulation treatment. These data are the basis for a quantitative assessment of the well and reservoir characteristics. Comparison of these results to pretreatment buildups can provide the best assessment of the success of the stimulation treatment.

In the final analysis, stimulation treatments are evaluated at the sales meter. If the treatment results in sustained oil production at a higher rate than before and if the revenue generated by the increased production represents an acceptable return on the cost of the stimulation, the treatment is considered a success. The designer can learn valuable information from the evaluation of

well performance, regardless of whether the stimulation is an economic success.

In addition to examining oil production response, changes in the total fluid production (oil, water and gas) in reservoir volumes, gas/oil ratio and water/oil ratio must be reviewed. Well productivity must also be examined. An increase in the productivity of total fluids may not be economic, but it may indicate that the target reservoirs were not stimulated or were watered-out in the candidate well. This can result in a change in treatment design philosophy (i.e., to sacrifice total stimulation effectiveness for the selective treatment of a limited part of the reservoir).

Correlation of the unwanted results from stimulation can provide data for improved performance in the future. They may also identify other opportunities to improve field performance, such as water or gas shutoff. In the end, the data acquired from evaluating recently stimulated wells can lead to improved reservoir management.

Ultimately, a treatment should be evaluated on the basis of the well performance and economic parameters used to justify the treatment. Factors such as rate, flowing bottomhole pressure, reservoir characterization, artificial lift performance and equipment performance have been discussed. Several weeks or even months may be required for production to stabilize and establish a representative trend. In addition, shutting in the well for pressure buildup is less attractive—and may not be acceptable—after the well has responded.

Using field data, the engineer can evaluate differences between the design and actual treatment. If a numerical simulator can be rerun with the actual treatment parameters, the model can be calibrated by adjusting reservoir parameters such as the damage radius, permeability per layer, skin effect per layer, damage mineralogy and diverter efficiency until a match with the actual treatment profiles is obtained. If a post-treatment well test is performed and evaluated, the resulting data can be used to further calibrate the simulator.

Wireline formation logs and the combination of radioactive tracers and gamma ray or gamma ray spectroscopy surveys (where the energy and intensity of the gamma rays are measured to enable the discrimination of multiple tracers) can be used to quantify zone coverage. Of course, the decision to run tracers and baseline logs must be made while planning

the stimulation. A pressure transient test (e.g., buildup, four-point) to quantify permeability and skin effect can be performed. Thus, adequate evaluation tools exist today to significantly improve matrix treatment success.

Future treatment designs for the well or field can be optimized with the calibrated model. All results should be compiled in a report with recommendations for all phases of the design, execution and evaluation (i.e., continuous improvement).

Stimulation operations present the engineer with an opportunity to significantly improve the economic performance of the assets under his or her stewardship. If properly designed, executed and evaluated, stimulation operations can teach the engineer about the current condition of the well and reservoir and identify other opportunities to improve economic performance.

# 14. Formation Damage: Origin, Diagnosis, and Treatment

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## 14-1. Introduction

Formation damage reduces the well production or injection capacity, and the removal of damage is one of the major goals of petroleum engineers. This chapter identifies and quantifies formation damage and includes ideas on treatment strategy. It is important to note that not all types of formation damage require a removal treatment. Some types of damage will clean up during production, and others can be removed by changes in operating practices. In addition, some producible impairment is misconceived as "damage," when it is actually poor well design that can be remedied with operational changes. Classifying damage correctly requires more than experience in the chemistry or physics of damage. A thorough knowledge of field operating conditions is essential, and correct identification is critical to successful removal.

The terms formation damage and skin effect damage have been applied to describe many well productivity impairments (Krueger, 1986; Porter, 1989). Damage can be anything that obstructs the normal flow of fluids to the surface; it may be in the formation, perforations, lift system, tubulars or restrictions along the flow path. Formation damage specifically refers to obstructions occurring in the near-wellbore region of the rock matrix. Other types of damage can be identified by location. Figure 14-1 shows some common types of damage; these production impairments can occur anywhere in the production system, from the wellbore to perforations and into the formation. Such a distinction is not usually made because seldom are most of the plugging phenomena located in only one part of the flow system. The importance of determining the causes of the observed damage cannot be understated. Only by knowing the damage mechanism, its location and how it is affecting flow can an effective treatment strategy be developed. There have been significant improvements over the past few years in recognizing and describing the various types of damage, and many publications have appeared on the subject (Allen, 1973; Hurst, 1973; Leon, 1973; Sands, 1973; Christian and Ayres, 1974; Bruist, 1974; Shaw and Rugg, 1974; Black and Rike, 1976; Maly, 1976; Sparlin and Hagen, 1983; Krueger, 1988; Amaefule *et al.*, 1998; Adair and Smith, 1994; Beadie, 1995; Reid, 1996).

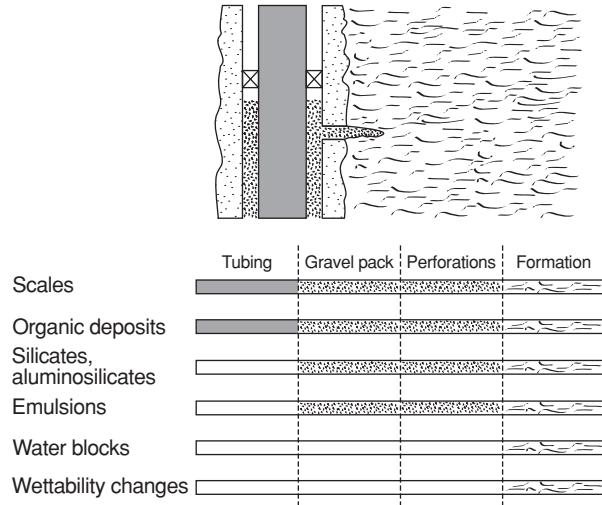


Figure 14-1. Location of various types of damage.

The goal of this chapter is to give a broad view of formation damage. Damage characterization is the key to proper design of removal treatments. A general description of the various damage types and mechanisms is presented, followed by a discussion of the origins of damage resulting from natural causes and well operations. The testing required to determine the presence of formation damage and its characterizations are also discussed. Treatment strategies for removing formation damage are presented.

## 14-2. Damage characterization

Damage characterization is the "history" in damage removal. The search for the identity of the damage begins in the production and development history of the well and even neighboring wells. Drilling records, completion design, offset well performance and/or operator experiences and past treatment records are all sources of information. The objective is to identify the location and types of damage that may be a problem. Although damage is usually considered a singular problem, multiple occurrences of damage are common, some with interfering removal treatments.

Formation damage identification and investigation include

- types of damage
- location of damage
- extent and screening of damage
- effect of damage on well production or injection.

### 14-2.1. Pseudodamage

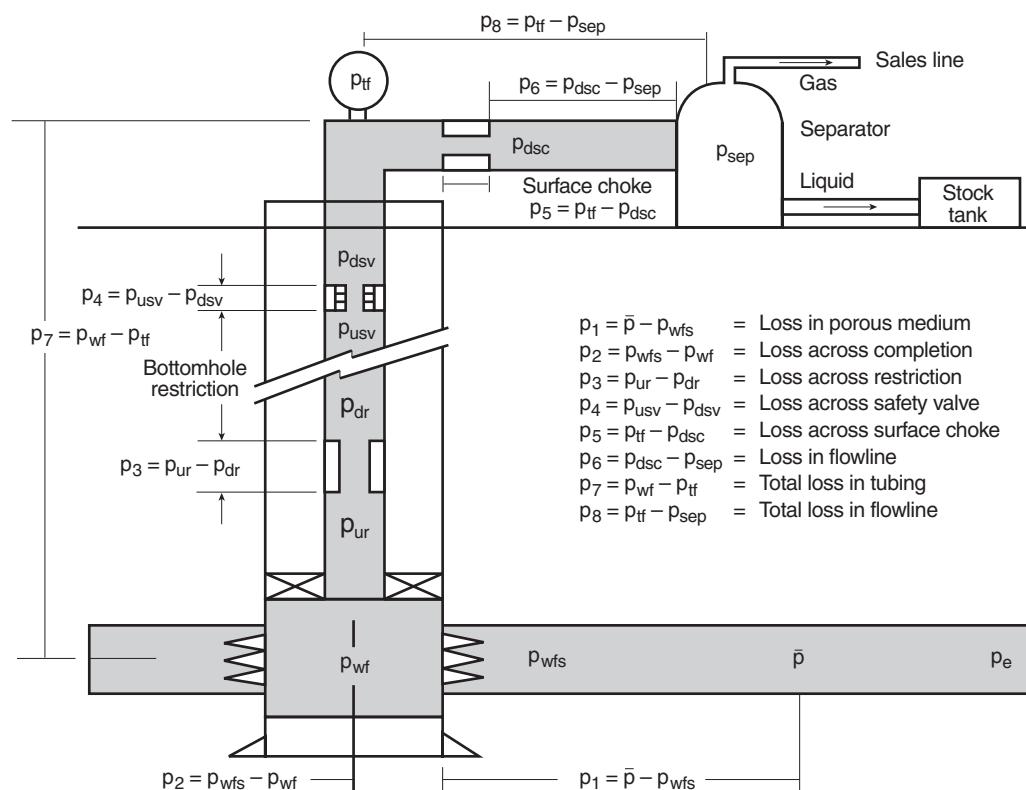
Chapter 1<sup>†</sup> demonstrates the impact of skin effect reduction on well performance. Chapter 2<sup>†</sup> describes techniques for estimation of the total well skin effect, which are accomplished primarily through well testing. As discussed in Chapter 1, not all skin effect is due to damage. There are other contributions that are not related to formation damage. These pseudoskin effects are generally mechanical, resulting from obstructions to flow or because of rate- and phase-dependent effects. Their values must be subtracted from the total skin effect to estimate the skin effect associated with formation damage (Petersen *et al.*, 1984). One way to accomplish

this is to use NODAL production system analysis to develop an inflow performance relationship (IPR) curve specific to the well. NODAL analysis allows optimizing production conditions for a given well and thus optimizing the well completion (Fig. 14-2).

### 14-2.2. Pseudoskin effects and well completion and configuration

Positive pseudoskin effects can result from the well completion design or well configuration. Problems include

- limited entry to flow (Odeh, 1968; Jones and Watts, 1971; Saidikowski, 1979)
- off-center wells (Denson *et al.*, 1976; Fetkovitch and Vienot, 1984)
- low perforation density, short perforations or incorrect phasing (Hong, 1975; Locke, 1981; McLeod, 1983)
- mechanical flow restrictions
- mismatched or inadequate fluid-lift systems
- laminated reservoirs (shale streaks).



**Figure 14-2.** Pressure losses in the producing system of a flowing well.  $p_{wf}$  = bottomhole flowing pressure,  $\bar{p}$  = average pressure,  $p_e$  = reservoir pressure,  $p_{dr}$  = downstream restriction pressure,  $p_{dsc}$  = pressure downstream of the surface choke,  $p_{dsv}$  = pressure downstream of the safety valve,  $p_{sep}$  = separator pressure,  $p_{tf}$  = tubing flowing pressure,  $p_{ur}$  = upstream restriction pressure,  $p_{usv}$  = pressure upstream of the safety valve,  $p_{wfs}$  = wellbore sandface pressure.

<sup>†</sup>See Reservoir Stimulation Third Edition (SMP-7075)  
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A negative pseudoskin effect always exists in deviated wells; it is a function of the deviation angle and the formation thickness (Cinco-Ley *et al.*, 1975).

#### ■ Pseudoskin and rate-and-phase effects

Operating pressures and production conditions may induce additional pressure drops or pseudo-skin effects. Producing a well at a high flow rate can cause turbulent flow in perforations and sometimes in the formation (Fig. 14-3) (Tariq, 1984; Himmatramka, 1981). The corresponding positive pseudoskin effect is proportional to the flow rate above a minimum threshold value. Below this critical value, this pseudoskin effect is suppressed (Jones *et al.*, 1976). The problem increases with gravel-packed perforations (for sand control) and for high-production-rate gas wells in general. The problem becomes particularly acute for the fracture-to-wellbore connection in deviated wells with fractures at an angle to the wellbore.

Scale precipitation in and around the perforations can progressively modify the reservoir flow conditions, increasing the pressure drop and changing the flow regime from Darcy to non-Darcy and creating a turbulence pseudoskin effect (Meehan and Schell, 1983). This is in addition to the actual damage skin effect.

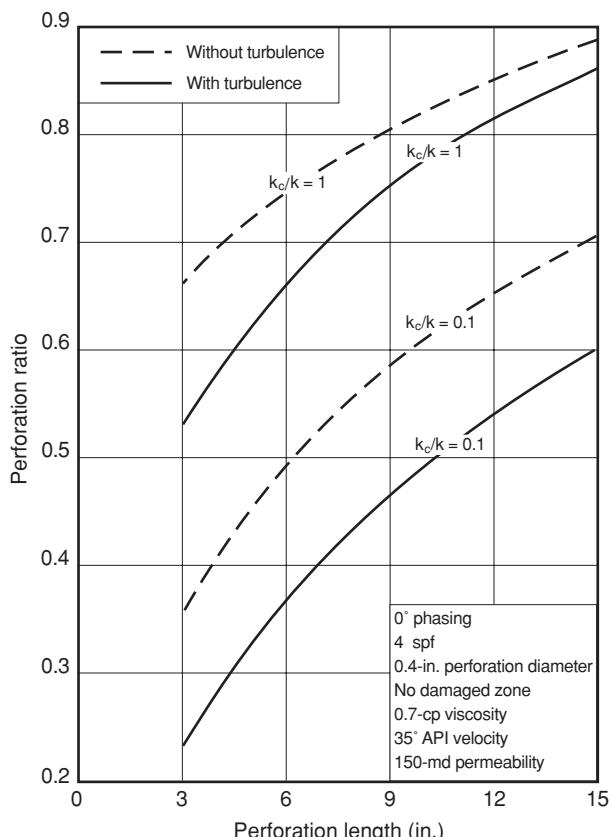
Producing a well below the bubblepoint pressure may cause a positive pseudoskin effect as liquids condense around the wellbore, impeding flow (Blacker, 1982; Hinchman and Barree, 1985; Economides *et al.*, 1989). This is a relative permeability phenomenon, with free gas concentrating around the wellbore causing a reduction to the relative permeability to oil. A similar but more severe problem can happen when producing gas condensate wells below the dewpoint. Both phenomena manifest as positive pseudoskin effects.

In unconsolidated sand reservoirs, a flow-rate-dependent skin effect can be caused by modifications of the sand arches around the perforations. Abrupt variations of skin effect and concomitant sand releases occur above the threshold flow rate value (Tippie and Kohlhaas, 1974).

#### ■ Other pseudodamages

Other mechanical causes of production impairment are

- tubing collapse or restriction by lost objects or any adhering deposit
- collapsed perforations in formations where the formation competence has been overestimated (Antheunis *et al.*, 1976; Chenevert and Thompson, 1985)



**Figure 14-3.** Effect of turbulence and a compacted zone (90% permeability reduction) on the productivity ratio (Tariq, 1984).  $k$  = permeability,  $k_c$  = damaged zone permeability.

– poor isolation between zones resulting from poor cementation of the annulus—e.g., oil invasion of a gas cap significantly reduces the relative gas permeability, mixing oils of two different zones may cause paraffin and asphaltene precipitation, or water invading an oil-bearing zone reduces the relative permeability to oil (water block), may create emulsions and may cause clay and scale problems. Stimulation treatments that do not achieve required results and that cause additional damage may have been sabotaged by bad isolation (Abdel-Mota'al, 1983).

– poor design of gas lift systems—small-diameter tubing, unadapted operating gas lift pressure (Blann and Williams, 1994), improper valve design and high surface backpressure (Jones and Brown, 1971).

## 14-3. Formation damage descriptions

Once mechanical pseudoskin effects are identified, positive skin effects can be attributed to formation damage. Formation damage is typically categorized by the mechanism of its creation as either natural or induced. Natural damages are those that occur primarily as a result of producing the reservoir fluid. Induced damages are the result of an external operation that was performed on the well such as a drilling, well completion, repair, stimulation treatment or injection operation. In addition, some completion operations, induced damages or design problems may trigger natural damage mechanisms.

Natural damages include

- fines migration
- swelling clays
- water-formed scales
- organic deposits such as paraffins or asphaltenes
- mixed organic/inorganic deposits
- emulsions.

Induced damages include

- plugging by entrained particles such as solids or polymers in injected fluids
- wettability changes caused by injected fluids or oil-base drilling fluids
- acid reactions
- acid by-products
- iron precipitation
- iron-catalyzed sludges
- bacteria
- water blocks
- incompatibility with drilling fluids.

Each of these mechanisms is addressed in detail in the following sections. Damage from iron precipitation and iron-catalyzed sludges is discussed elsewhere in this volume.

### 14-3.1. Fines migration

Formation damage can occur as a result of particle migration in the produced fluid. The particles can bridge across the pore throats in the near-wellbore region and reduce the well productivity. When the damaging particles come from the reservoir rock, they are usually referred to as fines. Migrating fines can be a variety of different materials, including clays (phylosilicates with a typical size less than 4 mm) and silts (silicates or aluminosilicates with sizes ranging from 4 to 64 mm). Kaolinite platelets (Fig. 14-4) are thought to be some of the more common migratory clays. Table 14-1 lists the major components

**Table 14-1. Major components of various clay and fines particles.**

Particle Mineralogy	Major Components	Surface Area (m <sup>2</sup> /g)
Quartz	Si, O	0.000015
Kaolinite	Al, Si, O, H	22
Chlorite	Mg, Fe, Al, Si, O, H	60
Illite	K, Al, Si, O, H	113
Smectite (montmorillonite)	Na, Mg, Ca, Al, Si, O, H	82

of various clays and fines particles. The table also lists the surface area of the clays, one of the indicators of how quickly the clay can react with a reactive fluid (Davies, 1978). Damage from fines is located in the near-wellbore area, within a 3- to 5-ft radius. Damage can also occur in a gravel pack (e.g., silicates and aluminosilicates in Fig. 14-1).

The distinction between types of clays depends more on the arrangement of the atoms in their crystalline structure rather than any major difference in chemical formula. These structural differences determine the surface area exposed to the reservoir fluids for each clay. Clay reactivity is a function of this surface area. The location of the clay is also critical to its reactivity. Authigenic clay is in a pore throat as fill or as a lining (i.e., grown in the pore from minerals in the connate water) (Wilson and Pittman, 1977). Authigenic clays have a large amount of surface area exposed in the pore and can be reactive. Detrital clay is part of the building material in the original matrix. Detrital clays are usually less reactive than authigenic clays because they have less surface area in contact with the fluids in the pore. The vast majority of detrital clays usually cannot be contacted by sufficient volumes of reactive fluids to cause problems. Clay may also act as a cement, holding the matrix grains together. As a binder or cement, clay may react with fluids such as acid and water to disaggregate the formation. If the clay cement is shielded by a quartz overgrowth, as is common in many sandstones, the clay will not be reactive.

Only authigenic clays, unprotected clay cements and the few detrital clays on the pore boundary are worth consideration as potential damage mechanisms. Scanning electron microscopy (SEM) is generally used to determine clay type; however, recognition of the type of clay should not be staked entirely on an SEM analysis. Focused dispersive X-ray analysis is much more accurate. Even after identification of the clay, laboratory core flow tests are typically required to determine if the clays within the flow channels are reactive with a given fluid. The common clays that account for most of the

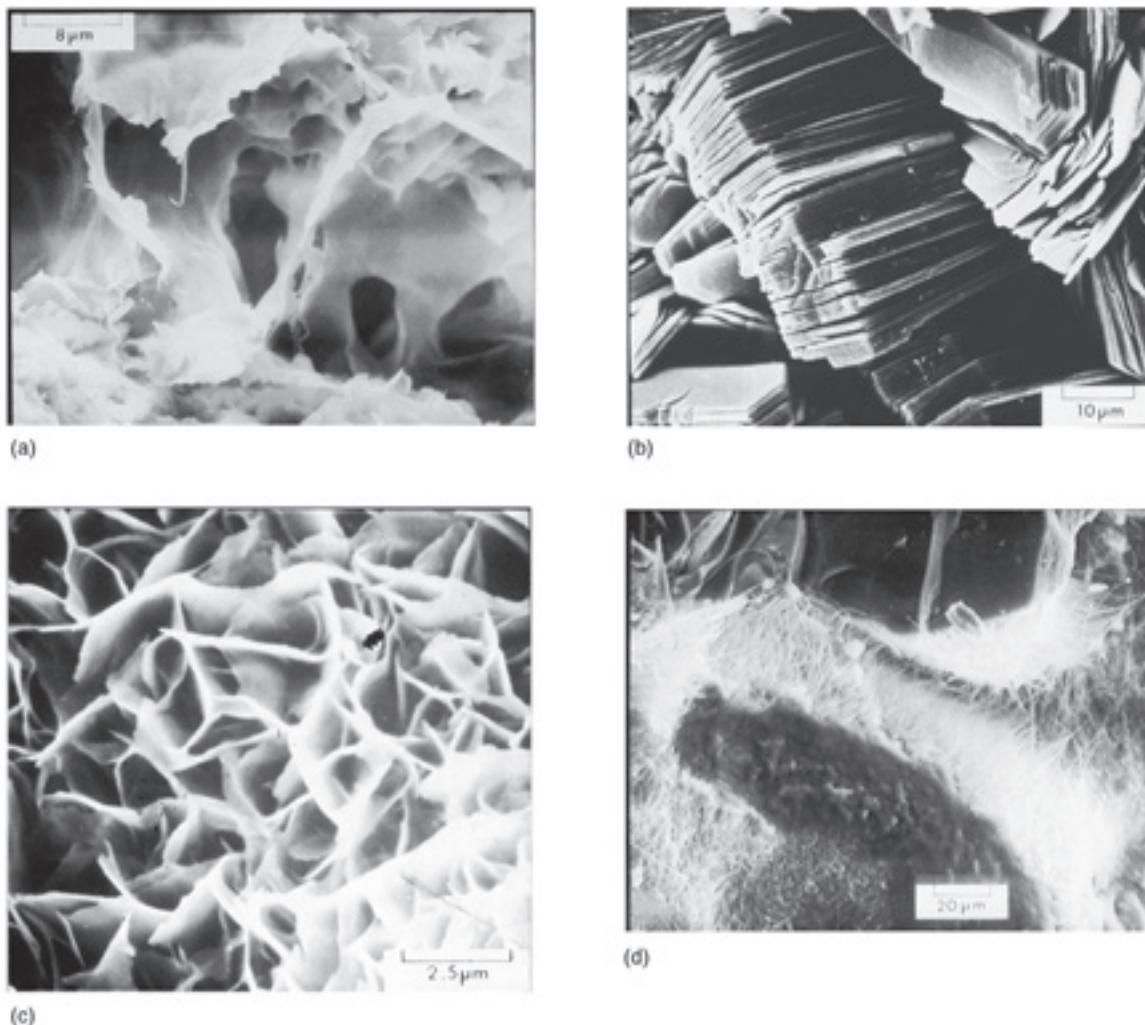
real and perceived clay problems are kaolinite, smectite (montmorillonite), illite and chlorite. The structures of kaolinite, smectite, illite and chlorite are shown in Fig. 14-4. Simply because the clay is in the rock does not mean that the clay is reactive.

### 14-3.2. Swelling clays

Clays may change volume as the salinity of the fluid flowing through the formation changes. Several authors have dealt with clay swelling in sandstones, showing either ion exchange, movement or critical salt concentration triggering clay dispersion (Azari and Leimkuhler, 1990b; Jones, 1964; Khilar and Fogler, 1983; Mungan, 1968; Sharma *et al.*, 1985; Priisholm *et al.*, 1987). Changes in formation permeability resulting from the alteration of clay are due to the amount, location and type of clay

minerals within the formation. The total quantity of clay inside the formation is a misleading indication of potential changes to permeability. It is the arrangement of the clay, its chemical state at the moment of contact and the location of the clay with respect to the flowing fluids that are responsible for the changes. Predicting the response of a clay to water flow is almost impossible without testing.

The most common swelling clays are smectite and smectite mixtures. Smectite swells by taking water into its structure. It can increase its volume up to 600%, significantly reducing permeability. If smectite clay occupies only the smaller pore throats and passages, it will not be a serious problem; however, if it occupies the larger pores and especially the pore throats, then it is capable of creating an almost impermeable barrier to flow if it swells.



**Figure 14-4.** Photomicrographs of (a) pore-filling smectite sheets, (b) “books” of kaolinite platelets in a pore space, (c) honeycomb growth of chlorite on a sand grain and (d) hairs of illite extending from a sand grain.

Clays or other solids from drilling, completion or workover fluids can invade the formation when these particles are smaller than the pore throat openings. Any subsequent increase in flow rate through the invaded zone will force a high concentration of particles into the rock matrix.

### 14-3.3. Scales

Scales are water-soluble chemicals that precipitate out of solution in response to changes in conditions or the mixing of incompatible waters. They can be present in the tubing, perforations and formation (Fig. 14-1). The most common oilfield scales are calcium carbonate, calcium sulfate and barium sulfate. Water-formed scale deposits are among the most troublesome damage problems (Cowen and Weintritt, 1976). Scale usually consists of precipitates formed from mixing incompatible waters or upsetting the solution equilibrium of produced waters. A water that may be stable under reservoir conditions may become supersaturated with an ion when the pressure decreases, which allows carbon dioxide ( $\text{CO}_2$ ) outgassing, or the temperature changes. The supersaturated solutions react by precipitating a compound from solution. The deposition of scale is influenced by pressure drop, temperature, dissolved gases, flow viscosity, nucleation sites and metal type—in short, anything that upsets the solution equilibrium.

The following scales are among the most troublesome.

- Calcium carbonate or calcite ( $\text{CaCO}_3$ )

$\text{CaCO}_3$  is usually formed when the pressure is reduced on waters that are rich in calcium and bicarbonate ions. The deposition can be affected by  $\text{CO}_2$  outgassing, which raises the pH value and makes the high concentrations of calcium unstable.

- Gypsum (“gyp”)

Gypsum may be the most common sulfate scale in the oil industry (Cowen and Weintritt, 1976). With a chemical structure of  $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ , it shares a similar composition to the hemihydrate  $\text{CaSO}_4 \cdot \frac{1}{2}\text{H}_2\text{O}$ , commonly called plaster of paris or by its mineral name, bassonite. It is also formulaically similar to the evaporite mineral anhydrite ( $\text{CaSO}_4$ ).

- Barium sulfate ( $\text{BaSO}_4$ )

$\text{BaSO}_4$  is a less common form of sulfate deposit, but it causes extensive problems. Almost any combination of barium and sulfate ions causes precipitation. It is difficult to remove, as it is not significantly soluble in acids and solvents unless it is finely ground or the structure is interrupted with impurities such as carbonate scale. Like calcium sulfate, barium

sulfate is usually thought to be a product of mixing incompatible waters, with precipitation accelerated by pressure drop, outgassing or turbulence. Some barium sulfate is radioactive; this is part of naturally occurring radioactive material (NORM) scales. The radioactivity results from a concentration of uranium in the lattice of the scale. The buildup of radioactive scale can be monitored using a gamma ray logging tool. Care must be exercised when analyzing well debris to avoid mislabeling barite ( $\text{BaSO}_4$ ) from drilling mud residue as barium sulfate scale.

Strontium sulfate or celestite ( $\text{SrSO}_4$ ) is a common substitute in the barium sulfate crystal lattice. Strontium scale can be associated with radioactive scale (NORM). It may be more soluble than barium sulfate in chemical remover systems.

- Iron scales

Iron scales such as iron carbonate and iron sulfide can be extremely difficult to remove. They are usually seen in wells that have both a high background iron count and a tendency to precipitate calcium carbonate. Iron sulfide scales react according to their structure. Seven different forms of iron sulfide scale have been identified. Only two of these iron sulfide forms are readily soluble in hydrochloric acid (HCl). The remaining iron sulfide scales are either slowly soluble or not significantly soluble.

- Chloride scales

Chloride scales, such as sodium chloride precipitation from water caused by temperature decrease or evaporation of the water, are common. There is no effective way to prevent salt precipitation, and cleanup has been accomplished using water only. Salt has a limited solubility in acid ( $\frac{1}{4}$  lbm/gal in 28% HCl), so using acid is not generally considered. Redesigning the mechanical system to avoid temperature loss and water evaporation is also a possibility.

- Silica scales

Silica scales generally occur as finely crystallized deposits of chalcedony or as amorphous opal. They are associated with alkaline or steamflood projects and stem from the dissolution of siliceous formation minerals by high-pH fluids (Lieu *et al.*, 1985) or high-temperature steam condensates (Reed, 1980; McCorriston *et al.*, 1981; Amaefule *et al.*, 1984). This dissolution can cause poorly consolidated sandstones to collapse or silica to reprecipitate at a distance from the wellbore where the alkalinity, temperature or both of the floods has decreased.

### 14-3.4. Organic deposits

Organic deposits are heavy hydrocarbons (paraffins or asphaltenes) that precipitate as the pressure or temperature is reduced. This is a form of distillation. They are typically located in the tubing, perforations or formation (Fig. 14-1). Although the formation mechanisms of organic deposits are numerous and complex (Houchin and Hudson, 1986), the main mechanism is a change in temperature or pressure in the flowing system. Cooling of the wellbore or the injection of cold treating fluids has a much more pronounced effect.

Organic deposits must not be confused with another type of deposit called sludge. Sludges are viscous emulsions produced by the reactions between certain crude oils and strong inorganic acids or some brines. Sludges cannot be easily dissolved.

#### ■ Paraffins

Paraffins are the simplest of hydrocarbons. They are composed of only carbon and hydrogen atoms, and the carbons occur as an unbranched chain. Carbon chain length associated with formation of solid paraffin deposits has a minimum of 16 carbon atoms per molecule and may have up to 60 or more. The precipitation of paraffins is triggered by a loss of pressure, loss of temperature or loss of short-chain hydrocarbon compounds (i.e., the light ends). The temperature at which the first solid paraffin crystal forms from an all-liquid solution is called the cloud point. Designing the completion so that produced fluid surface temperatures are above the cloud point and modifying the cloud point using chemical methods are accepted practices to prevent paraffin deposition in the tubing.

Melting points increase as the length of the paraffin chain increases. The hardness of the solid paraffin structure also increases with molecular size. Table 14-2 lists several paraffin chain lengths and their melting points. Impurities may cause the melting point of a field sample to vary slightly.

Paraffins can form anywhere in the producing system when conditions become favorable for precipitation (Cole and Jessen, 1960; Burger *et al.*, 1981; Newberry *et al.*, 1986; Thomas, 1988; Newberry, 1981; Sutton and Roberts, 1974). Paraffins are normally found in the tubing near the surface, where the temperature and pressure drops are highest. In cases such as reservoirs that are nearly pressure depleted or formations that have experienced dry gas cycling (which removes the light hydrocarbon ends), the paraffins can form at the perforations or in the formation. Paraffins may also be precipitated by the injection of a cool fluid. Although not typically considered, this latter cause can be the reason for the slow cleanup of many wells after stimulation.

#### ■ Asphaltenes

Asphaltenes are organic materials consisting of condensed aromatic and naphthenic ring compounds with molecular weights of several hundred to several thousand (Leontaritis, 1989; Leontaritis and Mansoori, 1987; Tuttle, 1983; Newberry and Barker, 1985; Addison, 1989; Bunger, 1979; Thawer *et al.*, 1990). They are characterized by the nitrogen, sulfur and oxygen molecules they contain and are defined as the organic part of the oil that is not soluble in a straight-chain solvent such as pentane or heptane. Asphaltenes are generally found in one of three distinctive forms:

- hard coal-like substance
- blackened sludge or rigid-film emulsion (usually triggered by iron in solution)
- in combination with paraffins.

In “solution,” they usually exist as a colloidal suspension, forming particles 30 to 65 Å in diameter and stabilized by maltene molecules in the oil. The volume of the maltene resins is the first key to the stability of the asphaltene in suspension. The actual quantity of asphaltenes in the oil is much less important. The stability of asphaltic dispersions depends on the ratio of the quantity of resins to the quantity of asphaltic materials. Ratios larger than 1:1 (resins to asphaltenes) are more stable, whereas ratios less than 1:1 are unstable and may precipitate during production. Ratios of more than 10:1 are known and are much less likely to cause significant problems. Although asphaltene contents up to 60% have been found, major problems occur with oils with a 1% to 3% asphaltene range.

Asphaltene precipitation can be influenced by pressure drop, shear (turbulence), acids, solution CO<sub>2</sub> (lowers the pH value), outgassing of CO<sub>2</sub> and other gases (turbulence), injected condensate, gas,

Table 14-2. Melting points of paraffins.

Carbon Atoms (no.)	Melting Point (°F)
16	64
17	72
18	82
20	100
23	122
25	129
32	158
42	181
49	196
60	211

commingling with other (incompatible) oils and charged metal surfaces (Danesh *et al.*, 1988; Monger and Trujillo, 1991; Kawanaka *et al.*, 1991; Monger and Fu, 1987; Pittaway *et al.*, 1987). Anything that takes away the resins or breaks the stability of the aggregate particle can lead to a precipitation of asphaltene. Iron ions in solution (usually during an acid job) compound and favor the formation of asphaltene deposition. As noted previously, the concentration of asphaltenes is not a good indicator of potential problems. Only the treatment history and well response examination can suggest the potential for asphaltene problems.

Asphaltene deposition on pore walls may not significantly decrease the formation porosity and absolute permeability. However, through this process, the rock tends to become oil-wet, which reduces the relative permeability to oil (Clementz, 1982; Collins and Melrose, 1983) and, under certain conditions, favors the buildup of emulsion blocks if water is simultaneously produced.

#### ■ Tar

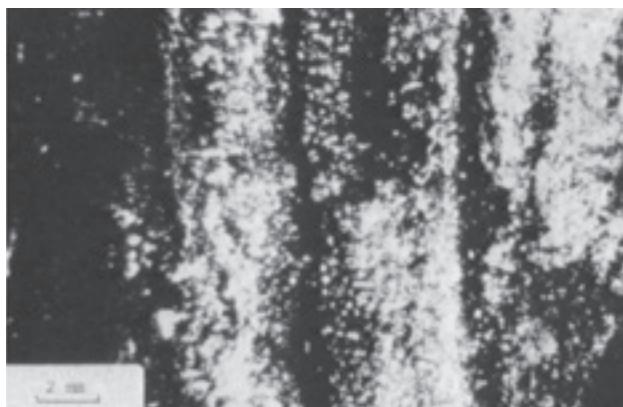
Tar is simply an asphaltene or other heavy-oil deposit. It cannot be removed by acid or mutual solvents. Removal requires dispersion in an aromatic solvent, and energy is typically necessary to achieve removal.

### 14-3.5. Mixed deposits

Mixed organic/inorganic deposits are a blend of organic compounds and either scales or fines and clays. When migrating, fines associated with an increase in water production in a sandstone reservoir become oil-wet, and they act as a nucleation site for organic deposits (Houchin and Hudson, 1986). Figure 14-5 shows such a mixed deposit in which clear (white) crystals of sodium chloride are dispersed in a dark organic matrix.

### 14-3.6. Emulsions

Emulsions are combinations of two or more immiscible fluids (including gas) that will not disperse molecularly into each other (Hoover, 1970; Sherman, 1968; Lissant, 1974; Lissant and Mayhan, 1973; Bandbach, 1970; Hausler, 1978; Bikerman, 1964; Ogino and Onishi, 1981; Gidley and Hanson, 1973; Coppel, 1975). Emulsions are composed of an external phase (also called nondispersed or continuous) and an internal phase (also called dispersed or discontinuous). The internal phase consists of droplets suspended in the external phase. Almost all emulsions found in the field are produced by the addition of some form of energy that produces mixing. Most emulsions break rapidly when the source of energy is removed. The



**Figure 14-5.** Thin section of a layered matrix deposit. The black layers are organic deposits, and the clear (white) layers are inorganic scales of mainly halite ( $\text{NaCl}$ ).

breaking mechanism of these unstable emulsions is by droplet contact and growth and then by fluid density separation. As the droplets draw near and touch, the surface film around the drop may thin and rupture, forming large drops in a process called coalescence. The larger droplets settle rapidly owing to density differences between the liquids forming separate layers. Only a portion of the drops that touch will coalesce. When minimum coalescence occurs, the emulsion is stable.

If separation of the emulsion does not occur, there is a stabilizing force acting to keep the fluids emulsified. The most common stabilizing forces are a modification of the surface film strength at the interface by chemical reaction, precipitation or the addition of partially wetted fine particles, electric charge, or high viscosity of the components or resultant fluid viscosity. These forces may act singly or in combination.

Natural surfactants help stabilize emulsions by stiffening the film around the droplet or by partially wetting small solid particles. Natural surfactants are present in many waters and most crude oils. They may be of several chemical formulas and may be a by-product of bacteria or originate as part of the oil-generation process. Like other surfactants, they have an oil-soluble end and a water-soluble end (usually possessing a small electric charge) and congregate at the oil/water interface.

Micron-size solids in the liquid may stabilize an emulsion by increasing the toughness of the surface film around the droplets or by acting as an emulsifier and binding droplets of the dispersed liquid with an electrical charge. Almost any solid can be a stabilizing agent if it is sufficiently small. For a solid to be effective in stabilizing an emulsion, it must be present at the interface of the drop and the continuous phase. The more common solid materials that stabilize oilfield emulsions are iron sulfide, paraffin, sand, silt, clay, asphalt, scale, metal flakes (from pipe dope), cuttings and corrosion products.

Changes in the pH value can affect emulsion stability. Most free-water knockouts and treaters operate efficiently at a pH value of 6 to 7, depending on individual well conditions. Following an acid treatment, the pH value may drop below 4 and emulsions may be created. Emulsions created in this manner are stable until the pH value rises above 6 or 7. When acid treating a well where the crude is an emulsifier or a sludge former, the wellhead may be equipped with a chemical injection port just upstream of the choke or a chemical injection valve may be placed in a gas-lift mandrel at some point in the treatment string. These ports are used to inject an emulsion breaker or de-emulsifier.

#### 14-3.7. Induced particle plugging

In addition to naturally occurring migrating particles such as clays and fines, many foreign particles are introduced into the formation during normal well operations. Drilling, completion, workover, stimulation, and secondary or tertiary production operations can cause the injection of extraneous particles into the formation.

Particle damage from injected fluids happens in the near-wellbore area, plugging formation pore throats. Problems include bridging of the pores, packing of perforations and the loss of large amounts of high-solids fluid into natural fractures or propped fracture systems. The best method of avoiding this type of damage is to use a clean fluid in a clean flow system with a controlled range of particle sizes that will stop fluid loss quickly by bridging at the wellbore.

Induced particles can be composed of a wide range of materials. Particulate materials in drilling fluids that are potentially damaging are clays, cuttings, weighting agents and loss-control materials, including polymers (Barna and Patton, 1972; Fisher *et al.*, 1973; Sloan *et al.*, 1975). These materials can be a problem independent of mud type (oil, water or polymer base). Workover and stimulation fluids can also contain suspended solids (Rike, 1980; Rike and Pledger, 1981) including bacteria and polymer residues (Tuttle and Barkman, 1974). Kill fluids in particular use various polymers as weighting agents or for fluid-loss control. Typical kill-fluid solids include salt pills with polymer, crosslinked polymers, hydroxyethylcellulose (HEC) polymers, lost-circulation pills and  $\text{CaCO}_3$  with polymer.

Particles in stimulation fluids are a result of poor water quality, tank coatings, tank residuals, and piping and tubing debris (e.g., dried mud, scale and pipe dope). The problem with stimulation fluids is that they can contain effective cleaners and acids that disperse and partially dissolve the debris inside of the tanks and piping on their way to the formation.

Particle damage after stimulation may also occur when partially dissolved parts of the formation or the damage materials come back, through either the pores or the natural fracture or propped fracture system. The release of fines from the formation is usually brought about by cleaners and mutual solvents. Acid treatments may also cause formation damage because of the precipitation of secondary acid reaction products. Precipitation products include iron hydroxide, calcium fluoride, potassium fluorsilicate and silica.

Geochemical models can predict the chemical nature of these by-products, depending on formation rock and treatment fluid compositions on one hand and pressure, temperature and contact time on the other (Walsh *et al.*, 1982; Dria *et al.*, 1988). The models cannot predict the damaging potential of these products because they do not include any physical description of the way they are precipitated. Hydrated silica (Crowe, 1985) may precipitate on clay surfaces but is not necessarily damaging. Compounds such as borosilicates (Thomas and Crowe, 1978) and fluoborates (Bertaux, 1989) can even be beneficial, probably because they precipitate as films that bind fines to the sand grains. This phenomenon, when purposely produced, leads to efficient fines-stabilization treatments (Thomas and Crowe, 1978; Sharma and Sharma, 1994). However, gelatinous precipitates, such as ferric hydroxide, can completely plug pores and can be particularly difficult to remove (Crowe, 1985). Another class of by-products consists of species such as fluorsilicates (Bertaux, 1989), which precipitate in the form of individual crystals that can migrate toward pore throats and produce a "log jam." Iron sulfide, which precipitates even at low pH values during the acid treatment of sour wells, is another compound belonging to this category.

#### 14-3.8. Wettability alteration

Formation plugging can be caused by liquid (or gas) changing the relative permeability of the formation rock. Relative permeability can reduce the effective permeability of a formation to a particular fluid by as much as 80% to 90%. The wettability and related relative permeability of a formation are determined by the flowing-phase quantity and by coatings of natural and injected surfactants and oils.

If a drop of a liquid is placed on the surface of another immiscible liquid or on the surface of a solid that it cannot dissolve, it may spread out into a thin film or it may remain in the form of a drop or a thick lens (Hausler, 1978). If the drop of liquid spreads, it wets the surface; if the drop of liquid does not spread, it does not wet the surface. The surface free energy of the two phases

and the interfacial tension between them determine whether the liquid spreads or remains in a deformed drop. Wettability is measured by the contact angle that a droplet of fluid forms on a particular surface. If the angle of contact  $\theta$  is less than  $90^\circ$ , the drop spreads from the initial ball shape and the surface is said to be wetted by the liquid. The smaller the angle, the greater the water wettability. If the angle is more than  $90^\circ$ , the surface is not wetted by the liquid. Wettability can be measured with a liquid surrounded by gas or a liquid surrounded by an immiscible liquid. Simple wetting has little meaning—it is the resultant effect of wetting on fluid flow that is important.

In the natural state, formations may be water-wet, oil-wet or neutral, depending both on the surface exposed to the fluid and the natural surfactants in the fluid. There are some instances, such as the Cardium reservoir in Alberta, Canada, where both oil- and water-wetting behavior have been reported in different sections of the reservoir.

When a surface of a pore passage is oil-wet, more of the passage is occupied by the bound oil (thicker monomolecular layer), and less of the pore is open to flow than in a water-wet pore. Naturally, to get as much flow capacity as possible in a formation, it is desirable to change the wettability to water-wet (in most cases). Unfortunately, it is impossible to change most naturally oil-wet surfaces for long. Wettability can be modified by preflushing the formation with a wetting surfactant or a solvent that establishes a new coating on the face of the formation or cleans the current coating from the formation. Regardless of the altered condition of a surface, the wettability is eventually decided by the surfactants in the produced fluid. Thus, the water-wet condition of a formation following an acid job can revert to an oil-wet condition after a sufficient volume of strongly oil-wetting crude is produced.

### 14-3.9. Acid reactions and acid reaction by-products

Numerous problems that may occur during acidizing treatments include

- damaging material from the tubing entering the formation
- oil-wetting of the reservoir by surfactants, especially corrosion inhibitors, which can create emulsion blocks
- water blocks
- asphaltene or paraffin deposition when large volumes of acid are injected.

In addition to these common damaging processes, production impairment can result from poor design of an acidizing treatment. Impairments include the following:

- sludges produced by the reaction between acids and asphaltenes, especially in the presence of some additives (particularly surfactants) or dissolved iron
- by-products precipitated by the reaction of acids with formation materials. Geochemical simulators can predict the chemical nature of the by-products, depending on the formation rock and treatment fluid compositions and the pressure and temperature. Simulators cannot predict the damaging potential of the by-products. Hydrated silica may precipitate on clay surfaces and is not necessarily damaging. Compounds such as borosilicates and fluoborates can even be beneficial. Gelatinous precipitates, such as ferric oxide, can completely plug pores and be particularly difficult to remove. Another class of by-products consists of species such as fluorsilicates precipitating in the form of individual crystals that can migrate toward pore throats and then bridge in the throats. Iron sulfide that precipitates, even at very low pH values during the acidization of sour wells, is another compound belonging to this category.
- precipitates formed by the addition of certain sequestering agents to acids to prevent iron problems when the acid is spent and no iron is present
- permeability impairment by residues present in corrosion inhibitors or produced through the thermal degradation of polymers, such as friction reducers.

### 14-3.10. Bacteria

Although many microorganisms can be present in the unsterile world of the oilfield, only a handful produce widespread problems (Shuler *et al.*, 1995; Clementz *et al.*, 1982; Crowe, 1968; Carlson *et al.*, 1961; Raleigh and Flock, 1965). Bacteria can be a serious problem in production operations because of what they consume and their by-products. Bacteria can grow in many different environments and conditions: temperatures ranging from 12 degF to greater than 250 degF [-11 degC to >120 degC], pH values ranging from 1 to 11, salinities to 30% and pressures to 25,000 psi.

Bacteria are classified as follows:

- Aerobic bacteria are bacteria that require oxygen.
- Anaerobic bacteria do not need oxygen (in fact, their growth is inhibited by oxygen).
- Facultative bacteria can grow either with or without oxygen because their metabolism changes to suit the environment. They usually grow about 5 times faster in the presence of oxygen.

The bacteria most troublesome in the oilfield are sulfate-reducing bacteria, slime formers, iron-oxidizing bacteria and bacteria that attack polymers in fracturing fluids and secondary recovery fluids.

Sulfate-reducing bacteria cause the most problems in a reservoir. Sulfate-reducing bacteria reduce the sulfate or sulfite in the water to sulfide and produce hydrogen sulfide ( $H_2S$ ) as a by-product. The reduction process provides the energy for bacterial growth. Biomass accumulation can lead to pitting of the steel under large colonies. The  $H_2S$  increases the corrosivity of the water and creates the possibility of blistering of carbon steels and sulfide cracking. The by-product of an  $H_2S$  attack on steel is iron sulfide (the general form is  $FeS$ ). Sulfate-reducing bacteria are anaerobic bacteria with slow growth rates when oxygen is present. Sulfate-reducing bacteria occur naturally in surface waters, including seawater. The growth of the sulfate-reducing bacteria is controlled by temperature and limiting their access to nutrients. The primary nutrients are carbon, nitrogen, phosphorus and dissolved iron. Bactericides are also used commonly to control these bacteria.

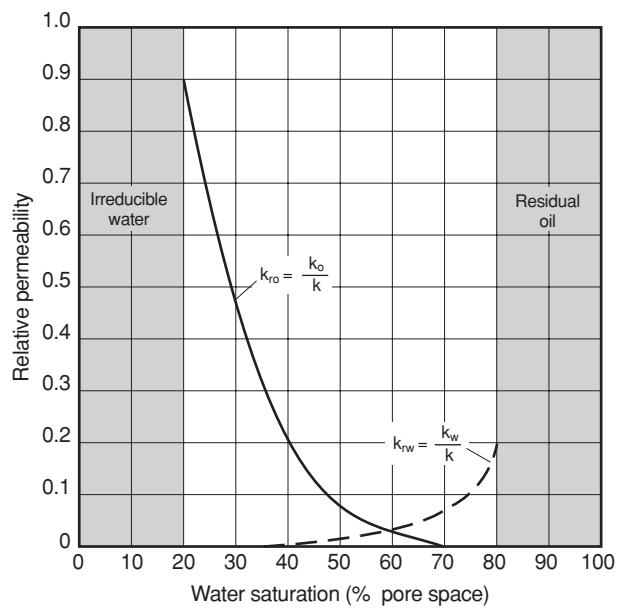
Iron-oxidizing bacteria are aerobic and convert iron from the ferrous ( $Fe^{2+}$ ) to the ferric ( $Fe^{3+}$ ) state. They produce gelatinous ferric hydroxide, which is highly insoluble and precipitates out of water. The bacteria metabolize dissolved iron in the water. Ferrous iron is soluble only at low pH values (i.e., when the water is acidic). Therefore,  $FeOH_3$  is typically considered an acid-reaction product. The iron-oxidizing bacteria produce some corrosion, but they usually cover sulfate-reducing bacteria colonies and protect them from attack.

Slime-forming bacteria are facultative and produce mats of high-density slime that cover surfaces. Their primary detrimental effects are the protection of colonies of sulfate-reducing bacteria and pore plugging.

The bacteria that attack polymers are various aerobic types and a few of the anaerobic bacteria. Most polymers are excellent carbon sources that are readily consumed to support rapid bacterial growth rates. The resulting large quantities of biomass contribute to formation plugging. All these bacteria can be controlled by the application of various biocides.

### 14-3.11. Water blocks

Water can cause blocking in low-permeability rocks (Fig. 14-6) (Keelan and Koepf, 1977). Water blocks are a special case of relative permeability problems. In a water block, water usually occupies the flowing spaces (either pores or natural fractures) that are typically used by hydrocarbons to flow to the wellbore. Because of the mobility and viscosity differences, the hydrocarbon fluid may not be capable of displacing the water. The most



**Figure 14-6.** Water blocks: increasing the water saturation from 20% to 35% decreases the relative oil permeability from 90% to 30%, respectively (Keelan and Koepf, 1977).  $k_o$  = oil effective permeability,  $k_{ro}$  = oil relative permeability,  $k_w$  = water effective permeability,  $k_{rw}$  = water relative permeability.

severe cases of water blocks are usually observed in low-pressure, low-permeability, gas-producing formations after treatment with water that has a high surface tension.

### 14-3.12. Oil-base drilling fluids

Oil-base mud (OBM) is the drilling fluid of choice for the lubricity required in many highly deviated wells and for formations that are extremely sensitive to water-base mud (WBM). Most OBM, and particularly those with densities greater than 14 lbm/gal, contain sufficient solids to create silt-stabilized emulsions when mixed with high-salinity brines or acids. These emulsions are viscous and resist breaking. Some of these emulsions have been shown to be stable for several months, both in the laboratory and in the wellbore. The level of damage caused by these emulsions can be so severe that an entire pay zone can be missed. For example, in a South Texas well the OBM emulsion created damage so severe that almost no flow from the well could be measured. When the damage was removed, the well tested at more than 12 MMscf/D.

A related problem with OBM is the relative permeability effects commonly created by the powerful wetting surfactants used for creating stable OBM. When these materials coat or adsorb onto the formation, the wettability of the formation is altered, and permeabilities may be only 10% to 20% of what they were initially. The most severe problems usually occur with muds weighing

more than 14 lbm/gal. The main cause of problems is oil-wetting of the fines from weighting and viscosifying agents and from cuttings.

## 14-4. Origins of formation damage

This section describes the origins of formation damage and reviews typical well operations, including drilling, cementing, completion, gravel packing, production, stimulation and injection for enhanced oil recovery. All are potential sources of damage. Damage is also commonly categorized by its associated well operation (Tables 14-3, 14-4 and 14-5).

### 14-4.1. Drilling

#### ■ Mud solids invasion

Mud solids can progressively fill the porosity of the reservoir rock if forced into the pay zone. Subsequent attempts to start production or injection at moderate or high flow rates may cause these materials to bridge and severely decrease the permeability of the near-wellbore area.

Such damaging processes are usually limited to the first few inches around the wellbore (an average value of 3 in. is commonly used), but the resultant permeability reduction can be as high as 90%. Invasion of formation rock by drilling fluid solids is favored by

- large pore size of the formation rock (Brownson *et al.*, 1980)
- presence of fissures and natural fractures in the reservoir

– small particle size of the solid components of the drilling fluid (the initial particle size of weighting agents and lost-circulation preventers is usually coarse but can be fragmented by the drill bit) (Abrams, 1977)

- low drilling rate resulting in mudcake destruction (mud-loss increase) and long formation-to-mud contact time
- high drilling fluid circulation rate (mudcake erosion)
- high drilling fluid density causing large overbalance pressure (Givens, 1976)
- scraping of mudcake, provoking pressure surges and increasing formation-to-mud contact time during bit trips (Records, 1976).

Using clear brines (containing no particulate materials) as drilling fluids minimizes formation invasion by fines but may create a large loss of fluids in the rock matrix.

When drilling a formation with natural fractures, some mud loss is expected in the natural fracture system. Because natural fractures are important to reservoir flow, avoiding loss of mud to the fracture system by using a high-quality fluid-loss control system is crucial. If the natural fractures are already damaged by mud, the success of the cleanout will depend on how much mud was lost and the type and condition of the mud when it was lost. If a low-solids mud was used in a system with minimal overbalance, little damage may have occurred. If a high-weight mud system with a large amount of fines was used or if the drilling overbalance was high (more than 2 lbm/gal overbalance equivalent), damage may be severe.

Table 14-3. Initial damage during drilling or completion.		
Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Unstable formation	<p>May occur in any formation that is poorly consolidated or that will fail under pressure</p> <p>May occur with onset of water production or loss of pressure from depletion</p> <p>Problems include embedment of proppant, closing of acidized channels in acid fractures, spalling of formation into perforations or wellbore, or production of solids.</p>	Gravel packing, fracture packing, plastic consolidation or production rate limits
Oil-base mud emulsion damage	<p>Common in wells drilled with OBM</p> <p>If treated with acid or brine before the sulfonate emulsifiers are washed off the cuttings by production or solvent treatments, an emulsion can lock up the well.</p> <p>The first one or two treatments may be short-lived as more mud and mud filtrate move back toward the wellbore, as is often the case in naturally fractured formations.</p>	Wash with aromatic solvent followed by mutual solvent and acid  May require several treatments  Cuttings removal is important.
Fracture plugging from mud	<p>Large whole-mud losses in naturally fractured formations</p> <p>Intermittent production at low and moderate rates</p> <p>Infrequent recovery of whole mud and mud fines</p> <p>Some emulsions, especially after acid treatments</p> <p>May also occur if the hole is poorly cleaned during drilling</p>	Acid useful if damage is shallow  Fracture if damage is deep  Prevent by improving solids recovery  In severe cases, a sidetrack drill of the pay may be necessary.
Particle damage from drilling and completions	<p>Skin effect on buildup test</p> <p>Injection difficult</p> <p>May show emulsions in oil wells</p> <p>Poor mud conditioning before cement</p> <p>Common in openhole completions and horizontal wells</p>	HCl or HCl-HF in matrix acid job and solvent wash followed with acid in wells with OBM  Foam or jetting cleanups can be useful.
Poor perforations	<p>Shows up as damage on a buildup test but cannot be cured with acid or mechanical changes in the well</p> <p>Common problems are screenouts of fracture downhole scale occurrence, unstable emulsions, and downhole paraffin and asphaltene deposits.</p>	Reperforate  Problems with a well that cannot be broken down or even pumped into should always be approached by reperforating the well.
Cement in natural fractures	Poor well response following completion when possible perforation problems have been eliminated	Small fracture treatment or sidetrack drill

Table 14-4. Damage during and after stimulation.		
Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Migrating fines	Kaolinite or fibrous illite clay or some feldspars (nonclays)  Brine changes may trigger fines movement.  Sporadic reductions in flow rate  Variable production rate tests  Fines in produced fluids  Emulsions rare but possible	Clay control for prevention  Retarded acid for removal  May require limiting rate in extreme case or fracture treatment to spread out draindown
Particle damage after stimulation	May also occur following acid or fracture stimulations or workover fluids where dirty water was used or the water was hauled or stored in a dirty tank	Filter treatment fluids  Use clean tanks
Particles in waterfloods	Reduced injection rate  Higher injection pressures  Backflow shows particles and oil carryover return.	Better water filtering
Wettability problems	Commonly occurs after an acid job where the corrosion inhibitor was not mixed in the acid just before injection  Emulsions and reduced flow are common, particularly after inhibitor loss or OBM contact. May be permanent, but usually cleans up slowly with time and flow  Attempts to reverse natural wettability are usually short-lived.  Natural wettability is determined by the natural surfactants in the produced fields.	Treat with mutual solvent wash over the pay, displace and soak
Relative permeability problems	May occur when oil is injected into a gas zone or gas is injected into an oil zone that is above the bubblepoint	Treat with a high-API-gravity solvent such as condensate or xylene (low flash point)  Squeeze and produce back
Poor load-fluid recovery	Usually formation dependent  May decrease production rate in severe cases or cause a long cleanup time  Most common in formations with small pores and in microporous clays	Avoid or minimize water contact and lower the surface tension of the water to prevent  Removal with alcohols and some surfactants
Water blocks	Usually in gas wells with small pore throats, untreated water and low-pressure formation  If low pressure (less than about 0.2 psi/ft), the pore throat size has no effect	Matrix treat with alcohol or surface-tension-lowering surfactant  Inject gas in gas reservoir to a distance of 10 ft
Swelling clay	Smectite clay, some illite and smectite interbedded clay  Permeability is sensitive to change in water salinity or brine type.	Acidize with HCl-HF if damage is shallow  Fracture if damage is deeper than 12 in.
Microporosity (water trapping)	Caused by some forms of clay  May bind water and make high $S_w$ readings on log without water production	No treatment necessary

**Table 14-5. Damage during production.**

Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Retrograde condensate	<p>This special case of the relative permeability effect is a condensate (liquid phase) that forms from a rich gas.</p> <p>If the condensate forms in the tubing or casing, heading may occur.</p> <p>If the condensate forms in the formation, creation of another phase will reduce permeability to gas.</p> <p>Usually occurs near the wellbore as pressure drops there</p>	<p>Control drawdowns and repressure reservoir</p> <p>Redesign tubing if forming in tubulars</p>
Paraffins in tubulars	<p>Pressure restriction in tubulars</p> <p>Soft to hard mass found at pressure drops</p> <p>Reddish brown to black in color, with white or gray also possible</p> <p>Also commonly occurs in tubing near the surface as oil cools and the cloud point is reached</p> <p>May increase as a problem as a field ages</p> <p>Most paraffin deposits melt at less than 150°F [65°C].</p>	<p>Scraping and cutting for mechanical removal</p> <p>Hot oil useful if the deposit is less than 100 ft from surface</p> <p>Solvent soaks on deeper deposits</p> <p>Inhibitors available for pipelines and some problem wells</p> <p>Some wells require continuous downhole treatment through "macaroni string."</p> <p>Special bacteria are useful.</p>
Paraffins in flowlines	<p>Soft to hard deposits (not a scale) in surface flowlines and equipment</p> <p>Paraffin melts when exposed to sufficient heat . (usually about 150°F).</p>	<p>Mechanical or solvent removal or pigging</p> <p>Inhibitors can be used</p>
Paraffins after stimulation	<p>Injection of a cool stimulation fluid may precipitate paraffin in the reservoir on contact.</p> <p>The well may be cleaned up slowly (1 to 4 weeks) after stimulation, although load fluid is recovered faster.</p> <p>May have decreasing skin if multiple buildup tests are performed</p>	<p>Allow the well to clean up on its own</p> <p>Where this problem is known to occur, prevent by using xylene preflush ahead of acid</p>
Paraffins in formation	<p>Seen as skin on test</p> <p>May disappear if well is shut in for several days</p> <p>Cloud point of oil is near the reservoir temperature.</p> <p>Pressure drop may trigger paraffin drop out.</p>	<p>Treat with downhole heat-generating processes if the well is a good producer</p> <p>Solvent soaks also used</p> <p>Some inhibitors can be used with a fracture treatment.</p>
Asphaltenes	<p>Black, soft to hard mass that may occur as flakes, sludge, marble-size balls and a sticky buildup that occurs with paraffins</p> <p>Precipitation is triggered by destabilization of maltenes resins caused by acid contact, outgassing, shear in pumps, electrically charged metal surfaces, temperature reduction and CO<sub>2</sub>.</p> <p>Asphaltenes soften with increasing temperature (&gt;150°F) but do not melt.</p>	<p>Treatment with aromatic (cyclic ring) solvents such as xylene or toluene</p> <p>Some surfactants are also useful for dispersion of the asphaltic mass.</p> <p>Use antisludge additive or xylene with acid in reservoirs with more than 0.5% asphalt to prevent sludges</p>

Table 14-5. Damage during production (continued).		
Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Tar	<p>Flows slowly into perforations during production of oil</p> <p>Usually associated with the presence of a tar deposit near pay and typically highly asphaltic</p> <p>May contain some water that is tied up as droplets or "pockets" in the high-viscosity mass</p>	<p>Solvent soak as required</p> <p>Test solvent with sample of tar before job</p> <p>Heat often helps.</p>
Emulsion	<p>Unstable emulsions that break on standing</p> <p>Created in tubing at pressure drop points in the piping system from pumps to choke</p>	<p>No downhole treatment suggested</p> <p>Treat on surface if string redesign is impractical</p>
Silt-stabilized emulsion	<p>Stable emulsion with partially wetted fines at interface</p> <p>Common after drilling mud dispersal or cleanup of mud or cement fines by acid</p> <p>May also occur on polymer cleanup</p> <p>Common in production from unconsolidated formations, especially after acid or gravel-pack operations</p>	<p>Treat with mutual solvent and acid</p> <p>Remove downhole source of solids if possible</p>
Surfactant-stabilized emulsion	<p>Stable to highly stable emulsion</p> <p>Common to severe after acid treatment</p> <p>Stabilized skin may be seen at the drop interface.</p>	<p>Treat on surface if temporary</p> <p>Use mutual solvent or surfactant to prevent emulsion with next acid treatment</p>
Sludge (iron/asphaltic)	<p>Sludge is an emulsion that is nearly solid.</p> <p>May be triggered by acid, OBM, asphaltenes or iron compounds</p> <p>Disperse the sludge in xylene and analyze for components, particularly iron</p>	<p>Prevention is the best cure.</p> <p>Use nonsludging acid systems, and test at the iron content expected in the well</p>
Bacterial infestation	<p>This difficult problem to predict is more common in injection wells where surface or produced water is injected.</p> <p>If the colony is established in the water handling system, it can occur with the injection of any waters.</p> <p>Brown to black slimy masses or an H<sub>2</sub>S odor when tubing is pulled</p> <p>Bacteria may cause slow reductions in the injectivity of an entire field.</p> <p>Complete removal of bacteria is rarely possible.</p> <p>Treatment is usually on a remedial basis.</p> <p>Untreated water in treatments</p> <p>Drilling fluid or injection water can sour reservoirs with sulfate-reducing bacteria.</p>	<p>Treat with sodium hypochlorite followed by HCl (do not allow contact of sodium hypochlorite and HCl)</p> <p>More than one treatment may be necessary.</p> <p>Alternative treatments are chlorine dioxide and bactericide slugs.</p>
Calcium carbonate scale	May form at any pressure drop, either in the formation or tubulars	HCl to remove and inhibitor to prevent

**Table 14-5. Damage during production (continued).**

Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Calcium carbonate scale (continued)	<p>May form quickly and can sharply limit production, especially at gravel-pack interfaces or near perforations in wells with high drawdown across the perforations</p> <p>May be more common in earlier stages in some fields when the pressure drop is more severe</p> <p>Usually has no crystal pattern</p>	<p>Inhibitor may be squeezed into the formation for longer lived protection.</p> <p>Some HCl jobs may trigger calcium carbonate scale in rare cases; inhibit acid or treat with EDTA if this is a problem.</p>
Calcium sulfate scale	<p>Usually forms at pressure drop induced by turbulence or dissolver with acid)</p> <p>More common where high-sulfate waters contact high-calcium waters and in CO<sub>2</sub> floods</p> <p>Scale is not acid soluble.</p> <p>May be found on the outside of pumps and at intakes and gas expulsion ports and valves downhole</p> <p>Crystals are characteristic for this scale.</p>	<p>Chemical converter or dissolver followed by acid (do not contact converter</p> <p>Acid is not useful alone.</p> <p>Inhibitors placed by squeeze treatments are useful for prevention.</p>
Barium sulfate scale	<p>Nonreactive scale that forms at pressure draw-downs or where outgassing occurs</p> <p>No readily apparent crystal pattern in many deposits</p> <p>May occur as NORM scale in areas where radioactive isotopes form in the lattice</p> <p>NORM scales are detectable with gamma ray logging tools.</p>	<p>Scraping, water blasting or other mechanical removal</p> <p>Chemical treatment is usually not possible if scale occurs as a nearly pure (greater than 90%) deposit or as thick (greater than <math>\frac{1}{4}</math> in.) deposits in pipe.</p> <p>Can be prevented by inhibitors</p>
Iron carbonate scale	<p>Carbonate scale tendencies with large iron content</p> <p>Molar acid reactivity on the scale</p> <p>Brownish colored scale (cleaned of oil)</p>	HCl for thin deposits or mechanical removal where possible
Iron sulfide scale	<p>Hard scale, dense and heavy</p> <p>Many forms are not acid soluble.</p> <p>Some forms are mildly magnetic.</p>	<p>Mechanical removal with mills or cutters</p> <p>Water jets may not work.</p>
Salt	<p>Precipitates as a white mass in the tubulars or in the formation</p> <p>Usually associated with a cooling of super-saturated water, but can also be triggered by a pressure drop</p> <p>May be seen early in some wells but becomes less of a problem as the water cut increases</p> <p>Problems in formations with produced water salinity that is near saturation</p>	Freshwater or weak brine wash
Hydrates (ice) in gas wells	<p>Gas well with intermittent flow to nearly total shutoff, followed by return to flow in a few minutes</p> <p>Produces a small amount of water</p>	<p>Glycol or alcohol injection below the hydrate formation point</p> <p>Insulated risers or tubing</p>

**Table 14-5. Damage during production (continued).**

Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Hydrates (ice) in oil wells	In oil wells, usually forms only near the mudline in Arctic regions  May also form in drilling fluid	Insulated risers
Fill in perforations	High skin effect  Well can be injected into at low rates.  Reperforating may show sharp increases.	Clean out or reperforate
Fill in casing	High skin effect  Difficult or impossible to inject into well  Partial fill shows skin effect on a buildup test, but injection is possible at a reduced rate.  Confirm with a sinker bar on wireline	Reverse circulation or regular circulation
Water coning	Onset of water production after extended production  Formation has no vertical permeability barriers and sufficient vertical permeability to allow water to move toward drawdown.	Limit rate  Some treatments may be temporarily useful.  Most water control products are not useful without natural reservoir barriers
Waterflood breakthrough through high-permeability zone	Examine produced water analysis and compare with flood water for identification  Watch for scale	High-permeability zones should be plugged deep (depth greater than 100 ft) from producer and injector when oil recovery from the zone is complete.
Commingled water production	Initial production of water with oil in primary, with breakthrough in flood  Water cut increases in flood.	Temporary or no treatment
Collapsed pipe	May show up as reduced rate or destruction of lift equipment  Check with a gauge ring on wireline or tubing  Most common causes are earth-shift loads caused by subsidence of producing formations with fluid and sand withdrawals, active faults and formation movement near salt zones.  Other causes include severe corrosion, malfunctioning perforating guns, pipe flaws and wear of tubulars from drilling or lift system.	If caused by earth-shift forces, use heavier pipe or multiple strings  Liners, cement and patches are used for repair.
Tubing problem	Well refuses to flow although pressure is sufficient with the expected assistance from dissolved gas.  Well may load up and die, or liquid slugs may be produced if the string is too large.  Rate is restricted by friction backpressure if tubing is too small.	Redesign string  A velocity string that fits inside the existing tubing may help if tubing is too large.
Leaks	Sudden changes in gas/oil ratio, water/oil ratio, pressure or chemical analysis of water	Repair  Consider corrosion control program

- Drilling fluid filtrate invasion

For economic reasons, wells have to be drilled as fast as possible. To increase the penetration rate, it is tempting to reduce the fluid-loss control of the mud (Black *et al.*, 1985; Simpson, 1985a, 1985b; Montogmery, 1985). About 600 bbl of fluid can be lost into a typical formation (Kutasov and Bizanti, 1985) during the drilling of a 10,000-ft well. Higher values of filtrate invasion may result from the deliberate choice of high penetration rates. Before this decision is made, the effect of the filtrate and any associated solids should be known.

The liquid phase of a drilling fluid also contains many potentially damaging compounds. Because filtrate invasion can be deep, as shown in Table 14-6 (Simpson, 1974; Hassen, 1980), drilling filtrate damage can be one of the most important causes of production impairment. The severity of this damage depends on the sensitivity of the formation to the filtrate. High-permeability clean sandstones undergo more invasion than low-permeability reservoirs (Phelps *et al.*, 1984) but are more likely to be less affected when their connate water is chemically compatible with the filtrate. An average permeability reduction of 40% has been suggested; however, any value between 0% and 100% is possible, depending on the nature of the formation rock and fluids.

Sensitive formations contain clays that can be dispersed or swollen, are low-permeability rocks in which saturation problems dominate or are reservoirs producing almost saturated brines or high-content asphaltene or paraffin oils.

Problems with clays are not detailed here. However, any change in the salinity of the pore fluids may affect the stability of clay particles in the porous medium. In particular, reducing the salinity or increasing the pH value of the water surrounding clay particles can

promote dispersion of these materials. Destabilized formation fines act similarly to mud particles forced into formation rocks. As production or injection starts, fines migrate toward pore throats and either block them or bridge over them, depending on the particle size. The severity of the resulting permeability impairment varies with the fines concentration in the reservoir rock (Krueger *et al.*, 1967; Drodgy *et al.*, 1988; Jiao and Sharma, 1992).

Factors that increase the probability of drilling fluid invasion include

- high permeability of the mud filter cake (a result of either poor design of the drilling fluid or detrimental drilling procedures)
- high overbalance
- long formation-to-drilling fluid contact time.

WBM filtrates may have a low salinity and a high pH value and may contain dispersants and polymers. Water is a cause of in-situ clay disturbance and water blocking in low-permeability rocks (Keelan and Koepf, 1977). The numerous drawbacks of water-base drilling fluids led to the development of OBM for drilling through sandstones containing clay (Methven and Kemick, 1969). The initial conclusion was that this new mud was a safe, all-purpose drilling fluid. It is now recognized, however, that although the problems of OBM are less numerous than those of WBM, they are commonly much more severe (Goode *et al.*, 1984). OBM filtrates contain additives that cause emulsion and wettability problems (Ballard and Dawe, 1988; McKinney and Azar, 1988; Sanner and Azar, 1994; Ventresca *et al.*, 1995). Polymer filtrates that are stable at circulating temperatures, but already potentially damaging, can decompose and form residues when exposed to static reservoir temperatures for long periods of time (Tuttle and Barkman, 1974), as previously discussed.

**Table 14-6. Depth of filtrate invasion (Simpson, 1974).**

Time (D)	Depth of Invasion (in.)		
	Oil-Base Mud	Low-Colloid Oil-Base Mud	Water-Base Mud
1	1.2	3.3	7.7
5	4.6	11	12
10	7.7	17	18
15	10	21	23
20	12	23	27
25	14	29	31
30	16	32	34

#### 14-4.2. Cementing

- Washes and spacers

The removal of drilling mud, while necessary for improving cement bonding, typically exacerbates formation damage through either increased fluid loss or incompatibility problems with cement washes and spacers.

The duration of a cementing job is short compared with the duration of drilling through a pay zone. The maximum depth of invasion by the filtrate from either spacers or cement slurries is a few inches, which is negligible compared to the few feet of drilling mud filtrate invasion. This does not mean that cement or spacer fluid loss should be neglected. Poor fluid-loss

control can result in premature job failure by either complete loss of the preflush fluids (insufficient volumes) and subsequent contamination (and strong gelling) of the cement slurry by the drilling fluid or dehydration of the cement slurry itself.

#### ■ Cement slurries

The broad particle-size distribution of cement grains, together with the use of high-efficiency fluid-loss agents, results in limited particle and filtrate invasion of cement slurries (Jones *et al.*, 1991b). However, there are four cases where large permeability impairments can occur:

- The relatively high pH value of cement slurry filtrates is particularly detrimental to formation clay minerals. Calcium ions liberated by cement particles are quickly exchanged on clays near the wellbore, and the resulting modification of the filtrate composition makes it a perfect destabilizing fluid in terms of dispersing ability (Cunningham and Smith, 1968).
- Cement filtrate that comes into contact with connate brines that contain high concentrations of calcium can provoke the precipitation of calcium carbonate, lime (Records and Ritter, 1978) or calcium silicate hydrate (Krueger, 1986).
- Overdispersed slurries (with no yield value) promote the rapid separation of cement particles at the bottom and water at the top of the cement column. A large invasion of free water will most likely take place, and the resulting water blockage may be significant.
- Loss of cement to the natural fracture system is a catastrophic problem when using a cased and perforated completion through formations with natural fracture systems. In side-by-side well comparisons, cement loss in natural fractures in the pay zone has been shown to decrease production to the point where the zone cannot flow effectively. Once cement is lost into the fracture system, hydraulic fracturing or sidetracking and redrilling the well are the best alternatives. In some carbonate formations, acid fracturing may be beneficial.

#### 14-4.3. Perforating

Perforations are the entry point from the formation to the wellbore, and all flow in a cased, perforated completion must pass through these tunnels. Although perforation job quality is at times overlooked in the search for reasons why a well does not produce as expected, any time that formation damage is suspected the perforations should be examined first. Perforating

is always a cause of additional damage (Suman, 1972). Extreme overbalance (EOB) perforating has been used expressly to reduce damage to the perforation tunnels (see Chapter 11<sup>†</sup>).

- Perforating mildly overbalance always forces formation and gun debris into perforation walls and decreases the permeability near the perforations (Keese and Oden, 1976).
- Perforating mildly overbalance in fluids that contain particles produces a similar effect (Paul and Plonka, 1973; Wendorff, 1974) and also builds a dense, impermeable cake on the perforation walls.
- Insufficient perforation penetration does not bypass drilling damage (Klotz *et al.*, 1974; Weeks, 1974). Penetration also decreases with formation effective stress (Saucier and Lands, 1978), a definite concern in deep wells.
- If the underbalance pressure required to achieve damage-free perforations is incorrectly estimated, the insufficient pressure difference will limit damage removal (Hsia and Behrmann, 1991; Behrmann, 1995; Bird and Dunmore, 1995), whereas excessive pressure differences lead to sand influx in the wellbore (King *et al.*, 1985; Seanard, 1986).
- Low perforation density restricts flow.

The perforating guns and processes should leave adequate entrance holes for the amount of fluid flowing into the wellbore. This can range from one shot every other foot in low-rate, homogenous formations (high vertical permeability) to as many as 12 to 16 shots per foot (spf). Most formations differ in vertical to horizontal permeability, with horizontal permeability from 3 to more than 10 times the vertical permeability. This property makes perforation density critical, especially if there are shale laminations in the pay zone. If too few perforations are used in a laminated or highly structured zone (many vertical permeability barriers), then flow from the zone will be only a fraction of what an openhole completion could be.

#### 14-4.4. Gravel packing

Formation damage mechanisms can affect gravel packs. Gravel packs are sand-exclusion techniques, essentially filters, in front of which formation fines are expected to bridge. It is almost universally true that gravel packs deteriorate with time, causing a progressive reduction of well performance. This is in contrast to current methods of sand production control and high-permeability fracturing (called frac and pack), in which well performance improves with time.

<sup>†</sup> See *Reservoir Stimulation Third Edition* (SMP-7075)  
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Major sources of damage in gravel packs are

- improper placement of the gravel pack (perforations remain empty or the annulus between casing and screen is incompletely filled), allowing perforation filling by formation sand, pack fluidization and subsequent intermixing of sand and gravel in the case of pressure surges (Stadalmann *et al.*, 1985; Jones *et al.*, 1991a; Chuah *et al.*, 1994)
- damage by unbroken gels or formation particles during placement as a result of incomplete perforation cleaning (Sparlin, 1974)
- invasion by loss-control materials (LCM) (Blanton, 1992; McLeod and Minarovic, 1994; Hodge *et al.*, 1995)
- thread dope, paint, rust and polymer residues forced between formation sand and the gravel pack during placement
- inadequate gravel size, leading to gravel-pack invasion by formation fines during production (Gulati and Maly, 1975)
- screens with slots too large (do not retain gravel) (Flanigan, 1980) or with slots too narrow that become plugged and reduce production.

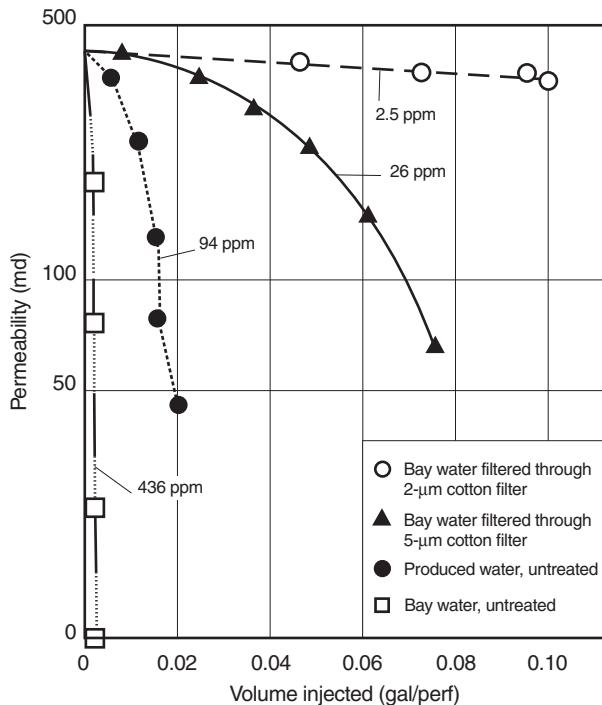
#### 14-4.5. Workovers

The various types of damage from completion and workover fluids are similar to the damage created by drilling fluids (Eaton and Smithey, 1971; Patton and Phelan, 1985):

- permeability impairment of formation rocks and productivity impairment of perforations by suspended solids (Rike, 1980; Rike and Pledger, 1981) including bacteria and polymer residues (Lissant, 1974)
- common problems resulting from filtrate invasion: clay swelling and dispersion (Azari and Leimkuhler, 1990a, 1990b), water blocks (Oudeman *et al.*, 1994) and emulsion blocks, and scale precipitation.

The necessity of using clean, filtered workover fluids has long been recognized (Fig. 14-7). Techniques to place these fluids adequately without contaminating them with the various particulate or gumlike materials in the wellbore (including thread dope) have also been proposed (Krause, 1986).

There is a strong requirement for fluid-loss control, especially in depleted reservoirs, and additives have been developed for this purpose (Crowe and Cryar, 1975; Mahajan and Barron, 1980). Another approach is to use foams, gases (Dahlgaard, 1983) or mists as completion fluids (Millhone, 1983). Instead of physically reducing the extent of filtrate invasion, the fluid-loss agents



**Figure 14-7.** Apparent permeability reduction in Cypress sandstone cores with the injection of various filtered and unfiltered waters (Tuttle and Barkman, 1974).

can deliberately be removed from workover fluids. In this approach, the compatibility of the fluid with formation minerals and brine must be carefully studied (Morgenthaler, 1986).

Workover brines (especially high-density brines) usually require inhibitors to control corrosion. These products can contribute to emulsion-block problems through the wettability modification of formation minerals and sometimes promote iron precipitation in the reservoir (Potter, 1984).

#### 14-4.6. Stimulation and remedial treatments

##### ■ Wellbore cleanup

When wells are cleaned to remove deposits or corrosion products from the tubing, high concentrations of damaging materials may invade the pay zone. Extreme care should be devoted to preventing these suspensions from being forced into the porous medium. Particularly dangerous are compounds that are soluble in the cleaning fluid because they cannot form impermeable cakes that prevent formation invasion. Rust in acid (Gougle et al., 1985) or paraffins in hot oil (Newberry and Barker, 1985) are the two most typical redissolved wellbore compounds. They reprecipitate in the formation and cause extensive, severe and usually permanent damage.

## ■ Acid treatments

Problems already encountered in other phases of the life of a well may also occur during acidizing treatments, especially in cases of inappropriate design. These include

- damaging materials from the tubing entering the formation rock
- oil-wetting of the reservoir by surfactants, especially corrosion inhibitors (Crowe and Minor, 1982), which can create emulsion blocks
- water blocks
- asphaltene/paraffin deposition when large volumes of acid are injected.

In addition to these common damaging processes, specific production impairment can result from poor design of acidizing treatments. These impairments include the following:

- sludges produced by reaction between acids and asphaltenes (Moore *et al.*, 1965; Houchin *et al.*, 1990), especially in the presence of some additives (particularly surfactants) (Knobloch *et al.*, 1978) or dissolved iron (Jacobs and Thorne, 1986)
- deconsolidation of the formation rock caused by excessive dissolution of the cementing materials by acids
- precipitation of by-products from the reaction of acids with formation minerals (Boyer and Wu, 1983; Gadiyar and Civan, 1994)
- precipitation caused by some sequestering agents added to acids to prevent iron problems if iron is suspected present (Smith *et al.*, 1969)
- permeability impairment by residues from corrosion inhibitors (Crowe and Minor, 1985) or produced through the thermal degradation of polymers, such as friction reducers (Woodroof and Anderson, 1977)
- dissolution of pack sands, to a limited extent, in hydraulically fractured and gravel-packed wells (Cheung, 1988; Yeager, 1990).

## ■ Fracture treatments

Damage resulting from hydraulic fracturing takes two distinct forms: damage inside the fracture itself (proppant-pack damage) and damage normal to the fracture intruding into the reservoir (fracture-face damage). The first generally occurs because of inadequate breaking of the fracturing fluid polymer; the second occurs because of excessive leakoff. Depending on the reservoir permeability, the impact of these two damages varies. For low reservoir permeability, neither one is much of a factor. As the permeability

increases, proppant-pack damage (and its avoidance) becomes increasingly important, whereas damage to the reservoir face is relatively unimportant. At high permeabilities, both are important, with fracture-face damage dominating at very high permeabilities.

The selection of fracturing fluids, polymer concentrations and breakers is critical in addressing these issues. Incomplete breaking of the polymers in fracturing fluid is the most obvious cause of damage within hydraulic fractures (Gidley *et al.*, 1992), as well as the poor selection of proppant fracturing fluids (Brannon and Pulsinelli, 1990) and formation rock spalling or creeping into the proppant pack (Strickland, 1985). True damage in the formation rock is the consequence of excessive leakoff in high-permeability reservoirs when polymer-base gels are used in combination with inefficient fluid-loss agents (Elbel *et al.*, 1995; Parlar *et al.*, 1995). These damages are usually severe and usually cannot be improved with matrix treatments. To alleviate this problem, polymer-free, surfactant-base fluids have been proposed (Stewart *et al.*, 1995); however, they cannot be used in the absence of crude oil, which is required for breaking the surfactant micelles.

## ■ Poor load-fluid recovery

Typical load-fluid recovery on a stimulation treatment or remedial treatment may range from as little as 20% to 100%. Load fluids can invade and become trapped in the formation by entering the smaller capillary pores during higher injection pressures, or they may coat clays with high microporosity (a condition in which a large surface area exists for water coating or trapping). Once the injection pressure is released, capillary pressure effects will hold significant volumes of the fluid in the formation. In some formations, more than 50% of the load fluid can be trapped after a treatment, and yet the formation may not appear damaged. Most of the flow is through the larger pore system and natural fractures, and these passages usually clean out quickly. The smaller pore passages can trap fluid by imbibing or absorbing it, but they have no real effect on the flow through the formation.

### 14-4.7. Normal production or injection operations

#### ■ Unconsolidated formations

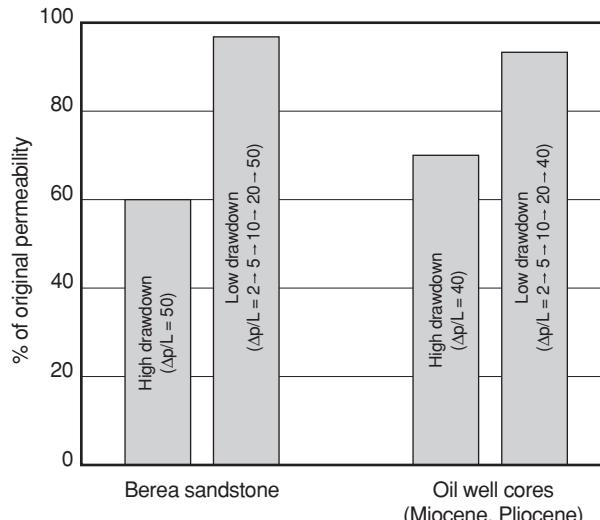
Formations that are capable of releasing parts of the matrix during production or after stimulation pose special treating problems. Although these situations are commonly thought of as sand-control problems rather than formation damage, the effect of mobile sand and the pressure drop caused by collapsed formation tunnels closely resemble the effect of formation damage. Some

reservoirs cannot be produced at high flow rates or large drawdowns without being affected adversely. Permanent damage, which cannot be removed simply by the reducing production rate, may be created.

A major problem is the movement of fines in the formation in response to either flow velocity or changes in the salinity of the flowing fluid. Although this subject was addressed in Section 14-3.1, it is worth mentioning again, because it is usually a significant factor in the behavior of unstable formations. Native silts and clays loosely attached to pore walls can be put into motion by high flow rates (Hower, 1974; Holub *et al.*, 1974), especially when two or more immiscible fluids are produced at the same time (Muecke, 1979; Sengupta *et al.*, 1982). Depending on their particle size, they can either block pore throats in the vicinity of their initial location or migrate toward the wellbore.

Whether migrating particles reach the wellbore or bridge over pore throat entrances depends on their original concentration in the formation, their size, the extent of the increase of their concentration near the wellbore (because of radial flow) and the maximum flow rate (Vaidya and Fogler, 1990; Gunter *et al.*, 1992; Oyeninen *et al.*, 1995). Bridging is promoted when one or more of these parameters are increased. Bridging is less detrimental than blocking because a short period of reverse flow, followed by production at a flow rate lower than that at which bridging occurred, may mechanically disperse bridges (Fig. 14-8). However, this cannot be achieved when the bridging agglomerates were previously cemented by precipitates (asphaltenes or scales) or chemically stabilized through the injection of flocculants (such as clay stabilizers).

Excessive drawdown can also decrease pore pressure near the wellbore to such an extent that the effective stress exceeds the formation rock compressive strength. This phenomenon is obvious in poorly cemented sandstones, where wellbore filling by formation sand is progressive (Stein and Hilchie, 1972; Stein *et al.*, 1974; Antheunis *et al.*, 1979). It is less apparent in chalks, where formation compaction and significant porosity reduction affect the near-wellbore region without any occurrence of formation debris in the produced fluids (Morita *et al.*, 1984; Blanton, 1978; Ben Marek, 1979; Van Ditzhuijzen and de Waal, 1984). Chalk compaction is four- to eightfold greater when soft waters are injected during completion (Newman, 1983). Formation breakage is particularly damaging in hydraulically fractured wells, where creeping inside the proppant pack results in large-scale drops in production (Strickland, 1985). It has to be emphasized that once created, this type of damage cannot be removed by matrix treatments.

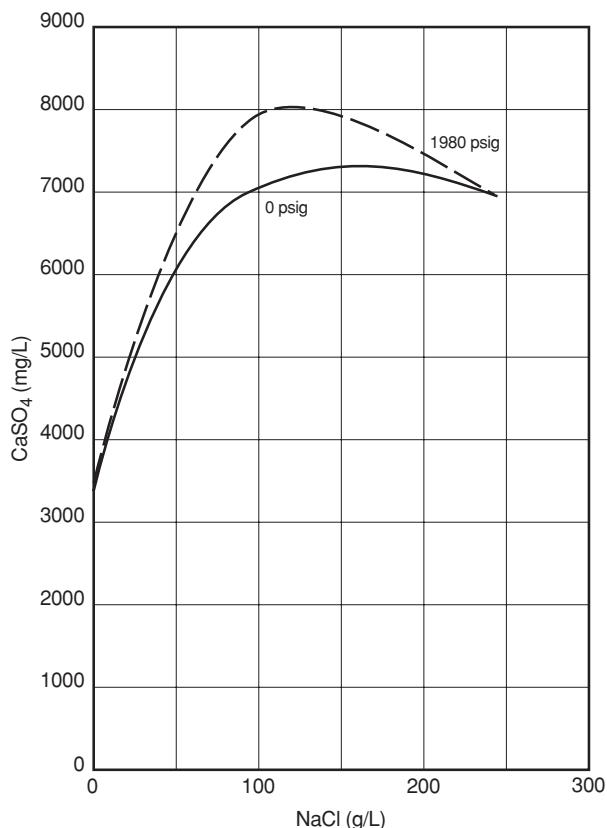


**Figure 14-8.** Effect of drawdown pressure during cleanup on the permeability regained by damaged sandstones (Krueger *et al.*, 1967).  $\Delta p$  = pressure difference,  $L$  = length.

Reduction in the pore pressure during production (Fig. 14-9) (Fulford, 1968), and sometimes cooling resulting from gas expansion, results in the precipitation of organic (Hirschberg *et al.*, 1984; McClafin and Whitfill, 1983; Schantz and Stephenson, 1991; Singhal *et al.*, 1991; Leontaritis *et al.*, 1992; Takhar *et al.*, 1995; Piro *et al.*, 1995) or inorganic materials. Generally, these deposits affect only the production string and surface equipment. However, they can reduce formation permeability. Seeds, such as high-surface-area clays, promote the deposition of organic materials (especially asphaltenes) (Rogers, 1976) or the precipitation of supersaturated salt solutions.

Common scales are calcium carbonate (Vetter and Kandarpa, 1980; Nancollas and Sawada, 1982; Gudmundson and Ortiz-R., 1984) and calcium sulfate (Vetter and Phillips, 1970; Oddo *et al.*, 1991; Lejon *et al.*, 1995). Problems associated with the deposition of elemental sulfur (Kuo, 1972), sodium chloride (Place and Smith, 1984) and barium sulfate (Wat *et al.*, 1992) have also been described. Commingled precipitation of asphaltene and calcium carbonate is common (Efthim *et al.*, 1990).

Special cases of spalling or sloughing of particles from brittle formations are also problems. These particles are derived from tensile failure created during flow that results in chips of the formation spalling into the perforations or the wellbore. Brittle formation behavior is seen typically in hard dolomites, brittle shales and a few shaly sandstones. Brittle formation failure is generally created by stresses in the formation and confining stresses caused by depletion. Prevention of these stresses is difficult without repressuring the reservoir.



**Figure 14-9.** Pressure effect on gypsum scale solubility at 95 deg [35 degC] (Fulford, 1968).

- Retrograde condensation and two-phase flow
- Retrograde condensation and bubblepoint problems are relative permeability blocking problems. Retrograde condensation is the condensation of a liquid from gas. When this happens, the relative permeability to gas can be reduced substantially. In oil reservoirs produced below the bubblepoint pressure, free gas is formed, which reduces the relative permeability to oil.

## 14-5. Laboratory identification and treatment selection

The objectives of laboratory experiments are to identify potential damage and aid selection of the optimum treatment fluid and design. To achieve these objectives, the formation material (cores), produced fluids and damaged material must be analyzed. Definitive core flow studies and solubility tests are usually required to identify the source of damage and to help determine the best procedure for damage removal.

### 14-5.1. Damage identification

- Core analysis

The detailed analysis of formation cores is required to design the damage removal treatment. It is difficult to determine formation mineralogy without the use of cores (sidewall or conventional). Conventional cores are recommended to complete the analysis because sidewall cores can be contaminated with drilling fluids and may not be representative of the formation. If sidewall cores are used, the analysis should be conducted on duplicate cores.

- Formation mineralogy

The formation mineralogy is an important parameter affecting stimulation success. Knowledge of the petrography of the formation is essential to understanding what the response of the rock (formation material) will be to any fluid. The relation between the rock and the treating fluid depends on the minerals present and the position of the minerals within the rock matrix. The analytical techniques used to characterize the mineralogy are X-ray diffraction (XRD), SEM and thin-section analysis.

XRD analysis provides rapid and accurate identification of the crystalline material of the rock matrix. Each crystalline material has a specific XRD pattern. The types and quantities of clays and feldspars can be qualitatively determined using XRD. Crystalline scale deposits can also be identified using XRD.

SEM provides information on mineralogy and morphology and the size of pore-lining materials. Quantitative elemental analysis and mineral identification can be achieved by using this technique in conjunction with energy-dispersive spectrophotometry (EDS). The primary advantages of SEM-EDS analysis over light microscopy are the depth of focus and magnification. The techniques are useful for observing clay platelet structure and analyses. The structures of smectite, kaolinite, chlorite and illite are shown in Fig. 14-4.

Thin-section analysis is used widely to study rock structure and quantify minerals. In addition, cementing minerals and the types and location of pores can be identified. The rock is impregnated with a blue-colored resin to fill the interconnected porosity. A thin (approximately 30  $\mu\text{m}$  in thickness) slice is cut perpendicular to the bedding plane, and the surfaces are polished. Using a polarized microscope, the minerals can be observed by transmitted light because they have characteristic optical properties. The pore structure is easily identified by the blue resin.

## ■ Formation wettability

Most formations (sandstone or carbonates) are water-wet. Occasionally, oil-wet formations are encountered, especially when the produced oil is a low-gravity oil. In some situations, the formation appears to be oil-wet because of the produced oil and the natural surfactants present in the oil; however, when the oil is removed using appropriate solvents, the formation may be water-wet. When the oil adheres to the rock matrix strongly, it must be removed prior to mineralogy or reactivity testing. If the formation material is coated with oil, it should be cleaned with an aromatic solvent such as xylene until all traces of oil have been removed and followed with a xylene- and water-miscible solvent such as methanol.

The simplest test to determine formation wettability is to take approximately 10 cm<sup>3</sup> of formation material and place it in the produced brine to equilibrate for approximately 30 min. The formation material is then placed in an oil (such as kerosene) and observed. To accentuate the test results, red dye can be added to the clear oil to aid identification of the oil adhering to the formation material. After it is allowed to equilibrate for an additional 30 min, the formation material is added to a fresh aqueous solution. Strongly water-wet formations or other fines disperse readily in aqueous fluids but agglomerate or clump together in the clear oil-base fluids. Conversely, oil-wet particles disperse in oil but agglomerate in water-base fluids. The surface is water-wet if the contact angle of the fluid with the formation material is less than 90°; the surface is oil-wet if the contact angle is greater than or equal to 90°. Wettability can exist in various degrees between extremely water-wet and extremely oil-wet. Intermediate wettability is difficult to identify and describe, with contact angles greater than 80° but less than 100°.

The wettability test can also be used to determine if the desired treatment fluid is water-wetting or oil-wetting and how the treatment fluid may affect the desired natural wettability. The cleaned formation material is treated as described previously except the formation material is placed in the desired treatment fluid instead of naturally produced brine. Changes in wettability resulting from the selected treatment fluid can be detected using this method.

## ■ Petrophysical characterization

Core porosity and permeability should be measured before performing a core flow evaluation.

### – Porosity

Porosity is the ratio of the void space volume to the bulk volume of the rock material. It is a measure of

the volume occupied by oil, gas and other fluids in the reservoir. Total, effective and residual porosities are defined in Chapter 1<sup>†</sup>.

The porosity of the rock sample can be determined using one of several techniques. The simplest technique for the determination of effective porosity uses Boyle's law; the pressure of nitrogen is determined in a constant-volume cell, with and without the core. The total porosity is derived by bulk and matrix density measurements with a helium pycnometer. When required, the pore-size distribution can also be measured using a mercury intrusion porosimeter. The size and number of pores can be calculated and the microporosity can be estimated. The microporosity can be more accurately determined using the Brunauer, Emmett, Teller (BET) gas adsorption technique if required.

### – Permeability

Permeability, an intrinsic characteristic of the rock, is a measure of the rock's capacity to transmit fluids. The measurement is usually made with gas (e.g., nitrogen [N<sub>2</sub>]) or liquids (e.g., brines and oils).

Permeabilities must be determined using simulated downhole temperature and stress conditions. In certain stress-sensitive formations, permeability determined under 1,000-psi confining stress may be 1 order of magnitude higher than the permeability determined at 10,000-psi stress.

## ■ Formation fluid analysis

Analysis of the formation brine and oil can aid in determining the types of damage that may be present.

### – Brine

Analysis of the formation brine can be used to predict scale formation. Common ions are listed in Table 14-7. Their presence can be determined using standard laboratory wet-chemical or instrumentation techniques.

**Table 14-7. Common ions in formation brines.**

Cations	Anions
Sodium (Na <sup>+</sup> )	Chloride (Cl <sup>-</sup> )
Potassium (K <sup>+</sup> )	Bicarbonate (HCO <sub>3</sub> <sup>-</sup> )
Calcium (Ca <sup>2+</sup> )	Carbonate (CO <sub>3</sub> <sup>2-</sup> )
Magnesium (Mg <sup>2+</sup> )	Sulfate (SO <sub>4</sub> <sup>2-</sup> )
Barium (Ba <sup>2+</sup> )	
Strontium (Sr <sup>2+</sup> )	
Iron (Fe <sup>2+</sup> and Fe <sup>3+</sup> )	

<sup>†</sup>See *Reservoir Stimulation Third Edition* (SMP-7075)

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Calculations are available to predict scaling tendencies. The intermixing of produced brines with spent acid can result in the formation of insoluble precipitates. Analysis of these brine data aids in selecting the treatment fluids and their sequence.

#### - Oil

Analysis and testing of the produced oil can also help stimulation treatment design. The use of treating fluids that are incompatible with the produced oil can result in the formation of emulsions and sludge that will subsequently result in an unacceptable response to the stimulation treatment. The oil may contain paraffins and asphaltenes that can interact with the treatment fluid. The quantity of various fractions of asphaltenes and paraffins and their ratio to each other are used to assess the possibility of organic precipitation damage. It is also imperative that the identity of deposits recovered from a well be determined. This is particularly true of organic deposits because treatments for paraffin and asphaltene removal are different.

A test of the API gravity is performed on the produced oil to evaluate sludging tendencies. Certified hydrometers are used to measure the specific gravity as a function of temperature.

For analysis of the asphaltene content, the produced oil is centrifuged to separate out emulsified aqueous fluids. Mixing the crude oil with pentane and centrifuging the sample enables preferential separation of asphaltenes from the produced fluid. Repeated extraction is performed until all oil has been removed. The precipitated asphaltene material is collected, and standard laboratory techniques are used to obtain the content by weight. The oil pentane fraction is saved and the pentane solvent is evaporated. The residual oil is then used to complete the analysis for the paraffin content.

For analysis of the paraffin content, a sample of vigorously mixed crude oil and acetone is centrifuged to enable preferential extraction of the paraffin material into acetone. Repeated extraction and holding at temperatures less than 32 degF [0 degC] result in precipitation of the paraffins. The acetone mixture is filtered to remove the paraffins, which are dried to remove residual acetone. On the basis of the total composition of the produced oil used for the analysis, the percentage of paraffin is determined.

## 14-5.2. Treatment selection

The solubility of the formation or damage material, treating fluid compatibility and core flow studies should be conducted to aid designing the best treatment for damage removal and to select the chemical products that are the most compatible.

### ■ Solubility tests

#### - Formation material

Calcite, dolomite and ankerite are soluble in HCl and mud acid systems. Clay and silt are soluble only in mud acid systems. Because of their high surface area, clays and other fines are much more reactive with mud acid than sand grains are. The total solubility of the formation material is the sum of the solubility of each mineral in the formation sample. Minerals other than carbonates are also soluble in HCl; therefore, solubilities should be used with caution. These minerals include sulfates (e.g., anhydrite), iron oxides and halite. The solubilities of common minerals are shown in Table 14-8.

Solubility tests are performed under ideal laboratory conditions and therefore exhibit the maximum formation solubility. The structure of the rock and the position of each mineral in relation to the flow paths in the rock matrix may result in different solubilities during actual acidizing operations. Solubility determined in the laboratory is not a definitive value for the maximum solubility that may result during the acidizing process, but it provides guidelines as to which treating fluids are most applicable.

A combination of solubility test results and XRD is commonly used to estimate the carbonate, silt and clay minerals and other mineral contents in the rock matrix. Determination of the acid solubilities of the various materials in HCl and mud acid determines the total solubility. When the results are used in conjunction with XRD analysis, the composition can be determined by the following procedure.

1. The total solubility in HCl is typically used as an estimate of the total carbonate content.
2. The solubility of the formation material in mud acid is used to determine the silt and clay content (total fines) and the carbonate content.
3. The difference between the solubilities in mud acid and HCl is considered the approximate content of clay and fines.

Table 14-8. Solubility of common minerals in acids.			
Mineral	Chemical Composition	Solubility	
		HCl	HF
Quartz	SiO <sub>2</sub>	None	Low
Feldspar			
Microcline	KAlSi <sub>3</sub> O <sub>8</sub>	None	Moderate
Orthoclase	KAlSi <sub>3</sub> O <sub>8</sub>	None	Moderate
Albite	NaAlSi <sub>3</sub> O <sub>8</sub>	Very low	Moderate
Plagioclase	(Na,Ca)Al(Si,Al)Si <sub>2</sub> O <sub>8</sub>	Very low	Moderate
Mica			
Biotite	K(Mg,Fe <sup>2+</sup> ) <sub>3</sub> (Al,Fe <sup>3+</sup> )Si <sub>3</sub> O <sub>10</sub> (OH) <sub>2</sub>	Low	Moderate
Muscovite	KAl <sub>2</sub> (AlSi <sub>3</sub> )O <sub>10</sub> (OH) <sub>2</sub>	Low	Moderate
Clay			
Kaolinite	Al <sub>2</sub> Si <sub>2</sub> O <sub>5</sub> (OH) <sub>4</sub>	Low	High
Illite	(H <sub>3</sub> O,K) <sub>y</sub> (Al <sub>4</sub> · Fe <sub>4</sub> · Mg <sub>4</sub> · Mg <sub>6</sub> )(Si <sub>8-y</sub> · Al <sub>y</sub> )O <sub>20</sub> (OH) <sub>4</sub>	Low	High
Chlorite	(Mg,Fe <sup>2+</sup> ,Fe <sup>3+</sup> )AlSi <sub>3</sub> O <sub>10</sub> (OH) <sub>8</sub>	Moderate	High
Smectite	(Ca <sub>0.5</sub> Na) <sub>0.7</sub> (Al,Mg,Fe) <sub>4</sub> (Si,Al) <sub>8</sub> O <sub>20</sub> (OH) <sub>4</sub> · nH <sub>2</sub> O	Low	High
Mixed layers	Kaolinite, illite or chlorite layered with smectite		
Carbonate			
Calcite	CaCO <sub>3</sub>	High	High <sup>†</sup>
Dolomite	CaMg(CO <sub>3</sub> ) <sub>2</sub>	High	High <sup>†</sup>
Ankerite	Ca(Fe,Mg,Mn)(CO <sub>3</sub> ) <sub>2</sub>	High	High <sup>†</sup>
Sulfate			
Gypsum	CaSO <sub>4</sub> · 2H <sub>2</sub> O	Moderate	High
Anhydrite	CaSO <sub>4</sub>	Moderate	High
Other			
Halite	NaCl	High	High
Iron oxide	Hematite (Fe <sub>2</sub> O <sub>3</sub> ), goethite ( $\alpha$ -FeO(OH)), magnetite (Fe <sub>3</sub> O <sub>4</sub> ), siderite (FeCO <sub>3</sub> )	High	High

<sup>†</sup> Precipitation of CaF<sub>2</sub>

- The total reactive silt content is calculated as the difference between the silt and clay content determined by solubility and the total clay content determined by XRD.

- Other minerals that are soluble in the acid should also be determined and confirmed by XRD.

#### – Scales

The solubility of scale deposits depends on the mineralogy of the rock. Tests similar to the tests performed to determine formation solubility can be performed to determine the best solvent for scale removal.

Identification of the deposit by XRD prior to the solubility evaluation is recommended to aid selecting the most active solvent. Typically, acids, chelating agents or mechanical systems are used for removal. These tests should be performed under simulated well conditions to determine the optimum treatment.

#### – Organic deposits

Solubility tests at temperature and pressure can be performed to evaluate the most effective solvent to remove the plugging deposit. Typically, paraffin, asphaltene and tar deposits are soluble in aromatic

solvents such as xylene or toluene; however, most deposits are a combined deposit and may require a combined treatment of an organic solvent with acid and other surface-active agents to improve the wettability of the deposit and enhance the dissolving capacity of the selected treatment fluid. Other solvents, such as mutual solvents and alcohols, may also aid the removal of an organic deposit.

#### – Bacterial slime

Bacterial slime is also removed by treating with solvents. These deposits are soluble in water containing oxidizing agents such as sodium hypochlorite. If required, solubility tests can be performed to evaluate the efficiency of the oxidizing agent. Tests should be performed using simulated downhole conditions, if possible.

### ■ Treating fluid–formation compatibility

Preventing emulsion and sludge formation following a damage-removal treatment requires an optimum fluid design to minimize or eliminate the formation of precipitates. The potential for the formation of acid and produced crude oil emulsions and optimization of the de-emulsifier treatment are currently evaluated using American Petroleum Institute (API) *Recommended Practices for Laboratory Testing of Surface Active Agents for Well Stimulation* (RP 42) (1977).

#### – Emulsion prevention testing

Prior to a stimulation treatment, the compatibility of the treatment fluid with the produced oil must be determined. Fine siliceous materials, ferric iron or both can be added to evaluate emulsion stability mechanisms. These fluid interactions can produce downhole emulsion problems. The quantity of additives used to control emulsion stability and sludge formation must be established. Additives such as corrosion inhibitors, surfactants and mutual solvents must also be included in the desired acid formulation for compatibility testing. The concentrations of these additives are established by core flow tests, metallurgy and the well conditions that occur during treatment.

Acid, or another aqueous treating fluid, is mixed with fresh crude oil (at low energy to simulate downhole mixing) in a glass container and observed at bottomhole temperature, if possible. The characteristics and time for emulsion breakout are determined. The quantity of aqueous fluid breakout is determined at set time intervals. The sample that provides the most rapid emulsion breakout is desired. The acid system is modified, including the type and quantity of nonemulsifier, until the minimum aqueous breakout time

is achieved. A clean oil/water interface and rapid emulsion break (less than 10 min) are desired. The oil phase must also be clear, with no emulsified water draining freely from the glass surface (signifying a water-wet surface).

Differences in emulsion stability are attributed to more dominant factors such as stabilization by solids precipitation (organic and inorganic), ferric ion interaction with the asphaltene component of crude oil and viscosity increase at the interface. Results presented by Coppel (1975) show that partially spent acids contain potentially precipitable materials in solution. As the pH value of the spent acid increases during flowback and mixes with other produced fluids, materials precipitate that can stabilize emulsions. Dunlap and Houchin (1990) recommended using polarized microscopy to evaluate return fluids to establish the cause for a stabilized emulsion. Specific damage mechanisms such as emulsion stabilization by organic deposits, solids and iron may be detected and identified. Stabilization by solids can be evaluated by the use of fine silica or clay in the emulsion test described previously.

Downhole emulsions can be attributed to inadequate prejob compatibility testing because the additives used in the acid system may preferentially adsorb onto the rock matrix or partition to the oil phase during production. Alternate testing procedures have been recommended to simulate reservoir conditions more accurately. Ali *et al.* (1994) recommended using an alternate procedure that better simulates downhole intermixing of the stimulation fluids and the produced crude. The formulated acid containing inhibitor, surfactants, mutual solvents and nonemulsifiers is filtered through a sand pack containing 10% silica flour, 10% clays (such as montmorillonite) and 80% 100-mesh sand prior to completion of the emulsion test. This procedure simulates the filtration of the acid system within the rock matrix. Surfactants, such as those used in nonemulsifiers, are adsorbed onto the mineral surfaces. This adsorption minimizes the availability of the surfactants in solution to prevent emulsions.

#### – Sludge prevention testing

Prior to the stimulation treatment, the compatibility of the treating fluid with the produced oil must be determined for sludging tendencies. Interaction of the acid with crude oil can generate the formation of solid precipitates, although the system does not form stable emulsions. These precipitates are

sludge and are insoluble in the hot formation oil or brine. The sludging tendencies are aggravated by intermixing with ferric iron. If not prevented, precipitated solids can result in decreased production following an acid treatment.

The sludging evaluation is similar to the emulsion test previously described. The oil should be free of solids and emulsified water. Following completion of the emulsion test, the acid and oil mixture is maintained at the bottomhole temperature for 1 to 4 hr. The mixture is then filtered through a 100-mesh screen, and the precipitated sludge on the filter is identified.

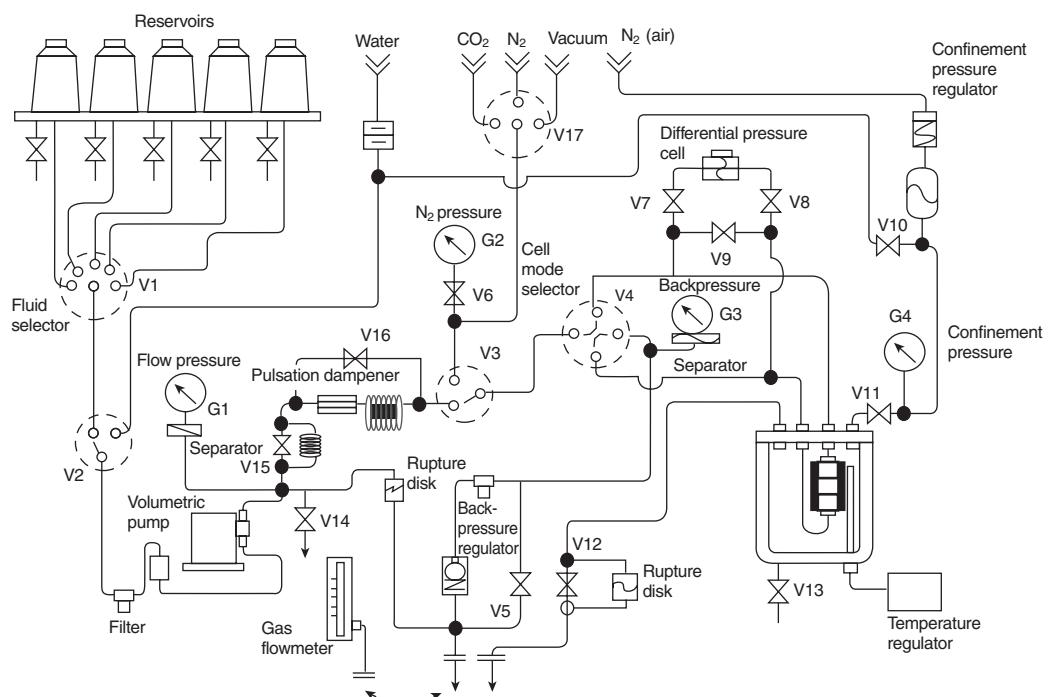
To eliminate the formation of sludge, the acid system must contain an antisludge additive. The concentration of antisludge additive is increased in the acid system until formation of the sludge precipitate is eliminated.

#### Core flow tests

Core flow tests are used to determine the effects of treatment fluids on formation samples at simulated well treating conditions. The structure of the rock and the position of each mineral in relation to the flow channels in the rock matrix may result in different

solubilities during actual acidizing operations. Therefore, the permeability changes depend on the dissolution and precipitation reactions that occur. Observations that indicate what dissolves and what precipitates are extremely useful in selecting the best treatment fluid.

The effects of sequential injection of the different treatment fluids can also be observed. Fluid injection rates range from 0.2 to 10 mL/min and pressures range up to 1500 psi. Flow rates should be selected to ensure that the fluid movement has minimal effect on the movement of fines contained within the pore structure. The 1-in. diameter, 12-in. long cores are placed in a core holder and confined under pressure to simulate reservoir stresses. To ensure fluid flow through the core, the confinement pressure should be greater than the pressure required to initiate flow through the core. Tests should also be performed with backpressure. For core flow studies of acids, a backpressure of at least 1,000 psi is required to maintain the CO<sub>2</sub> produced by acid dissolution of carbonate deposits in solution. For scale and deposit removal, sufficient backpressure is required to prevent vaporization of the treating fluid. The diagram of the core flow apparatus is shown in Fig. 14-10.



**Figure 14-10.** ARC core flow test apparatus.

The results of these tests are shown by an acid response curve (ARC), as illustrated in Fig. 14-11. The evolution of permeability versus the volume of treating fluids is determined and the effect of each fluid on the core permeability is calculated and displayed. Core holders utilizing multiple pressure taps can be used to examine the effect of each fluid as it penetrates deeper into the formation.

Permeability changes depend on dissolution and precipitation reactions. Tests to determine what dissolves and what precipitates are not used to determine treatment volumes, which depend on the type and extent of damage. If formation cores are used for the study, they should be cleaned with aqueous alcohol or ethylene glycol monobutyl ether solutions to remove traces of oil and ensure that the cores are water-wet.

## 14-6. Treatment strategies and concerns

Once the damage and its origin have been characterized, the correct remedial action can be taken. Various types of damage can coexist because almost every operation performed on the well (drilling, completion, workover, production and stimulation) is a potential source of damage (Krueger, 1986).

The efficiency of a matrix treatment in sandstones depends primarily on removing the damage affecting productivity or injectivity (Williams *et al.*, 1979). This restriction is usually shown by an overall lower level of or sharper than expected decline in production. The

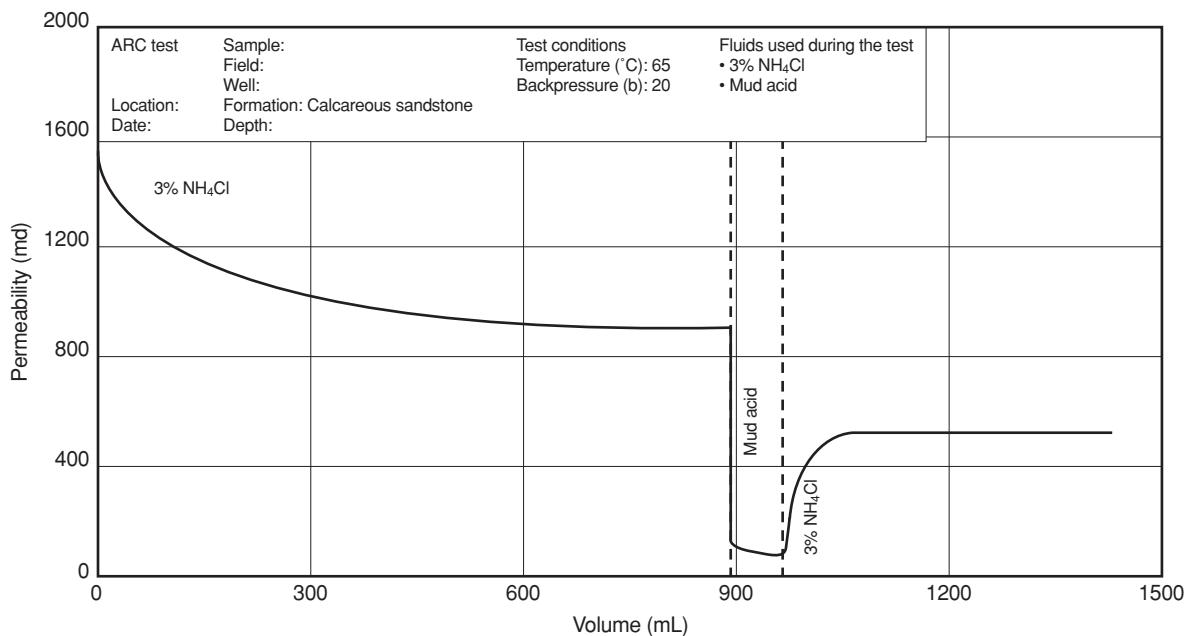
extent of damage is typically estimated using pressure transient analysis.

The physical characteristics, not the origin, of the damage determine the treating fluid. A fluid can be used to treat occurrences of the same type of damage, regardless of what caused the damage. Seven basic types of damage are shown in Fig. 14-12.

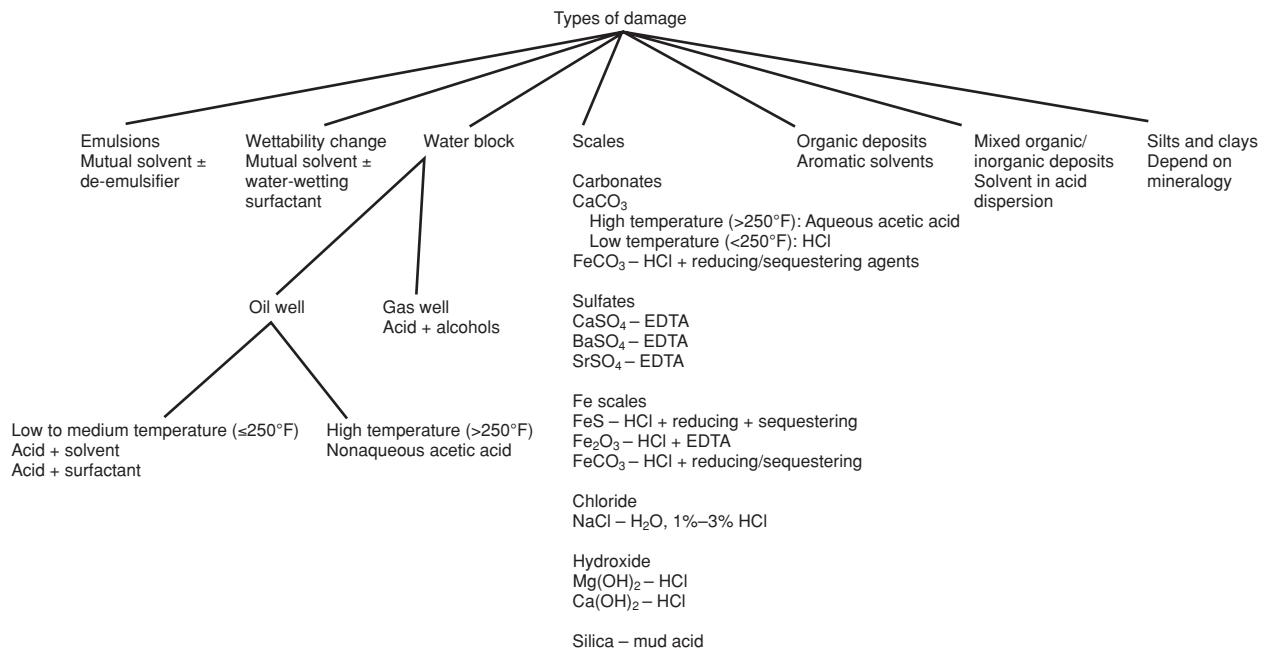
When formation damage has reduced the productivity of a well, matrix acidizing is usually the appropriate treatment, though reperforating with deeper penetrating holes may be a ready alternative for shallow damage. Typically, formation damage is associated with partial plugging of the rock matrix around the wellbore. The objective of matrix acidizing is to remove the damage or bypass it by creating channels, such as wormholes. When matrix acidizing or reperforating is not possible, a short proppant fracturing treatment can be an alternative.

Matrix acidizing treatments remove damage by injecting reactive fluids into the natural porosity of the reservoir at "matrix" (subfracturing) rates and pressures. These relatively low rates and pressures are necessary to remove the damage located in the near-wellbore area. The flow rate is also limited to prevent fracturing of the formation, which would result in the loss of treatment fluid behind the damaged zone.

Inexpensive and readily available inorganic acids, such as HCl or hydrofluoric acid (HF), are used to dissolve some of the damaging materials, rock constituents or both. A certain volume of acid is pumped into the formation to restore near-well permeability (sandstones) or to increase rock permeability (carbonates).



**Figure 14-11.** ARC of a carbonate-cemented sandstone to mud acid.



**Figure 14-12.** Treatment selection and the nature of damage.

Treatment strategies for the various formation damages discussed previously are reviewed in the following sections. In addition, strategies for some common types of wellbore damage are discussed.

#### 14-6.1. Fines and clays

##### ■ Migrating fines

The treatment of moveable fines can be accomplished by either prevention (using a clay-control process) or removal. Removal of migrating fines in sandstone formations is best accomplished by treatment with a fluid containing HF and HCl mixtures—these are the commonly used mud acids. Deeply penetrating acid systems, containing fluoboric acid, show a good possibility for particle destruction and extend some potential for clay stabilization. Fracturing the formation is also a treatment possibility because the effect from linear flow in the walls of the fracture has a less detrimental effect on production than inward radial flow in an unfractured well. The success of both clay control and fines removal depends on the depth extent of the fines movement problem. In many cases, tip-screenout (TSO) fracture design using a short fracture for damage bypass is a better alternative.

HCl systems are typically used to remove fines damage in a carbonate formation. Because the fines are not dissolved, but are dispersed in natural fractures or the wormholes that are created,  $\text{N}_2$  is usually recommended to aid fines removal when the well has a low bottomhole pressure.

##### ■ Swelling clays

The removal of smectite is usually accomplished with HF or fluoboric acid, depending on the depth of penetration. In the event of deep clay-swelling problems (more than 2 ft), the best treatment is usually a fracture to bypass the damage.

##### ■ Unconsolidated formations

Two basic problems determine the method of treatment for unconsolidated formations. If the formation moves as discrete large particles (i.e., the building blocks of the formation are moving), then the problem is a lack of cementation between the grains for the applied production forces, and the formation is classified as a low-strength formation. Treating low-strength formations can be difficult if the cementing materials are reactive with the fluid that is injected to remove formation damage or to improve permeability. Fortunately, the cementing materials in most formations have a small surface area and are less reactive with acids than with fines or clay particles in the pores of the rock.

When formations expel large grains into the wellbore, it may be beneficial to add additional perforations to reduce the velocity across the sandface or to design a fracture to reduce the drawdown. (It is common to fracture formations with permeabilities higher than 100 mD.) These fractures are usually TSO designs that provide short, highly conductive fractures that can reduce the drawdown and control sand movement by both pressure reduction and use of the

proppant at the interface contacts of a gravel pack as an “in-formation” gravel pack.

The treatment of spalling problems is extremely difficult. Propped fractures may help contain the formation and spread out the drawdown to reduce the spalling force, although totally halting spalling may be impossible. One of the keys to treatment selection is whether the spalling is caused by high initial pressures that will quickly deplete or by cyclic mechanical loads that will recur. If high initial pressure is the problem, a cleanout may suffice. If cycling is the problem, a permanent control method is the best solution. Control methods include gravel packing, fracture packing, selective perforating (along the fracture axis) and some plastic-bonding methods.

## 14-6.2. Scales

Various solvents dissolve scales, depending on their mineralogy. The most common treatments for the scales in a well are as follows:

- Carbonate scale ( $\text{CaCO}_3$  and  $\text{FeCO}_3$ )—HCl will readily dissolve all carbonate scales if the acid can penetrate to the scale location (Tyler *et al.*, 1985).
- Gypsum ( $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ ) or anhydrite ( $\text{CaSO}_4$ )—These calcium sulfate scales are removed with compounds that convert the sulfate to a hydroxide or other ion form followed by acid or by direct dissolvers such as ethylenediaminetetraacetic acid (EDTA) or other types of agents. Following a calcium sulfate dissolver with acid may double the amount of scale dissolved because most scales are mixtures of materials and HCl has some ability to dissolve the finest particles of calcium sulfate. The tetrasodium salt of EDTA is preferred because its dissolution rate is greater at a slightly alkaline pH value; the more acidic disodium salt has also been used, as well as other strong sequestrants of the same family, although they do not show a marked difference from the EDTA performance. Care must be used not to over-run the spent scale dissolver or converter solutions with acid because massive reprecipitation of the scale will occur.
- Barite ( $\text{BaSO}_4$ ) or celestite ( $\text{SrSO}_4$ )—These sulfate scales are much more difficult to remove, but their occurrence is more predictable. Barium and strontium sulfates can also be dissolved with EDTA if the temperature is high enough and contact times are sufficient (typically a 24-hr minimum soaking time for a 12,000-ft well with a bottomhole temperature of about 212 degF [100 degC]; Clemmit *et al.*, 1985). Barium and strontium sulfate removal methods are usually mechanical. Most chemical removers are

only slightly reactive, especially in thick deposits, but mixtures of barium sulfate and other scales can usually be removed by properly formulated dissolvers with sufficient soak times. Thick deposits should be removed by mechanical or abrasive methods. Care must be exercised when analyzing well debris to avoid mislabeling barite from drilling mud residue as barium sulfate scale.

- Sodium chloride ( $\text{NaCl}$ )—Sodium chloride scale is readily dissolved with fresh water or weak acidic (HCl, acetic) solutions. Redesigning the mechanical system to avoid heat loss and water drop-out are also treatment possibilities.
- Iron scales, such as iron sulfide ( $\text{FeS}$ ) or iron oxide ( $\text{Fe}_2\text{O}_3$ )—HCl with reducing and sequestering (EDTA) agents dissolves these scales and prevents the reprecipitation of by-products, such as iron hydroxides and elemental sulfur (Crowe, 1985). Soak times of 30 min to 4 hr are usually beneficial in removing these scales when using acid. Where iron sulfide is a thick deposit, mechanical action such as milling is suggested. Water jetting typically will not cut an iron sulfide scale except where it is dispersed with other scales or exists as a thin coating.
- Silica scales—Silica scales generally occur as finely crystallized deposits of chalcedony or as amorphous opal and are readily dissolved by HF.
- Hydroxide scales: magnesium ( $\text{Mg}(\text{OH})_2$ ) or calcium ( $\text{Ca}(\text{OH})_2$ ) hydroxides—HCl or any acid that can sufficiently lower the pH value and not precipitate calcium or magnesium salts can be used to remove these deposits.

Contact time is an important factor in the design of a scale removal treatment. The major concern in treating scale deposits is allowing sufficient time for the treating fluid to reach and effectively dissolve the bulk of the scale material. The treating fluid must dissolve most of the scale for the treatment to be successful.

## 14-6.3. Organic deposits

Organic deposits are usually resolubilized by organic solvents. Blends of solvents can be tailored to a particular problem, but an aromatic solvent is an efficient, general-purpose fluid. Environmental concerns have led to the development of alternative solvents (Samuelson, 1992).

Paraffin removal can be accomplished using heat, mechanical scraping or solvents. Heating the tubing with a hot oiler may be the most common type of treatment. It may also be the most damaging and least effective in some cases. Injection of hot oil from the surface will melt the paraffin from the walls of the pipe, but the depth to which the injected fluid stays hot is a function of the well

configuration. If the well is allowed to circulate up the annulus while the hot oil is injected down the tubing, the heat will not penetrate more than a few joints of tubing from the surface. The heat is quickly transferred through the steel tubing to the fluids rising in the annulus and little, if any, heat reaches deep in the well. As the hot oil cools, the paraffin picked up in the upper part of the well can precipitate. If hot oiling is required at depths greater than 150 ft, an alternate method of placement must be used. Deeper application of heat is available with other processes that feature heat generation as part of an exothermic chemical reaction. The processes require close control and are generally expensive.

Mechanical scraping can be useful in cases where extensive deposits of paraffin must be removed routinely. Scraping is usually accomplished with slickline and a cutter. In wells that utilize a rod string, placing scrapers on the string may automatically scrape the tubing walls.

Solvent treating to remove paraffin may be based around a straight- or aromatic-chain solvent. The most appropriate solvent depends on the specific paraffin and the location of the deposit. Heat (at least to 130 degF [55 degC]) and agitation significantly increase the rate of removal.

Removal treatments for asphaltenes use aromatic solvents such as xylene and toluene or solvents containing high percentages of aromatics. Naphtha is usually not effective as a solvent. Some materials being tested provide dispersant benefits without stabilizing the entire mass of the asphaltene. Solvent soak time, heat and agitation are important considerations for treatment.

#### 14-6.4. Mixed deposits

Combined deposits require a dual-solvent system, such as dispersion of a hydrocarbon solvent (usually aromatic) into an acid.

#### 14-6.5. Emulsions

Emulsions are stabilized by surface-active materials (surfactants) and by foreign or native fines. Generally, mutual solvents, with or without de-emulsifiers, are used for treating emulsion problems. De-emulsifiers, which may work well in a laboratory or in a separator or tank because of the large number of droplets in contact per unit volume, may not work by themselves in a porous medium because of mass-transport phenomena in getting the product to where it should work. Another reason they may not work alone is the mechanism involved in breaking emulsions, which should provoke the coalescence of droplets and then phase separation.

Asphaltic iron-catalyzed sludges are the most difficult emulsions to break. These emulsions are catalyzed by dissolved iron in the acid or water and resemble a crosslinked oil polymer in some instances. Prevention is the best treatment. An effective antisludge treatment for the area and an iron-reducing agent in the acid are the best methods. Removal of an existing asphaltene sludge is usually accomplished by dispersing it in a solvent and attacking the components of the sludge with additives designed for cleanup and removal.

#### 14-6.6. Bacteria

Prevention of polymer destruction by bacteria is usually handled with biocides and tank monitoring. Control of bacteria downhole is more difficult and involves scraping or treatments with sodium hypochlorite or other oxidizers followed by acidizing and then treatment with an effective biocide at a level at least 1.2 times the minimum kill level. Frequent rotation of the type of biocide is also necessary to prevent the development of biocide-resistant strains of bacteria.

#### 14-6.7. Induced particle plugging

##### ■ Mud solids

To remove shallow mud damage in natural fractures, a solvent or cleaner that will disperse the mud should be selected on the basis of tests of a field sample of the mud. Energizing the fluid with N<sub>2</sub> can assist in removing large masses of drilling mud from a fracture system. Experience with drilling mud cleanup from natural fracture systems shows that slugs of drilling mud may flow back on initial treatment, and damage can often reassert itself as mud moves from the outer reaches of the fracture system into the wellbore. This condition can require repeated treatments of the same high-efficiency cleaner, plus N<sub>2</sub>, to get good cleanup of the well. Acid may help, but tests of the acid's effect on the field mud sample are required.

When extremely large volumes of heavyweight mud are lost, it may be beneficial to sidetrack the well and redrill the pay zone. Whenever possible, the drilling mud overbalance should be minimized, and the mud should be conditioned to reduce solids before the pay zone is drilled. Experience with drilling highly fractured formations has led to experimentation with underbalance drilling in some zones. Underbalance drilling can result in only minimal damage in producing wells in comparison with the damage created by traditional drilling methods. There are dangers, however, in underbalance drilling, and the risk versus benefit must be evaluated carefully.

Mudcakes are usually damaging only in openhole completions without significant fractures (Burton, 1995). In vertical wells, they are usually easily mechanically removed to a great extent by pressure drawdown. In long horizontal wellbores, the necessary drawdown is almost impossible to impose on any section other than the heel, particularly when a compressible fluid is in the hole. Circulations for mudcake removal should be conducted with minimum clearance between the wash pipe and the borehole to promote turbulence. Residual mudcake in prepacked screens or slotted liners completions is particularly problematic because it can plug the screen (Browne *et al.*, 1995; Ryan *et al.*, 1995).

#### ■ Dirty fluids

When particle damage is known to have occurred because of the use of unfiltered or poor-quality fluids, cleanup depends on finding a solvent or acid that can either remove the particles or break the structure of the bridges formed in the formation or fracture system. Surfactants, acids and mutual solvents are usually the most beneficial materials. The addition of N<sub>2</sub> to provide a high-energy boost may also be beneficial.

The decision of which surfactant or mutual solvent to use should be based on core tests or field response. Including a gas such as N<sub>2</sub> or CO<sub>2</sub> is based on fluid and solids recovery requirements and wellbore unloading ability. For designing cleanup operations for particulate damage, flowing the well back quickly after the treatment helps in the removal of the particles. Lower pressure formations may require a gas boost. In higher pressure formations, natural flow is usually adequate to unload these solids, especially when a properly designed fluid has been used and the solids are no deeper than the surface of the wellbore face. Mechanical scraping and cleaning can exert influence only as far as the wellbore wall.

#### ■ Acidizing

The leading edge of an otherwise effective mutual solvent and acid system can be loaded with debris cleaned off the walls of the tanks and tubing. For this reason, the leading edge of the acid job is usually circulated out of the well using a process called pickling the tubing. In this treatment, acid and solvents are injected down the tubing to disperse and dissolve iron, pipe dope, mud and other debris from the tubing and are then circulated or reversed out of the well without being injected into the formation. These jobs are extremely effective when the tubing has not been cleaned or its condition is unknown. Volumes of both acids and additive treatments range from 1 to 2½ tubing volumes depending on the condition of the

tubulars. Minimum acid and solvent volumes typically range from 250 to 500 gal. Coated tubing can reduce iron scale significantly, but other contaminants, such as scale and pipe dope, may still be present.

If load-fluid recovery influences well production, surfactants or mutual solvents that reduce surface and interfacial tension are usually beneficial. The treatment volumes depend on the fluid, formation and amount of load fluid lost.

#### ■ Waterfloods

The removal of particles injected during waterflood operations depends on the identity of the material and use of a cleaner and an acid to disperse the material. One of the best techniques for cleaning up injection wells or disposal wells is to backflow the well as hard as possible prior to the treatment. This usually removes enough mass from the wellbore to eliminate the need for stimulation. However, if backflowing does not adequately clean the wellbore, acid and a mutual solvent in volumes ranging from 50 to 100 gal/ft are usually necessary. When large amounts of solids are expected, the well should be backflowed after acidizing. If oil carryover and emulsions are the problem, acid and a mutual solvent can be injected and displaced permanently with injection water behind the acidizing job.

### 14-6.8. Oil-base drilling fluids

The prevention of OBM emulsions is relatively easy. Either a surfactant-base cleaner that is mixed after specific OBM testing or a more general xylene wash of the zone must be done before contact with either high-salinity brine or acid. After the cuttings and mud fines have been cleaned and totally water-wetted, the remaining damage problems of wettability can be reversed with a formation cleaner or mutual solvent. Acid is usually used as a following stage after cleaning to remove mud particles and clean up formation debris. Removal of known OBM emulsions resulting from mixing with high-salinity brine or acid usually requires an aromatic solvent wash or a specialized surfactant treatment that targets the silt-stabilized emulsion. Evaluation of any cleanup mechanism or treatment using laboratory samples of OBM should be avoided. Only field samples of the mud are appropriate for designing the removal treatment. Treatment fluid volumes range from 15 to 50 gal/ft of aromatic solvent or surfactant mixture, and the agitation and soak times are critical to the success of the treatment. Application difficulties include trapping the treating fluids across the pay in a column of heavyweight fluids where density segregation may be rapid. Packers and gelled plugs are the first line of isolation.

### 14-6.9. Water blocks

Removal of a water block can be accomplished using a surfactant or alcohol applied as a preflush to reduce surface tension, followed by a postflush of N<sub>2</sub> or CO<sub>2</sub> to remove the water from the near-wellbore area and reestablish gas saturation. Once the water has been mixed with the surface-tension-lowering materials, removal is easier. The difficulties in this type of operation are placement of the fluid and getting an even distribution of the fluid around the wellbore. Repeated treatments are usually necessary, and selective injection devices are beneficial.

### 14-6.10. Wettability alteration

Wettability alteration damage is removed by injecting (mutual) solvents to remove the oil-wetting hydrocarbon phase and then injecting strongly water-wetting surfactants. Again, a surfactant by itself will not work. The oil phase, which is usually precipitated asphaltenes or paraffins, must first be removed with a solvent. (The same applies to an adsorbed oleophilic surfactant.) Then, a strongly water-wetting surfactant can be injected and adsorbed onto the rock minerals. This reduces the tendency for new hydrocarbon precipitates to stick to the mineral surfaces and oil-wet them again.

For retrograde condensation problems, the most appropriate treatment technique is the injection of neat natural gas in a periodic "huff and puff" operation. Condensate is picked up by the gas and transported into the reservoir. Reprecipitation requires the retrograde of the process after several months of production.

### 14-6.11. Wellbore damage

#### ■ Mechanical damage from drilling

The drilling process itself modifies the local stresses around the wellbore, generating a zone of reduced permeability in the near-wellbore area (Dusseault and Gray, 1992). It has been shown that such damage affects primarily soft formations where the difference between the minimum and maximum stresses orthogonal to the wellbore is large. In the worst cases, the extent of the permeability decrease can be as large as  $\frac{1}{2}$  wellbore diameters (Morales *et al.*, 1995), and perforations do not bypass the damaged zone. Because permeability impairment in this case is the result of rock compaction, acidizing is ineffective. Short proppant fracturing treatments are apparently the only cure, though extreme overbalance perforating may give positive results in some cases (Petitjean *et al.*, 1995).

#### ■ Pipe problems

Whenever well production is reduced, the first determination should be to establish that the tubing is open and the lift system is working. Numerous pipe problems from leaks to collapsed pipe can occur, and fill in the tubing is also a possibility. Well conditions change over time, and an effective completion at the start of the well's life may not be effective after several years of production as the reservoir pressure declines.

#### ■ Poor perforations

The usual treatment for poor perforations is to add additional perforations. In zones that are extremely laminated, such as the shaly sands of the U.S. Gulf Coast and other areas, 8 to 12 spf is considered adequate, but perforation breakdowns (i.e., small fractures) may be required for complete linking. Lower perforation density is possible if the well will be fractured. Fracturing will cross the barriers of laminations, and in many field cases has provided extensive productivity increases.

Adding perforations is easy, but the typical 0° phased, small through-tubing guns deliver only small holes and short penetrations. The newer downhole-deployable guns that provide minimum clearance and phasing are preferred, especially when hydraulic fracturing will be performed.

#### ■ Hydrates

Hydrates are mixtures of ice and other elements, principally natural gas, that may resemble a dirty ice deposit. Unlike ice, they can form at temperatures greater than 32 degF. The formation of hydrates is usually associated with a drop in temperature or a reduction in pressure that may accompany the production of fluids. Hydrates may also form in gas-cut drilling mud, particularly when the mud is circulated near the seafloor in cold locations. Hydrate plugging of chokes and valves can be a serious problem. Hydrate particle abrasion of equipment is also possible.

The most common occurrence of hydrates is in gas wells with a small amount of water production. The quantity of water relative to the quantity of gas production is critical. As the water cut increases, many hydrate problems disappear. Hydrates are prevented by adding a freezing-point depressant such as alcohol or glycol below the hydrate formation point. They may also be controlled by temperature preservation in the produced fluid or the elimination of severe pressure drops that allow expanding gas to chill the liquids to their freezing points.

- Fill

Debris from formation spalling into the perforation or wellbore can be one of the most serious detriments to production. Fill in the wellbore is easily identified with a sinker bar on the wireline and is usually easily removed using tubing or coiled tubing and N<sub>2</sub> or foam unloading practices. Fill in the perforations is more difficult to identify and much more difficult to remove. When fill in the perforations is suspected, reperforating the well is generally the most direct method of testing the theory and restoring the well to productivity. Where the fill is acid soluble, acid injection may be useful; however, injecting acid into a perforation that is filled with small debris is usually difficult.

- Water problems

Water production is not only a major economic problem in surface separation, but it also causes a major reduction in the relative permeability of oil and gas. Water production from the well can lead to significant problems such as corrosion, backpressure, emulsions and movement of the formation or fines. Water may flow from the bottom (coning), rise through fractures or flow from the edge in fractures through the matrix or in high-permeability streaks. Because of its low viscosity, water flows much easier than oil, and once in the pores of the rock it is difficult to displace with low-viscosity fluids such as gas. Shutting off water (water control) is a special technique and is discussed elsewhere in the literature.

- Microporosity

Microporosity is created by a number of clays and a few minerals. It is simply a condition where a large surface area exists for water coating or trapping. Microporosity rarely presents a problem except when it occupies the pore throat area of the formation. In these cases, it may trap either debris or water and obstruct flow. The removal of microporosity can generally be accomplished with HF, or deep problems can be bypassed by fracturing.

## 14-7. Conclusions

To maximize well performance, the paths from the formation to the pipeline must present the lowest pressure impedance possible. Achieving this condition requires both a well-designed completion and the elimination of formation damage. The tools are an array of stimulation and damage removal techniques and chemicals that are readily available. Still, although formation damage removal seems easily achievable, the goal of a damage-free completion can be elusive. The problem is not so much one of finding a tool, but one of finding the right tool. A little experience shows that the right tool can be selected only when the problem has been identified. The effort and expense to understand the nature and identity of the problem can be the wisest investments.

The most common damage mechanisms and suggested methods of removal are listed in Tables 14-3, 14-4, and 14-5. It bears repeating that many damage conditions have similar symptoms and that there are no universal treatments.

# 15. Additives in Acidizing Fluids

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## 15-1. Introduction

Proper fluid selection is critical to the success of a matrix treatment. Figure 15-1 shows the types of damage that may occur and what types of treatment would be required. The treatment may be a failure if the proper additives are not used. The treating fluid is designed to effectively remove or bypass the damage, whereas additives are used to prevent excessive corrosion, prevent sludging and emulsions, prevent iron precipitation, improve cleanup, improve coverage of the zone and prevent precipitation of reaction products. Additives are also used in preflushes and overflushes to stabilize clays and disperse paraffins and asphaltenes. The functions of some of the additives are discussed briefly in this chapter.

Throughout this chapter references are made to the interactions of additives with the formation. Schechter (1992) provided an excellent discussion of the chemical properties of formation materials and their interactions

with fluids. Clay minerals are important because of their large surface area and because the surface carries an electrical charge. Although relatively minor, some surface charge results from ionic substitution and structural imperfections. For instance, the substitution of  $\text{Al}^{3+}$  for  $\text{Si}^{4+}$  in tetrahedral sheets or  $\text{Mg}^{2+}$  or  $\text{Fe}^{2+}$  for  $\text{Al}^{3+}$  in octahedral sheets is the origin of negative charges in the lattice of smectites. These are unaltered by changes in the solutions that contact them.

Silicon and aluminum oxides, the principle ingredients of sandstone and clays, exhibit amphoteric behavior. Therefore, the surface charges of these minerals depend on the pH of the solutions in contact with them. The surface charge changes from positive to negative as the pH increases. The point at which the surface charge is neutral is known as the point of zero charge (pzc). Table 15-1 provides the approximate values of the pzc for several common minerals.

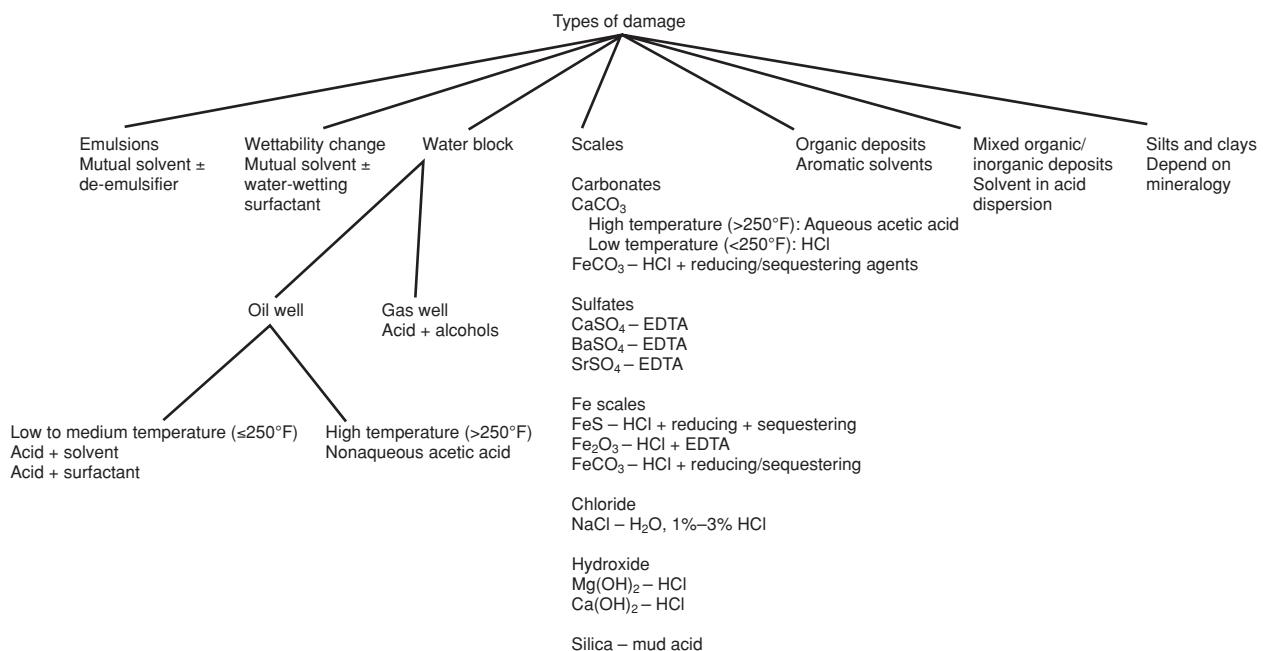


Figure 15-1. Types of damage.

**Table 15-1. Point of zero charge of some representative reservoir materials.**

Material	Point of Zero Charge
Quartz ( $\text{SiO}_2$ )	2.7
Corundum ( $\text{Al}_2\text{O}_3$ )	9.0
Hematite ( $\text{Fe}_2\text{O}_3$ )	5.0
Calcite ( $\text{CaCO}_3$ )	9.5
Kaolinite ( $\text{Al}_4\text{Si}_4\text{O}_{10}(\text{OH})_8$ )	4.6
Montmorillonite ( $\text{Al}, \text{Mg}, \text{Fe})(\text{Al}, \text{Si})_8\text{O}_{20}(\text{OH})_4 \cdot n\text{H}_2\text{O}$ )	2.0
Albite ( $\text{NaAlSi}_3\text{O}_8$ )	2.0

Thus, the way in which additives interact with the reservoir actually depends on the pH. Under the conditions normally associated with the matrix acidization of sandstones, the pH of the acid is less than the pzc of the reservoir constituents, which causes the formation materials to behave as positively charged. It is important to keep this concept in mind.

## 15-2. Corrosion inhibitors

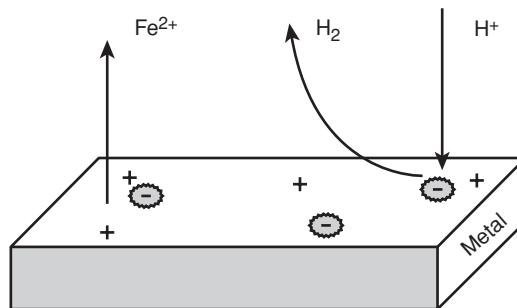
The most important acid additives are corrosion inhibitors. A corrosion inhibitor is a chemical that slows the attack of acid corrosion on drillpipe, tubing or any other metal that the acid contacts during treatment. Brief explanations of corrosion mechanisms, corrosion inhibition and techniques for evaluating inhibitor performance are presented in this section.

### 15-2.1. Corrosion of metals

Any metal surface is a composite of electrodes electrically short-circuited through the body of the metal itself (Fig. 15-2). As long as the metal remains dry, local currents and corrosion are not observed. However, on exposure of the metal to aqueous salt, alkali or acid solutions, local action cells are able to function, leading to chemical conversion of the metal to corrosion products.

### 15-2.2. Acid corrosion on steel

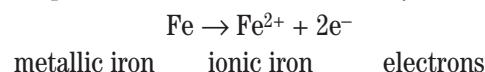
All uninhibited acid solutions corrode steel. The attack of acid on steel occurs through the dissociated hydrogen ions in the acid solution. This results in the oxidation and dissolution of iron at the anodic sites on the metal



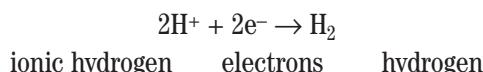
**Figure 15-2.** A metal surface composed of both anodic and cathodic sites (Schechter, 1992).

surfaces, along with the reduction of hydrogen ions and formation of hydrogen at the cathodic sites.

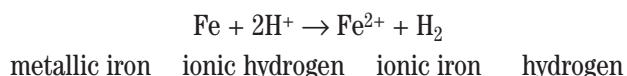
The equations for an anodic reaction (oxidation):



and a cathodic reaction (reduction):



can be combined to show the overall reaction:



The unit of measurement used to determine the amount of corrosion is  $\text{lbf}/\text{ft}^2$ . Acceptable corrosion limits for low-alloy steel are shown in Table 15-2. The acceptable range is from 0.02 to 0.09  $\text{lbf}/\text{ft}^2$  of metal surface, depending on the temperature and exposure time. Acids corrode more evenly, with less pitting, at higher temperatures. At elevated temperatures, more corrosion may occur, but the chance of forming a hole in the drillpipe or tubing string is actually less.

The effectiveness of a given corrosion inhibitor depends on the metal. McDougall (1969) reported tests of five different commercial corrosion inhibitors on N80, J55, and P105 tubulars. These results clearly

**Table 15-2. Corrosion limits for low-alloy steel.**

Temperature, degF [degC]	Corrosion Limit ( $\text{lbf}/\text{ft}^2$ )
200 [95]	0.02
200–275 [95–135]	0.05
275–350 [135–175]	0.09

show the necessity of matching the inhibitor to the steel, because a wide range of responses was obtained for a given inhibitor. Smith *et al.* (1978) pointed out that American Petroleum Institute (API) designations for steels are inadequate to distinguish corrosion rates because they identify yield strength, whereas corrosion characteristics are determined primarily by chemical composition. Because yield strength may be achieved either by physical or chemical modifications in manufacturing, it is essential that the metal coupons tested are representative of the tubulars to be protected.

### 15-2.3. Pitting types of acid corrosion

In uninhibited acid solutions, the corrosion of steel is usually uniform. The constant shifting of anodic and cathodic areas spreads corrosion fairly evenly over the entire surface of the metal. In inhibited acids, pitting of the surface occurs in some situations as a result of inhibitor breakdown, insufficient inhibitor or metal impurities.

- Inhibitor breakdown

Pitting-type corrosion is not uncommon on steel containing an inferior corrosion inhibitor that is exposed to acid solutions. All corrosion inhibitors eventually break down after some period of time, depending on various factors including temperature, acid strength and metal type. When this point is reached, an inferior inhibitor may actually promote pitting by desorbing from the metal surface in localized areas.

- Insufficient inhibitor

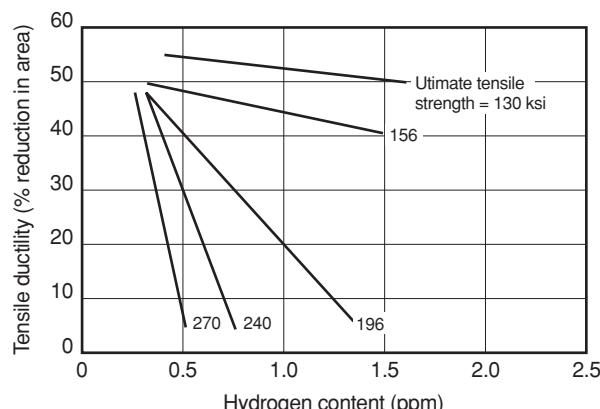
Regardless of the quality of the corrosion inhibitor, pitting may also occur if there is an insufficient amount of inhibitor to effectively coat the steel surfaces. Unprotected steel surfaces are rapidly attacked by the acid solution and pitting occurs.

- Metal impurities

Another condition that promotes pitting is the presence of impurities or inclusions within the steel. For example, small pieces of slag may become trapped during the forming of the steel, or improper heat treating or quenching of the steel may produce discontinuities in its grain structure. These imperfections may, in turn, become anodic relative to the surrounding steel structure and thus promote acid attack.

### 15-2.4. Hydrogen embrittlement

Hydrogen embrittlement results from the cathodic reaction described previously in which hydrogen ions are reduced to elemental hydrogen. Elemental hydrogen results from acidizing operations. Elemental hydrogen adsorbed by a metal can lower ductility to the point that the metal becomes brittle. Figure 15-3 shows the effect of hydrogen content and tensile strength on the loss of ductility of steel. The N80, P110 and Q125 grades of tubing and casing are prone to embrittlement as a result of acidizing. Consequently, inhibitor selection must take this into account.



**Figure 15-3.** Reduction in ductility with increasing hydrogen content and strength (Tetelman, 1973). 1 ksi = 100 lbf/in.<sup>2</sup>.

### 15-2.5. Corrosion by different acid types

The degree of dissociation of hydrogen ions from the acid molecule, along with the acid concentration, determines the hydrogen ion activity, which is directly proportional to its corrosivity on steel. The relative degree of dissociation for some common acids is hydrochloric > formic > acetic. Therefore, hydrochloric acid (HCl) is more corrosive on steel than formic acid, which is more corrosive than acetic acid. Quite logically, the more aggressive an acid is in its attack on steel, the more difficult it is to inhibit. However, the mechanism of attack is the same for all acid types.

## 15-2.6. Inhibitor types

Inhibitors function by interfering with the chemical reactions that occur at the anode or cathode of the corrosion cell. The two basic types of corrosion inhibitors are inorganic and organic. There are also inhibitor aids.

### ■ Inorganic corrosion inhibitors

This class of inhibitors includes the salts of zinc, nickel, copper, arsenic, antimony and various other metals. Of these, the most widely used are the arsenic compounds. When these arsenic compounds are added to an acid solution, they "plate out" at cathodic sites of exposed steel surfaces. The plating decreases the rate of hydrogen ion exchange, because the iron sulfide that forms between the steel and the acid acts as a barrier. It is a dynamic process in which the acid reacts with iron sulfide, rather than the metal.

Some advantages of inorganic inhibitors are that they

- work effectively at high temperatures for long contact times

- cost less than organic inhibitors.

Disadvantages of inorganic inhibitors are that they

- tend to lose their effectiveness in acid solutions stronger than about 17% HCl
- react with hydrogen sulfide ( $H_2S$ ) through the iron sulfide that may be present to form an insoluble precipitate such as arsenic sulfide
- poison refinery catalysts (such as platinum)
- may liberate toxic arsine gas as a corrosion by-product
- are difficult to mix and unsafe to handle.

### ■ Organic corrosion inhibitors

Organic corrosion inhibitors are composed of polar organic compounds capable of adsorbing onto the metal surface, thereby establishing a protective film that acts as a barrier between the metal and the acid solution. They usually serve as a cathodic polarizer by limiting hydrogen ion mobility at cathodic sites. Organic inhibitors are composed of rather complex compounds, with one or more polar groups made of sulfur, oxygen or nitrogen.

Some advantages of organic inhibitors are that they

- can be used in the presence of  $H_2S$  without the precipitation of salts such as arsenic sulfide (which can plug the wellbore)
- do not poison refinery catalysts
- work effectively in all acid concentrations.

Disadvantages of organic inhibitors are that they

- chemically degrade with time in the presence of acid and thus do not readily provide long-term protection at temperatures above 200 degF [95 degC] (Table 15-3)

- cost more than the inorganic corrosion inhibitors.

### ■ Inhibitor aids

Although these additives do not function as inhibitors, they increase the effectiveness of organic inhibitors. The common inhibitor aids are potassium iodide, cuprous iodide, cuprous chloride and formic acid. The addition of these materials to existing organic inhibitor formulations greatly extends the range of their effectiveness, particularly in higher temperature applications.

**Table 15-3. Effectiveness of corrosion inhibitors at high temperatures in 15% HCl.**

Inhibitor	Inhibitor Concentration (%)	Temperature (degF)	Protection Time <sup>†</sup> (hr)
Organic	0.6	200	24
	1.0	250	10
	2.0	300	2
Inorganic	0.4	200	24
	1.2	250	24
	2.0	300	12

<sup>†</sup> Time required for 15% HCl to remove 0.05 lbm/ft<sup>2</sup> of exposed metal area

## 15-2.7. Compatibility with other additives

Any additive that alters the tendency of the corrosion inhibitor to adsorb will also change its effectiveness. For example, surfactants added to acid for various purposes may form micelles that solubilize the inhibitor, thereby decreasing the tendency for the inhibitor to adsorb on the metal surface. Inorganic salts and mutual solvents can also interfere with inhibitor adsorption. If possible, additives that reduce the effectiveness of inhibitors should be included in a preflush or overflush rather than in the acid solution.

### 15-2.8. Laboratory evaluation of inhibitors

The laboratory evaluation of a corrosion inhibitor involves subjecting a coupon of the metal to be protected to the acid to be used. The coupon is normally inserted into a mixture of the acid and corrosion inhibitor to be evaluated and placed in a heated pressure vessel. The replication of downhole conditions is important. The amount of corrosion is determined by weighing the coupon before and after the test. Inhibitor effectiveness is expressed in terms of metal loss per unit area of metal exposed per unit of time. The typical unit is lbm/ft<sup>2</sup>/day.

Also to be noted is pitting, which is a localized attack. If appreciable attack is confined to a relatively small area of the metal acting as an anode, then the resultant pits may be deep. A pitting factor, defined as the ratio of the deepest metal penetration to the average penetration, as determined by the weight loss of the specimen, is sometimes reported. A pitting factor of unity represents uniform attack. Many factors influence the corrosion rate measured in such tests. Of major importance are

- degree of agitation
- metal type
- exposure time
- temperature
- acid type and concentration
- inhibitor type and concentration
- metal-to-acid volume ratio
- gas composition (if an interface is present)
- pressure
- presence of other additives such as surfactants.

### 15-2.9. Suggestions for inhibitor selection

Some metal loss from wellbore tubular goods must be expected when acidizing, and the primary issue is what level can be tolerated. Most service company information is based on the assumption that a metal loss of 0.02 lbm/ft<sup>2</sup> can be tolerated during the treatment if no pitting occurs. For some cases an amount as high as 0.095 lbm/ft<sup>2</sup> is allowable. If these metal losses cannot be sustained without adverse effects, a more effective inhibitor must be found.

If inhibitor cost becomes prohibitive, it may be possible to reduce the cost by careful treatment design. Precooling the tubing by injecting a large water preflush will be helpful. Using formic acid rather than HCl helps reduce the corrosion problem. Also, minimizing the contact time reduces inhibitor requirements.

The most important aspect is the proper testing of representative metal samples using the precise acid formulation to be applied at the most adverse conditions of temperature and pressure. The test should be conducted in an oxygen-free environment. Only under these conditions can a decision about the adequacy of the corrosion inhibitor be made.

### 15-3. Surfactants

Surfactants, or surface-active agents, are used in acidizing to break undesirable emulsions, reduce surface and/or interfacial tension, alter wettability, speed cleanup, disperse additives and prevent sludge formation. The use of surfactants requires careful selection of an appropriate molecule. Remarkably, in the design of most well treatments, surfactants are selected with little or no laboratory data to support the choice and sometimes without full knowledge of their properties at the conditions in which they will be applied. Improper surfactant selection can lead to results contrary to those intended and may be detrimental to the success of the treatment.

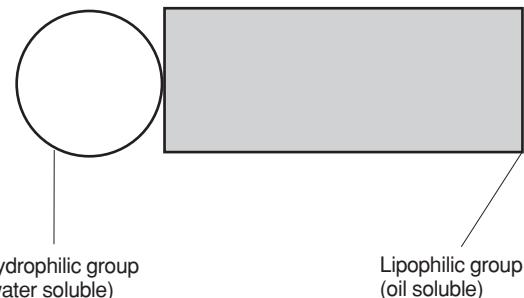


Figure 15-4. Dipolar surfactant composition.

Surfactants owe their properties to their “dipolar” composition (Fig. 15-4). The surfactant molecule consists of a water-soluble (hydrophilic) group and an oil-soluble (lipophilic) group, which are separated from each other although linked by a strong covalent chemical bond. The molecules are classified into five groups according to the ionic charge carried by the water-soluble group:

- anionic
- cationic
- nonionic
- amphoteric
- fluorocarbons.

The hydrophilic-lipophilic balance (HLB) depends on the composition of the organic chain, which can be 100% oleophilic (e.g., an alkane chain) or contain some oxygen atoms (e.g., an ethylene oxide chain) and become more hydrophilic. The HLB value of a surfactant indicates how much its chains can oil wet a mineral.

### 15-3.1. Anionic surfactants

Anionic surfactants are commonly added to well treatment fluids. These surfactants carry a negative charge when they ionize in an aqueous solution. Because most reservoir minerals are also negatively charged at nearly neutral and higher pH values, anionic surfactants exhibit minimal adsorption. Some examples of anionic surfactants are

Sulfates	$R—O—SO_3^-$
Sulfonates	$R—SO_3^-$
Phosphates	$R—O—PO_3^-$
Phosphonates	$R—PO_3^-$

where R is an oil-soluble organic group.

Of these, the most common anionic surfactants are sulfates and sulfonates. Anionic surfactants are sensitive to multivalent ions such as  $Ca^{2+}$  and  $Mg^{2+}$ . These tend to precipitate anionic surfactants, although this tendency can be overcome to some extent by increasing the surfactant concentration. Anionic surfactants are used primarily as nonemulsifying agents, retarding agents and cleaning agents.

### 15-3.2. Cationic surfactants

Cationic surfactants carry a positive charge when they ionize in aqueous solutions. There are two general categories of cationic surfactants. The first category consists of long-chain primary, secondary and tertiary amines. These are soluble only in acidic solutions, where they ionize to form a long-chain cation and simple anion salt. Figure 15-5 shows various molecular cationic structures.

The second important category of cationic surfactants is the quaternary ammonium compounds. These ionize to form long-chain cations over a wide range of solution pH. Cationic surfactants experience the same sensitivity to multivalent ions or increased concentrations of dissolved solids as anionic surfactants; therefore, the same care must be exercised in their application as with anionic surfactants.

Cationic and anionic surfactants are generally incompatible. When mixed, they tend to precipitate in aqueous solutions.

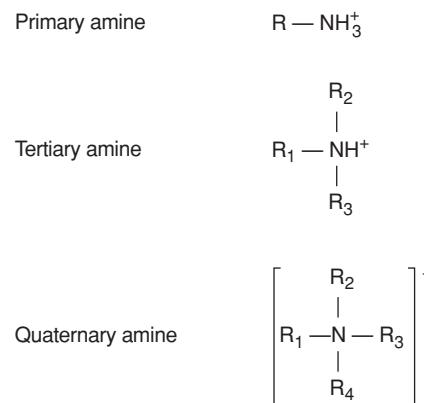


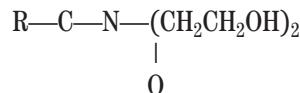
Figure 15-5. Various types of cationic surfactants.

### 15-3.3. Nonionic surfactants

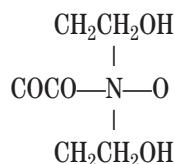
Nonionic surfactants have no charge at all in the hydrophilic group and a long-chain organic (R) for the lipophilic group. The water-soluble group is a polymer made from either ethylene oxide or propylene oxide. Other types include alkanol amine condensates and amine oxides. The general formulas for these products are as follows:

Ethylene oxide polymer	$R—O—(CH_2CH_2O)_xH$
Propylene oxide polymer	$R—O—(CHCH_2O)_yH$ $ $ $CH_3$

Alkanol amine condensate



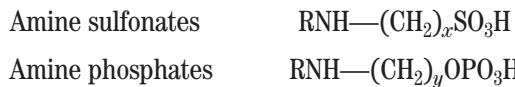
Amine oxides



Nonionic surfactants obtain their water solubility by attaching the long hydrocarbon chain to a highly soluble molecule such as polyhydric alcohol or by reacting it with ethylene oxide. Most of the compounds in this classification are esters, ethers and ether-esters. The lipophilic group may be derived from natural oils and fats, petroleum oils or synthesized hydrocarbons. The hydrophilic group is usually a polyhydric alcohol or an alkyl oxide polymer. These surfactants are used as nonemulsifiers and foaming agents.

### 15-3.4. Amphoteric surfactants

Amphoteric surfactants have a hydrophilic group that changes from cationic to nonionic to anionic with increasing pH. In other words, if the solution is acidic, the amphoteric surfactant acts like a cationic surfactant; if the solution is neutral, it acts like a nonionic surfactant; and if the solution is basic, it acts like an anionic surfactant. These properties are derived from the two groups of opposite charge on the surfactant head. The amphoteric surfactants are usually either amine sulfonates or amine phosphates. The general formulas are as follows:



### 15-3.5. Fluorocarbon surfactants

Fluorocarbons form surfaces of lower free energy than hydrocarbon surfaces. Consequently, fluorocarbon surfactants lower the surface tension of solutions to a greater extent than hydrocarbon surfactants. Surface tensions as low as 30 dynes/cm can be obtained using surfactants with a hydrocarbon tail. Values as low as 17 dynes/cm have been reported using fluorocarbon surfactants. Fluorocarbons are commercially available in anionic, cationic and nonionic forms.

### 15-3.6. Properties affected by surfactants

The main properties of a fluid or a mineral affected by surfactants are the surface and interfacial tensions, emulsification tendency, wettability, micelle formation and dispersibility.

- Surface and interfacial tensions

Rosen (1989) presented a good discussion of how surface and interfacial tensions are reduced by surfactants. Figure 15-6 is a simplified diagram of the interface between two condensed phases. A molecule in the bulk of a liquid is surrounded by molecules like itself and the forces are balanced. At the interface, however, the forces acting on the molecules in the two liquids are different from the forces acting on the molecules in the bulk liquids. The terms  $A_{aa}$  and  $A_{bb}$  in Fig. 15-6 represent the interaction energy between molecules at the interface and similar molecules in the bulk of the liquid whereas  $A_{ab}$  represents the interaction energy between dissimilar molecules at the interface.

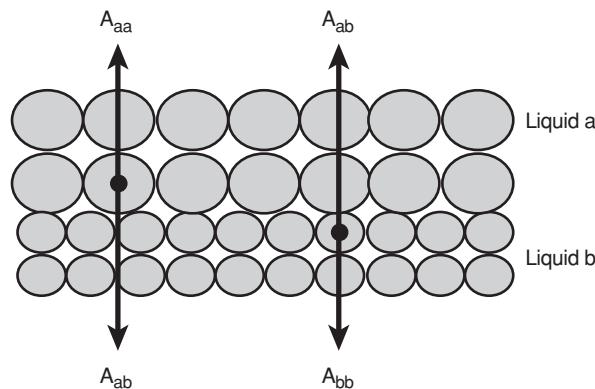


Figure 15-6. The interface between two liquids (Rosen, 1989).

The increase in potential energy of the molecules at the interface compared with that of the molecules in the bulk liquid is simply  $A_{aa} - A_{ab}$  and  $A_{bb} - A_{ab}$ . Therefore, the total increase in potential energy at the interface becomes  $A_{aa} + A_{bb} - 2A_{ab}$ . The interfacial free energy per unit of surface area, which is also known as the interfacial tension  $\gamma_I$ , becomes

$$\gamma_I = \gamma_a + \gamma_b - 2\gamma_{ab}, \quad (15-1)$$

where  $\gamma_a$  and  $\gamma_b$  are the surface tensions of pure liquid  $a$  and liquid  $b$ , respectively, and  $\gamma_{ab}$  is the interaction energy per unit of surface area between liquids  $a$  and  $b$ .

The value of  $\gamma_{ab}$  tends to be large when similar liquids are in contact; this causes  $\gamma_l$  to be small. Conversely, if liquid  $a$  is quite different from liquid  $b$ , then the interaction energy is small and the interfacial tension between the two liquids is large. Surface tensions of some liquids are listed in Table 15-4.

**Table 15-4. Surface tension of some liquids.**

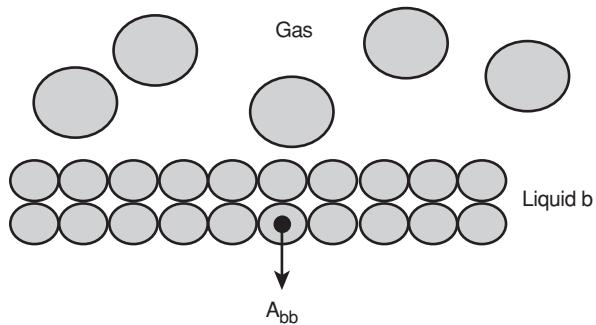
Liquid	Surface Tension (dynes/cm)
Water	72.0
15% HCl	72.0
Spent 15% HCl	76.9
Octane	21.8

Figure 15-7 illustrates the interaction between a liquid and a gas. In this case the interface is the surface of the liquid. The interaction between a gas molecule and other gas molecules is negligible, as is the interaction between gas molecules and the liquid. Therefore,  $\gamma_l = \gamma_b$ ; in other words, the interfacial tension is simply the surface tension of the liquid.

A surfactant, when added to two immiscible phases, adsorbs at the interface. If one of the liquids is water and the other is a hydrocarbon, the hydrophobic end of the surfactant will be oriented toward the hydrocarbon, and the hydrophilic group will be oriented toward the water phase. This causes a change in the interface. Now the interaction is between the hydrophilic group of the surfactant and the water phase and the hydrophobic group of the surfactant and the hydrocarbon phase. These interactions are much stronger than the original interaction between the water and hydrocarbon, which effectively leads to an increase in  $\gamma_{ab}$  and a concomitant decrease in  $\gamma_l$ .

#### ■ Emulsification tendency

An emulsion is a mixture of two fluids in which fine droplets of one fluid are suspended in the other. Emulsions may be oil external or water external. In the first instance, oil is the continuous phase with



**Figure 15-7. The interface between a liquid and a gas.**

the water droplets dispersed throughout. This is the most common emulsion found in wellbores. A water-external emulsion has an aqueous external phase with oil droplets distributed throughout.

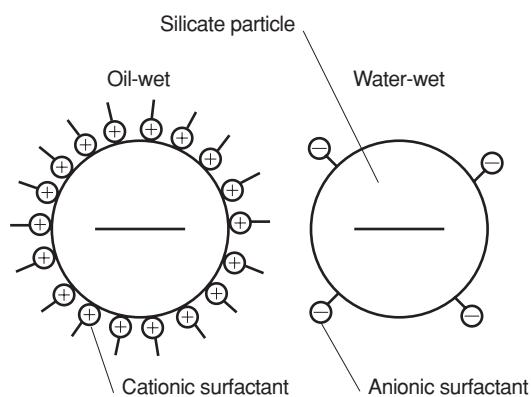
Many crudes contain naturally occurring surfactants that reduce the surface tension between oil and formation water and thus promote the development of emulsions. Treatment of the formation with certain surfactants can also lead to the development of emulsions. However, appropriate surfactants can be used to treat wells with emulsion problems. Laboratory testing is required to determine the appropriate surfactant.

#### ■ Wettability

Oil and water are immiscible liquids that compete for space on the formation surface. Which liquid preferentially wets the rock surface is an important factor in acidizing. When the formation surface is completely covered by a film of oil, the formation is termed oil-wet. Conversely, when covered by water, the formation is water-wet.

An electrochemical approach helps to explain the ability of a surfactant to adsorb at interfaces between liquids and solids and alter the wettability of solids. Sand usually has a negative surface charge. When a cationic surfactant is present and the pH rises above the pzc, the positive water-soluble group is adsorbed by the negative silica particle. This leaves the oil-soluble group to influence wettability. As a result, cationic surfactants generally create an oil-wet sand, although cationic surfactants can be chemically

modified to yield a water-wet sand. When anionic surfactants are used, the sand and silicate minerals are generally left in their natural water-wet state. Wettability characteristics exhibited by anionic and cationic surfactants on a silicate particle are shown in Fig. 15-8. Carbonates have a pzc at a pH of 9–10 and thus are normally oil-wet by cationic surfactants above a pH of 9 whereas anionic surfactants oil wet the rock below a pH of 9.



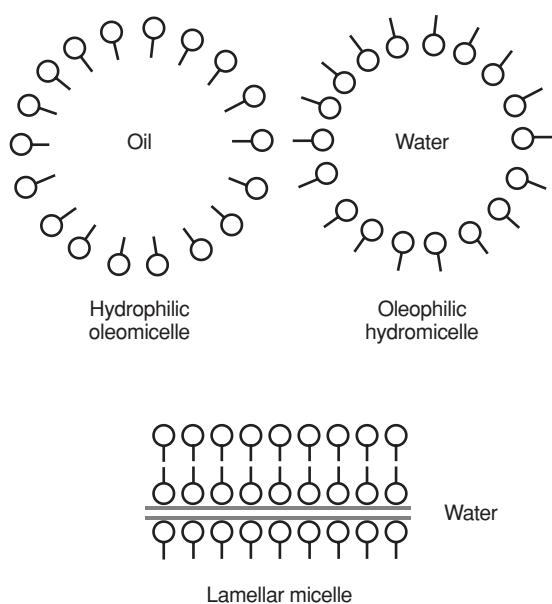
**Figure 15-8.** Silicate particle wettability characteristics (Hall, 1986).

#### ■ Micelle formation

Surfactants can form micelles in liquids when present above a specific concentration for each molecule, solvent and temperature. This concentration is referred to as the critical micelle concentration (CMC). Below the CMC, many properties of the system are concentration dependent. Some of these properties are surface tension, interfacial tension, foam stability and emulsion tendencies. Figure 15-9 shows examples of surfactant micelles.

#### ■ Dispersibility

To separate a highly associated structure (e.g., a sludge) into its particulate elements usually requires energy. If the dispersed phase is not in intimate contact with the continuous liquid phase, then the energy transfer will not be very efficient. A wetting surfactant that wets the dispersed phase with the liquid phase greatly improves the dispersibility. This is one aspect of aiding dispersion. Once the aggregate has been dispersed, a different surfactant may be required to prevent the dispersed particles from rejoining.



**Figure 15-9.** Examples of surfactant micelles that can form in liquids above a specific surfactant concentration (Hall, 1986).

### 15-3.7. Applications and types of surfactants

In recent years, the uses of surfactants have grown quickly. This unique class of chemicals has found application in almost all phases of acidizing. A comprehensive review is beyond the scope of this chapter. However, a brief review follows.

#### ■ De-emulsifiers

A de-emulsifier is used to break oil-water emulsions, which occur commonly. The action of a de-emulsifier depends on how quickly it can concentrate at the oil/water interface. The faster the concentration at the interface, the more rapid will be the rate of emulsion breaking. These surfactants are usually oil-soluble chemicals that are blended with other de-emulsifying surfactants to achieve a synergistic response.

#### ■ Nonemulsifiers

These surfactants are added to well treating or workover fluids to prevent emulsions. Chemical suppliers and service companies have many different surfactants that are classified as nonemulsifiers. The chemicals are usually mixtures of surfactants and solvents that are blended to obtain a final composition with broader applications. Normally, the surfactants are chosen so that they will water wet the formation. They should also mix easily with treating or workover fluids and prevent the formation of emulsions with the reservoir fluids.

## ■ Emulsifiers

Specialized emulsions are often used as treating fluids. Many solvent systems concurrently use aqueous and hydrocarbon phases. Such emulsions may exhibit higher viscosity than either base fluid. Emulsions also have the ability to isolate the internal phase so that it is not as reactive. A common example of this technology is the use of emulsified acid.

With these properties, emulsions are efficient scale removal systems. When an inorganic scale is deposited in combination with a hydrocarbon scale (paraffin or asphaltene), an efficient scale removal system can be formulated by emulsifying a solvent for the inorganic scale—usually HCl—with the hydrocarbon. Usually, the emulsion has a low viscosity with a stability of up to several hours at bottomhole conditions. The stability of the emulsion is low to minimize the potential for damaging the well with the emulsion during workover. The hydrocarbon phase ranges from 10% to 30% by volume with a water-base fluid as the external phase. Most emulsifiers used in this application are nonionic.

## ■ Silt-suspending agents

Surfactants can also be used to remove acid-insoluble clay and silt during an acidizing treatment. A surfactant is added that adsorbs onto the clay or silicate particles and keeps them suspended by electrostatic repulsion. With this surfactant present, damaging insoluble residues can be removed with the spent acid. These particles, if not removed, can stabilize emulsions or settle out and block the pore throats of the producing formation.

The mechanism for suspending silt with a surfactant can also be best understood by an electrochemical approach. Silt particles are minerals, such as quartz, feldspars and clays, that, assuming the treating fluid has a pH above the pzc, carry a negative surface charge. Silt-suspending surfactants are cationic, and the positively charged end of the molecule adsorbs onto the surface of these minerals. This normally renders the particles oil-wet and causes them to act more like droplets of oil than solid particles. As long as they remain oil-wet, they tend to remain suspended in the spent acid.

Another force working to suspend the silt particles is electrostatic repulsion. Because all the particles carry the same charge, the particles repel each other and tend to not agglomerate. This combination of oil-wetting and electrostatic repulsion makes an effective silt-suspending system.

## ■ Antisludge agents

When acid contacts some crude oils, a sludge can form at the acid/oil interface. This is most severe with high-strength acid systems (20% or higher). Once formed, the sludge is difficult to redissolve into the oil. As a result, the sludge accumulates in the formation and decreases permeability.

To combat the formation of sludge, cationic and anionic surfactants are used to adsorb and provide a continuous layer of protection at the acid/oil interface. Sludge development can often be prevented by lowering the acid strength.

## ■ Surface tension reducers

Surfactants are commonly used in treating tight gas wells and in scale removal treatments. Their main function is to lower the surface and interfacial tensions of the treating fluid. This reduces the capillary pressure, which makes it easier to recover fluid from the capillary pore channels and to prevent oil-wetting films. Lowering the capillary pressure aids in cleaning up the well because less differential pressure is required to move the fluid through the capillary channels. The maximum differential pressure available to clean up a well is the reservoir pressure less the lowest drawdown that can be achieved at the perforations. If this maximum differential pressure is not high enough to move the liquid out of a pore channel, a block exists and its removal may require a surfactant that provides a lower surface tension (i.e., lower capillary pressure).

## ■ Corrosion inhibitors

Corrosion inhibitors function by adsorbing onto the steel and providing a protective barrier between it and the acid. Surfactants that are effective as corrosion inhibitors include certain quaternary amines and acetylenic nonionics. Generally, these materials contain some cationic species.

## ■ Bactericides

When treating a formation, it is usually desirable to leave it water-wet to aid the production of oil. This is done with an appropriate surfactant. It is also desirable to leave the formation free of contaminating bacteria that may have been inadvertently pumped into the well with the treating fluid. Many cationic surfactants possess this biocidal property and are commonly used in conjunction with other wetting surfactants.

- Clay treaters

Drilling muds commonly contain the highly water swelling clay smectite (bentonite). While a well is being drilled and completed, some of the clay may invade the producing zone and decrease formation productivity. Several chemical solutions are used for the removal of this invading clay.

The swelling properties of smectite may be changed by chemical reactions, because all clays are negatively charged at pH values above their pzc values. Thus, positively charged cations (calcium, sodium, potassium and hydrogen) may be attracted to the clay and are known as exchangeable cations. The particular cation and the quantity present in a clay system govern the degree of water swelling or clay expansion. For example, hydrogen smectite swells less in water than sodium smectite. By reacting sodium smectite (bentonite) with acid, hydrogen ions will replace the sodium ions by the cation-exchange process. Because hydrogen clay retains less water than sodium clay, the treatment of drilling mud with acid can shrink smectite and clean up mud filter cake. However, acid may also cause clay particles to flocculate. This flocculation results in larger clay particles that may be more difficult to remove from the well.

Surfactants have been developed to inhibit the flocculation of clays, even in solutions of high ionic strength. This is accomplished by using a surfactant that effectively disperses clay particles and minimizes the formation of aggregates. In addition, smaller particles are easier to suspend, resulting in more efficient removal from the well.

- Foaming agents

Surfactants are used to generate a stable foam. The following guidelines are usually applicable for surfactant application:

- nonionic—stable foam with acid or brine; because of cloud point problems, nonionics normally cannot be used above 200° to 250 degF [95 degC to 120 degC]
- anionic—stable foam with brine; can be used up to 300 degF [150 degC]
- cationic—stable foam with acid or brine; can be used up to 300 degF
- amphoteric—stable foam with acid or brine; can be used up to 350 degF [175 degC].

Foam stability usually can be improved by gelling the liquid.

## 15-4. Clay stabilizers

Chemicals used to stabilize clays and fines function by being adsorbed, usually by electrostatic attraction or ion exchange, on the minerals to be stabilized. Because silicates above their pzc values have a negative charge, the most effective stabilizer has a positive charge (cationic). Common clay stabilizers are highly charged cations, quaternary surfactants, polyamines, polyquaternary amines and organosilane.

### 15-4.1. Highly charged cations

Two highly charged cations that were once widely used as clay stabilizers are hydroxyaluminum ( $\text{Al}_6(\text{OH})_{12}(\text{H}_2\text{O})_{12}^{6+}$ ) and zirconium ( $\text{Zr}^{4+}$ ) added as zirconium oxychloride ( $\text{ZrOCl}_2$ ). Solutions containing either stabilizer are usually pumped after various preflushes. The stabilizer solution is then overflushed with a compatible fluid to remove excess clay stabilizer from the near-wellbore region, and the well is shut in. These systems do not appreciably affect formation wettability.

The primary advantages of these systems are

- inexpensive
- treat for both migration and swelling damage
- can treat a large area of rock.

The disadvantages are

- hydroxyaluminum is not acid resistant
- require shut-in to polymerize
- can cause plugging
- difficult to use in fracturing
- require proper preflushes and overflushes.

Systems such as hydroxyaluminum can also be used in treating water injection and disposal wells to stabilize silicates and minimize future plugging from colloidal fines in the injection water.

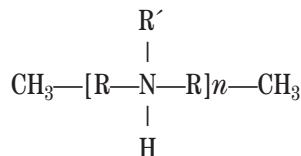
### 15-4.2. Quaternary surfactants

Quaternary surfactants have been used as clay stabilizers for dry gas wells. At conditions above the pzc, these surfactants are readily adsorbed by silicates owing to electrostatic attraction between the positively charged surfactant and negatively charged clay. The resulting charge neutralization reduces the ion-exchange capacity of the clay. Therefore, the clay is not as susceptible to swelling resulting from the adsorption of hydrated cations.

Quaternary surfactants promote oil-wetting of the silicate, which tends to minimize the adsorption of water by the silicate. However, if any liquid hydrocarbons are present, the silicate can readily become oil-wet. This, of course, reduces the relative permeability of the rock to hydrocarbons. Also, clays swell by imbibing fluids into their lattice structure.

### 15-4.3. Polyamines

Polyamines are organic polymers that contain more than one amine group. For the purpose of this discussion, only primary, secondary and tertiary amines are considered polyamines. Polyamines are positively charged in acidic fluids. The general structure of a polyamine is as follows:



where R is a repeating hydrocarbon unit, R' can be either a hydrocarbon unit or a hydrogen, and n is the number of amine units in the polymer.

Because the polymer has many amine units, it can adsorb strongly on the silicate with many points of attachment. The polymers can effectively neutralize the negative charge of the silicate. By carefully controlling the carbon:nitrogen ratio, usually 8:1 or less, the polymers also promote water-wetting of the silicate. In addition, polymers of sufficient length can promote polymeric bridging between silicate particles.

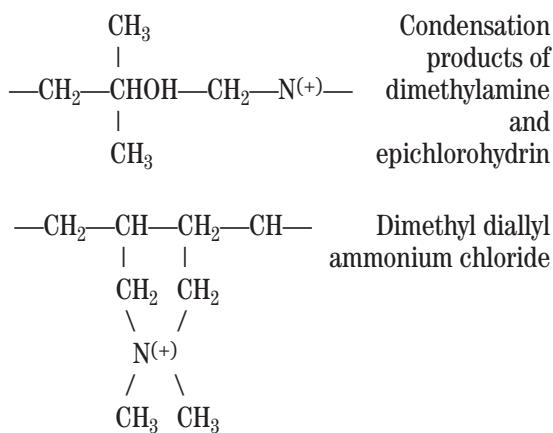
If a treated silicate is contacted by brines, the polyamine can lose its positive charge and be washed off the silicate. When this occurs, that silicate is no longer stabilized.

The disadvantages of polyamines are that

- treatment may not be permanent
- they are expensive.

### 15-4.4. Polyquaternary amines

Polyquaternary amines can be used in any water-base fluid, including acids and bases. The chemical structure of the two polyquaternary amines that have been widely used is as follows:



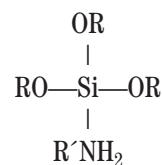
Clays and fines are stabilized by charge neutralization, water-wetting and polymeric bridging. Silica fines have a lower charge density than clays. Therefore,

polyquaternary amines preferentially adsorb on clays as opposed to silica. When acidizing a water-sensitive formation with hydrofluoric acid (HF), clay stabilizer should be used if possible. If it is not possible to put clay stabilizer in all fluids, it should be used in the overflush, which should be overdisplaced with fluid that contains no clay stabilizer to ensure that no unadsorbed clay stabilizer is left at the wellbore. A normal concentration of polyquaternary amine for applications in HF treatments is 5 gal/1,000 gal of active polymer in all fluids or 7½ gal/1,000 gal of clay stabilizer in 200 gal of overflush.

There has been concern regarding the distinction between fines migration and clay migration. Fines consist predominantly of silt-sized particles of quartz and feldspars. Laboratory data indicate that the polyquaternary amines are not as effective in controlling fines migration as compared with clays (Hall, 1986; Ayorinde *et al.*, 1992).

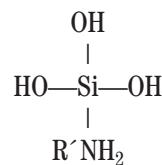
### 15-4.5. Organosilane

Kalfayan and Watkins (1990) proposed that an organosilane compound can be used as an additive to HCl-HF mixtures to prevent poststimulation fines migration. Organosilane has the following general structure:



where R and R' are hydrolyzable organic groups.

As an additive to acid, organosilane hydrolyzes to form silanols, which have the following structure:



The silanols react with each other and with silanol ( $\text{Si}-\text{OH}$ ) sites present on siliceous mineral surfaces to form covalent siloxane ( $\text{Si}-\text{O}-\text{Si}$ ) bonds by a condensation/polymerization reaction mechanism. The reaction of the silanols with one another and with the silanol sites on siliceous mineral surfaces forms a non-oil-wetting polysiloxane coating on siliceous mineral surfaces. The length of the polysiloxane chain formed by the hydrolysis of the organosilane, and the subsequent condensation/polymerization of silanols, is not known but is believed to be short. Acid, which catalyzes the initial hydrolysis of the organosilane, also retards the growth of polymer chains.

The mechanism by which the polysiloxane coating stabilizes fines is different from the ion-exchange mechanism by which other clay stabilizers work. However, it is similar to the coating process proposed for fluoboric acid (Boyer and Wu, 1983). The polysiloxane coating binds clay and other siliceous fines in place through covalent siloxane bonds. The polysiloxane coating stabilizes fines by blocking ion-exchange sites and increasing interparticle attractive forces. Interparticle attractive forces can include van der Waal forces and hydrogen bonding. These forces, in addition to the electrostatic forces, help maintain the fines in their aggregated state along the pore wall. By blocking the ion-exchange sites, the polysiloxane coating decreases the magnitude of double-layer repulsion.

The polysiloxane formed can bind to minerals that have low-cation-exchange capacities (quartz), as well as to clays that have high-cation-exchange capacities. Therefore, the organosilane additive is well suited for formations that contain nonclay fines as well as clay fines.

## 15-5. Mutual solvents

Mutual solvents, as the name implies, are chemicals that are mutually soluble in both hydrocarbons and water. The most efficient mutual solvents are glycol ethers, a reaction product of alcohols and ethylene oxide. These chemicals are relatively safe and easy to use in the field. The preferred glycol ethers contain at least a butyl or higher molecular weight group.

The use of mutual solvents in the acid stimulation of a sandstone reservoir is a common practice. Mutual solvents are used in acid solutions and overflushes to

- aid in reducing water saturation around the wellbore by lowering the surface tension of the water to prevent water blocks
- solubilize a portion of the water into a hydrocarbon phase to reduce the water saturation
- aid in providing a water-wet formation to maintain the best relative permeability to oil
- help to prevent insoluble fines from becoming oil-wet and stabilizing emulsions
- help to maintain the required concentration of surfactants and inhibitors in solution by reducing adsorption of these materials
- help to dissolve both the adsorbed inhibitor and acid-insoluble residue (certain acid corrosion inhibitors contain acid-insoluble residues that can cause formation plugging and inhibitor adsorption on formation minerals and change the wettability)

- dissolve any oil on the formation pore surface
- serve as a de-emulsifier
- improve the cleanup of spent acid following treatment.

Commonly used mutual solvents and their normal concentrations are

- ethylene glycol monobutyl ether (EGMBE): 10% by volume
- ether/surfactant/alcohol blends: 5% by volume.

### 15-5.1. Adsorption of mutual solvents

King and Lee (1988) studied the adsorption properties of an alcohol-mixture mutual solvent, such as a blend of isopropyl alcohol and isoctyl alcohol, and EGMBE. They found that adsorption of the mutual solvent can be severe depending on the type of mutual solvent. For deep damage removal, products that are lost during injection through the formation are not acceptable because the mutual solvent is removed from the leading edge of the acid. Although there appears to be no direct damage caused by adsorption of the mutual solvent, the acid is left after the loss without any material to lower surface tension or to break emulsions. Paktinat (1991) recommended the use of ethoxylated alcohol with EGMBE to minimize adsorption, thus resulting in deeper penetration of the mutual solvent and reduced emulsion tendencies.

### 15-5.2. Chlorination of mutual solvents

King and Lee (1988) presented data on the chlorination of mutual solvents with 15% and 28% HCl at temperatures from 70° to 250 degF [20 degC to 120 degC]. The chlorination issue has long been of interest because chlorinated hydrocarbons poison refinery catalysts. Their data show that the chlorination of mutual solvents is a function of

- type of mutual solvent
- temperature
- concentration of HCl (i.e., spending of HCl reduces the possibility).

At temperatures exceeding 200 degF, especially with 28% HCl, the chlorination of most mutual solvents was severe, if there were no carbonates with which the acid could react. The presence of carbonates resulted in very low production of chlorinated hydrocarbons.

## 15-6. Iron control additives

### 15-6.1. Sources of iron

When appreciable quantities of iron in the form of  $\text{Fe}^{3+}$  (ferric ions), rather than the usual  $\text{Fe}^{2+}$  (ferrous ions), are dissolved by the acid, iron precipitation and permeability reductions can occur after acidizing. The oxidation state of the iron governs precipitation. Ferric iron precipitates at a pH of about 2, whereas ferrous iron precipitates at a pH of about 7—the actual values depend on the concentrations of the ferrous and ferric ions. Because spent acid solutions seldom rise to a pH above 6, precipitation of ferrous iron is seldom a problem. Sources of iron include

- corrosion products found on the walls of the tubulars
- mill scale
- iron-bearing minerals.

Iron occurs naturally in formation waters or in formation minerals (Table 15-5). However, the tubulars in the well are one of the most prominent sources of iron. Before the acid reaches the formation, it flows for a relatively long time through the tubing. Tubing usually contains rust, which is dissolved by acid. Newly manufactured tubing has a crust of mill scale.

The thickness of the mill scale on oilfield tubulars varies considerably depending on the cooling rate and how much the pipe was manipulated during the straightening procedure. Mill scale is composed of two distinct layers—a hard, dense layer next to the pipe that is approximately 0.003 in. thick; on top of the dense mill scale is a layer of softer, flaky mill scale that is approximately 0.007 in. thick. Most of the softer scale pops off the pipe during the straightening procedure.

The theoretical quantity of 15% HCl required to remove 0.073 lbm of mill scale from 2½-in. tubing is 69 gal/1,000 ft of tubing. If a 10,000-ft well is acidized for damage removal, approximately 690 gal of 15% HCl could be neutralized by the mill scale. Of course, the acid contact time and temperature control the quantity of mill scale removed. If acid is spent on mill scale, it will contain 85,900 ppm of total iron. Of this, 57,300 ppm will

be ferric iron ( $\text{Fe}^{3+}$ ). Thus, the leading edge of the treating fluid may be partially spent acid that contains a high concentration of iron. The ferric iron can be precipitated as ferric hydroxide ( $\text{Fe(OH)}_3$ ), a dark brown gelatinous precipitate that can be damaging to the formation.

It should be emphasized that acid dissolves iron compounds regardless of the presence of any type of inhibitor used to protect the elemental iron in the steel. Iron control additives help prevent the precipitation of iron hydroxide.

Concern is often expressed about the dissolution of iron-containing minerals (siderite, hematite and chlorite) from the formation and subsequent precipitation of the dissolved iron. Previous studies indicate that most of the iron contained in these minerals occurs in the  $\text{Fe}^{2+}$  oxidation state (Table 15-5) and does not present a precipitation problem. However, numerous exceptions to this rule exist. Streaks of pure hematite ( $\text{Fe}_2\text{O}_3$ ) occur in some sandstones, whereas others contain  $\text{Fe}^{3+}$ -type minerals uniformly distributed within the matrix of rock. Where these conditions are present, greater amounts of an iron control additive are required to control ferric hydroxide precipitation.

### 15-6.2. Methods of iron control

The three methods currently used to help keep iron in solution are pH control, sequestering agents and reducing agents (also effective as oxygen scavengers). These may be used individually or in combination, depending on the source and amount of iron dissolution expected.

#### ■ pH control

pH control is accomplished by the addition of a weak acid that is very slow to react so that a low pH is maintained after the HCl has spent. Acetic acid is typically used for this purpose. A low pH aids in preventing the secondary precipitation of iron.

#### ■ Sequestering agents

Sequestering agents bond to the iron and hold it in solution so that it cannot precipitate. Citric acid, ethylenediaminetetraacetic acid (EDTA) and nitrilotriacetic acid (NTA) are some of the more commonly used sequestering agents.

#### ■ Reducing agents

Reducing agents convert ferric ( $\text{Fe}^{3+}$ ) to ferrous ( $\text{Fe}^{2+}$ ) iron. Secondary precipitation of ferric iron occurs at a pH of about 2.0. The secondary precipitation of ferrous iron hydroxides does not occur until the pH is above 7.0. Returned spent acids never have a pH this high. Erythorbic acid and sodium erythorbate are commonly used as reducing agents. Erythorbic acid is preferred over sodium erythorbate in sandstone acidizing because the addition of sodium salts of either sequestering or reducing agents to

Table 15-5. Oxidation state of iron in formation minerals.

Mineral	Chemical Formula	Oxidation State
Hematite	$\text{Fe}_2\text{O}_3$	$\text{Fe}^{2+}$
Magnetite	$\text{FeO}-\text{Fe}_2\text{O}_3$	$\text{Fe}^{2+}-\text{Fe}^{3+}$
Pyrite	$\text{FeS}$	$\text{Fe}^{2+}$
Siderite	$\text{FeCO}_3$	$\text{Fe}^{2+}$
Chlorite clay	—	$\text{Fe}^{2+}$
Mixed-layer clay	—	$\text{Fe}^{2+}$

mud acid can lead to the precipitation of insoluble hexafluosilicate. Hall and Dill (1988) reported that erythorbic acid is unstable in hot HCl and decomposes to form an insoluble precipitate. Although this is true, the decomposition process is slow and the acid normally spends long before precipitation can occur (Crowe, 1985).

Most reducing agents also act as oxygen scavengers that remove dissolved oxygen from the fluid. The scavengers prevent the oxidization of ferrous iron to ferric iron. This maintains iron in solution by preventing the precipitation of ferric iron. The amount of iron that can be reduced depends on the quantity of chemical added. Aeration of the solution can introduce additional oxygen.

Table 15-6 compares iron control additives, showing their advantages and disadvantages and the amount of each required in 1,000 gal of 15% HCl to sequester 5,000 ppm of ferric iron at 150 degF [65 degC] for a minimum of 2 days.

The safest way to prevent damage to the reservoir from precipitated iron hydroxide is to clean or pickle

the pipe with acid before acidizing the formation. The acid should contain large quantities of iron control additives and should be circulated out of the well, not pumped into the formation. In conjunction with this treatment, a dispersed hydrocarbon phase should be incorporated or used as a preflush to remove pipe dope that could plug the perforations.

The treatment of sour wells presents an entirely different type of precipitation problem. In addition to free sulfur precipitation, by the reaction of  $\text{Fe}^{3+}$  with  $\text{H}_2\text{S}$ , the dissolved  $\text{Fe}^{2+}$  also precipitates as ferrous sulfide ( $\text{FeS}$ ) on spending of the acid.  $\text{FeS}$  precipitates at a pH of about 2. Laboratory and field data presented by Hall and Dill (1988) show that a combination of NTA, EGMBE and a sulfide modifier is an effective system for controlling the precipitation of  $\text{FeS}$  and free sulfur when acidizing sour wells. Crowe (1985) previously proposed a two-component system to address sour well problems. The system incorporates erythorbic acid to reduce ferric iron to ferrous iron and EDTA to chelate ferrous iron and eliminate the precipitation of  $\text{FeS}$ .

**Table 15-6. Comparison of various iron control agents.**

Control Agent	Advantages	Disadvantages	Amount (lbm)
Citric acid	Effective at temperatures up to 400°F [205°C]	Precipitates as calcium citrate if excess uncomplexed quantities are used (more than 10 lbm/1000 gal)	175
Citric acid–acetic acid mixture	Very effective at lower temperatures	Even for the indicated amount, calcium citrate precipitates unless at least 2000-ppm $\text{Fe}^{3+}$ is present in spent acid.  Efficiency decreases rapidly at temperatures above 150°F [65°C]	Citric: 50 Acetic: 87
Lactic acid	Little chance of calcium lactate precipitation if excessive quantities are used	Not very effective at temperatures above 100°F [40°C]	190 (at 75°F [25°C])
Acetic acid	No problem from possible precipitation as calcium acetate	Effective only at temperatures at about 150°F	435
Gluconic acid	Little chance of calcium gluconate precipitation	Effective only at temperatures up to 150°F  Expensive on a cost-performance basis	350
Tetrasodium salt of EDTA	Large quantities may be used without precipitation of calcium salt.  Effective at temperatures up to 400°F	More expensive to use than many other agents	296
Nitrilotriacetic acid	Effective at temperatures up to 400°F  More soluble in acid than EDTA—higher concentrations can be used  Less expensive than EDTA		150
Sodium erythorbate	Smaller quantities required  Effective at temperatures up to 400°F	Increased corrosion inhibitor concentration required for certain applications  Should not be used in HF—use erythorbic acid	23

## 15-7. Alcohols

Alcohols are used in acidizing fluids to remove water blocks, enhance fluid recovery, retard acid reactivity and decrease water content. The most common alcohols used in acidizing are isopropanol and methanol. Their physical and chemical properties are listed in Table 15-7.

**Table 15-7. Physical and chemical properties of isopropanol and methanol.**

Property	Isopropanol	Methanol
Density at 68 degF [20 degC]	0.785	0.792
Weight (lbm/1,000 gal)	6.54	6.60
Flash point (closed up, degF [degC])	54 [12]	54 [12]
Solubility in water	Complete	Complete

Isopropanol is normally used at a maximum of 20% by volume. Methanol is used at various concentrations, but a typical concentration may be 25% by volume. Alcohol is used in acidizing fluids for the following reasons.

- Removal of water blocks

One problem that can severely decrease production is blockage of the pore spaces by water; this is commonly known as a water block. Water blocks may form where high capillary forces are present in porous rocks. The most severe water block problems occur in formations with gas permeabilities less than 120 mD. The alcohol in the treating fluid reduces the capillary forces within the reservoir, thus enabling easier removal of the liquid phases.

- Enhancement of fluid recovery

Another problem that occurs in treating oil or gas wells is the recovery of treating fluids, especially in gas reservoirs. The high surface tension of water or acid solutions hinders their penetration and recovery. Conventional surfactants help, although they lose much of their activity by adsorption. The addition of alcohol to acid solutions reduces their surface tension. The concentration of alcohol normally used for this purpose is sufficient so that loss by adsorption is not a problem.

- Retardation of acid reactivity

Alcohol has a retarding effect on acid reactivity. The retardation rate is related to the type and percentage of alcohol added.

- Decrease of water in acids

Some formations contain a large amount of water-sensitive clays. To minimize the amount of water contained in acidizing solutions, alcohols are used in place of the dilution water.

The major disadvantages of using alcohol in acidizing fluids are as follows:

- Effective concentration

It takes a large amount of alcohol, 20% or more, to provide beneficial effects.

- Cost

Replacing water with alcohol in the acidizing solution makes the treatment more expensive.

- Low flash point

Both isopropanol and methanol, and even acid solutions containing 20% or more by volume of either, have low flash points.

- Increase in corrosiveness

Corrosion tests have shown that alcohol-acid mixtures require a higher concentration of inhibitor than equivalent acid mixtures without alcohol.

- Adverse reactions

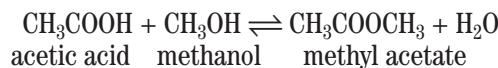
Formation brines with a high concentration of dissolved salts can "salt out" in the presence of alcohols. To help prevent the occurrence of salt precipitation, treating solutions should not exceed 20% by volume of isopropanol or 40% by volume of methanol.

- Incompatibility

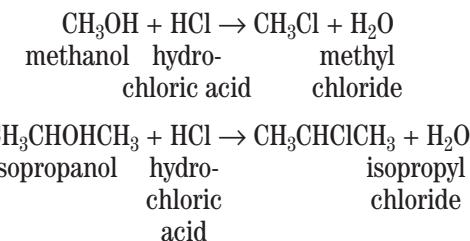
Some crude oils are incompatible with both methanol and isopropanol. Compatibility tests should be conducted before acidizing a well with a fluid containing alcohol. Some formation types may even be extremely sensitive to aqueous solutions that contain high concentrations of alcohols.

- Side reactions

There are undesirable side reactions when alcohols are used in acidizing. Even under moderate temperature conditions, alcohols react readily with acid. In the case of organic acids (e.g., acetic or formic acid), these reactions result in ester formation, with the only resulting problem being a possible loss of available acid for the stimulation reaction. Even this may be of small consequence, because the esterification reaction is reversible and regeneration of the organic acid for the desired stimulation reaction is possible (Keeney and Frost, 1975):

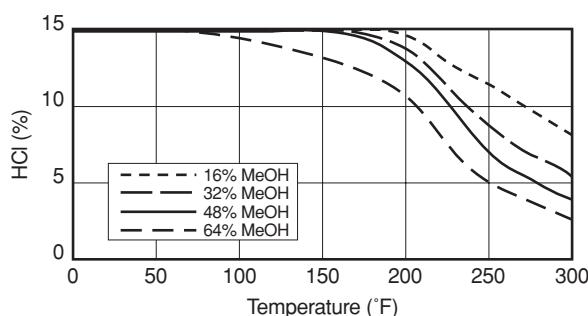


However, in an alcoholic solution of HCl, a reaction takes place that results in the formation of the following organic chlorides:



This poses a genuine problem in gas well stimulation because the second and third of these reactions are irreversible, and any HCl lost to this process cannot be regenerated, as is possible with organic acids in the first equation. Thus, these reactions reduce the HCl content. A second problem concerns the reaction products themselves. Although the presence of organic chlorides in natural gas might not present any special problems, their presence in produced crudes or distillates is considered serious contamination, because of the detrimental effect of chlorinated hydrocarbons on refinery catalysts.

Figure 15-10 shows the effects of increasing temperature on the reduction of acid strength for four concentrations of methanol. The data show that there is no significant loss of acid strength with methanol concentrations up to 32% by volume until the temperature exceeds 175 degF [80 degC].



**Figure 15-10.** Effect of various concentrations of methanol on acid strength at increasing temperatures (courtesy of Halliburton Services).

## 15-8. Acetic acid

A common problem in HF acidizing is the precipitation of reaction products. Many of the precipitation reactions occur almost immediately on spending the acid solution. Most of these precipitation problems can be overcome by the use of an adequate acid preflush and ammonium chloride ( $\text{NH}_4\text{Cl}$ ) overflush. However, precipitation can also occur days, months or even years after an HF acidizing treatment. This precipitation is often called aluminosilicate scaling. Scales of this type are believed to form when the spent HF mixes with formation fluid to slightly raise the pH, thus causing precipitation.

Recent field trials by Shuchart and Ali (1992) show that the use of 3% acetic acid in HF acidizing sequences decreases the occurrence of scaling. The use of acetic acid delays the precipitation of aluminosilicate scale by two mechanisms—a buffering effect and a chelating effect.

## 15-9. Organic dispersants

A relatively new method of removing organic deposits is the use of a dispersant surfactant with xylene. These surfactants can penetrate and loosen organic deposits so that the xylene can effectively dissolve or remove the deposit. Concentrations of 1% to 10% volume/volume are used depending on the deposit type, hardness and adhesion and the bottomhole temperature. For matrix, wellbore and tubing cleanup treatments, a soaking period of several hours is recommended.

## 15-10. Organic solvents

As Fig. 15-1 shows, organic solvents used alone or in combination with acid and other materials are useful for removing water blocks and solids. King (1986) provided a good discussion of the uses of these solvents alone and in combination with acid for damage removal. Organic solvents include alcohols in addition to more traditional solvents such as xylene, toluene and diesel.

Organic solvents are particularly useful for the removal of organic deposits. An organic solvent can be combined with acid when the inorganic scales are mixed with or coated by asphaltenes and paraffins. An oil-external emulsion with the appropriate acid as the internal phase is useful for treating mixed deposits. The emulsion provides a further benefit of retarding the acid, thus allowing the deeper penetration of live acid.

## 15-11. Diversion

Diversion is often required to ensure that the treating fluid works effectively. Diverters function simply by equalizing the flow so that zones of differing permeabilities can be treated. Schechter (1992) provided a good discussion of diversion principles. The emphasis in this section is on diversion through the use of particulates added to the treating fluid and foams rather than the use of packers or ball sealers.

Ideally the diverter should

- be insoluble in the treating fluid
- form an essentially impermeable layer on the formation face without penetrating deeply into the formation
- be easily removed following the treatment.

Generally all, or at least most, of these criteria can be met using materials such as oil-soluble resins, benzoic acid flakes and other particulates. Particulate diverters may cause damage and can be difficult to clean up as a result.

Foams may also provide effective diversion (Zerhboub *et al.*, 1991). Foamed fluids have the additional advantage of good cleanup with little or no potential for damaging the formation. The ratio of nitrogen to fluid depends on the bottomhole conditions during the treatment. Diversion and fluid placement strategy are addressed in Chapter 19.

## 15-12. Additive compatibility

All additives should be tested in the laboratory. Compatibility of additives with formation fluids should be tested using a sandpack method developed by Ali *et al.* (1994). This procedure is more representative of downhole conditions and uses more sand than the test in *API Recommended Practices for Laboratory Testing of Surface Active Agents for Well Stimulation* (RP 42) (1977). The acid system with additives is drawn through a pack of formation core material or a mixture consisting of 10-wt% illite-bentonite, 10-wt% silica flour and 80-wt% 100-mesh sand. There are no universal additives for all formation problems. Any potential incompatibilities between additives and formation fluids must be identified and corrected before acidizing.

## 15-13. Facility upsets following acid stimulation

### 15-13.1. Discharge requirements

The chemicals used in acidizing treatments have been linked with oil and water separation facility upsets, causing noncompliance with environmental discharge regulations. On flowback, emulsion and oil/water separation problems that occur can potentially result in excess oil solubilized in the water by the formation of microemulsions. Emulsion problems under such circumstances can result in thousands of gallons of non-pipeline-quality oil and could shut down the separation unit and minimize production from these wells. Dehydrated oil and clean discharge water are required to maintain normal uninterrupted production.

Regulations for the disposal of produced water in offshore operations are becoming increasingly stringent. The U.S. National Pollutant Discharge Elimination System (NPDES) has established discharge levels for oil and grease at a 29-mg/L monthly average with a grab sample maximum of 42 mg/L. This is a reduction in the allowable levels from 48 to 29 mg/L. The penalty for noncompliance by the operator can be severe. These discharge levels are causing the reevaluation of acidizing treatments.

During the flowback immediately following an acid treatment, significantly higher levels of oil and grease than those permitted for discharge have also been recorded. During flowback, spikes in the basic sediment and water (BS&W) values occur immediately after an acid treatment. Microemulsions are suspected of occurring during flowback. The produced oil is solubilized in the returned spent acid, and this results in significantly higher levels of oil and grease. The use of matrix additives is believed to contribute to the solubilization of the oil and additives. These additives should be optimized to minimize emulsion upsets and the levels of oil and grease.

Verification and optimization of the additives used in acid stimulation treatments have been requested by operators. Obtaining an answer to treatment facility upsets by additive optimization in matrix treatments can have a tremendous impact on acidizing workover operations. Research by Bansal (1993) determined the following maximum concentrations of inhibitors, surfactants and mutual solvents that may be present in the returned fluids to maintain oil and grease levels below 48 mg/L:

- inhibitors: 80 ppm
- surfactants: 10 ppm
- mutual solvents: 100 ppm.

The common denominator for each of these additives is surface-active compounds (i.e., surfactants). The surfactants provide acceptable fluid performance, such as corrosion inhibition, dispersion and wetting properties, as they were initially designed for the acid treatment. However, if the additives are used in excessive concentrations, they may exacerbate the emulsification tendencies of fluids during flowback.

The difference in emulsion stability is attributed to other, more dominant factors (e.g., stabilization by solids precipitation [organic and inorganic], ferric ion interaction with the crude oil and viscosity increase at the interface). Results presented by Coppel (1975) show that acids partially spent on formations contain potentially precipitable materials in solution. As the pH of the produced acid increases during flowback and mixes with other produced fluids, precipitates form that can stabilize emulsions. Dunlap and Houchin (1990) recommended polarized microscopy to evaluate return fluids to establish the cause for a stabilized emulsion. Specific damage mechanisms, such as emulsion stabilization by organic deposits, solids and iron, could be detected and identified.

### 15-13.2. Prevention of facility upsets

Preventing upsets requires optimizing the fluid design to minimize or eliminate the formation of precipitates and using the optimum de-emulsifier. The potential for the formation of emulsions of acid and produced crude oil while still providing the required downhole function optimization of the de-emulsifier treatment is evaluated currently by the procedures recommended in API RP 42 (1977). Vigorous mixing of acid with fresh crude oil in a glass container is observed under bottomhole temperatures (hot-water bath) to determine the characteristics and time for emulsion breakout. Fine siliceous materials, ferric iron or both can be added to evaluate emulsion stability.

These fluid interactions can simulate the downhole emulsion problems encountered; however, these tests fail to accurately predict the interaction of the treating fluids with the acid-sensitive crudes during flowback. As a result, marginal treatment response is observed. Downhole emulsions and facility upsets may be attributed to inadequate prejob compatibility testing, because the additives employed in the acid system may preferentially adsorb out onto the rock matrix or partition to the oil phase during production.

Alternate testing procedures have been developed to more accurately simulate reservoir conditions. Ali *et al.* (1994) recommended an alternate procedure that better simulates downhole intermixing of the stimulation fluids and the produced crude. The procedure involves filtering formulated acid, containing inhibitor, surfactants, mutual solvents and nonemulsifiers, through a sandpack containing 10-wt% silica flour, 10-wt% clays (such as montmorillonite) and 80-wt% 100-mesh sand prior to completion of the emulsion test. This procedure simulates the filtration of the acid system within the rock matrix. Surfactants, such as those used in nonemulsifiers, are adsorbed onto mineral surfaces. The adsorption minimizes the availability of the surfactants in solution to prevent emulsions.

Durham *et al.* (1995) reported that oil and water emulsion upsets could be minimized by proper selection of the acidizing additives and surface treating chemicals. When acid flowbacks are introduced into a production system, the control of emulsions by chemical treatment can significantly change in comparison with control during production of the well prior to treatment. These authors completed extensive emulsion breaker and water clarification tests with the desired acid/additive systems and fresh crude oil to duplicate the commingling of the acid with the oil during flowback. The low pH of the water in the emulsion rendered the current treating program ineffective until the acid flowback was completed. Nonionic de-emulsifiers were found to be more effective than sulfonate-type additives for treating these emulsions. On-site testing is recommended to select an effective chemical treatment.

Ali *et al.* (1997) reported the optimization of acidizing additives to reduce production facility upsets. The authors combined additive treatment optimization with a new absorption/filtration process. The optimized treatments involved the evaluation of surfactants and mutual solvents, which are considered to be the additives primarily responsible for emulsion problems during acid flowback. Elimination of some additives, minimizing the concentrations of other additives and using a dual-purpose mutual breakout solvent reduced facility upsets. All recommendations were based on laboratory testing using the sandpack method and on-site testing with a laboratory unit. The filtration process used a specialized absorption medium to aid in lowering oil and grease levels. This combination of treatment optimization with filtration/absorption reduced facility upsets while not interfering with the efficacy of the treatment.

# 16. Fundamentals of Acid Stimulation

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## 16-1. Introduction

Matrix stimulation is a technique in which a solvent is injected into the formation to dissolve some of the materials present and hence recover or increase the permeability in the near-wellbore region. Such treatments are called “matrix” treatments because the solvent is injected at pressures below the parting pressure of the formation so that fractures are not created. The objective is to greatly enhance or recover the permeability near the wellbore, rather than affect a large portion of the reservoir.

The most common matrix stimulation treatment is acidizing, in which an acidic solution is injected to dissolve minerals in the formation. However, other solvents are also used. The next most common fluids are organic solvents aimed at dissolving waxes, paraffins, asphaltenes or other organic damaging materials. Nonacid matrix stimulation is addressed in Chapter 14. This chapter focuses on matrix acidizing; however, the reader should keep in mind that many of the theories and calculation procedures presented here can also be applied to nonacid solvent treatments.

The most common acids are hydrochloric acid (HCl), used primarily to dissolve carbonate minerals, and mixtures of HCl and hydrofluoric acid (HF), used to attack silicate minerals such as clays and feldspars. Other acids, particularly some weak organic acids, are used in special applications, such as high-temperature wells. Matrix acidizing is a near-wellbore treatment, with all the acid reacting within about 1 ft of the wellbore in sandstone formations and within a few inches to perhaps as much as 10 ft from the wellbore in carbonates.

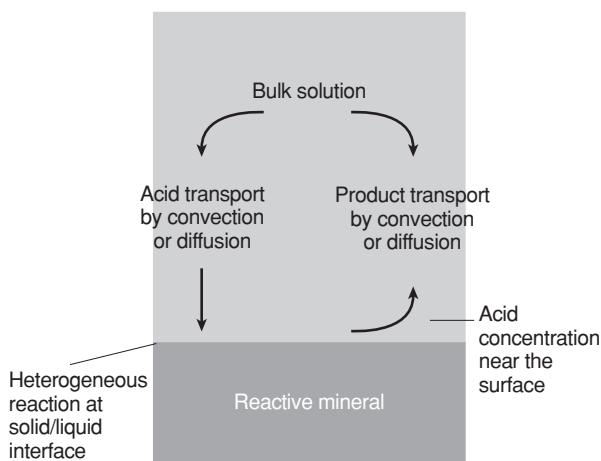
Matrix acidizing can significantly enhance the productivity of a well when near-wellbore formation damage is present and, conversely, is of limited benefit in an undamaged well, as shown in Chapter 1<sup>†</sup>. Thus, matrix acidizing generally should be applied only when a well has a high skin factor that cannot be attributed to partial penetration, perforation efficiency or other mechanical aspects of the completion. Two exceptions to this rule may occur. First, in highly productive wells, the productivity improvement of about 20% that is possible

with matrix stimulation of an undamaged well may be economic. Second, in naturally fractured or highly vugular carbonate reservoirs, live acid may penetrate to a sufficient distance to yield a productivity enhancement greater than that normally expected from a true matrix treatment.

An ideal matrix treatment restores the permeability in the near-wellbore region to a value at least as high as the original undamaged permeability; it accomplishes this over the entire completed interval and it leaves the formation in the treated region with high relative permeability to the oil and/or gas phase. Designing a treatment should strive to achieve this ideal at the lowest possible cost, which requires consideration of the many physical and chemical interactions taking place between the injected fluids and the reservoir minerals and fluids. The most important of these phenomena are the following:

- mass transfer of acid molecules to the mineral surface and subsequent reaction at the surface—This fundamental process of acidizing is illustrated in Fig. 16-1. Acid reactions with minerals are termed heterogeneous reactions because they occur at a boundary between the solid and the liquid rather than in the bulk phases. Before the reaction can occur, acid must be transported to the mineral surface by convection or diffusion. The overall reaction rate (i.e., the rate of change of the concentration of one component in the bulk liquid phase) may depend on both the rate of mass transfer and the rate of surface reaction. Many times, however, one of these processes is much slower than the other and controls the overall rate, in which case the faster process can be ignored.
- changing pore structure—The physical change in the pore structure caused by dissolution of some of the minerals by acid is the mechanism by which matrix acidizing increases permeability. The manner in which the pore structure changes is fundamentally different in sandstones and carbonates, which leads to radically different approaches to modeling the acidizing process in these two mineralogies.

<sup>†</sup> See *Reservoir Stimulation Third Edition* (SMP-7075)  
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**Figure 16-1.** Acid reaction occurring in a system.

- precipitation of reaction products—Secondary reactions occur in acidizing, particularly in sandstones, that can result in the precipitation of reaction products from the bulk liquid phase. Obviously, precipitated solids may block pore spaces and work against the goal of matrix acidizing.
- acid fluid–reservoir fluid interactions—The acid solution injected in matrix acidizing may interact physically and/or chemically with the reservoir fluids as well as with the minerals. These interactions can result in changes in wettability, phase saturation distribution, precipitation of solids or emulsification.
- variations in reservoir permeability or the distribution of damage—A successful acidizing treatment requires contacting all damaged regions around the well with acid. This is usually complicated by variations in the injectivity to acid along the wellbore, which leads to the use of techniques to affect good acid coverage (acid diversion).

In considering the many aspects of the matrix acidizing process, the focus is on the key design variables; to be useful, any model of the process must aid in optimizing the design. The primary design considerations are

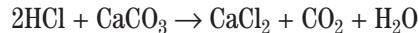
- fluid selection—acid type, concentration and volume
- injection schedule—planned rate schedule and sequence of injected fluids
- acid coverage and diversion—special steps taken to improve acid contact with the formation
- real-time monitoring—methods to evaluate the acidizing process as it occurs
- additives—other chemicals included in the acid solution to enhance the process or to protect tubular goods.

Treatment design is considered in detail in other chapters. This chapter lays the foundation for the design methods aimed at optimizing a matrix acidizing treatment by reviewing the underlying chemistry and physics of the acidizing process and introducing the latest models of the processes involved. First, the interaction of acids with reservoir minerals is addressed. Then, current models of the matrix acidizing process in sandstones and in carbonates are presented.

## 16-2. Acid-mineral interactions

### 16-2.1. Acid-mineral reaction stoichiometry

The amount of acid required to dissolve a given amount of mineral is determined by the stoichiometry of the chemical reaction, which describes the number of moles of each species involved in the reaction. For example, the simple reaction between HCl and calcite ( $\text{CaCO}_3$ ) can be written as

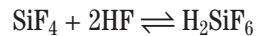


which shows that 2 moles of HCl are required to dissolve 1 mole of  $\text{CaCO}_3$ . The numerals 2 and 1 multiplying the species HCl and  $\text{CaCO}_3$  are the stoichio-metric coefficients  $v_{\text{HCl}}$  and  $v_{\text{CaCO}_3}$  for HCl and  $\text{CaCO}_3$ , respectively.

When HF reacts with silicate minerals, numerous secondary reactions may occur that influence the overall stoichiometry of the reaction. For example, when HF reacts with quartz ( $\text{SiO}_2$ ), the primary reaction is



producing silicon tetrafluoride ( $\text{SiF}_4$ ) and water. The stoichiometry of this reaction shows that 4 moles of HF are required to consume 1 mole of  $\text{SiO}_2$ . However, the  $\text{SiF}_4$  produced may also react with HF to form fluosilicic acid ( $\text{H}_2\text{SiF}_6$ ) according to



If this secondary reaction goes to completion, 6 moles of HF, rather than 4 moles, will be consumed to dissolve 1 mole of quartz. A complication is that the fluosilicates may exist in various forms, so that the total amount of HF required to dissolve a given amount of quartz depends on the solution concentration.

Typical reactions involved in HF acidizing are summarized in Table 16-1. Only the primary reaction products,  $\text{AlF}_2^+$  and  $\text{SiF}_4$ , are shown although many other products are possible (Labrid, 1975; Hekim and Fogler, 1982; Walsh *et al.*, 1982; Sevoulian *et al.*, 1992; Shuchart and Gdanski, 1996). How many moles of mineral are dissolved by a mole of acid is an important consideration in the selection of an acid treatment volume that may

**Table 16-1. Primary chemical reactions in acidizing.**

HCl	
Calcite	$2\text{HCl} + \text{CaCO}_3 \rightarrow \text{CaCl}_2 + \text{CO}_2 + \text{H}_2\text{O}$
Dolomite	$4\text{HCl} + \text{CaMg}(\text{CO}_3)_2 \rightarrow \text{CaCl}_2 + \text{MgCl}_2 + 2\text{CO}_2 + 2\text{H}_2\text{O}$
Siderite	$2\text{HCl} + \text{FeCO}_3 \rightarrow \text{FeCl}_2 + \text{CO}_2 + \text{H}_2\text{O}$
HCl-HF	
Quartz	$4\text{HF} + \text{SiO}_2 \rightleftharpoons \text{SiF}_4$ (silicon tetrafluoride) + $2\text{H}_2\text{O}$
	$\text{SiF}_4 + 2\text{HF} \rightleftharpoons \text{H}_2\text{SiF}_6$ (fluosilicic acid)
Albite (sodium feldspar)	$\text{NaAlSi}_3\text{O}_8 + 14\text{HF} + 2\text{H}^+ \rightleftharpoons \text{Na}^+ + \text{AlF}_2^+ + 3\text{SiF}_4 + 8\text{H}_2\text{O}$
Orthoclase (potassium feldspar)	$\text{KAlSi}_3\text{O}_8 + 14\text{HF} + 2\text{H}^+ \rightleftharpoons \text{K}^+ + \text{AlF}_2^+ + 3\text{SiF}_4 + 8\text{H}_2\text{O}$
Kaolinite	$\text{Al}_4\text{Si}_4\text{O}_{10}(\text{OH})_8 + 24\text{HF} + 4\text{H}^+ \rightleftharpoons 4\text{AlF}_2^+ + 4\text{SiF}_4 + 18\text{H}_2\text{O}$
Montmorillonite	$\text{Al}_4\text{Si}_8\text{O}_{20}(\text{OH})_4 + 40\text{HF} + 4\text{H}^+ \rightleftharpoons 4\text{AlF}_2^+ + 8\text{SiF}_4 + 24\text{H}_2\text{O}$

differ substantially from the values shown in Table 16-1. As an example of the uncertainty, Schechter (1992) suggested that for conservative design purposes, about 20 moles of acid are required to dissolve 1 mole of feldspar rather than the 14 moles shown in Table 16-1. Depending on the composition of the acid solution, the actual value may be substantially less. This is especially the case if the silicon extracted from the feldspar crystals appears finally as the precipitate  $\text{Si}(\text{OH})_4$  rather than as soluble  $\text{SiF}_4$  as shown in Table 16-1. If the final silicon product is, in fact,  $\text{Si}(\text{OH})_4$ , then only 1 mole of HF would be required to dissolve a single mole of albite.

In modeling the acidizing process, it is therefore crucial to determine the local solution composition as the process progresses. To satisfy this requirement, Sevoulian *et al.* (1992) developed a geochemical model that considers a local partial equilibrium among certain reactions involved in the acidizing process. This is an important modeling capability; for example, Shuchart and Gdanski (1996) observed that the  $\text{AlF}_2^+/\text{AlF}_2^+$  ratio obeys a pseudoequilibrium relation over a range of reaction conditions. This implies local equilibrium among the various aluminum fluoride species in the aqueous phase. To utilize the full capability of the Sevoulian *et al.* model, the rates of both the homogeneous and heterogeneous reactions that are not fully at equilibrium are required. Not all the important reaction rates are known.

Thus, the chemistry of the reactions of HF with the minerals found in sandstone formations is complex and difficult to model. An additional complexity is the tendency for some of the reaction products to precipitate as the acid reactions go to completion (see Section 16-2.3). For practical purposes, it is convenient to express the stoichiometry in terms of the approximate “dissolving power,” as introduced by Williams *et al.* (1979).

The dissolving power expresses the amount of mineral that can be consumed by a given amount of acid on a mass or volume basis. First, the gravimetric dissolving power  $\beta$ , which is the mass of mineral consumed by a given mass of acid, is defined as

$$\beta = \frac{V_{\text{mineral}} M W_{\text{mineral}}}{V_{\text{acid}} M W_{\text{acid}}}, \quad (16-1)$$

where the  $n$  terms are the stoichiometric coefficients and  $M W_{\text{mineral}}$  and  $M W_{\text{acid}}$  are the molecular weights of the mineral and the acid, respectively. Thus, for the reaction between 100% HCl and  $\text{CaCO}_3$ ,

$$\beta_{100} = \frac{(1)(100.1)}{(2)(36.5)} = 1.37 \text{ lbm CaCO}_3/\text{lbm HCl}, \quad (16-2)$$

where the subscript 100 denotes 100% HCl. The dissolving power of any other concentration of acid is  $\beta_{100}$  times the weight fraction of acid in the acid solution. For the commonly used 15% HCl,  $\beta_{15} = 0.15 \times \beta_{100} = 0.21 \text{ lbm CaCO}_3/\text{lbm HCl}$ . The stoichiometric coefficients for common acidizing reactions are found from the reaction equations in Table 16-1.

The volumetric dissolving power  $X$ , which is similarly defined as the volume of mineral dissolved by a given volume of acid, is related to the gravimetric dissolving power by

$$X = \beta \frac{\rho_{\text{acid solution}}}{\rho_{\text{mineral}}}. \quad (16-3)$$

A 15% HCl solution has a specific gravity of about 1.07 and  $\text{CaCO}_3$  has a density  $\rho$  of 169 lbm/ft<sup>3</sup>. For the reaction of these species, the volumetric dissolving power is

$$\begin{aligned} X_{15} &= 0.21 \left( \frac{\text{lbm CaCO}_3}{\text{lbm 15\% HCl}} \right) \left( \frac{(1.07)(62.4) \frac{\text{lbm 15\% HCl}}{\text{ft}^3}}{169 \frac{\text{lbm 15\% CaCO}_3}{\text{ft}^3}} \right) \\ &= 0.082 \frac{\text{ft}^3 \text{CaCO}_3}{\text{ft}^3 \text{15\% HCl}}. \end{aligned} \quad (16-4)$$

The dissolving powers of various acids with limestone and dolomite and of HF with quartz and albite are given in Tables 16-2 and 16-3, respectively (Schechter, 1992). Sidebar 16A is an example calculation using dissolving power.

### 16-2.2. Acid-mineral reaction kinetics

The reaction between an acid and a mineral occurs when acid reaches the surface of the mineral by diffusion or convection from the bulk solution. The overall rate of acid consumption or mineral dissolution depends on two distinct phenomena—the rate of transport of acid to the mineral surface by diffusion or convection and the actual reaction rate on the mineral surface. Usually, one of these processes is much slower than the other. In this case, the fast process can be ignored, because it can be thought of as occurring in an insignificant amount of time compared with the slow process.

For example, the HCl-CaCO<sub>3</sub> reaction rate is extremely high, so the overall rate of this reaction is usually controlled by the rate of acid transport to the surface, the

slower of the two processes. On the other hand, the surface reaction rates for many HF-mineral reactions are slow compared with the acid transport rate, and the overall rate of acid consumption or mineral dissolution is reaction-rate controlled. The “kinetics” of a reaction is a description of the rate at which the chemical reaction takes place, once the reacting species have been brought into contact.

A reaction rate is generally defined as the rate of appearance in the solution of the species of interest in units of moles per second (mol/s). A surface reaction rate depends on the amount of surface exposed to reaction, so these reactions are expressed per unit of surface area. In general, the surface reaction rate of an aqueous species of acid A reacting with mineral B is

$$R_A = r_A S_B, \quad (16-5)$$

where  $R_A$  is the rate of appearance of acid A in mol/s,  $r_A$  is the surface area-specific reaction rate of A in mol/s·m<sup>2</sup>, and  $S_B$  is the surface area of mineral B. When A is being consumed, the reaction rates  $r_A$  and  $R_A$

**Table 16-2. Dissolving power of various acids (Schechter, 1992).**

<b>Formation</b>	<b>Acid</b>	<b>X (%)</b>				
		$\beta_{100}$	<b>5</b>	<b>10</b>	<b>15</b>	<b>30</b>
Limestone (CaCO <sub>3</sub> )	Hydrochloric (HCl)	1.37	0.026	0.053	0.082	0.175
	Formic (HCOOH)	1.09	0.020	0.041	0.062	0.129
	Acetic (CH <sub>3</sub> COOH)	0.83	0.016	0.031	0.047	0.096
Dolomite (CaMg(CO <sub>3</sub> ) <sub>2</sub> )	Hydrochloric	1.27	0.023	0.046	0.071	0.152
	Formic	1.00	0.018	0.036	0.054	0.112
	Acetic	0.77	0.014	0.027	0.041	0.083

Notes:  $\rho_{\text{CaCO}_3} = 2.71 \text{ g/cm}^3$ ,  $\rho_{\text{CaMg(CO}_3)_2} = 2.87 \text{ g/cm}^3$

**Table 16-3. Dissolving power of hydrofluoric acid (Schechter, 1992).**

<b>Acid concentration (wt%)</b>	<b>Quartz (SiO<sub>2</sub>)</b>		<b>Albite (NaAlSi<sub>2</sub>O<sub>8</sub>)</b>	
	<b><math>\beta</math></b>	<b>X</b>	<b><math>\beta</math></b>	<b>X</b>
2	0.015	0.006	0.019	0.008
3	0.023	0.010	0.028	0.011
4	0.030	0.018	0.037	0.015
6	0.045	0.019	0.056	0.023
8	0.060	0.025	0.075	0.030

Notes:  $\beta$  = mass of rock dissolved/mass of acid reacted, X = volume of rock dissolved/volume of acid reacted

## 16A. Calculating minimum acid volume using dissolving power

The volume of acid required for a matrix acidizing treatment can be estimated using the concept of dissolving power. Because the volumetric dissolving power  $X$  is the volume of a particular mineral that is dissolved by a given volume of a particular acid solution, the minimum acid requirement to remove that mineral can be calculated with little information other than the dissolving power. Consider the following problem:

A sandstone formation with a porosity of 0.2 contains 5-vol% albite (sodium feldspar). What is the minimum volume of 3% HF solution required to dissolve all the albite a distance of 6 in. beyond a 6-in. diameter wellbore?

### Solution

The minimum acid volume is the amount  $V_{HF}$  required to dissolve all the feldspar plus the amount  $V_p$  required to fill the pore space in the region of feldspar dissolution. These volumes are

$$\begin{aligned} V_{feldspar} &= \pi(r_{HF}^2 - r_w^2)(1-\phi)x_{feldspar} = \pi(0.75^2 - 0.25^2)(1-0.2)(0.05) \\ &= 0.063 \frac{\text{ft}^3}{\text{ft}} \text{feldspar} \end{aligned} \quad (16A-1)$$

$$V_{HF} = \frac{V_{feldspar}}{X_3} = \frac{0.063}{0.011} = 5.7 \frac{\text{ft}^3 \text{HF}}{\text{ft}}. \quad (16A-2)$$

In these equations,  $r_{HF}$  is the radial penetration distance of HF,  $r_w$  is the wellbore radius,  $\phi$  is the porosity, and  $x_{feldspar}$  is the volume fraction of the sandstone that is feldspar. The volume of pore space within 6 in. of the wellbore after removal of the feldspar is

$$\begin{aligned} V_p &= \pi(r_{HF}^2 - r_w^2)(\phi + x_{feldspar}(1-\phi)) = \pi(0.75^2 - 0.25^2)(0.2 + 0.05(1-0.2)) \\ &= 0.38 \frac{\text{ft}^3}{\text{ft}}, \end{aligned} \quad (16A-3)$$

so the total volume of HF required is

$$V_{HF,T} = V_{HF} + V_p = (5.7 + 0.38) \frac{\text{ft}^3}{\text{ft}} \left( \frac{7.48 \text{ gal}}{\text{ft}^3} \right) = 46 \frac{\text{gal}}{\text{ft}}. \quad (16A-4)$$

Thus, the minimum volume of 3% HF solution required to remove all feldspar in a radial region extending 6 in. beyond the wellbore is 46 gal/ft of reservoir thickness. In an actual acidizing treatment, the injected acid does not react with feldspar only, and as shown by examining models of the acidizing process, the acid is not spent uniformly, as tacitly assumed in this calculation. Nevertheless, this simple calculation provides a ballpark figure for acid requirements and is a handy check of more complex models of the process.

are negative. Acid-mineral reaction rates are typically expressed as the rate of dissolution of the mineral  $R_B$ , which is related to the acid consumption rate through the stoichiometry of the reaction

$$R_A = \frac{v_A}{v_B} R_B, \quad (16-6)$$

where  $v_A$  and  $v_B$  are the stoichiometric coefficients for acid A and mineral B.

The reaction rate  $r_A$  generally depends on the concentrations of the reacting species. However, in the reaction between an aqueous species and a solid, the concentration of the solid can be ignored, because it remains essentially constant. For example, a grain of quartz has a fixed number of moles of quartz per unit volume of quartz, irrespective of reactions that may be occurring on the surface of the grain. Incorporating concentration dependence into the rate expression yields

$$-R_A = E_f C_A^\alpha S_B, \quad (16-7)$$

where  $E_f$  is a reaction rate constant in mol A/[m<sup>2</sup>-s-(mol A/m<sup>3</sup>)<sup>α</sup>],  $C_A$  is the concentration of species A at the reactive surface, and  $\alpha$  is the order of the reaction (i.e., a measure of how strongly the reaction rate depends on the concentration of A). The reaction rate constant depends on temperature and sometimes on the concentration of chemical species other than A. Finally, Eq. 16-7 is written in the conventional manner for a species of acid that is being consumed from solution, by placing a minus sign with  $R_A$  so that  $E_f$  is a positive number.

### ■ Laboratory measurement of reaction kinetics

To measure the surface reaction rate of acid-mineral reactions, it is necessary to maintain a constant mineral surface area or measure its change during reaction and to ensure that the rate of acid transport to the mineral surface is fast relative to the reaction rate. The two most common methods of obtaining these conditions are with a well-stirred slurry of mineral particles suspended in an acid solution (a stirred reactor) or with a rotating disk apparatus (Fogler *et al.*, 1976.) In the rotating disk apparatus, a disk of

the mineral is placed in a large container holding the acid solution. The disk is rotated rapidly, so that the acid mass-transfer rate is high relative to the surface reaction rate. A third, more indirect method is by matching the coreflood response to acidizing with a model of the process of flow with reaction.

Lund *et al.* (1975, 1973) measured the kinetics of the HCl-calcite and HCl-dolomite reactions, respectively. Their results may be summarized as

$$-r_{HCl} = E_f C_{HCl}^\alpha \quad (16-8)$$

$$E_f = E_f^o \exp\left(-\frac{\Delta E}{RT}\right). \quad (16-9)$$

The constants  $\alpha$ ,  $E_f^o$  and  $\Delta E/R$  are listed in Table 16-4. SI units are used in these expressions, so  $C_{HCl}$  is in kg-mol/m<sup>3</sup> and temperature  $T$  is in degrees Kelvin. The reaction rate  $r_{HCl}$  is expressed as kg-mol HCl reacted/m<sup>2</sup>-s.

- Reactions of hydrochloric and weak acids with carbonates

HCl is a strong acid, meaning that when HCl is dissolved in water, the acid molecules almost completely dissociate to form hydrogen ions ( $H^+$ ) and chloride ions ( $Cl^-$ ). The reaction between HCl and carbonate minerals is actually a reaction of the  $H^+$  with the mineral. With weak acids, such as acetic or formic acid, the reaction is also between  $H^+$  and the mineral, with the added complication that the acid is not completely dissociated, thus limiting the supply of  $H^+$

available for reaction. Because  $H^+$  is the reactive species, the kinetics of the HCl reaction can also be used for weak acids by considering the acid dissociation equilibrium.

The kinetics of a weak acid–carbonate mineral reaction may therefore be obtained from Eq. 16-8 as follows (Schechter, 1992):

$$-r_{weak\ acid} = E_f K_d^{\alpha/2} C_{weak\ acid}^{\alpha/2}, \quad (16-10)$$

where  $K_d$  is the dissociation constant of the weak acid and  $E_f$  is the reaction rate constant for the HCl-mineral reaction.

- Reactions of hydrofluoric acid with sandstone minerals
- HF reacts with virtually all of the many mineral constituents of sandstone. Reaction kinetics have been reported for the reactions of HF with quartz (Bergman, 1963; Hill *et al.*, 1977), feldspars (Fogler *et al.*, 1975) and clays (Kline and Fogler, 1981a). These kinetic expressions can all be represented by

$$-r_{mineral} = E_f [1 + K(C_{HCl})^\beta] C_{HF}^\alpha, \quad (16-11)$$

for which the parameters  $a$ ,  $b$ ,  $E_f$  and the empirical kinetic constant  $K$  are listed in Table 16-5.

These expressions show that the dependence on HF concentration is approximately first order ( $a = 1$ ). For feldspar reactions, the reaction rate increases with increasing HCl concentration, although HCl is not consumed in the reaction. Thus, HCl catalyzes HF-feldspar reactions. Kline and Fogler (1981a)

**Table 16-4. Constants in HCl-mineral reaction kinetics models.**

Mineral	$\alpha$	$E_f^o$	$\frac{\Delta E}{R}$ (K)
Calcite ( $CaCO_3$ )	0.63	$7.291 \times 10^7$	$7.55 \times 10^3$
Dolomite ( $CaMg(CO_3)_2$ )	$6.18 \times 10^{-4} T$ $1-2 \times 10^{-3} T$	$\frac{9.4 \times 10^{11}}{1000^\alpha}$	$11.32 \times 10^3$

showed that the reactive area depends on the crystalline structure of the clay reacting with an HCl-HF mixture and is generally only a small fraction of the total surface area of clays as determined by traditional methods of measurement. Thus, the surface area of montmorillonite as determined by nitrogen ( $N_2$ ) adsorption may be as high as  $5 \times 10^5 \text{ m}^2/\text{kg}$ , whereas the reactive surface area is approximately  $104 \text{ m}^2/\text{kg}$ . The surface areas in Eq. 16-8 must be the reactive areas that are actually in contact with the acidic solution. Therefore, the morphology of the mineral assemblage becomes an important issue. Comparison of the reaction rates of various minerals requires placing the rates on the basis of a unit of reactive area. On this basis, montmorillonites and kaolinites react about 2 orders of magnitude slower than feldspars, and illites react at least 1 order of magnitude slower than kaolinite. Viewing thin sections of rocks following acid treatment with HCl-HF mixtures shows that the feldspars are usually removed because of their high specific reaction rates. Authigenic clays also appear to react rapidly

because of their intimate exposure to the acidic solution. On the other hand, clastic clays are commonly found in thin sections following acid treatment (Hill *et al.*, 1977). Thus, it is not only the specific reaction rate but also the area in contact with the acid that determines the rate of removal of a specific mineral. An example calculation of relative reaction rates of sandstone minerals is in Sidebar 16B.

#### ■ Reactions of fluosilicic acid with sandstone minerals

As discussed in Section 16-2.1, fluosilicic acid is produced when HF dissolves silicate minerals, and the fluosilicic acid itself may then react with aluminosilicates. From models of coreflood experiments, Bryant (1991) and da Motta *et al.* (1992a, 1992b) suggested that the reaction between fluosilicic acid and clays and feldspars is slow at room temperature, but that it is of the same order of magnitude as the HF reactions with these minerals at temperatures above 125 degF [50 degC]. These conclusions have been substantiated by more direct experimentation (see Shuchart and Gdanski, 1996).

**Table 16-5. Reaction rate constants for Eq. 16-11.**

Mineral	$E_f$	$K$	$\beta$	$\alpha$
	$\left( \frac{\text{kg-mol mineral}}{\text{m}^2 \cdot \text{s} \left( \frac{\text{kg-mol HF}}{\text{m}^3} \right)^\alpha} \right)$	$\left( \left( \frac{\text{kg-mol HF}}{\text{m}^3} \right)^{-\beta} \right)$		
Potassium feldspar <sup>†</sup> (orthoclase)	$0.127 \exp \left( -\frac{4680}{T} \right)$	$5.66 \times 10^{-2} \exp \left( \frac{956}{T} \right)$	0.4	1.2
Sodium feldspar <sup>†</sup> (albite)	$9.50 \times 10^{-3} \exp \left( -\frac{3930}{T} \right)$	$6.24 \times 10^{-2} \exp \left( \frac{554}{T} \right)$	1.0	1.0
$\alpha$ -quartz <sup>‡</sup>	$1.39 \times 10^{-7} \exp \left( -\frac{1150}{T} \right)$	0	—	—
Montmorillonite <sup>§</sup>	$1.1 \times 10^{-2} \exp \left( -\frac{5200}{T} \right)$	0	—	1.0
Kaolinite <sup>§</sup>	$0.86 \exp \left( -\frac{6800}{T} \right)$	0	—	1.0

<sup>†</sup>Fogler *et al.* (1973)

<sup>‡</sup>Adapted from Hill *et al.* (1977)

<sup>§</sup>Adapted from Kline and Fogler (1981)

## 16B. Relative reaction rates of sandstone minerals

A matrix acidizing treatment is aimed at overcoming the effects of near-wellbore formation damage. Ideally, the injected acid attacks only the material causing the damage, which in most instances is clay particles or other fines. How efficiently the acid is being used can be determined by calculating the reaction rates of all major mineral species present with the injected acid.

Consider a sandstone formation that has been damaged by the invasion of bentonite (montmorillonite) particles from drilling mud. After the carbonate minerals have been removed by an HCl preflush, this clean sandstone contains 90% quartz, 5% albite (sodium feldspar) and 5% montmorillonite by weight. The reactive surface areas of the minerals are 10 m<sup>2</sup>/kg for the quartz and albite and 8000 m<sup>2</sup>/kg for the montmorillonite. (A cube of quartz with a side of 1 mm has a surface area of 2.2 m<sup>2</sup>/kg; if it is 0.1 mm on a side, its surface area is 22 m<sup>2</sup>/kg. Clays have a much larger surface area than detrital grains of quartz or feldspar.) Assume stoichiometric ratios of 6 moles HF/mole quartz, 20 moles HF/mole feldspar and 40 moles HF/mole montmorillonite.

If this rock is contacted with a 12% HCl–3% HF solution at 125°F [50°C], what proportion of the HF will initially be consumed by each of the three minerals? What are the mineral proportions of the rock dissolved?

### Solution

Per unit mass of rock, the surface area of each mineral is its reactive surface area times the mass fraction of the mineral present in the sandstone. For example, the reactive surface area of quartz per mass of sandstone  $S_q$  is  $(10 \text{ m}^2/\text{kg})(0.9) = 9 \text{ m}^2/\text{kg}$  rock. Similarly, the surface areas of feldspar and montmorillonite are 0.5 and 400 m<sup>2</sup>/kg rock, respectively. The acid concentrations in Eq. 16-11 are in units of kg-mol/m<sup>3</sup> solution (equivalent to gmol/L); the concentrations given as mass fractions are converted to these units by multiplying by the solution density and the acid molecular weight, yielding 1.61 kg-mol HF/m<sup>3</sup> solution and 3.53 kg-mol HCl/m<sup>3</sup> solution. Quartz is used to illustrate the calculation sequence to determine the reaction rates for each mineral.

First, the rate constant is calculated with the data from Table 16-5:

$$E_i = 1.39 \times 10^{-7} \exp\left(-\frac{1150}{273 + 50}\right) = 3.95 \times 10^{-9} \frac{\text{kg-mol quartz}}{\text{m}^2 \cdot \text{s} \left( \frac{\text{kg-mol HF}}{\text{m}^3 \text{ solution}} \right)}. \quad (16B-1)$$

Then, the specific reaction rate for quartz from Eq. 16-11 is

$$-r_q = 6.59 \times 10^{-10} (1.61) = 1.06 \times 10^{-9} \frac{\text{kg-mol quartz}}{\text{m}^2 \cdot \text{s}}. \quad (16B-2)$$

The overall reaction rate for quartz is the specific reaction rate multiplied by the reactive surface area:

$$-R_q = 1.06 \times 10^{-9} (9) = 9.54 \times 10^{-9} \frac{\text{kg-mol quartz}}{\text{kg rock-s}}, \quad (16B-3)$$

which is multiplied by the molecular weight of quartz to put it on a mass basis:

$$-R_q = 9.54 \times 10^{-9} (60.1) = 5.73 \times 10^{-7} \frac{\text{kg quartz}}{\text{kg rock-s}}. \quad (16B-4)$$

Finally, the rate of consumption of HF by the quartz reaction is obtained with Eq. 16-9, assuming 6 moles of HF are consumed for each mole of quartz dissolved:

$$-R_{HF,q} = 9.54 \times 10^{-9} (6) = 3.44 \times 10^{-7} \frac{\text{kg-mol HF}}{\text{kg rock-s}}. \quad (16B-5)$$

The results of these calculations for all three minerals are summarized in Table 16B-1.

The fraction of HF expended in a particular reaction is the overall reaction rate for the mineral divided by the sum of the reaction rates, which shows that 1.1% of the HF is reacting with quartz, 5.7% is reacting with feldspar and 93.2% is reacting with montmorillonite. On the basis of the mass of mineral being dissolved, 95.1% of the rock dissolved is clay, 4.3% is feldspar, and less than 0.6% is quartz. This is because of the high surface area of the authigenic clays (including, however, clay particles from drilling muds) and the low reactivity of the quartz. Because clay and feldspar have relatively high reaction rates and generally form a small portion of the total rock mass, they are dissolved first in sandstone acidizing. The quartz reaction becomes important in regions where most of the clay, except clastic clays, and feldspar have already been removed.

**Table 16B-1. Relative reaction rates of sandstone minerals.**

Mineral	$-r_i$ (kg-mol $i/\text{m}^2 \cdot \text{s}$ )	$S_i$ (m <sup>2</sup> /kg rock)	$-R_i$ (kg $i/\text{kg rock-s}$ )	$-R_{HF,i}$ (kg-mol HF/kg rock-s)
Quartz	$5.73 \times 10^{-8}$	9	$3.44 \times 10^{-6}$	$3.44 \times 10^{-7}$
Feldspar	$1.77 \times 10^{-7}$	0.5	$2.32 \times 10^{-5}$	$1.77 \times 10^{-6}$
Clay	$1.81 \times 10^{-9}$	400	$5.19 \times 10^{-4}$	$2.89 \times 10^{-5}$

Note: The subscript  $i$  denotes the mineral.

## 16B. Relative reaction rates of sandstone minerals (continued)

### Notes for Sidebar 16B

Given 90% quartz, 5% albite and 5% montmorillonite by weight, the surface areas are 10 m<sup>2</sup>/kg quartz, 10 m<sup>2</sup>/kg albite and 8000 m<sup>2</sup>/kg montmorillonite. The reaction rates used are from Table 16-5.

- Quartz (*MW* = 60.1)

Because 1 kg rock has 0.9-kg quartz, the quartz area is (0.9)(10)90 m<sup>2</sup>/kg rock.

$$E_f = 1.39 \times 10^{-7} \exp\left(-\frac{1150}{273 + 50}\right) = 3.95 \times 10^{-9}$$

$$-r_q = E_f C_{HF} = 6.36 \times 10^{-9} \frac{\text{kg-mol quartz}}{\text{m}^2 \cdot \text{s}}$$

$$-R_q = (6.36 \times 10^{-9})(9) = 5.72 \times 10^{-8} \frac{\text{kg-mol quartz}}{\text{kg rock-s}}$$

$$-R_q = (5.72 \times 10^{-8})(60.1) = 3.44 \times 10^{-6} \frac{\text{kg quartz}}{\text{kg rock-s}}$$

$$R_{HF} = \left( \frac{5.72 \times 10^{-8} \text{kg-mol quartz}}{\text{kg rock-s}} \right) (6) = 3.43 \times 10^{-7} \frac{\text{mol HF}}{\text{kg rock-s}}$$

- Albite (*MW* = 262,  $\beta$  = 1.0,  $\alpha$  = 1.0)

$$K = 6.24 \times 10^{-2} \exp\left(\frac{554}{323}\right) = 0.3468$$

$$C_{HCl} = 3.53 \text{ kg mol/m}^3$$

$$E_f = 9.5 \times 10^{-3} \exp\left(-\frac{3930}{323}\right) = 4.938 \times 10^{-8}$$

$$R_A = \left( \frac{10^3 \text{ m}^3}{\text{kg albite}} \right) \left( \frac{0.05 \text{ kg albite}}{\text{kg rock}} \right) \left( 1.77 \times 10^{-7} \frac{\text{kg-mol albite}}{\text{m}^2 \cdot \text{s}} \right) = 8.84 \times 10^{-8} \frac{\text{kg-mol albite}}{\text{kg rock-s}}$$

$$R_A = 8.84 \times 10^{-8} (262) = 2.32 \times 10^{-5} \frac{\text{kg albite}}{\text{kg rock-s}}$$

$$R_A = 8.84 \times 10^{-8} \frac{\text{kg-mol albite}}{\text{kg rock-s}} \left( 20 \frac{\text{kg-mol HF}}{\text{kg-mol albite}} \right) = 1.77 \times 10^{-6} \frac{\text{kg-mol albite}}{\text{kg rock-s}}$$

- Montmorillonite (*MW* = 720)

$$E_f = 1.1 \times 10^{-2} \exp\left(-\frac{5200}{323}\right) = 1.12 \times 10^{-9}$$

$$-r_{montmorillonite} = (1.12 \times 10^{-9})(1.61) = 1.81 \times 10^{-9} \frac{\text{kg-mol montmorillonite}}{\text{m}^2 \cdot \text{s}}$$

$$\text{surface area} = \left( 8000 \frac{\text{m}^2}{\text{kg montmorillonite}} \right) \left( \frac{0.05 \text{ kg montmorillonite}}{\text{kg rock}} \right) = 400 \frac{\text{m}^2}{\text{kg rock}}$$

$$R_{montmorillonite} = 7.22 \times 10^{-7} \frac{\text{kg-mol montmorillonite}}{\text{kg rock-s}}$$

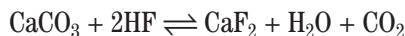
$$R_{montmorillonite} = 5.20 \times 10^{-4} \frac{\text{kg montmorillonite}}{\text{kg rock-s}}$$

$$R_{montmorillonite} = 7.22 \times 10^{-7} (40) = 2.89 \times 10^{-5} \frac{\text{kg montmorillonite}}{\text{kg rock-s}}$$

### 16-2.3. Precipitation of reaction products

A major concern in acidizing, particularly the acidizing of sandstones, is damage caused by the precipitation of acid-mineral reaction products. In acidizing sandstones with HF, the formation of some precipitates is probably unavoidable. However, the amount of damage they cause to the well productivity depends on the amount and location of the precipitates. These factors can be controlled to some extent with proper job design.

The most common damaging precipitates that may occur in sandstone acidizing are calcium fluoride ( $\text{CaF}_2$ ), colloidal silica ( $\text{Si(OH)}_4$ ), ferric hydroxide ( $\text{Fe(OH)}_3$ ) and asphaltene sludges. Calcium fluoride is usually the result of the reaction of calcite with HF, according to



Calcium fluoride is highly insoluble, so the precipitation of  $\text{CaF}_2$  is likely if any calcite is available to react with the HF. Inclusion of an adequate HCl preflush ahead of the HCl-HF stage prevents the formation of  $\text{CaF}_2$ .

Production of some colloidal silica precipitate is probably unavoidable in sandstone acidizing. The equilibrium calculations of Walsh *et al.* (1982) show that there are virtually always regions where the spent acid solution has the tendency to precipitate colloidal silica. However, laboratory corefloods suggest that the precipitation is not instantaneous and in fact may occur at a fairly slow rate (Shaughnessy and Kunze, 1981) that, however, increases with temperature. To minimize the damage caused by colloidal silica, it is probably advantageous to inject at relatively high rates, so that the potential precipitation zone is rapidly displaced away from the wellbore. Also, spent acid should be produced back immediately after the completion of injection, because shutting in the well for even a relatively short time may allow significant silica precipitation to occur in the near-well vicinity.

When ferric ions ( $\text{Fe}^{3+}$ ) are present, they can precipitate from spent acid solutions as  $\text{Fe(OH)}_3$  when the pH is greater than about 2. Ferric ions may result

from the dissolution of iron-bearing minerals in an oxidative environment or may derive from the dissolution of rust in the tubing by the acid solution. When a high level of ferric irons is likely in the spent acid solution, sequestering agents can be added to the acid solution to prevent the precipitation of  $\text{Fe(OH)}_3$ . However, Smith *et al.* (1969) suggested using these sequestrants with caution, as they may cause more damage through their own precipitation than would have been caused by the iron.

Finally, in some reservoirs, contact of the crude oil by acid can cause the formation of asphaltene sludges. Simple bottle tests in which a sample of crude oil is mixed with the acid can indicate whether the crude has a tendency for sludge formation when contacted by acid. When sludge formation is a problem, emulsions of acid in aromatic solvents or surface-active additives have been used to prevent asphaltene precipitation (Moore *et al.*, 1965).

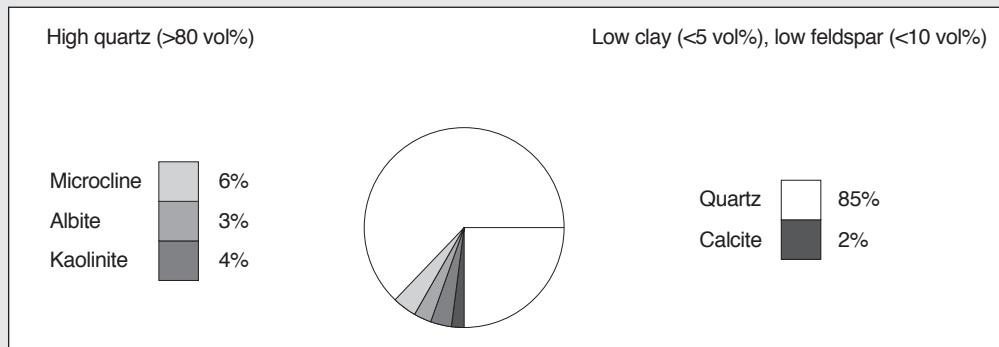
The tendency for precipitation reactions to occur in acidizing is predicted with comprehensive geochemical models of the chemical reactions between aqueous species and the host of minerals present. The most common type of geochemical model used to study sandstone acidizing is the local equilibrium model, such as described by Walsh *et al.* (1982) and Faber *et al.* (1994). This type of model assumes that all reactions are in local equilibrium; i.e., all reaction rates are infinitely fast. A typical result from this model is shown in Fig. 16-2, a time-distance diagram for the injection of 11% HCl–4% HF into a formation containing calcite, kaolinite and quartz. This plot shows regions where amorphous silica and aluminum fluoride will tend to precipitate. A vertical line on the plot represents the mineral species present as a function of distance if all reactions are in local equilibrium. By coupling this model with a model of the formation permeability response to both dissolution and precipitation, predictions of the productivity improvement expected from particular acid formulations may be obtained, as illustrated in Fig. 16-3 (Faber *et al.*, 1994).

Recently, Sevoulian *et al.* (1992) and Quinn (1994) presented a geochemical model that includes kinetics for both dissolution and precipitation reactions (see Sidebar 16C). This model predicts less permeability

damage than a local equilibrium model because the finite rate of the reactions allows displacing the precipitate farther from the wellbore.

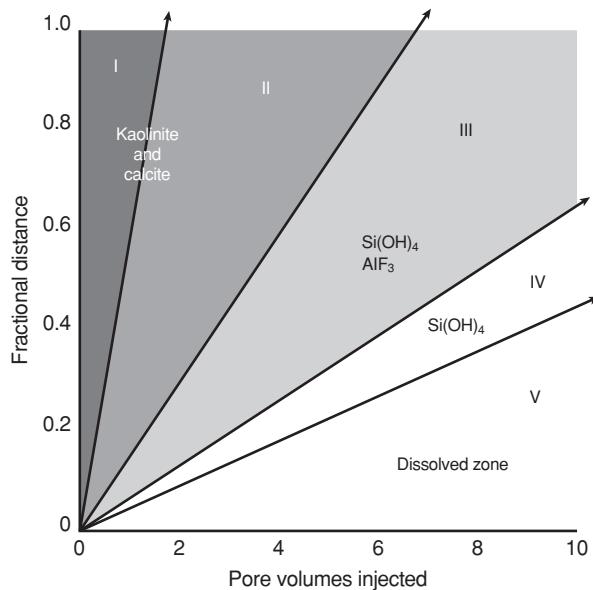
### 16C. Geochemical model predictions

An example presented by Quinn (1994) illustrates how acid formulation can be evaluated with a comprehensive geochemical model. A high-quartz-content sandstone will be acidized with 100 gal/ft<sup>3</sup> of 12% HCl–3% HF solution (commonly referred to as full-strength mud acid). The mineralogy is illustrated in Fig. 16C-1. The region to be studied includes a damaged zone extending 6 in. beyond the wellbore.

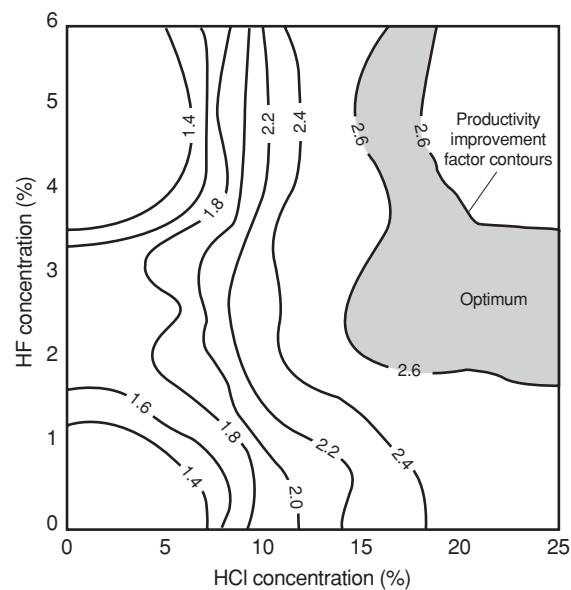


**Figure 16C-1.**  
A representative  
sandstone used in  
acidizing simulation.

The geochemical model predicts the distribution of acid and minerals after injection of the acid, as shown in Fig. 16C-2. All the HF is consumed near the wellbore; some precipitation occurs, but the amorphous silica precipitation occurs beyond the damage zone, where its effect is small. From these results, the porosity distribution around the wellbore is determined. Then, a model of the permeability response generates a prediction of the productivity improvement expected for this treatment.



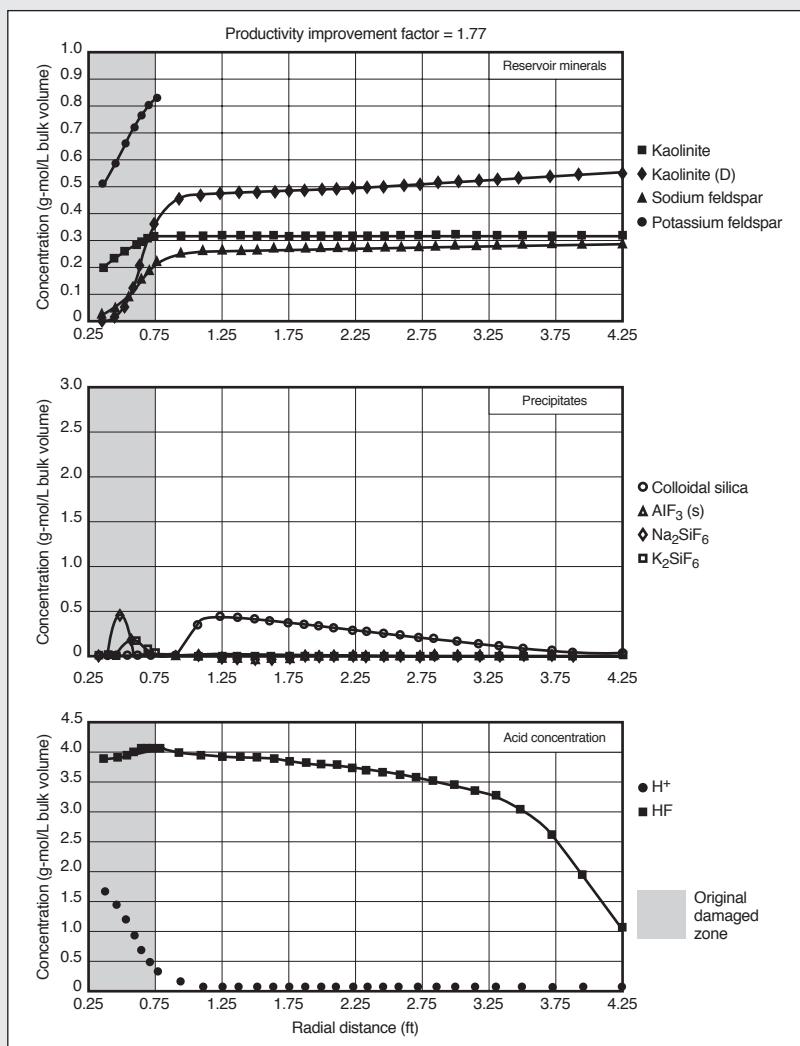
**Figure 16-2.** Time-distance diagram showing regions of possible precipitation (Schechter, 1992).



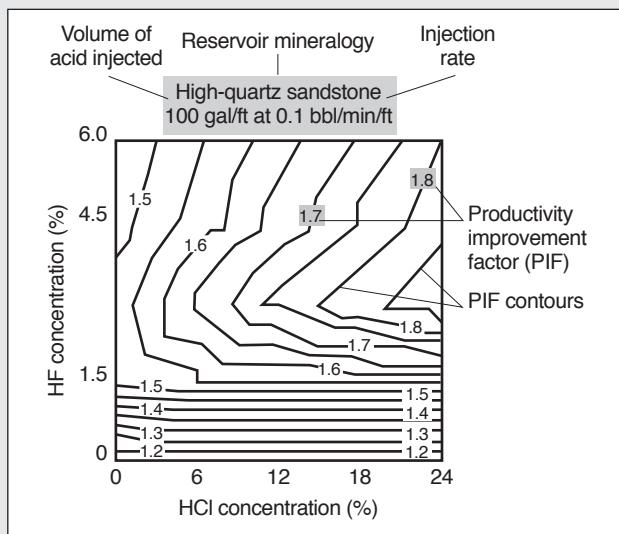
**Figure 16-3.** Productivity improvement plot (Faber et al., 1994).

## 16C. Geochemical model predictions (continued)

By repeating this modeling procedure for many different acid concentrations, the optimal acid formulation can be determined (Fig. 16C-3). For this formation, 3% HF and high HCl concentrations are optimal.



**Figure 16-C-2.** Partial local equilibrium assumption (PLEA) model mineral profile of a high-quartz sandstone after acidization with 100 gal/ft of 12% HCl-3% HF injected at 0.1 bbl/min/ft at 125°F [50°C].



**Figure 16C-3.** Productivity improvement plot.

## 16-3. Sandstone acidizing

### 16-3.1. Introduction

A typical acid treatment in sandstones consists of the injection of an HCl preflush, with 50 gal/ft of formation a common preflush volume, followed by the injection of 50 to 200 gal/ft of HCl-HF mixture. A postflush of diesel, brine or HCl then displaces the HCl-HF from the tubing or wellbore. Once the treatment is completed, the spent acid should be immediately produced back to minimize damage by the precipitation of reaction products.

A sandstone acidizing treatment design begins with the selection of the type and concentration of acid to be used. The volumes of preflush, HCl-HF mixture and postflush required and the desired injection rate(s) are considered next. In virtually all acid treatments, the placement of the acid is an important issue—a strategy to ensure that sufficient volumes of acid contact all productive parts of the formation should be carefully planned. Proper execution of the treatment is critical to acidizing success, so the conduct of the treatment, including the mechanical arrangements for introducing the acid to the formation and the methods of treatment monitoring, should be planned in detail. Finally, numerous additives are incorporated with acid solutions for various purposes. The types and amounts of additives to be used in the treatment must be determined on the basis of the completion, formation and reservoir fluids. These design factors are considered in detail in other chapters: acid selection in Chapters 13 and 18, treatment design (rate and volume) in Chapter 18, fluid placement and diversion in Chapter 19, treatment monitoring and evaluation in Chapter 20 and acid additives in Chapter 15. This section presents models of the sandstone acidizing process that provide a foundation for the design methods used for field application.

### 16-3.2. Acid selection

The type and strength (i.e., concentration) of acid used in sandstones are selected primarily on the basis of field experience with particular formations. For years, the standard sandstone acidizing formulation consisted of a 12% HCl–3% HF mixture, preceded by a 15% HCl preflush. In fact, the 12% HCl–3% HF mixture has been so common that it is referred to generically as mud acid. In recent years, however, the trend has been toward the use of lower strength HF solutions (Brannon *et al.*, 1987).

The benefits of lower concentration HF solutions are a reduction in damaging precipitates from the spent acid and lessened risk of unconsolidation of the formation around the wellbore. The selection of acidizing fluids should always begin with an assessment of the formation damage present—in general, the damaging material must be soluble in the treating fluids. Geochemical models can be used to guide acid selection, once the composition of the damaged formation is determined, as described in Section 16-2.3. Chapters 17 and 18 provide a comprehensive treatment of acid selection for sandstone and carbonate reservoirs, respectively.

### 16-3.3. Sandstone acidizing models

#### ■ Two-mineral model

Numerous efforts have been made over the years to develop a comprehensive model of the sandstone acidizing process that could then be used as a design aid. The most common model in use today is the two-mineral model (Hill *et al.*, 1977; Hekim *et al.*, 1982; Taha *et al.*, 1989) that divides all minerals into two categories—fast-reacting and slow-reacting species. Schechter (1992) categorizes feldspars, authigenic clays and amorphous silica as fast reacting, and detrital clay particles and quartz grains are the primary slow-reacting minerals. The model consists of material balances applied to the HF acid and reactive minerals, which for linear flow, such as in a coreflood, are

$$\frac{\delta(\phi C_{HF})}{\delta t} + u \frac{\delta C_{HF}}{\delta x} = -\{S_F^* V_F E_{f,F} + S_S^* V_S E_{f,S}\}(1-\phi)C_{HF} \quad (16-12)$$

$$\frac{\delta}{\delta t}[(1-\phi)V_F] = \frac{-MW_{HF}S_F^*V_F\beta_F E_{f,F}C_{HF}}{\rho_F} \quad (16-13)$$

$$\frac{\delta}{\delta t}[(1-\phi)V_S] = \frac{-MW_{HF}S_S^*V_S\beta_S E_{f,S}C_{HF}}{\rho_S}. \quad (16-14)$$

In these equations,  $C_{HF}$  is the concentration of HF in solution and  $MW_{HF}$  is its molecular weight,  $u$  is the acid flux,  $s$  is the distance,  $S_F^*$  and  $S_S^*$  are the specific surface areas per unit volume of solids,  $V_F$  and  $V_S$  are the volume fractions,  $E_{f,F}$  and  $E_{f,S}$  are the reaction rate constants (based on the rate of consumption of HF),  $MW_F$  and  $MW_S$  are the molecular weights,  $\beta_F$  and

$\beta_S$  are the dissolving powers of 100% HF, and  $\rho_F$  and  $\rho_S$  are the densities of the fast- and slow-reacting minerals, respectively, denoted by the subscripts  $F$  and  $S$ . When made dimensionless, assuming porosity remains constant, these equations become

$$\frac{\delta\psi}{\delta\theta} + \frac{\delta\psi}{\delta\varepsilon} + \{Da^{(F)}\Lambda_F + Da^{(S)}\Lambda_S\}\psi = 0 \quad (16-15)$$

$$\frac{\delta\Lambda_F}{\delta\theta} = -Da^{(F)}A_c^{(F)}\psi\Lambda_F \quad (16-16)$$

$$\frac{\delta\Lambda_S}{\delta\theta} = -Da^{(S)}A_c^{(S)}\psi\Lambda_S, \quad (16-17)$$

where the dimensionless variables are defined as

$$\psi = \frac{C_{HF}}{C_{HF}^o} \quad (16-18)$$

$$\Lambda_F = \frac{V_F}{V_F^o} \quad (16-19)$$

$$\Lambda_S = \frac{V_S}{V_S^o} \quad (16-20)$$

$$\varepsilon = \frac{x}{L} \quad (16-21)$$

$$\theta = \frac{ut}{\phi_o L}, \quad (16-22)$$

where  $\psi$  is the dimensionless HF concentration,  $\Lambda$  is the dimensionless mineral composition,  $\varepsilon$  is dimensionless distance,  $\theta$  is dimensionless time (pore volumes), and  $\phi$  is the porosity. The superscript  $o$  denotes initial values prior to acid treatment. For a coreflood,  $L$  is the core length. In Eqs. 16-15 through 16-17, two dimensionless groups appear for each mineral: the Damköhler number  $Da$  and the acid capacity number  $A_c$ . These two groups describe the kinetics and the stoichiometry of the HF-mineral reactions. The Damköhler number is the ratio of the rate of acid consumption to the rate of acid convection, which for the fast-reacting mineral is

$$Da^{(F)} = \frac{(1-\phi_o)V_F^o E_f^{(F)} S_F^* L}{u}. \quad (16-23)$$

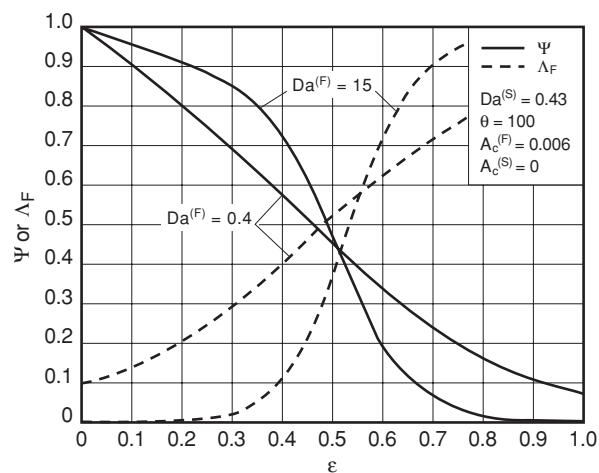
The acid capacity number is the ratio of the amount of mineral dissolved by the acid occupying a unit

volume of rock pore space to the amount of mineral present in the unit volume of rock, which for the fast-reacting mineral is

$$A_c^{(F)} = \frac{\phi_o \beta_F C_{HF}^o M W_{HF}}{(1-\phi_o) V_F^o \rho_F}. \quad (16-24)$$

The Damköhler and acid capacity numbers for the slow-reacting minerals are similarly defined.

As acid is injected into a sandstone, a reaction front is established by the reaction between the HF and the fast-reacting minerals. The shape of this front depends on  $Da^{(F)}$ . For low values of  $Da$ , the convection rate is high relative to the reaction rate and the front is diffuse. With a high  $Da$ , the reaction front is relatively sharp because the reaction rate is high compared with the convection rate. Figure 16-4 (da Motta *et al.*, 1992a) shows typical concentration profiles for high and low values of  $Da^{(F)}$ .



**Figure 16-4.** Acid and fast-reacting mineral concentration profiles (da Motta *et al.*, 1992a).

Equations 16-15 through 16-17 can be solved only numerically in their general form. Numerical models providing solutions to these equations, such as that presented by Taha *et al.* (1989), are frequently used for acidizing design. However, analytical solutions are possible for certain simplified situations. Schechter (1992) presented an approximate solution that is valid for relatively a high  $Da$  ( $Da^{(F)} > 10$ ). This solution approximates the HF/fast-reacting-mineral front as a sharp front, behind which all the fast-reacting minerals have been removed. Conversely, ahead of

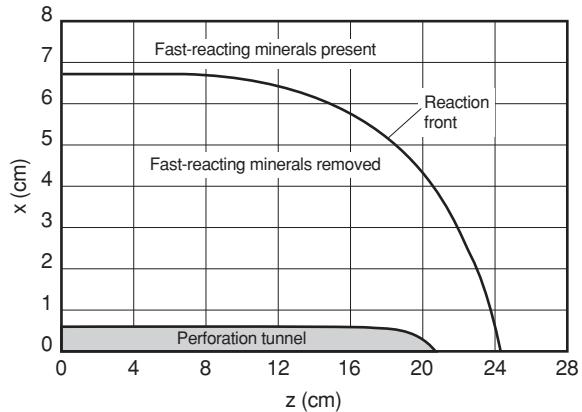
the front, no dissolution has occurred. The reaction between slow-reacting minerals and HF behind the front serves to diminish the HF concentration reaching the front. The location of the front is

$$\theta = \frac{\exp(Da^{(S)}\varepsilon_f) - 1}{A_c^{(F)} Da^{(S)}} + \varepsilon_f, \quad (16-25)$$

which relates dimensionless time (or equivalently acid volume) to the dimensionless position of the front  $\varepsilon_f$ , defined as the position of the front divided by the core length for linear flow. The dimensionless acid concentration behind the front is

$$\psi = \exp(-Da^{(S)}\varepsilon). \quad (16-26)$$

A particularly convenient feature of this approximation is that it is applicable to linear, radial and ellipsoidal flow fields with the appropriate definition of dimensionless variables and groups. Radial flow represents the flow of acid from an openhole, gravel-pack or slotted liner completion and may also be a reasonable approximation of the flow from a perforated well with sufficient perforation density. The ellipsoidal flow geometry approximates the flow around a perforation (Fig. 16-5). The proper dimensionless variables and groups for these three flow fields are given in Table 16-6. For the perforation geometry, the position of the front  $\varepsilon_f$  depends on position along the perforation. In Table 16-6, expressions are given for the front position of the acid extending directly from the tip of the perforation and



**Figure 16-5.** Ellipsoidal flow around a perforation (Schechter, 1992).

for acid penetration along the wellbore wall. These two positions should be sufficient for design purposes; the reader is referred to Schechter (1992) for methods to calculate the complete acid penetration profile in this geometry (see Sidebar 16D).

The characteristic lengths referred to in Table 16-6 are the length of a core  $L$ , wellbore radius  $r_w$  and length of the perforation  $l_p$ . Different measures of acid flow are used in which  $u$  is the linear flux in a core,  $q_i/h$  is the volumetric rate of acid injection per foot into an openhole, and  $q_{perf}$  is the volume of acid per time entering a perforation. The definition of  $Da$  must correspond to the geometry considered, but  $\psi$ ,  $\Lambda_F$  and  $A_c^{(F)}$  as defined by Eqs. 16-18, 16-19 and 16-24, respectively, apply to all geometries.

**Table 16-6. Dimensionless groups in sandstone acidizing models.**

Flow geometry	$\varepsilon$	$\theta$	$Da^{(S)}$
Linear	$\frac{x}{L}$	$\frac{ut}{\phi_o L}$	$\frac{(1-\phi_o)V_s^o E_f^{(S)} S_s^* L}{u}$
Radial	$\frac{r^2}{r_w^2} - 1$	$\frac{q_i t}{\pi r_w^2 h \phi_o}$	$\frac{(1-\phi_o)V_s^o E_f^{(S)} S_s^* \pi r_w^2 h}{q_i}$
Ellipsoidal Penetration from the tip of the perforation			
	$\frac{1}{3}\bar{z}^3 - \bar{z} + \frac{2}{3}; \bar{z} = \frac{z}{l_p}$	$\frac{q_{perf} t}{2\pi l_p^3 \phi_o}$	$\frac{2\pi(1-\phi_o)l_p^3 S_s^* V_s^o E_f^{(S)}}{q_{perf}}$
Penetration adjacent to the wellbore	$\frac{1}{3}\left(\bar{x} + \frac{1}{\bar{x} + \sqrt{\bar{x}^2 + 1}}\right)^3 - \frac{1}{3}; \bar{x} = \frac{x}{l_p}$		

## 16D. Comparison of acid volumes for radial and perforation flow

The amount of acid required to remove damage beyond the tip of a perforation is typically larger than the amount required to remove damage to the same distance in radial flow. This is illustrated by using Schechter's (1992) model to find the volume of acid required to penetrate a given distance for these two geometries.

Consider a formation with 20% porosity containing 10% fast-reacting minerals (feldspar, clay or both), 5% calcium carbonate and 85% quartz. A damage region extends 6 in. into the formation (a radial region or 6 in. beyond the tip of a perforation), and the initial skin effect resulting from the damage is 10. The wellbore radius is 0.328 ft. In the perforated well case, there are 4 shots per foot (spf) and the perforations are 6 in. long with a diameter at the wellbore of 0.5 in. A 12% HCl–3% HF solution is injected at 0.1 bbl/min/ft after the injection of sufficient preflush of 15% HCl to remove the carbonates from the region to be contacted with live HF. Determine the acid volume required as a function of the penetration distance of the acid and the skin effect evolution for radial and perforation geometries. The downhole treating temperature is 125°F [50°C]. For these conditions, the Damköhler number  $Da$  for the slow-reacting mineral in radial flow is 0.013.

### Solution

Equation 16-25 can be used with the appropriate definitions of the dimensionless variables and groups for the two geometries from Table 16-6. The acid capacity number  $A_c$  is the same for either geometry; the ratio of the Damköhler numbers is

$$\frac{Da_{perf}}{Da_{rad}} = \frac{21^3_{perf} (SPF)}{r_w^2} = \frac{(2)\left(\frac{6}{12}\right)^3 4}{(0.328)^2} = 93, \quad (16D-1)$$

where  $SPF$  is the perforation density in spf.  $Da$  for the slow-mineral reaction is calculated as 0.12 for perforation flow.  $A_c$  for the fast-mineral reaction is 0.021. (The values of  $Da$  and  $A_c$  used in this example were obtained from laboratory core-flood tests as described by Economides *et al.*, 1994).

Using these values in Eq. 16-25 for acid penetration ranging from 0 to 6 in. obtains the results shown in Figs. 16D-1 and 16D-2. For acid penetrations beyond 2 in., more acid is required for the perforation geometry than for radial flow. The skin effect evolution reflects the larger volumes of acid required to penetrate through the damaged region for the perforation geometry compared with the radial geometry.

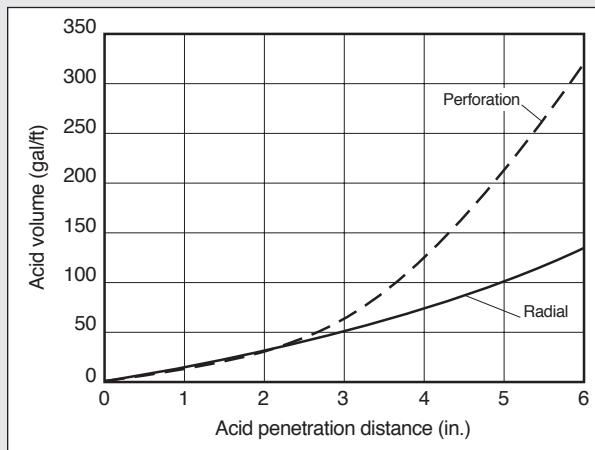


Figure 16D-1. Acid penetration for radial and perforation flow.

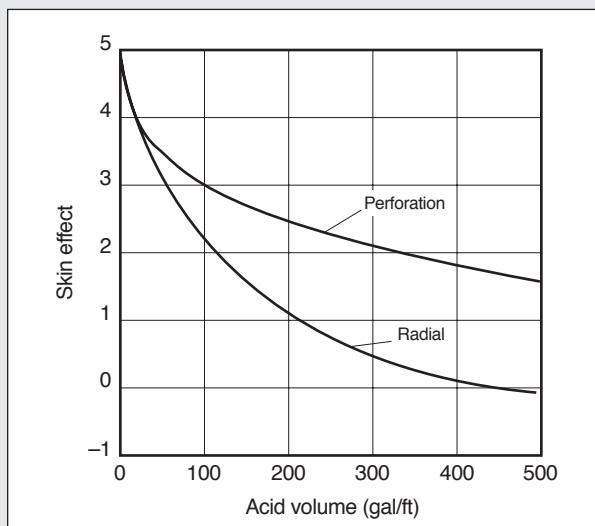


Figure 16D-2. Reduction in skin effect value for radial and perforation flow.

It is interesting to note that the slow-reacting mineral  $Da$  and the fast-reacting mineral  $A_c$  are the only dimensionless groups that appear in this solution.  $Da^{(S)}$  regulates how much live HF reaches the front; if the slow mineral reacts fast relative to the convection rate, little acid is available to propagate the fast-mineral front.  $A_c$  for the slow-reacting mineral is not important because the supply of slow-reacting mineral is almost constant behind the front.  $A_c^{(F)}$  directly affects the frontal propagation rate—the more fast-reacting mineral present, the slower the front will move.  $Da^{(F)}$  does not appear because a sharp front is assumed, implying that  $Da^{(F)}$

is infinite. This solution can be used to estimate the volume of acid required to remove the fast-reacting minerals from a given region around a wellbore or perforation.

The dimensionless groups  $Da^{(S)}$  and  $A_c^{(F)}$  can be calculated with Eqs. 16-23 and 16-24, respectively, and Table 16-6 on the basis of the rock mineralogy or can be obtained from experiments.

### ■ Two-acid, three-mineral model

Recently, Bryant (1991) and da Motta *et al.* (1992b) presented evidence that the sandstone acidizing process is not well described by the two-mineral model,

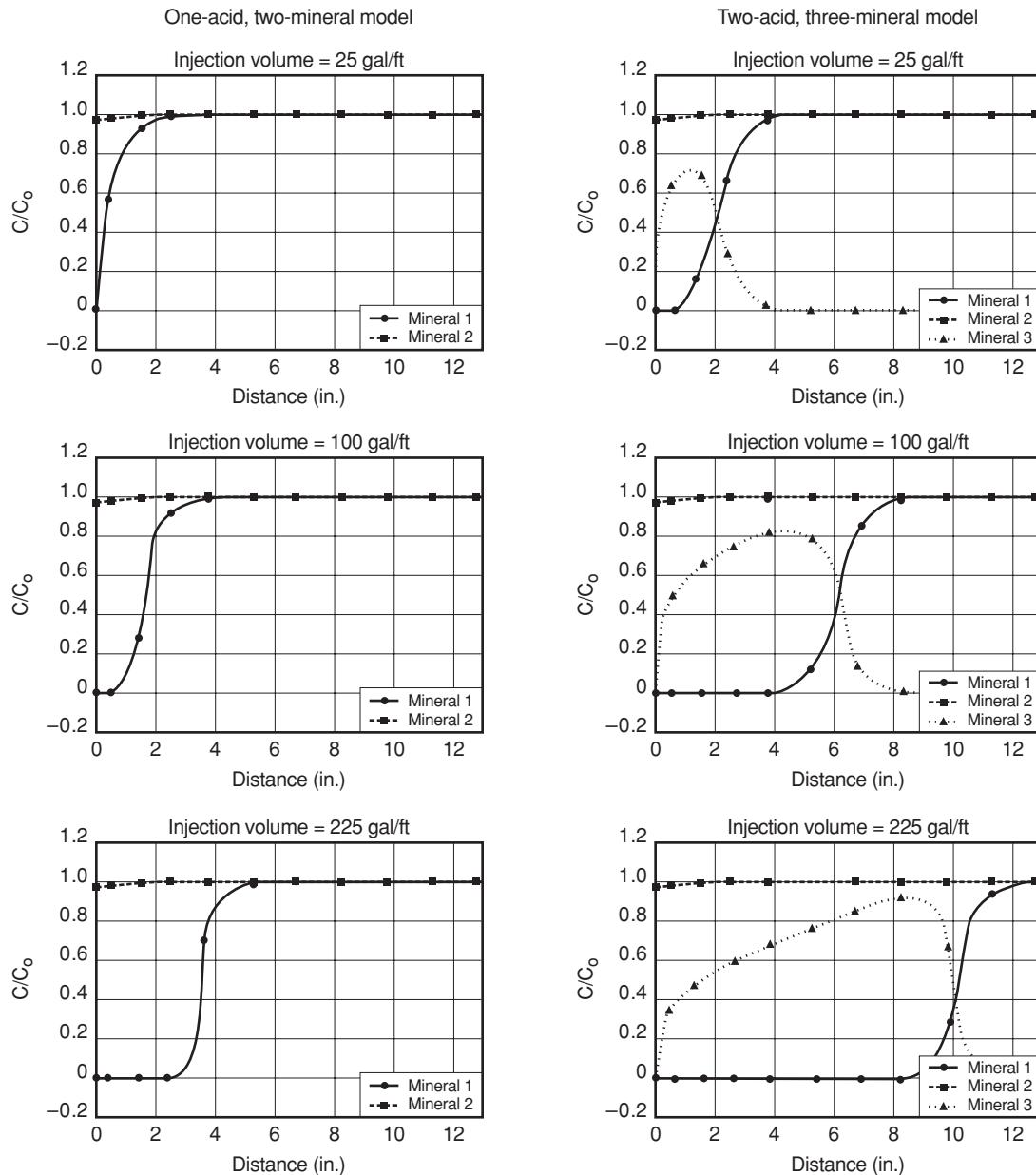
particularly at elevated temperatures. These studies suggest that the reaction of fluosilicic acid with aluminosilicate (fast-reacting) minerals may be significant. Thus, an additional acid and mineral must be considered to accommodate the following reaction, which is added to the two-mineral model:



The practical implications of the significance of this reaction are that less HF is required to consume the fast-

reacting minerals with a given volume of acid because the fluosilicic acid also reacts with these minerals and the reaction product of silica gel ( $\text{Si(OH)}_4$ ) precipitates. This reaction allows live HF to penetrate farther into the formation; however, there is an added risk of a possibly damaging precipitate forming.

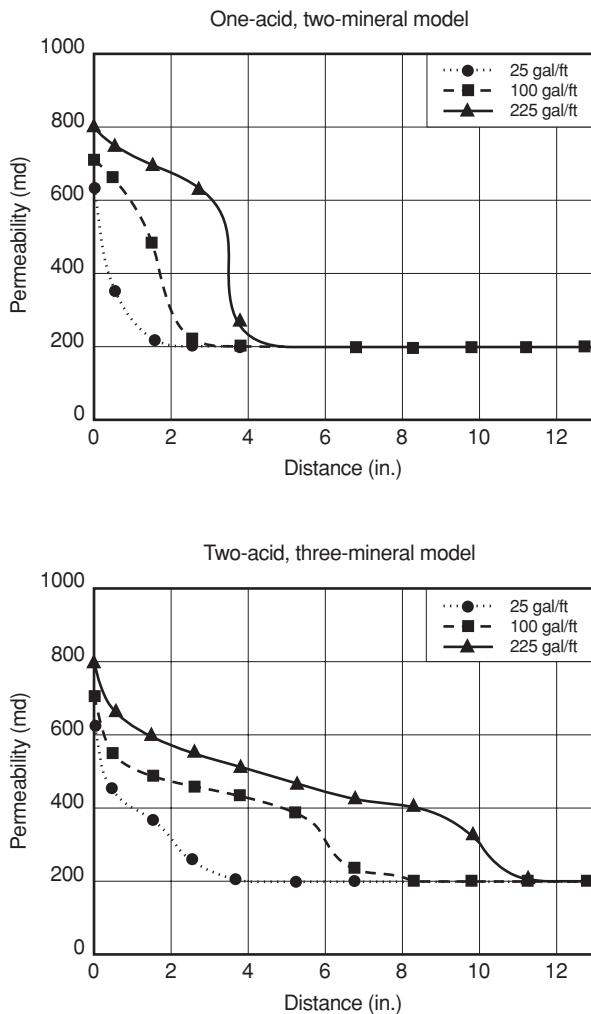
Sumotarto (1995) presented an example that illustrates the improved performance predicted with the two-acid, three-mineral model compared with the one-acid, two-mineral model. Figure 16-6 compares the mineral concentration profiles predicted by these two



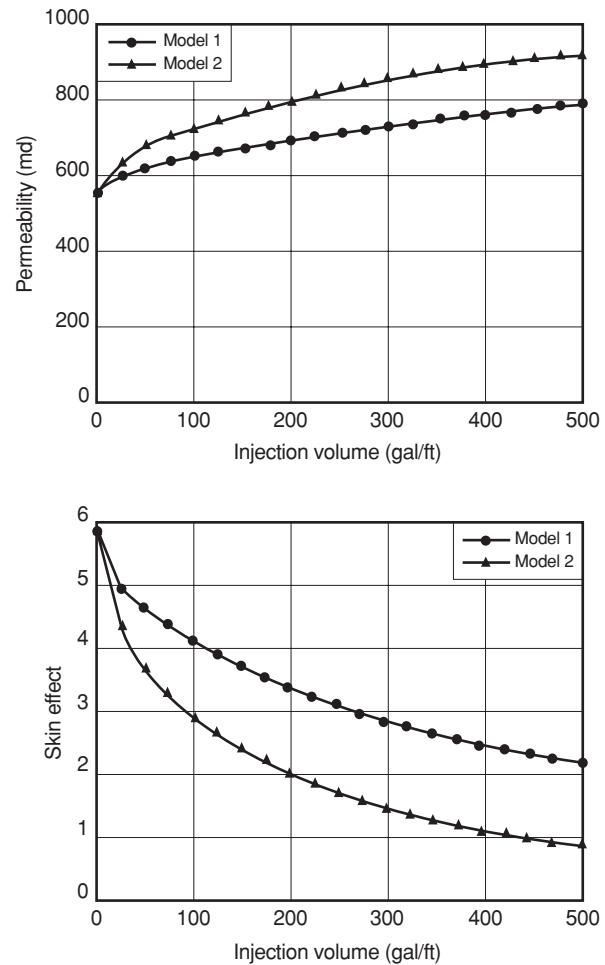
**Figure 16-6.** Dimensionless mineral concentrations at various injection volumes.

models for the injection of 12% HCl–3% HF into a damaged formation composed initially of 17% clays and feldspars (fast reacting) and 83% quartz (slow reacting). In this figure, mineral 1 is clay and feldspar, mineral 2 is quartz, and mineral 3 is silica gel. After 100 gal/ft<sup>3</sup> of injection, the feldspars and clays have been dissolved in a region extending about 6 in. beyond the wellbore according to the two-acid, three-mineral model, whereas only 2 in. of dissolution is predicted by the one-acid, two-mineral model. In addition, a significant zone of silica

precipitation is predicted by the two-acid, three-mineral model. Using a model of the permeability response to both mineral dissolution and precipitation, the permeability and skin effect response are predicted for each model and compared in Figs. 16-7 and 16-8. Although some precipitation is indicated by the two-acid, three-mineral model, improved performance because of the fluosilicic acid reactions is predicted compared with the one-acid, two-mineral model.



**Figure 16-7.** Permeability at various injection volumes.



**Figure 16-8.** Top: Average permeability versus injection volume obtained from running the simulator with models 1 (one-acid, two-mineral model) and 2 (two-acid, three-mineral model). Bottom: Skin effect calculated using models 1 and 2 as a function of injection volume (time).

### 16-3.4. Permeability response

To predict the response of a formation to acidizing, it is necessary to predict the change in permeability as acid dissolves some of the formation minerals and other minerals precipitate. The permeability change as a result of acidizing is an extremely complicated process because it is affected by several different, sometimes competing phenomena in the porous media. The permeability increases as the pores and pore throats are enlarged by mineral dissolution. At the same time, small particles are released as cementing material is dissolved, and some of these particles lodge (perhaps temporarily) in pore throats, reducing the permeability. Any precipitates formed also tend to decrease the permeability. The formation of carbon dioxide ( $\text{CO}_2$ ) as carbonate minerals are dissolved may also cause a temporary reduction in the relative permeability to liquids. The result of these competing effects is that the permeability in corefloods usually decreases initially; with continued acid injection, the permeability eventually increases to values significantly higher than the original permeability.

The complex nature of the permeability response has made its theoretical prediction for real sandstones impractical, though some success has been achieved for more ideal systems such as sintered disks (Guin *et al.*, 1971). As a result, empirical correlations relating the permeability increase to the porosity change during acidizing are used. The most common correlations are those of Labrid (1975), Lund and Fogler (1976) and Lambert (1981). The Labrid correlation is

$$\frac{k}{k_o} = M \left( \frac{\phi}{\phi_o} \right)^n, \quad (16-27)$$

where  $k_o$  and  $\phi_o$  are the initial permeability and porosity and  $k$  and  $\phi$  are the permeability and porosity after acidizing, respectively.  $M$  and  $n$  are empirical constants, reported to be 1 and 3, respectively, for Fontainebleau sandstone.

The Lund and Fogler correlation is

$$\frac{k}{k_o} = \exp \left[ M \left( \frac{\phi - \phi_o}{\Delta\phi_{max}} \right) \right], \quad (16-28)$$

where  $M = 7.5$  and the difference in maximum porosity is  $\Delta\phi_{max} = 0.08$  from best-fit data for Phacoides sandstone.

The Lambert correlation is

$$\frac{k}{k_o} = \exp [45.7(\phi - \phi_o)]. \quad (16-29)$$

The Lambert expression is identical to that of Lund and Fogler when  $M/\Delta\phi_{max} = 45.7$ .

Using the values of the constants suggested, the Labrid correlation predicts the smallest permeability increase, followed by the Lambert and then the Lund and Fogler correlations. The best approach in using these correlations is to select the empirical constants on the basis of coreflood responses, if available. If data are lacking for a particular formation, the Labrid equation will yield the most conservative design.

## 16-4. Carbonate acidizing

### 16-4.1. Distinctive features

In this chapter, sandstone acidizing is distinguished from carbonate acidizing although sedimentary rocks exhibit a spectrum of compositions ranging from almost pure calcite or dolomite to very clean sands. The fundamental distinguishing feature is the HCl-soluble fraction. If the HCl solubility of a rock is less than 20%, a sandstone treatment using an HCl-HF mixture (for a discussion of such rules of thumb, see McLeod, 1984) would most likely be applied. Formations composed largely of calcite or dolomite, including chalks and marls, are largely soluble in HCl and are candidates for carbonate acidizing using HCl without HF.

Carbonate acidizing with HCl is not complicated by a tendency for precipitates to form, as is the case for sandstone acidization. As shown by the typical reactions in Table 16-1, the reaction products  $\text{CO}_2$  and  $\text{CaCl}_2$  are both quite water soluble (for a discussion of their solubilities, see Shaughnessy and Kunze, 1981; Schechter, 1992). Therefore, the formation of a precipitate or a separate  $\text{CO}_2$ -rich phase is generally not a problem. Even if  $\text{CaCl}_2$  precipitates or a  $\text{CO}_2$  phase separates, these phases are readily dissolved when oil (or gas) and water production is resumed. Despite the simplified chemistry, HCl acidizing is a difficult process to model. The origin of the difficulty is the rate at which the reactions take place as compared with those of HF with the various minerals prevalent in sandstones. Reaction rates are discussed in Section 16-2.2, and it is instructive to compare some of them. HCl reactions with carbonates are orders of magnitude faster than HF reactions with sand (quartz), clays, etc.

Because of the high reaction rate, HCl tends to etch preferred pathways in carbonate rocks, apparently following local high-permeability streaks (Wang, 1993), rather than progressing through the formation as a uniform front, as is the case in sandstone acidizing. These pathways are soon enlarged by acid reaction at the walls

into sizable holes that have a diameter much larger than that of naturally occurring pores. The process continues until a few large holes become so dominant that essentially all the injected acid flows through these pathways, both enlarging and extending them.

It is this tendency for macroscopic pathways to form that makes HCl acidizing difficult to model. Because the holes that form are large, they become the most important feature of the process. To model carbonate acidizing, the formation of these holes must be taken into account. In fact, it is believed that the success of acid stimulation of carbonate formations is due to the formation of these preferred flow paths extending outward from the wellbore or perforation. If the pathways extend through the damaged zone, the produced fluids can flow into the wellbore through these flow paths with relatively little pressure drop because the holes are much larger than the natural pores.

Thus, the fundamental physics of carbonate acidizing is embodied in three topics discussed in this section. The first concern is the characterization of the holes or flow paths created by the acid. Second, the conditions under which they form must be defined. And third, the rate at which they are extended is an issue of considerable practical significance.

#### 16-4.2. Wormholes

It is not known who first described the acid-etched pathway as a “wormhole,” but this appellation is commonly accepted by those familiar with the complex etch pattern produced by acidizing carbonate cores in the laboratory. Perhaps it was A. R. Hendrickson of Dowell. Figure 16-9 shows that the terminology is apt. This is a photograph of a metal casting of a wormhole created by forcing molten metal into a wormhole, allowing the metal to solidify and then dissolving the remaining rock with HCl. The casting illustrates the complex morphology of the etch pattern. This is typical of many castings, which have been produced under a variety of experimental conditions. The chaotic nature of the pattern seemingly discourages any attempt to characterize its structure. However, it has been suggested that there is an underlying regularity that may be useful for modeling.

Daccord and Lenormand (1987) considered the characterization of a wormhole in terms of its fractal dimen-



**Figure 16-9.** Wormholes created by acid dissolution of limestone (Hoefner and Fogler, 1988; reproduced with permission of the American Institute of Chemical Engineers. Copyright 1998 AIChE. All rights reserved.).

sion. A fractal is a self-similar geometric pattern. This implies that under increasing magnification the same pattern will continue to reappear. Thus, according to this notion the structure of a large wormhole is repeated with branches from the main trunk that are smaller replicas of the larger one. This replication is repeated as the magnification is increased until the pores of the native rock come into view. These do not resemble acid etch patterns because they were created by different processes. The discovery by Daccord and Lenormand that wormholes are fractals is a significant contribution.

One manifestation of the repeating, or self-similar, character is that the perimeter or the length of a wormhole increases as the degree of magnification used in its measurement increases. This is because at higher magnification, more of the detailed structure becomes evident and is, therefore, susceptible to measurement. For self-similar systems, the length of a wormhole plotted against the length of a ruler used to measure the length is a straight line on a log-log plot. The slope of this line is related to the fractal dimension. In the case of wormholes, Daccord and Lenormand reported that the fractal dimension is 1.6. This implies that the length of a wormhole is proportional to  $L^{1.6}$  rather than  $L$ , where  $L$  is the macroscopic length. Daccord *et al.* (1989) utilized this fractal dimension in developing a field design method for carbonate acidizing. In their approach, the complexity of the wormhole is portrayed by its fractal dimension. This is only a partial characterization, because it is not possible to describe the minute details of wormhole geometry.

Although a precise description of a wormhole is not attainable, it is desirable to have a model that provides guidance in determining the best treatment parameters. What should be the injection rate? Should the injection rate be constant during the entire course of the treatment? What acid type and concentration are best? What additives should be included in the acidic solution? These questions relate to controllable variables and, therefore, must be addressed each time an acid treatment is designed. Rather than depending solely on past experience, some theoretical help is welcome for developing the best strategy possible based on the information available.

The problem is approached in the following sections by addressing two separate issues, both of which are relevant to the questions posed. The first concerns the conditions requisite for the initiation of wormholes, and the second deals with their growth or propagation. Both of these studies provide information required for the design of carbonate acid treatments. The Appendix to this chapter discusses advances in understanding and predicting wormhole formation.

#### 16-4.3. Initiation of wormholes

The fractal, or self-similar, topology of a wormhole structure implies that the mechanism for the initiation of wormholes is a “local” phenomenon that occurs continuously along its bounding surfaces as well as at its tip. Thus, tiny wormholes may be initiated whenever live acid enters the pores of the virgin rock irrespective

of the etch pattern already in existence. Experiments have shown that in cases where the acid flux entering the matrix is quite small, wormhole initiation is not prolific, thereby indicating a flow-rate dependence of the initiation process. The proof of this assertion is based primarily on metal casts of wormholes, such as that shown by Fig. 16-9. However, adopting the notion of a flow-rate-dependent initiation process allows interpreting the results of laboratory acidizing experiments and understanding the origin of the fractals. Furthermore, this approach leads to prediction of the optimum injection rate in linear core experiments that has been experimentally observed. Thus, the analysis presented here represents a foundation upon which the design of acid treatments can be based, but further work is required to achieve the desired goal, namely, the ability to predict the stimulation resulting from an acid treatment given the essential parameters of acid composition, injection rate, formation temperature and rock properties.

The initiation of wormholes occurs when live acid penetrates into pores present in the native rock. These pores are distributed in size and shape; therefore, the amount of acid flowing through each of the pores differs. The rate at which a given pore is enlarged by the acid depends, of course, on the amount of acid entering that pore and the fraction of the acid reacted at the walls of the pore before the acid exits and then enters other pores located downstream. Thus, even at the pore level, the processes that contribute to the creation of an etch pattern are complex, involving convection, diffusion and chemical reactions within each of the invaded pores. It has not been proved practical to consider these processes in a single pore and then attempt to consider the collective behavior to derive a macroscopic etch pattern. Schechter and Gidley (1969) used this approach, but to make progress using their results requires knowing in advance the entire distribution of pore sizes, permeability and porosity of the native rock to be acidized. Even armed with this knowledge, which is seldom available, prediction of the etch pattern is not routine.

The prediction of wormhole initiation is, however, based on a result that emerged from considering the behavior of each pore in the medium. If a pore is represented as a cylindrical hole with a radius  $R$  and a length  $l$ , then the rate at which the pore cross-sectional area  $A$  increases as a result of acid reaction at the pore walls may, in general, be written in the form

$$\frac{dA}{dt} = \psi A^n, \quad (16-30)$$

where  $\psi$  is a function of the fluid velocity in the pore, reaction rate and other parameters that determine the rate at which rock is dissolved. The exponent  $n$  is also a function of the many parameters that contribute to  $\psi$ . The advantage of representing the rate of acid reaction within a pore in this form is that the stability of the enlargement process depends on the value of the exponent  $n$  (see Schechter, 1992). If  $n > 1$  for a certain few pores in the native rock, then these pores become larger faster than all the other pores that have growth characterized by exponents smaller than unity. This criterion for uncontrolled growth determines whether a wormhole is initiated. The growth of each individual pore is characterized by the value of the exponent  $n$ . Wormholes form whenever one or more of the pores grow at a rate determined by  $n > 1$ .

Thus, this criterion for wormhole initiation hinges on the value of the exponent  $n$ . To investigate the factors determining  $n$ , recall that the rate of acid reaction at a pore wall is given by the empirical expression

$$\text{reaction rate} = -E_f C_w^m. \quad (16-31)$$

The acid concentration  $C_w$  in this equation is the concentration near the solid/liquid interface. The acid that reacts at the pore surface must be replenished by acid diffusing from the bulk solution to the pore wall. If this diffusion rate is slow, the rate of pore area enlargement may be limited by diffusion. However, the native pores are generally small enough so that diffusion is relatively fast, and the average velocity within a pore  $\bar{v}$  is sufficient to maintain a rate of mass transfer to the surface so that the acid reaction at the wall is the controlling factor. The rate at which a pore is enlarged is, therefore, (see Schechter, 1992)

$$l \frac{dA}{dt} = \bar{v} A X C_0 \left[ 1 - \exp \left( - \frac{2\sqrt{\pi} E_f C_0^{m-1} l}{\sqrt{A} \bar{v}} \right) \right], \quad (16-32)$$

where  $l$  is the length of a pore defined as the distance the acid in a pore travels before mixing with acid emerging from other pores. The acid concentration  $C_0$  is the concentration at the pore entrance.

The average velocity in a pore  $\bar{v}$  depends on the local Darcy flux  $u$  and the pore cross-sectional area. The flow within a single pore is laminar, so that

$$\bar{v} = \frac{dp}{dt} \frac{A}{8\pi\mu} = \frac{uA}{8\pi k}, \quad (16-33)$$

where  $k$  is the permeability of the rock matrix.

Equation 16-32 looks formidable, but the goal is to reduce this expression to a form that reveals the exponent  $n$ . To accomplish this goal, two extreme conditions are considered. First, examine the limit

$$\frac{2\sqrt{\pi} E_f C_0^{m-1} l}{\sqrt{A} \bar{v}} \ll 1, \quad (16-34)$$

which implies that only a small fraction of the acid reacts within the pore. In this limit, which applies for large  $\bar{v}$ , the rate of pore enlargement reduces to

$$\frac{dA}{dt} \rightarrow 2\sqrt{\pi} E_f C_0^{m-1} X A^{1/2} = \Psi_1 A^{1/2}. \quad (16-35)$$

Thus, in this limit the exponent  $n$  is  $\frac{1}{2}$  ( $n < 1$ ) and pores with a cross-sectional area such that the inequality of Eq. 16-34 is satisfied do not form wormholes. The pores will enlarge rather uniformly, and the acid front will remain sharp, progressing through the porous matrix also rather uniformly. Not all pores, however, satisfy the inequality. A second limit for some of the pores may be possible. This second limit occurs when the pores are of such a size that the inequality of Eq. 16-34 is reversed, implying almost complete acid reaction within these pores. In this second limit, which applies for small  $\bar{v}$ , can be found

$$\frac{dA}{dt} \rightarrow \frac{\bar{v} X C_0}{8\pi l} A^2 = \Psi_2 A^2. \quad (16-36)$$

Thus, pore areas satisfying the second limit are unstable ( $n > 1$ ). They grow more rapidly than the neighboring pores. They become small wormholes and continue to evolve into the macroscopic etch patterns shown by the metal casts.

For a given reaction rate and acid flux, there are pores that are essentially too small to become wormholes and perhaps others that are of sufficient size to exhibit uncontrolled growth and eventually become macroscopic. Thus, for a given acid flux, the native pores may fall into two different categories: candidates for incipient wormhole formation and noncandidates. There is, therefore, a critical (or transitional) pore size  $A_T$  that may be estimated as the value where the two limiting growth rates become equal:

$$\Psi_1 A_T^{1/2} = \Psi_2 A_T^2. \quad (16-37)$$

Solving this expression for  $A_T$  yields

$$A_T \cong 20 D a^{2/3} (kl)^{2/3}, \quad (16-38)$$

where  $Da = E_f C_0^{m-1}/u$  and  $k$  is the formation permeability (Wang, 1993; Wang *et al.*, 1993). Thus, if all the pores in the native rock have cross-sectional areas less than  $A_T$ , wormhole initiation cannot occur until at least one of the pores has been enlarged by acid reaction to a size sufficient to allow wormhole development. The critical, or transitional, area depends on both the reaction rate and the acid flux. This condition has, as discussed subsequently in this chapter, considerable practical relevance.

The average length of a pore is a rather nebulous quantity that, on the basis of a number of laboratory experiments using two different limestones and a dolomite, appears to be about 0.1 mm. If we use this value, the criterion for the critical pore dimension becomes

$$A_T = 0.93[Da k]^{2/3}, \quad (16-39)$$

where both  $k$  and  $A_T$  must be expressed as  $\text{cm}^2$ .<sup>†</sup>

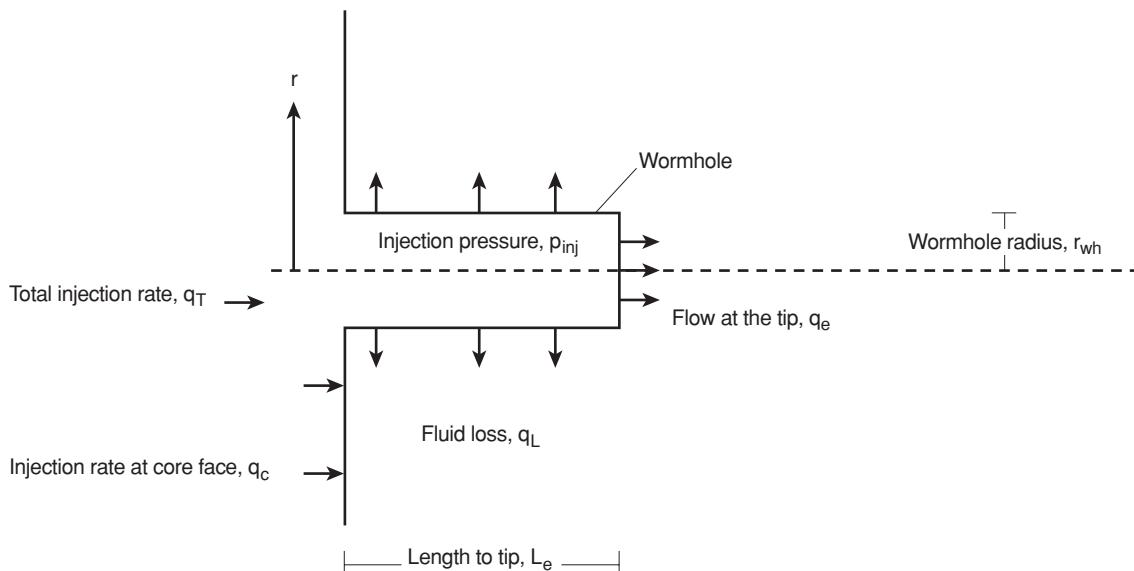
This equation is quite simple in appearance, but its implications are profound and these may be tested experimentally. Laboratory results that are seemingly counterintuitive may be satisfactorily explained by invoking the concept embodied by Eq. 16-39.

#### 16-4.4. Acidizing experiments

Essentially two different types of results are found on the basis of acidizing carbonate cores in the laboratory. One is the metal cast of a wormhole and the other is the pressure drop measured while acidizing at a constant injection rate. Both types of experiments have proved instructive. The transition area defined by Eq. 16-39 depends on the acid flux and reaction rate, which in turn is a function of the acid concentration, reaction temperature and rock composition. The acid flux is the easiest to control and is the most widely studied variable.

- Acid flux

The flow rate is expected to influence the acid etch pattern for reasons that may be best understood by considering the idealized depiction of a wormhole shown by Fig. 16-10. It is a cylinder with fluid loss about the perimeter as well as at the tip. Depending on the external pressure field surrounding the wormhole, the fluid-loss flux may vary from point to point about the surface of the cylinder. If the flux into the rock is small at some points,  $A_T$  as determined by Eq. 16-38 may exceed the cross-sectional area of all the native pores, and wormholes will not form at that



**Figure 16-10.** Single-wormhole model.

<sup>†</sup>Given a permeability in mD, multiply by  $9.869 \times 10^{-12}$  to obtain the dimensions in  $\text{cm}^2$

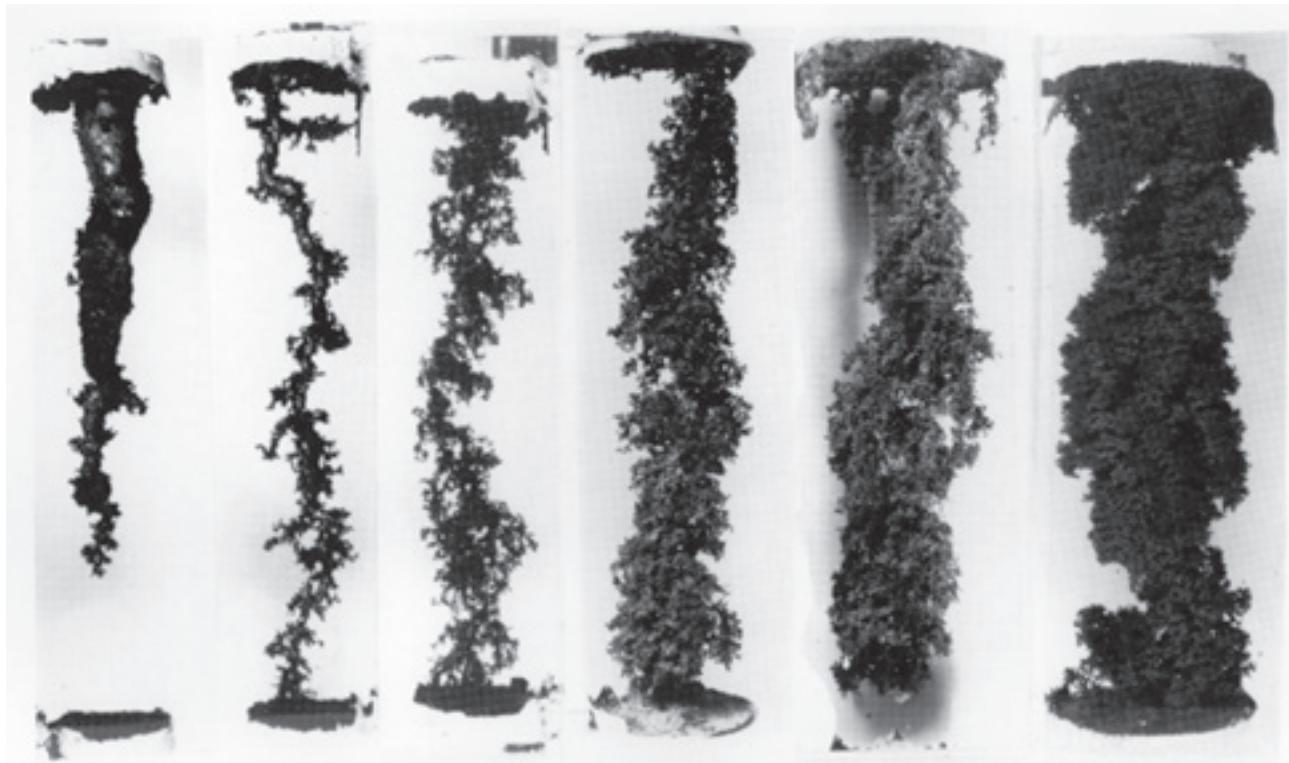
point. The walls of the wormhole will then be eroded in a generally uniform manner. If, however, the flux at the tip is large enough to initiate wormholes, a network of small wormholes will continuously form at the tip, rapidly extending its length.

In summary, it is expected that for injection rates that are very slow, wormholes will not form and the face of the core will dissolve rather uniformly. At modest injection rates, large enough to initiate wormholes at the tip of the primary wormhole, an etch pattern is expected to develop that shows little branching from the primary wormhole. Most of the acid is then expended in extending the primary wormhole. If the rate of acid injection is then increased, the acid fluid-loss flux into the rock matrix may be large enough everywhere—or at least at many points—to allow the initiation of wormholes along the boundary of the primary one. A highly ramified wormhole structure is expected at the higher injection rates.

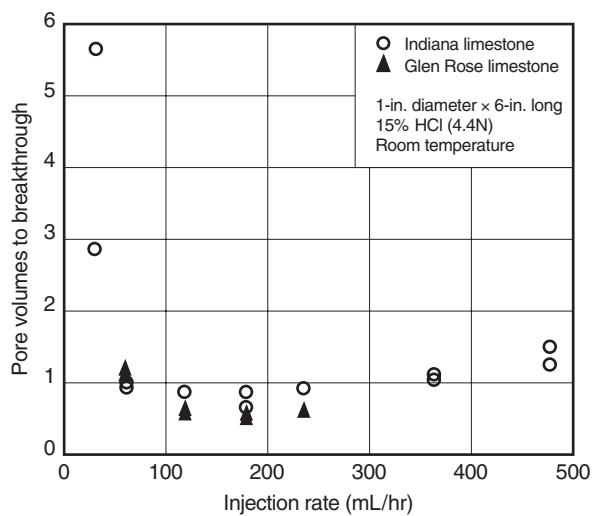
Hoefner and Fogler (1988) prepared metal casts of wormholes that developed in calcite cores at various rates of injection (Fig. 16-11). The casts are arrayed from left to right to correspond to increasing flow

rate. The left-hand core at the lowest flow rate is an example of a nearly uniform dissolution front, where the inlet face of the core has essentially been dissolved. The flow rate was evidently less everywhere than the critical one. As predicted, the wormholes that developed at the higher flow rates show substantial branching, displaying the fractal structure postulated by Daccord and Lenormand (1987). At higher rates, much of the acid is expended in the creation of the highly ramified structure shown by the casts.

Of primary practical interest are the wormholes created at intermediate injection rates. They develop a minimum of side branches extending from the perimeter of the main channel, in agreement with the etch pattern anticipated by consideration of a critical pore area. Indeed, the series of casts in Fig. 16-11 confirms the existence of a transitional area. Although the casts provide strong evidence supporting the hypothesis set forth in the preceding section, they also suggest a means for further verification. It seems evident in considering the series of casts that a wormhole formed with a minimum of side branching will penetrate through the core using a smaller quantity of acid than would be required otherwise.



**Figure 16-11.** Metal casts of wormholes that developed in calcite cores at various rates of injection are arrayed from left to right to correspond to increasing flow rate (Hoefner and Fogler, 1988).



**Figure 16-12.** Coreflood results for Indiana and Glen Rose limestones.

Wang *et al.* (1993) measured the volume of acid required to achieve wormhole penetration through a core (breakthrough). Figure 16-12 is a plot of the acid pore volumes to breakthrough as a function of the injection rate. As anticipated, an optimum injection rate exists. Wang *et al.* calculated the acid fluxes about the wormhole that develop during the experiment to find the flux at the tip as well as along the sides of the wormhole. They calculated for the optimum case (i.e., the experiment requiring the least volume of acid) that the flux at the tip is well predicted by Eq. 16-39. The critical size  $A_T$  was determined by the capillary entry pressure and the reaction rate was determined by Eq. 16-8.

A subsequent study by Bazin *et al.* (1995) using two other limestones (Lavoux and Savonnieres) shows the importance of core length in laboratory studies. As the length of the dominant wormhole increases, the amount of acid lost through the lateral boundaries increases, thereby reducing the volume of acid reaching the tip and ultimately resulting in an acid flux at the tip that is too small to initiate wormholes there. In such a case, the wormhole can extend only slowly while it is also being enlarged. Wormhole growth is slowed, as observed by Bazin *et al.* T. Huang (pers. comm., 1996) studied the rates of wormhole propagation reported by Bazin *et al.* and found them predictable on the basis of Eq. 16-39 when fluid loss is properly taken into account.

Thus, Eq. 16-39 appears to be the key to the determination of the effect of acid injection rates in field operations. Ideally, a few dominant wormholes should be initiated extending from the wellbore in openhole completions or from the perforations in cased holes. This would initially entail a modest acid injection rate (calculated by Eq. 16-39). As the acid treatment progresses and the lengths of the few dominant wormholes increase, higher injection rates are then desirable to continue to extend the dominant wormholes, if possible. Nierode and Williams (1971) were apparently the first to emphasize the primary importance of fluid loss from wormholes as a limiting factor in extending them. Their hypothesis is in no way weakened by the experiments and analysis presented here. Acid fluid loss from a wormhole remains a limiting factor in the propagation of wormholes.

#### ■ Reaction temperature

Increasing the reaction temperature increases  $E_f$  exponentially (see Eq. 16-9). In accordance with Eq. 16-39, this should result in a corresponding increase in  $A_T$ . Therefore, the optimum injection rate must correspondingly be increased (see Sidebar 6E). This predicted trend is shown by Fig. 16-13. The optimum injection rate at a temperature of 125 degF is almost twice as large as the optimum at room temperature. According to Wang *et al.* (1993), the increased rate is predicted by Eq. 16-39. An implication of this result is that, if possible, deep wells should be acidized at higher rates than shallow ones; but in either case, increasing the rate during the course of the treatment is apt to be beneficial in extending the wormholes. Initially, however, the acid flux should be restricted by the value determined with Eq. 16-39 if this rate is possible without fracturing the formation. As shown by Figs. 16-12 and 16-13, the volume of acid required to achieve breakthrough does not increase rapidly for injection rates in excess of the optimum, so maintaining the optimum injection rate is not thought to be critical. Stimulations conducted at rates somewhat in excess of those demanded by Eq. 16-39 may not differ greatly from those achieved at optimum. On the other hand, the amount of acid to achieve breakthrough does increase substantially for rates less than the optimum, so maintaining a sufficient rate if possible is recommended.

## 16E. Optimum injection rate for initiating carbonate treatment

Consider an acid treatment of a well in a carbonate formation known to be composed of calcite with little dolomite and to have a permeability of 5 md. The treatment will be conducted using 15% HCl injected initially, if possible, at a rate nearly corresponding to the optimum one. The reservoir temperature is 125°F [50°C]. The thickness of the formation to be treated is 30 ft. The well is completed openhole with a wellbore diameter of 6 in.

To determine the optimum injection rate, the cross-sectional area of the largest native pores must be estimated. Generally, this cross-sectional area is determined from the capillary entry pressure measured by mercury porosimetry, if an adequate core sample is available. For the present example, use  $A_T = 1.45 \times 10^{-7} \text{ cm}^2$ . If a sample of the formation is not available, then  $A_T$  may be estimated as a multiple of the formation permeability (Dullien, 1979). What is the optimum acid injection rate?

### Solution

Based on the data provided in Table 16-4,

$$E_r = 7.291 \times 10^7 \exp\left[-\frac{7.55 \times 10^3}{(50 + 273)}\right] = 5.14 \times 10^{-3}, \quad (16E-1)$$

and because the acid is 15%,  $C_0 = 4.4 \text{ kg-mol/m}^3$  ( $= 4.4 \text{ mol/L}$ ). Therefore,

$$E_r C_0^{m-1} = \frac{(5.14 \times 10^{-3})(4.4)^{0.63}}{4.4} = 2.97 \times 10^{-3} \text{ m/s}. \quad (16E-2)$$

In an appropriate set of units,  $k = (5 \text{ md})9.869 \times 10^{-12} \text{ cm}^2/\text{md} = 4.9345 \times 10^{-11} \text{ cm}^2$ . Therefore, the optimum flux from Eq. 16-39 is  $u = 2.38 \times 10^{-3} \text{ m/s} = 0.0078 \text{ ft/s}$ . This corresponds to an initial acid injection rate of 3.9 bbl/min (0.13 bbl/min/ft). If this injection rate exceeds the formation parting pressure, injection would be at the highest possible matrix rate during the entire treatment.

The optimum rate decreases with formation temperature. Consider the same treatment when the temperature is 85°F [30°C] rather than 125°F. Then,  $E_r = 1.1 \times 10^{-3}$ . This leads to an optimum flux  $u = 5.09 \times 10^{-4} \text{ m/s}$  corresponding to an injection rate of 0.8 bbl/min. This rate is usually sustainable without fracturing the matrix.

Thus, most calcite formations are treated using rates near the maximum that the matrix will accept, except perhaps in cool, shallow formations. Once the treatment has been initiated, it may be beneficial to increase the rate to propagate the wormholes created by the initial acid contact.

### Formation composition

The reaction rate of HCl with dolomite is much slower than that with calcite (see Table 16-4). This being the case, Eq. 16-39 indicates that unless the acid flux is greatly reduced, many of the native pores are likely to exceed  $A_T$  in size and be candidates for wormhole initiation. Thus, closely spaced multiple wormholes

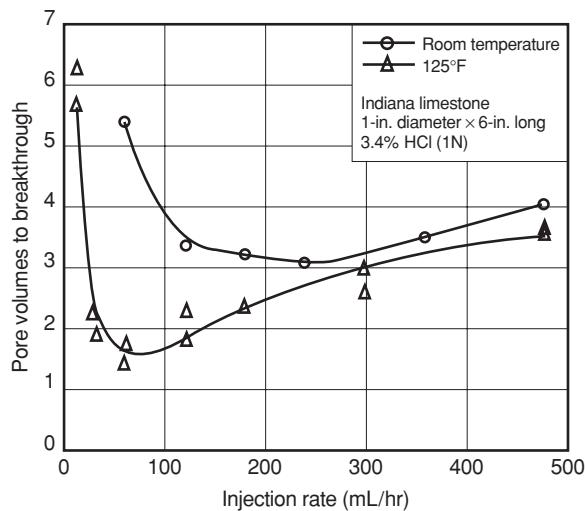
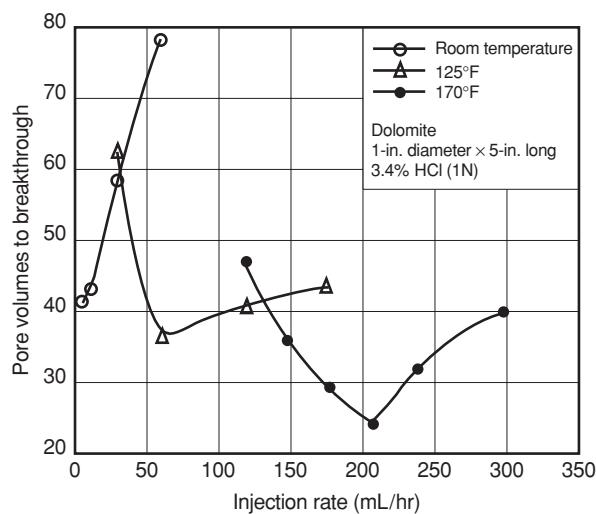


Figure 16-13. Indiana limestone coreflood results at different temperatures.

are likely to form, producing a highly ramified structure that is inefficient in developing an etch pattern consisting of a few dominant wormholes. It is, therefore, expected that corresponding to a substantial decrease in the reaction rate, there must be an associated decrease in the acid injection rate to remain at optimum. Figure 16-14 shows the acid pore volumes to breakthrough as a function of the injection rate for dolomite cores. The optimum rate at room temperature is not readily discernible, but it is evident that slow rates are preferred to higher ones. Hoefner and Fogler (1988) also studied the acidization of dolomite cores and found results similar to those shown by Fig. 16-14. The results for dolomite represent a striking confirmation of predictions based on Eq. 16-39.

The field implication is that acidizing in shallow dolomite formations should be conducted at low rates. High rates result in a multiple wormhole pattern that does not penetrate far into the formation and appears as uniform acid invasion dissolving the face of the wellbore, which is inefficient for removal of skin effect damage compared with producing a few dominant wormholes that penetrate into the formation. In deeper dolomite formations, the rate may be increased to some extent because the reaction temperature increases with depth. The increased optimum rate with increasing temperature shown in Fig. 16-14 confirms predictions based on Eq. 16-39.



**Figure 16-14.** Effect of temperature on the variation of volumes to breakthrough with the injection rate for dolomite.

#### 16-4.5. Propagation of wormholes

Once wormholes are initiated in the rock surrounding the face of the wellbore or perforation, it is desirable to extend them into the formation as far as possible with a given volume of acid. The skin effect should be reduced within the regions penetrated by wormholes. To promote understanding of the factors governing the rate of extension of a wormhole, Hung *et al.* (1989) modeled wormhole growth by considering it to be a cylinder with fluid loss as depicted by Fig. 16-10. Hung *et al.* took into account a number of factors, including the contributions of both acid diffusion and convection resulting from fluid loss to the walls of the wormhole where the acid reacts. These are important factors because the acid reactions in a wormhole are, in general, limited by mass transfer as contrasted to those in natural pores, which are controlled by the reaction rate.

The rate of wormhole extension is determined by the amount of the acid arriving at the tip:

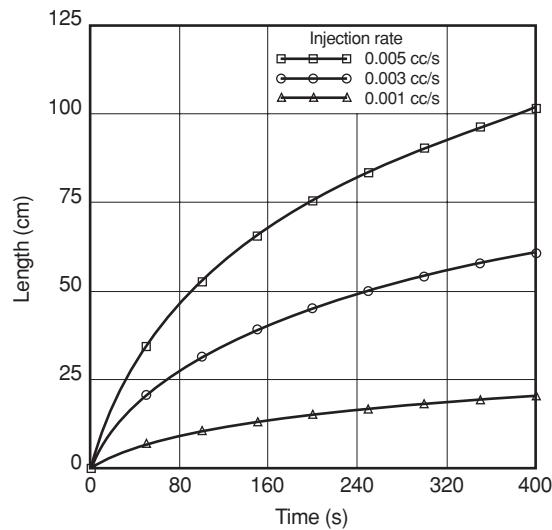
$$\frac{dL}{dt} = \frac{u_e C_e \beta_{100}}{(1-\phi)\rho_{rock}} = \frac{u_e C_e}{\phi C_0} A_c, \quad (16-40)$$

where the subscript *e* refers to conditions evaluated at the end or tip of the wormhole,  $\rho_{rock}$  is the density of the rock, and  $L$  is the length of the wormhole. This equation shows the importance of diffusion, acid convection and fluid loss on wormhole propagation. The greater the rate

of acid diffusion toward the wall, the lower the concentration of acid at the tip of the wormhole and the slower its rate of propagation. Increased fluid-loss rates serve to convect acid to the wall and at the same time reduce the acid flux reaching the tip, thereby decreasing the rate of propagation. Taking into account both fluid loss and diffusion, Hung (1987) found that for a constant injection rate, the rate of extension of a wormhole begins to decrease as the wormhole length increases. The length appears to ultimately reach a plateau, as shown by Fig. 16-15 (Hung, 1987) but never actually ceases to grow. Hung attributed the diminishing growth rate entirely to fluid loss. Thus, it is anticipated that wormhole penetration will essentially cease after a certain length has been attained as long as the injection rate is fixed. In long-core experiments, an ultimate length was observed by Bazin *et al.* (1995).

Hung calculated that the wormhole evolves in shape depending on the local rate of acid reaction and fluid loss and the rate of fluid injection. Once the wormhole length stabilizes, the acid that is injected serves primarily to increase the diameter. Because Hung's model does not account for the meandering nature of wormholes caused by small-scale heterogeneities in the rock or the creation of side branches, it tends to overpredict wormhole length.

Daccord *et al.* (1989) recognized the importance of propagating the wormhole to the fullest extent possible and proposed a model based on laboratory experiments



**Figure 16-15.** Predicted wormhole length (Hung, 1987).

that differs from that proposed by Hung. Daccord *et al.*'s expression for the rate of wormhole propagation in linear systems is

$$\frac{dL}{dt} = \frac{aA_c}{A\phi} \left( \frac{q}{D} \right)^{2/3}, \quad (16-41)$$

where  $a$  is a constant determined experimentally,  $D$  is the molecular diffusion coefficient, and  $A$  is the cross-sectional area of the wormhole. Daccord *et al.*'s model considers the influence of acid diffusion but does not

take into account fluid loss; therefore, this equation does not indicate a plateau value as the wormhole lengthens. Thus, the equation is applicable to short wormholes where fluid loss is not a factor, but it should not be used for the prediction of wormhole penetration length.

Thus, none of the existing models for the rate of wormhole propagation is strictly correct. Because wormhole length is thought to be a crucial factor in determining stimulation, better models incorporating the important features of the ones that have been proposed are required.

# 16. Appendix: Advances in Understanding and Predicting Wormhole Formation

Christopher N. Fredd, Schlumberger Dowell

## Introduction

The transport and reaction of reactive fluids in carbonate porous media results in the formation of highly conductive flow channels, or wormholes. Wormholes significantly influence the flow of reservoir fluids because their conductivity is several orders of magnitude larger than that of the porous medium. Therefore, the success of carbonate stimulation treatments is highly dependent on wormhole formation (i.e., wormhole formation during matrix acidizing treatments and lack thereof during fracture acidizing treatments). Wormhole formation is desirable during matrix acidizing treatments because the wormholes are capable of bypassing near-wellbore damage. In contrast, wormhole formation increases fluid leakoff during fracture acidizing and, consequently, limits the depth of acid penetration. The structure of the wormhole channel varies significantly with the flow conditions and the properties of the fluid-mineral system. Because the structure ultimately controls the effectiveness of the stimulation treatment, a fundamental understanding of the dissolution phenomenon is required to design effective treatments.

Wormhole formation occurs because carbonate dissolution is influenced by mass-transfer processes. Many investigators have recognized the importance of mass transfer to the phenomenon of wormhole formation in the hydrochloric acid (HCl)-limestone system (Barron *et al.*, 1962; Williams *et al.*, 1970; Nierode and Williams, 1971; Hoefner and Fogler, 1988; Daccord *et al.*, 1993; Wang *et al.*, 1993; Frick *et al.*, 1994b; Mostofizadeh and Economides, 1994; Bazin *et al.*, 1995; Huang *et al.*, 1997; Fredd and Fogler, 1998a). Recent studies demonstrate that in the presence of weak acids and chelating agents wormhole formation is influenced by a variety of transport and reaction processes (Fredd and Fogler, 1998b). Thus, to provide the reader with a full understanding of the dissolution phenomenon, this Appendix to Chapter 16 discusses the various transport and reaction processes that influence carbonate dissolution in a variety of fluid systems including strong acids, weak acids and chelating agents. A brief review of the theories of wormhole formation is provided, and wormhole formation is discussed in terms of the Damköhler number for flow and reaction.

The existence of an optimum Damköhler number for effective wormhole formation is demonstrated by laboratory experiments, and a new extension of the theory is introduced to predict optimum injection strategies for matrix acidizing treatments in the field.

## Carbonate dissolution

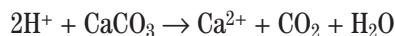
### Influence of transport and reaction

The dissolution of carbonate minerals involves a heterogeneous reaction that may be influenced by a variety of transport and reaction processes. These processes include the transport of reactants to the surface, the reversible surface reaction and the transport of products away from the surface. The rate-limiting process depends on the fluid-mineral system and may vary significantly in the presence of strong acids, weak acids and chelating agents.

This section demonstrates the interplay between the various transport and reaction processes and summarizes results from kinetic studies for a variety of fluid-mineral systems. The results are based on experimental studies conducted using a rotating disk apparatus, which allows the differentiation of the surface reaction kinetics from the transport processes because of the well-defined hydrodynamics. From an understanding of the processes that influence the dissolution, as well as appropriate expressions for the kinetics of the surface reaction and rate of mass transfer, the overall rate of carbonate dissolution can be determined as discussed in "Generalized description of carbonate dissolution."

#### ■ Strong acids

The rate of calcite dissolution has been shown to be mass-transfer limited in a variety of acidic media (pH less than about 4) ranging from HCl to pseudoseawater (Williams *et al.*, 1970; Lund *et al.*, 1975; Plummer *et al.*, 1978; Sjöberg and Rickard, 1984; de Rozières *et al.*, 1994). In strong acids such as HCl, calcite is readily dissolved and the reaction may be considered irreversible:

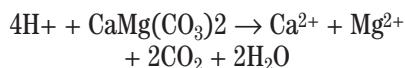


Because the reaction is essentially irreversible, the products do not influence the rate of dissolution, and the observed mass-transfer limitations are due to the transport of hydrogen ions to the calcite surface. The mass-transfer limitations are more significant when HCl is emulsified or gelled because of a reduction in the effective diffusivity (Hoefner and Fogler, 1985; de Rozières *et al.*, 1994). The dissolution of calcite by HCl becomes influenced by the kinetics of the surface reaction at temperatures below about 32 degF [0 degC] (Lund *et al.*, 1975). The following rate expression was found to describe the rate of the surface reaction:

$$r_D = k_r C_i^n, \quad (1)$$

where  $C_i$  is the concentration at the solid/liquid interface,  $k_r$  is the surface reaction rate constant, and  $n$  is the reaction order. The kinetic parameters are summarized in Table 16-4 (Lund *et al.*, 1975).

The dissolution of dolomite by HCl is mass-transfer limited at temperatures greater than about 200 degF [95 degC] (Lund *et al.*, 1973) and reaction rate limited at temperatures less than about 125 degF [50 degC]. Between these two temperatures, the dissolution is influenced by both the rate of mass transfer and the kinetics of the surface reaction. Like for calcite, the reaction can be considered irreversible, so the influence of mass transfer is due to the transport of hydrogen ions to the dolomite surface.



The kinetics of the surface reaction is also described by Appendix Eq. 1, using the kinetic parameters summarized in Table 16-4 (Lund *et al.*, 1973).

#### ■ Weak acids

In weak acids (i.e., partially dissociating acids), carbonate dissolution still occurs through hydrogen ion attack (see the two preceding chemical reactions). However, dissolution is complicated by the reversible surface reaction (Chatelain *et al.*, 1976) and the additional influence of the mass transfer of products away from the surface. The dissolution of calcite by acetic acid was found to be influenced by the rate of transport of reactants to the surface and the rate of transport of products away from the surface at ambient temperature (Fredd and Fogler, 1998d). The interplay between the two transport processes causes transport limitations that are much more significant than either limitation independently. This interplay results in an apparent effective diffusion coefficient that is over an order of magnitude lower than that

of acetic acid. Similar results were observed during the dissolution of calcite by formic and maleic acids (Takulpakdee, 1998).

The kinetics of the surface reaction for the dissolution of calcite by acetic acid was shown to be a significant limitation at pH values greater than about 3.7 (Fredd and Fogler, 1998d). The rate of the surface reaction can be expressed as

$$r_D = k_r (C_i - C_{pi}/K_{eq}), \quad (2)$$

where  $C_i$  and  $C_{pi}$  are the reactants and products concentrations at the solid/liquid interface, respectively, and  $K_{eq} = K_c/C_{Coi}$  is the effective equilibrium constant. The reactants concentration is the total concentration of associated and dissociated hydrogen ions (i.e., acetic acid and  $\text{H}^+$ ), whereas the products concentration represents the total concentration of calcium-containing species. The total interface concentration of carbonate species  $C_{Coi}$  was found to be independent of the rate of mass transfer (Fredd, 1998) and was, therefore, lumped into the effective equilibrium constant. The effective equilibrium constant also includes the conditional equilibrium constant  $K_c$ , which is a complex function of the equilibrium constants for the various equilibrium reactions occurring near the interface.

Kinetic parameters evaluated at 72 degF [22 degC] using a rotating disk (Fredd and Fogler, 1998d) are listed in Appendix Table 1. Additional data for various acid concentrations and higher temperatures (125 degF) are in the literature (Fredd and Fogler, 1998d). These kinetic parameters are influenced by a variety of adsorption processes and equilibrium reactions. Therefore, extrapolation of the parameters to significantly higher temperatures requires careful evaluation of the surface chemistry involved in the dissolution. The method of approximating the surface reaction rate reported by Schechter (1992) (see Eq. 16-10) provides an order-of-magnitude estimate of the reaction rate constant but does not account for the significant contribution of the reverse reaction.

The rate of dolomite dissolution by weak acids is currently not available in the literature. Because the dissolution occurs through hydrogen ion attack, the rate of the surface reaction can be estimated from Appendix Eq. 2 by scaling the surface reaction rate constant by the ratio of the surface reaction rate constants of dolomite to calcite for HCl. This scaling should provide a reasonable order-of-magnitude estimate from which the relative influences of transport and reaction can be determined.

**Appendix Table 1. Parameters used to calculate the overall dissolution rate constant at 72°F.**

	$D_e$ (cm <sup>2</sup> /s)	$D_{pe}$ (cm <sup>2</sup> /s)	$k_r$ (ΔE [kcal/mol])	$K_{eq}$
0.25M CDTA (pH = 4.4)	$4.5 \times 10^{-6\dagger}$	$3 \times 10^{-6\dagger}$	$2.3 \times 10^{-4\$}$	$1 \times 10^{10\dagger\dagger}$
0.25M DTPA (pH = 3.3)	$4 \times 10^{-6\dagger}$	$3 \times 10^{-6\dagger}$	$7.8 \times 10^{-5\$}$	$1 \times 10^{10\dagger\dagger}$
0.25M DTPA (pH = 4.3)	$4 \times 10^{-6\dagger}$	$3 \times 10^{-6\dagger}$	$4.8 \times 10^{-5\$}$	$1 \times 10^{10\dagger\dagger}$
0.25M DTPA (pH = 12.5)	$4 \times 10^{-6\dagger}$	$3 \times 10^{-6\dagger}$	$2.6 \times 10^{-5\$}$	$1 \times 10^{10\dagger\dagger}$
0.25M EDTA (pH = 4)	$6 \times 10^{-6\ddagger\#}$	$4 \times 10^{-6\$}$	$1.4 \times 10^{-4\$}$ (12) <sup>§</sup>	$1 \times 10^{10\dagger\dagger}$
0.25M EDTA (pH = 8 to 13)	$6 \times 10^{-6\$}$	$4 \times 10^{-6\$}$	$5.3 \times 10^{-5\$}$	$1 \times 10^{10\dagger\dagger}$
0.5M acetic acid (pH = 2.5)	$1.1 \times 10^{-5\dagger\dagger\dagger}$	$8 \times 10^{-6\#\#\#}$	$5 \times 10^{-3\$\$\$}$	$1.6 \times 10^{-1\$\$\$}$
0.5M acetic acid (pH = 4.6)	$1.1 \times 10^{-5\dagger\dagger\dagger}$	$8 \times 10^{-6\#\#\#}$	$2.1 \times 10^{-4\$\$\$}$	$2.7 \times 10^{-1\$\$\$}$
0.5M HCl	$3.6 \times 10^{-5\dagger\dagger\dagger\dagger}$	$2 \times 10^{-5\#\#\#}$	$2 \times 10^{-1\dagger\dagger\dagger\dagger}$ (15) <sup>††††</sup>	$1 \times 10^{10\dagger\dagger}$

Note:  $D_e$  = effective diffusion coefficient,  $D_{pe}$  = effective diffusion coefficient for reaction products,  $k_r$  = effective surface reaction rate constant,  $\Delta E$  = activation energy,  $K_{eq}$  = effective equilibrium constant

<sup>†</sup> Estimated from the Stokes-Einstein equation

<sup>‡</sup> Assumed on the basis of  $D_e$  and value for Ca-EDTA

<sup>§</sup> Fredd and Fogler (1998c)

<sup>††</sup> Assumed on the basis of the irreversibility of surface reactions

<sup>‡‡</sup> Assumed equal to the diffusion coefficient of EDTA at pH = 13

<sup>§§</sup> Assumed on the basis of the value for Ru-EDTA (Jiang and Anson, 1992)

<sup>†††</sup> Vitagliano and Lyons (1956)

<sup>††††</sup> Estimated from ionic diffusion coefficients (Cussler, 1984)

<sup>§§§</sup> Fredd and Fogler (1998d)

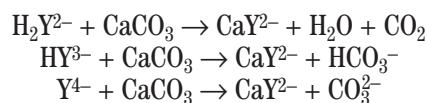
<sup>††††</sup> Lund *et al.* (1975)

## ■ Chelating agents

In the presence of calcium chelating agents such as ethylenediaminetetraacetic acid (EDTA), the rate of calcite dissolution is influenced predominantly by the rate of transport of reactants to the surface and the kinetics of the surface reactions at ambient temperature (Fredd and Fogler, 1998c). Although the reactions are essentially irreversible because of the formation of a stable calcium complex, the reactions are influenced by the transport of products away from the surface. This influence is due to the blocking of surface sites involved in the dissolution. The dissolution mechanism is different from conventional acids in that hydrogen ions are not required. However, the rate of dissolution is enhanced at low pH as a result of the combined influence of hydrogen ion attack and chelation.

The rate of calcite dissolution varies considerably with pH and the type of chelating agent because of changes in the ionic form of the chelating agent and the influence of hydrogen ion attack. In general, the

rate of calcite dissolution increases as the number of hydrogen ions associated with the chelating agent increases. As the pH is increased from about 4.5 to 8.5 to 13, EDTA successively deprotonates from  $H_2Y^{2-}$  to  $HY^{3-}$  to  $Y^{4-}$ . The corresponding overall surface reactions are



The rate of calcite dissolution by chelating agents can be described by Appendix Eq. 2. The appropriate kinetic parameters are listed in Appendix Table 1 for EDTA, 1,2-cyclo-hexanediaminetetraacetic acid (CDTA) and diethylenetriaminepentaacetic acid (DTPA) (Fredd and Fogler, 1998c). Calcite dissolution requires the formation of stable calcium chelates. For example, nitrilotriacetic acid (NTA), which forms a relatively weak calcium chelate, is ineffective for calcite dissolution (Fredd, 1998).

The dissolution of dolomite by chelating agents has not been thoroughly investigated. Preliminary experiments with EDTA at ambient temperature reveal no significant dolomite dissolution. The dissolution mechanism is probably inhibited by the low stability of the magnesium chelate at that temperature.

### Generalized description of carbonate dissolution

A generalized description of carbonate dissolution is required to account for the various transport and reaction processes that may influence the rate of dissolution. This description is provided by modeling the overall carbonate dissolution mechanism as three sequential processes (Fredd and Fogler, 1998b) of the mass transfer of reactants to the surface, reversible surface reactions and mass transfer of products away from the surface (Appendix Fig. 1). At steady state, the rates of the three sequential processes are equal and the rate of reactant consumption  $r_A$  is

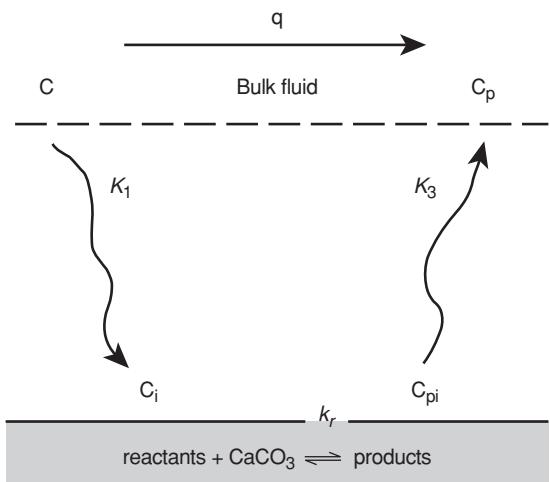
$$\begin{aligned} r_A &= v r_D \\ &= K_1 (C - C_i) \\ &= v k_r (C_i - C_{pi}/K_{eq}) \\ &= v K_3 (C_{pi} - C_p), \end{aligned} \quad (3)$$

where  $n$  is the stoichiometric ratio of reactants consumed to products produced and  $K_1$  and  $K_3$  are the mass-transfer coefficients for the reactants and products, respectively. Appendix Eq. 3 assumes that the surface reaction can be expressed as a first-order heterogeneous reaction. This expression is valid for weak acids and chelating agents. It is a reasonable approximation for strong acids when the concentration dependence is lumped into the reaction rate constant (i.e.,  $k_r = k_r' C_i^{n-1}$ ). This approximation does not significantly affect the interplay between transport and reaction for systems that are mass-transfer limited.

The expressions in Appendix Eq. 3 were solved simultaneously for the interface concentrations, which were then substituted back into the equation. Making an additional substitution for  $C_p$  based on the stoichiometry of the reaction, the rate of reactant consumption can then be expressed as

$$r_A = \kappa \left[ C_o - \frac{C_o}{1 + v K_{eq}} \right], \quad (4)$$

where  $\kappa$  is the overall dissolution rate constant and  $C_o$  is the initial reactant concentration. The overall dissolution rate constant depends on the sum of resistances in series:



**Appendix Figure 1.** Carbonate dissolution involves reactants transport, reversible surface reaction and products transport.

$$\kappa = \frac{1 + \frac{1}{v K_{eq}}}{\frac{1}{K_1} + \frac{1}{v k_r} + \frac{1}{v K_{eq} K_3}}. \quad (5)$$

Appendix Eqs. 4 and 5 have been used to describe the rate of dissolution observed during rotating disk experiments (Fredd and Fogler, 1998c, 1998d) and during flow and reaction within carbonate porous media (Fredd and Fogler, 1998b). These equations can be used to determine the rate of carbonate dissolution in any flow geometry, provided that an appropriate expression for the rate of mass transfer is available.

### Wormhole formation

The transport and reaction of reactive fluids in carbonate porous media results in the formation of highly conductive flow channels, or wormholes. Wormholes form because of the natural heterogeneity of the porous medium and the rapid and almost complete dissolution of the mineral in the reactant fluid. During stimulation, the fluid preferentially flows to the regions of highest permeability (i.e., the largest pores, vugs or natural fractures). The initial flow paths are enlarged by rapid dissolution of the matrix material, causing these regions to receive even more of the flow. A dominant channel quickly forms and continues to propagate while diverting flow from other regions. Once formed, the wormhole channels provide negligible resistance to flow and carry essentially all the injected fluid.

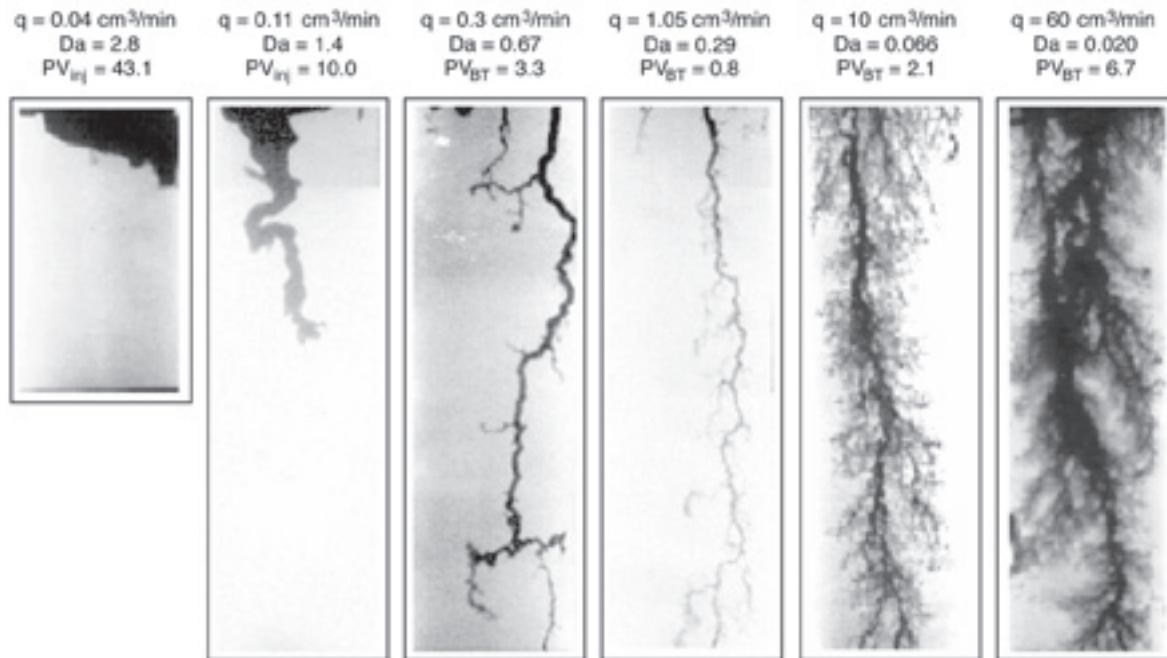
## Dissolution structures

The structure of the dissolution channel is highly dependent on the injection rate and fluid-mineral properties. The typical dependence on the injection rate is demonstrated in Appendix Fig. 2 by neutron radiographs of dissolution structures formed during the dissolution of limestone by 0.5M [1.7%] HCl at 72 degF. At low injection rates (far left structure), the reactant is consumed on the inlet flow face of the core, resulting in complete dissolution of the core starting from the inlet flow face. This face dissolution (also referred to as compact dissolution) consumes large volumes of reactant and provides negligible increases in permeability. At slightly higher injection rates, the reactant can penetrate into the porous matrix and enlarge flow channels. However, a significant amount of reactant is consumed on the walls of the flow channels. This consumption results in the formation of a conical-shaped dissolution channel and requires the injection of several pore volumes of fluid for the channel to break through the porous medium.

At intermediate injection rates, unconsumed reactant reaches the tip of the evolving flow channels. Subsequent consumption at the tip propagates the dissolution channels and eventually leads to the formation of a dominant wormhole. The wormhole provides significant permeability increases and requires a minimum

pore volume of fluid to break through the rock matrix. At high injection rates, the flow channels become more highly branched or ramified (far right structure) as fluid is forced into smaller pores. Dissolution occurs over a high surface area, which results in an increase in the number of pore volumes to breakthrough. At extremely high injection rates, all the pores are dissolved uniformly as unconsumed reactant penetrates deep into the porous medium. This uniform dissolution is typically observed when dolomite is dissolved by HCl at ambient temperature (Hoefner and Fogler, 1988).

The flow rate at which the various dissolution structures are formed is influenced by mass-transfer and reaction processes. Therefore, the structures depend on the temperature and fluid-mineral system. For example, the same trend of decreasing channel branching observed when the injection rate is decreased is also observed when the temperature is increased (Fredd, 1998). Increasing the temperature results in an increase in the mass-transfer limitations (because the activation energy for diffusion is less than the activation energy for reaction) and causes more reactant to be consumed on the walls of the dissolution channel. The result is an increase in the number of pore volumes to breakthrough and an increase in the injection rate required to form the dominant wormhole channels (Wang *et al.*, 1993; Fredd, 1998). Thus, although the dissolution must be influenced by mass transfer (i.e.,



**Appendix Figure 2.** Neutron radiographs of dissolution structures formed during the dissolution of limestone by 0.5M HCl at 72°F (Fredd and Fogler, 1998a).  $PV_{inj}$  = number of pore volumes injected,  $PV_{BT}$  = number of pore volumes to breakthrough.

the surface reaction rate must be rapid) for wormhole formation to occur, ineffective wormhole formation will occur if the system is too mass-transfer limited. Hence, there is an optimum degree of transport and reaction limitations for effective wormhole formation (Fredd, 1998).

### Optimum injection rate

Several investigators have studied the phenomenon of wormhole formation in a variety of fluid-mineral systems and reported the existence of an optimum injection rate (Hoefner and Fogler, 1988; Daccord *et al.*, 1989, 1993; Wang *et al.*, 1993; Frick *et al.*, 1994b; Mostofizadeh and Economides, 1994; Bazin *et al.*, 1995; Huang *et al.*, 1997; Fredd and Fogler, 1998a, 1998b). The optimum injection rate represents the conditions at which a minimum volume of fluid is required to obtain a given depth of wormhole penetration. The optimum injection rate corresponds to the formation of dominant wormhole channels. Because no significant difference in the conductivity of the various dissolution structures is observed for the same depth of penetration (C. N. Fredd, unpubl. data, 1998), the injection rate at which the volume of fluid is minimized represents the most effective condition for matrix stimulation.

The existence of an optimum injection rate is demonstrated in Appendix Fig. 3, which shows the dependence of the number of pore volumes to breakthrough on the injection rate for a variety of fluid-limestone systems (Fredd and Fogler, 1998b). The figure includes data from linear coreflood experiments with 0.25M CDTA (pH = 4.4), 0.25M DTPA (pH = 4.3), 0.25M EDTA (pH = 4 and 13), 0.5M acetic acid and 0.5M HCl. All the fluids exhibit an optimum injection rate at which the number of pore volumes to breakthrough is minimized and dominant wormhole channels are formed. The number of pore volumes to breakthrough increases to the left and right of the minimum owing to the formation of conical dissolution channels and ramified wormholes, respectively.

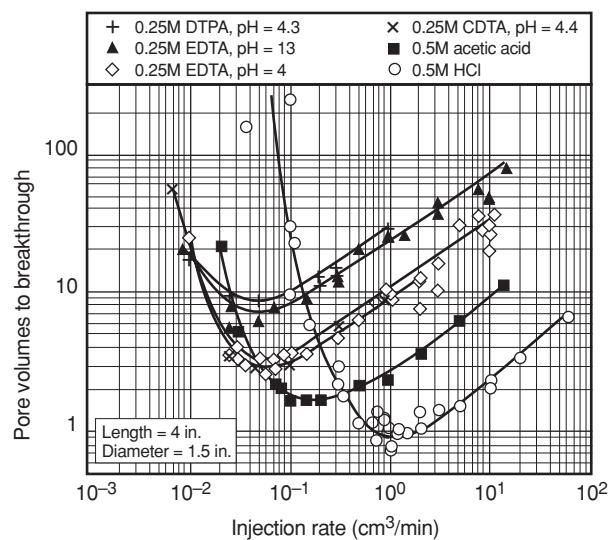
The importance of mass transfer on the dissolution phenomenon is demonstrated by the influence of the diffusion coefficient on the optimum injection rate. As the fluid type was varied, the optimum injection rate decreased with decreasing diffusion coefficient in the order of HCl > acetic acid > chelating agents. (The diffusion coefficients are listed in Appendix Table 1.) Because of this influence of diffusion, alternative fluid systems such as chelating agents and weak acids are more effective than HCl when injected at rates below about 0.2 cm<sup>3</sup>/min in linear coreflood experiments. Therefore, in shallow or tight formations where low injection rates are required to prevent fracturing the formation or when injection rates are limited because of frictional pressures, alternative fluids may be more effective than HCl for matrix stimulation.

## Fundamentals of wormhole formation

### Influence of transport and reaction

The obvious importance of wormhole formation on carbonate acidizing has led many investigators to study the dissolution phenomenon. Early investigators recognized the significant influence of mass transfer on the dissolution of limestone by HCl (Barron *et al.*, 1962; Williams *et al.*, 1970; Nierode and Williams, 1971). This influence has served as a basis for many of the theories describing wormhole formation.

Daccord *et al.* (1989) investigated a water–plaster of paris system and reported wormhole formation to depend on the Peclet number  $Pe$ .  $Pe$  is defined as the ratio of transport by convection to transport by diffusion (see Chapter 17). A similar dependence on  $Pe$  was observed for the HCl-limestone system (Daccord *et al.*, 1993; Mostofizadeh and Economides, 1994; Buijse, 1997). Daccord *et al.* (1993) and Frick *et al.* (1994b) combined the concepts of fractal geometry with the dependence on  $Pe$  to describe wormhole formation in the HCl-limestone system. Bazin *et al.* (1995) studied the HCl-limestone system and reported efficient wormhole formation to occur at the transition between convection-limited and mass-transfer-limited regimes. In contrast, Wang *et al.* (1993) and Huang *et al.* (1997) investigated HCl-carbonate systems and proposed that the optimum injection rate occurred at a transition between reaction-rate-limited and fluid-loss-limited regimes (see Chapter 16). Despite the major influence of mass transfer on wormhole formation, diffusion plays only a minor role in their theory.



**Appendix Figure 3.** Optimum injection rates for the dissolution of limestone by various stimulation fluids at 72°F (Fredd and Fogler, 1998b).

Hoefner and Fogler (1988) investigated HCl-carbonate systems and found that the phenomenon of wormhole formation is governed by the Damköhler number  $Da$  for flow and reaction.  $Da$  is defined as the ratio of the overall rate of dissolution to the rate of transport by convection. When the overall rate of dissolution is mass-transfer limited,

$$Da_{mt} = aD_e^{2/3}l/q, \quad (6)$$

where  $D_e$  is the effective diffusion coefficient,  $q$  is the flow rate,  $l$  is the pore length, and  $a$  is a constant that depends on the carbonate core. On the other hand, when the net rate of dissolution is reaction rate limited,

$$Da_{rxn} = ak_r dl/q, \quad (7)$$

where  $d$  is the pore diameter. The units of  $a$  vary from Appendix Eq. 6 to 7 such that  $Da$  is dimensionless. Hoefner and Fogler observed that a minimum volume of fluid was required for channel breakthrough (i.e., optimum conditions for wormhole formation) when  $Da$  was varied over several orders of magnitude. This observation is consistent with the existence of an optimum injection rate for constant fluid-mineral properties because the value of  $Da$  is inversely proportional to the injection rate.

Recently, a similar dependence on  $Da$  was demonstrated for the flow and reaction of chelating agents and weak acids in carbonate porous media (Fredd and Fogler, 1998a, 1998b). These alternative fluid systems are influenced by both transport and reaction processes (as described previously in “Carbonate dissolution”) and therefore cannot be described by theories developed in previous studies. To describe wormhole formation with these fluid systems, the various transport and reaction processes were included in a generalized description of the dissolution phenomenon. A common dependence on  $Da$  was observed when the combined effects of transport and reaction were taken into account. This common dependence on  $Da$  is described in detail in the sections that follow.

### Dependence on the Damköhler number

To simulate transport and reaction within a wormhole channel, the dissolution of a porous medium was modeled as the dissolution of a representative cylindrical tube (Fredd and Fogler, 1998b). The cylindrical tube represents the dominant flow channels within the porous medium (i.e., the wormholes). Convection and reaction in the tube were included in a reactant mass balance, where Appendix Eq. 4 was used for the rate of reactant consumption. Solution of the reactant mass balance equation resulted in an expression for the

concentration profile along the length of the channel that is dependent on  $Da$ :

$$\frac{C}{C_o} = \frac{1 + vK_{eq}e^{-Da}}{1 + vK_{eq}}, \quad (8)$$

where  $Da$  is defined as

$$Da = \frac{\pi dl\kappa}{q}, \quad (9)$$

where  $d$  and  $l$  are the diameter and length of the capillary tube, respectively. Because of the dependence on the overall dissolution rate constant, this  $Da$  includes the effects of reactants transport, reversible surface reactions and products transport. This  $Da$  reduces to those defined in Appendix Eqs. 6 and 7 for reactants-transport-limited ( $\kappa = K_1$ ) and reaction-rate-limited ( $\kappa = k_r$ ) dissolution, respectively. Physically,  $Da$  provides a measure of the amount of reactant being consumed on the walls of the wormhole, as opposed to being transported to the tip of the wormhole, where it can be consumed efficiently. Unlike previous parameters that assume either mass-transfer-limited or reaction-rate-limited dissolution, this  $Da$  accounts for a variety of transport and reaction processes and is, therefore, able to describe alternative fluid systems such as chelating agents and weak acids.

To determine the overall dissolution rate constant, the mass-transfer coefficients were obtained from Levich's (1962) solution of the convective diffusion equation for laminar flow in a cylindrical tube. The average mass-transfer coefficient  $K_{mt}$  along the length of a tube is

$$K_{mt} = 1.86 D_e^{2/3} \left( \frac{u}{dl} \right)^{1/3}, \quad (10)$$

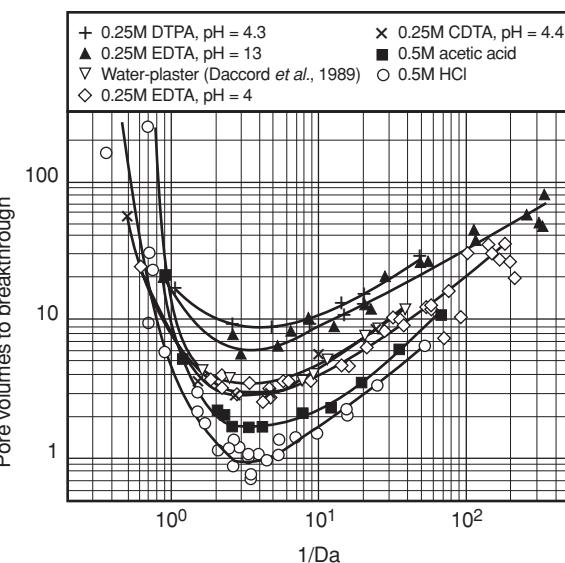
where  $K_{mt}$  is for either reactants or products ( $K_1$  or  $K_3$ ), depending on the value of the diffusion coefficient, and  $u$  is the superficial velocity in the capillary tube. Because the diameter and length of the capillary tube, or wormhole channel, change with time, the mass-transfer coefficients and  $Da$  were evaluated on the basis of the final wormhole dimensions. The diameter was measured from neutron radiographs. Typical diameters were of the order of 0.02 in. The length was assigned a representative length of the wormhole (one-half the core length). The effective surface reaction rate constant and effective equilibrium constant were obtained from independent kinetic studies using a rotating disk. The effective constants are listed in Appendix Table 1 with values for the diffusion coefficients for reactants and products. For the case of HCl and the chelating agents,  $K_{eq}$  is relatively high, so the products transport and reverse reaction terms become negligible.

## Optimum Damköhler number

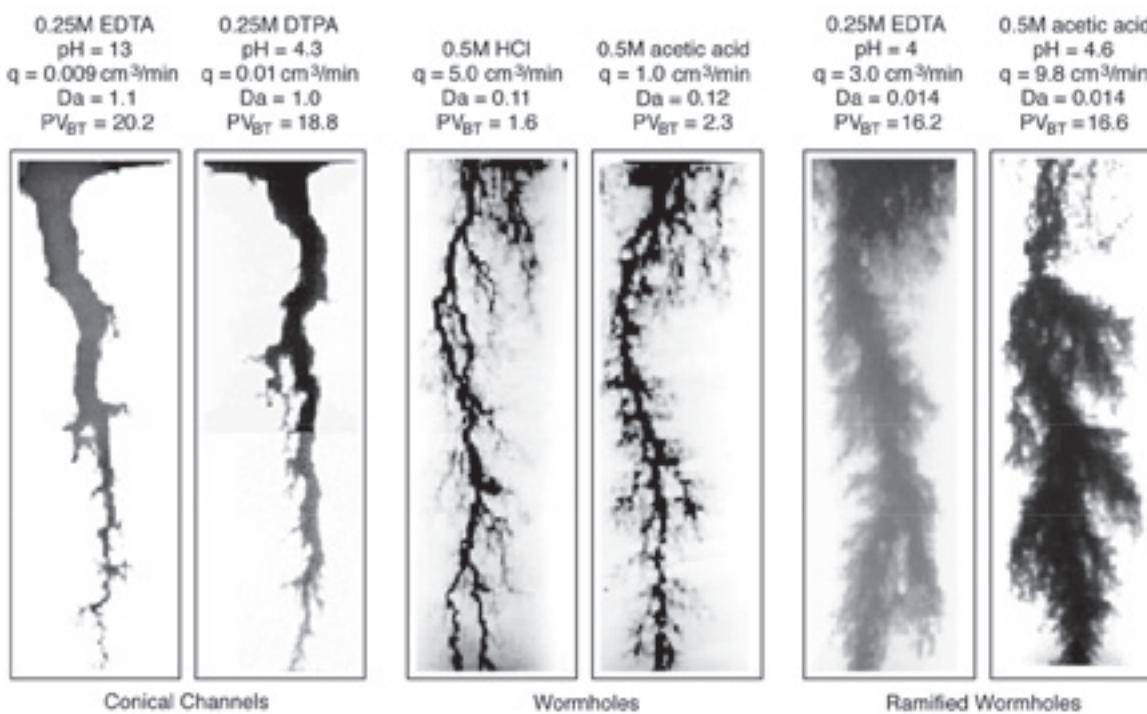
$Da$  has been shown to describe the phenomenon of wormhole formation for a wide range of fluid-mineral systems (Fredd and Fogler, 1998b). A common dependence of wormhole formation on  $Da$  is observed when the various transport and reaction processes are taken into account. This dependence is shown in Appendix Fig. 4, where the number of pore volumes to breakthrough is plotted as a function of the inverse of  $Da$  (as defined in Appendix Eq. 9). The curves for the chelating agents and acetic acid are shifted to the right in comparison with Appendix Fig. 3 such that the minimum number of pore volumes to breakthrough occurs at about the same value of  $Da$  for all the fluids. Thus, these fluids are all characterized by the same optimum  $Da$ . This optimum is observed for fluid-limestone systems that range from reactants transport limited (HCl) to reactants transport and surface reaction influenced (chelating agents) to reactants and products transport limited (acetic acid). Also included in Appendix Fig. 4 are data from Daccord *et al.* (1989) for the dissolution of plaster of paris by water. This system, which is limited by the transport of products away from the surface (Christofferson and Christofferson, 1976), also exhibits the same optimum  $Da$ . For this wide range of fluid-mineral systems, the optimum  $Da$  occurs at a value of approximately 0.29.

The dependence of the wormhole structure on  $Da$  is shown in Appendix Fig. 5 for a variety of fluid-limestone

systems. The pairs of neutron radiographs are at similar values of  $Da$  and represent a wide range of transport and reaction limitations. The neutron radio-graphs show wormhole structures formed at  $Da$  values of approximately 1.1, 0.11 and 0.014. The wormhole structures exhibit similarities in the amount and type of channel branching at each of these values. As  $Da$  is decreased, the dissolu-



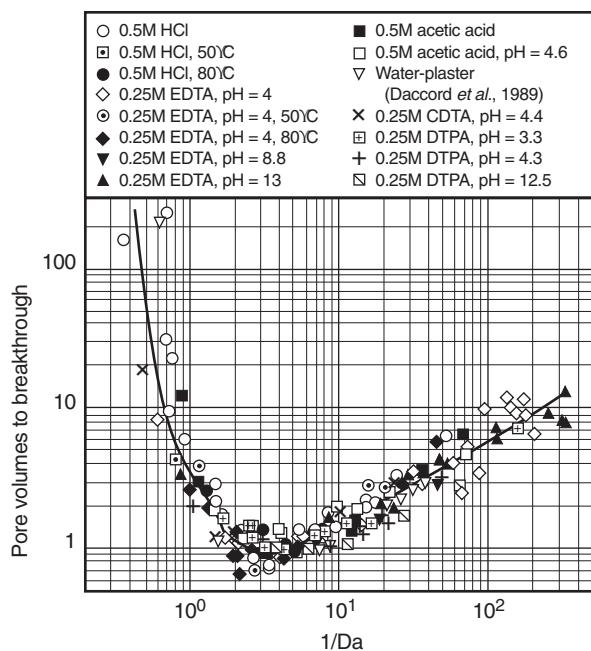
**Appendix Figure 4.** The optimum  $Da$  for the dissolution of limestone by various stimulation fluids (Fredd and Fogler, 1998b).



**Appendix Figure 5.** Comparison of wormhole structures formed at similar  $Da$  values by a variety of fluid systems (Fredd, 1998).

tion structures change from conical-shaped channels to dominant wormholes to highly ramified wormholes. These similarities demonstrate that  $Da$  dictates the structure of the dissolution channels formed by systems with a wide range of mass-transfer and reaction limitations.

A variety of fluid systems exhibit similar trends in the number of pore volumes to breakthrough and the corresponding wormhole structures. Because these trends are a result of a common dependence on  $Da$  and, therefore, the transport and reaction processes, a single description of the dissolution phenomenon is possible. This single description is obtained by normalizing the number of pore volumes to breakthrough by the minimum number of pore volumes to breakthrough for the respective fluids (Fredd, 1998). The normalized number of pore volumes to breakthrough is plotted versus the inverse of  $Da$  in Appendix Fig. 6. The results reveal a single curve for a wide range of fluid-mineral systems, including different fluid types, pH values and temperatures. (Unless otherwise stated, the data are for the dissolution of limestone at ambient temperature.) This single curve provides a means of estimating the entire curve for the number of pore volumes to breakthrough and the wormhole structures from a single coreflood experiment near the optimum  $Da$ . Thus, the need for exhaustive coreflood studies to determine the effectiveness of a fluid under particular reservoir conditions is eliminated.



**Appendix Figure 6.** Normalized number of pore volumes to breakthrough versus  $Da$  (Fredd, 1998).

## Wormhole formation modeling

In addition to involving a variety of transport and reaction processes, the dissolution of porous media is complicated by the stochastic nature in which the flow channels evolve. The difficulties associated with accounting for all the complexities of wormhole formation have led to many simplifications of the dissolution phenomenon. These simplifications typically limit the models to either mass-transfer-limited or reaction-rate-limited dissolution and include an ideal representation of the porous medium. Early investigators simulated mass-transfer-limited dissolution using models of the porous medium that were based on bundles of capillary tubes (Nougaro and Labbé, 1955; Rowan, 1959). These simple models were extended by Schechter and Gidley (1969) to include the effects of pore merging and either mass-transfer-limited or reaction-rate-limited dissolution. Although the dominant pores were observed to grow more rapidly, these models were unable to capture the branching characteristics of the dissolution phenomenon.

More recently, Hoefner and Fogler (1988) successfully modeled the phenomenon of wormhole formation using a network model. They simulated pore-scale flow and reaction by representing the porous medium as a two-dimensional network of nodes connected by cylindrical bonds. The model provided qualitative predictions of the dissolution structure (see Fig. 17-1) and corresponding permeability response for both mass-transfer-limited and reaction-rate-limited dissolution. Similar results were observed by Daccord *et al.* (1989), who utilized a network model to simulate the mass-transfer-limited dissolution of plaster of paris by water. Although these network models do not include pore merging, they were able to predict the experimentally observed trends in wormhole formation because they capture the effects of pore-level heterogeneity on the macroscopic dissolution phenomenon.

The combined effects of transport and reaction have been included in a three-dimensional physically representative network (PRN) model for flow and reaction in porous media (Fredd and Fogler, 1998b). The PRN model is based on a packed-bed description of the porous medium (Bryant *et al.*, 1993; Thompson and Fogler, 1997). Although the use of a packed-bed description of the medium limits the ability of the model to represent consolidated carbonate porous media, it is a major advancement over the capillary tube representations typically used. The model provides a complete topological description of the medium and a fundamental description of the pore-scale hydrodynamics. These descriptions serve as a physical basis for determining macroscopic parameters, such as the permeability. Dissolution is simulated by allowing the spherical particles that compose the bed to shrink as reactant is consumed. The pores naturally merge as the

spherical particles are dissolved. The simulations are in qualitative agreement with experimental observations and demonstrate the common dependence of wormhole formation on  $Da$ . More importantly, the existence of an optimum  $Da$  is substantiated by PRN model simulations.

## Prediction of optimum field conditions

The ultimate goal of all laboratory studies is to aid the design of effective field treatments. Two main design requirements are predicting the optimum injection rate and selecting the most appropriate stimulation fluid. Unfortunately, the direct application of laboratory data to the field is not straightforward, as noted by several investigators (Daccord *et al.*, 1989; Frick *et al.*, 1994b; Bazin, 1995; Buijse, 1997). Wormhole formation in the field is complicated by the effects of fluid loss through the walls of the wormhole in the radial geometry and by competition among wormholes for the injected fluid (Appendix Fig. 7). The importance of these processes has been demonstrated theoretically (Nierode and Williams, 1971; Hung *et al.*, 1989; Buijse, 1997). However, these studies were limited in their ability to predict optimum injection conditions in the field because of a lack of consideration of the critical parameters required for effective wormhole formation.

To account for the influence of fluid loss and wormhole competition on wormhole formation, two approaches are the most obvious:

- simulate wormhole formation using large network models that account for the effects of pore-scale transport and reaction
- account for the added complications in macroscopic theories such as the existence of an optimum  $Da$ .

Network models inherently include the effects of fluid loss and wormhole competition because the pressure profile and flow rates through all pores in the network are continually updated during the simulation. Although the use of network models would eliminate the need for macroscopic correlations, the ability to simulate wormhole formation at the field scale is limited by the excessive memory and computational time required for such simulations. Thus, the most tractable approach at this time is to extend macroscopic theories. This section introduces an extension of the optimum  $Da$  to predict optimum injection strategies for matrix stimulation treatments in the field.

## Significance of the Damköhler number

The existence of an optimum  $Da$  was observed in laboratory experiments conducted in linear cores. In these experiments, only one wormhole was typically observed

because of the limited cross-sectional area available for flow. In addition, essentially all the flow is through that single wormhole because the conductivity of the wormhole is several orders of magnitude higher than that of the porous medium and fluid loss through the walls of the wormhole is insignificant in the linear geometry. Therefore, these experiments demonstrate the optimum  $Da$  within a single wormhole with negligible fluid loss. Applying the concept of the optimum  $Da$  to the field requires knowledge of both the relative amount of reactant lost from the wormhole because of fluid loss and the number of wormholes that will form per unit surface area of the formation (i.e., wormhole density). To account for the effects of fluid loss and wormhole competition on wormhole formation, it is first necessary to understand the conditions at which the dependence on  $Da$  is affected most significantly by these processes.

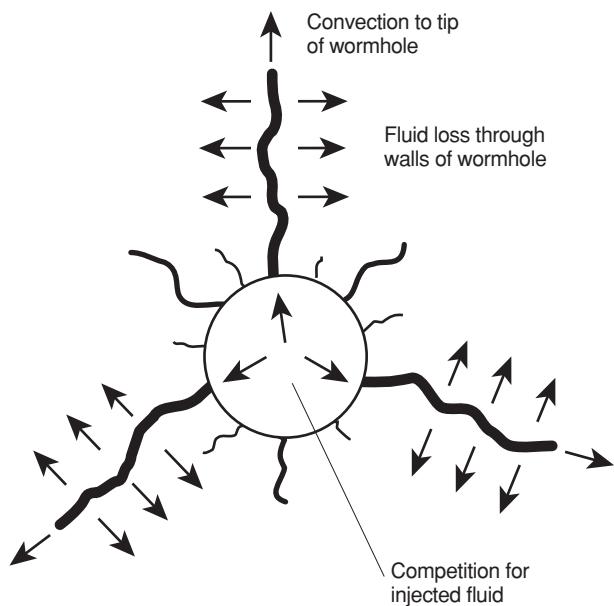
### ■ Fluid loss

Fluid loss through the walls of a wormhole has three main effects on transport and reaction within the wormhole. These effects are decreasing the flow rate along the length of the wormhole, affecting the rates of mass transfer within the wormhole (because of the combined influence of convection and diffusion normal to the walls of the wormhole) and increasing the amount of reactant lost through the walls of the main wormhole channel (because of reactant leak-off). Each of these effects reduces the amount of reactant that is transported to the tip of the wormhole (because of either increased consumption or leakoff) and, consequently, reduces the rate of wormhole propagation.

The significance of these effects depends on the rate of fluid loss and, therefore, depends on the permeability of the medium that is being stimulated. Fluid-loss velocities reported in the literature range from about  $1 \times 10^{-4}$  to  $1 \times 10^{-2}$  cm/s at a permeability of about 1 mD (Hung *et al.*, 1989; Wang *et al.*, 1993; Settari, 1993). This range provides a conservative estimate of fluid-loss velocities expected in typical matrix stimulation treatments, which are usually conducted in damaged formations with near-wellbore permeabilities of less than 1 mD. This range of fluid-loss velocities serves as the basis for the discussion that follows. Although there is a complex interplay between the three fluid-loss effects, they are discussed independently.

### – Flow rate

Fluid loss results in a decrease in the flow rate along the length of the wormhole and, hence, leads to an increase in the value of  $Da$ . As  $Da$  increases, an increasing amount of reactant is consumed on the walls of the wormhole. Thus, fluid loss reduces the amount of reactant being transported to the tip



**Appendix Figure 7.** Idealized representation of fluid loss from the walls of wormholes and competition among wormholes for injected fluid.

of the wormhole and leads to ineffective wormhole propagation. Ineffective propagation can be overcome by changing the injection conditions (i.e., increasing the flow rate or decreasing the overall rate of dissolution) to maintain the optimum  $Da$ . Increasing the injection rate to maintain efficient wormhole formation is consistent with investigators reporting a higher optimum injection rate in radial experiments than in linear experiments (Frick *et al.*, 1994b; Mostofizadeh and Economides, 1994).

#### – Mass transfer

Fluid loss affects the rates of mass transfer (and, consequently, the overall rate of dissolution) within the wormhole as a result of the combined influence of convection and diffusion normal to the walls of the wormhole. Fluid loss increases the rate of reactants transport to the walls of the wormhole, because mass transfer and fluid loss act in the same direction. Conversely, fluid loss decreases the rate of products transport away from the walls of the wormhole to the bulk fluid. The overall rate of products transport increases because of the added effect of products leaking off into the formation. These changes lead to an increase in the amount of reactants consumed on the walls of the wormhole and a decrease in the effectiveness of wormhole formation.

The effect of fluid loss on the rates of mass transfer can be taken into account by correcting the mass-transfer coefficient  $K_{mt}$  used in the absence of fluid loss. In considering rapid mass transfer resulting from both diffusion and convection, the corrected mass-transfer coefficient  $K$  is (Cussler, 1984)

$$K = \frac{v_L}{e^{(v_L/K_{mt})} - 1}, \quad (11)$$

where  $v_L$  is the fluid-loss velocity. The value of  $v_L$  is negative for flow in the direction of diffusion (i.e., for the transport of reactants to the surface). At typical reservoir conditions, the corrected and uncorrected mass-transfer coefficients differ by less than an order of magnitude, a difference that becomes less significant as  $v_L/K_{mt}$  decreases. For high  $v_L$  values at 200 degF, the mass-transfer coefficients for HCl and EDTA are increased by factors of about 2 and 5, respectively. The mass-transfer coefficients for the products are decreased more significantly. However, the decrease is more than offset by products leaking off into the formation and, hence, reducing their concentration near the interface. As a result of these corrections,  $Da$  is increased by a factor of only about 2 if the flow rate is increased to offset the effects of fluid loss.

#### – Reactant leakoff

Fluid loss decreases the amount of reactants transported to the tip of the main wormhole channel because of reactants leaking off into the formation. Although reactant leakoff leads to dissolution of the rock matrix surrounding the wormhole, the dissolution is ineffective because it contributes to propagation of the dominant flow channel. To quantify the effects of fluid loss on the concentration of reactants transported along the wormhole, fluid loss was added to the model for the dissolution of a representative cylindrical tube discussed in “Dependence on the Damköhler number.” Fluid loss (i.e., convection in the radial direction) was included in the reactant mass balance within the cylindrical tube. To obtain an analytical solution, the concentration of reactants leaking off into the formation was assumed to equal the concentration at the solid/liquid interface. This assumption is valid for three cases: zero fluid-loss velocity, reaction-rate-limited dissolution and mass-transfer-limited dissolution. This assumption is commonly used to model fracture acidizing and has been described in more detail in the literature (Settari, 1993). The

resulting expression for the concentration profile along the length of the flow channel is similar to that in Appendix Eq. 8:

$$\frac{C}{C_o} = (1 - B)e^{-(Da + \xi)} + B, \quad (12)$$

where

$$B = \frac{Da}{(Da + \xi)} \left( 1 - \frac{v_L}{K_1} \right). \quad (13)$$

The exponent in Appendix Eq. 12 includes  $Da$  as defined in Appendix Eq. 9 (with  $\kappa$  based on the corrected mass-transfer coefficients, as defined in Appendix Eq. 11) and an additional dimensionless fluid-loss term:

$$\xi = \frac{\pi d l v_L}{q} \left( 1 - \frac{\kappa}{K_1} \right). \quad (14)$$

The obvious importance of  $v_L$  is demonstrated by the fluid-loss term  $\xi$ . As  $v_L$  decreases, the influence of  $\xi$  decreases and  $Da$  eventually dominates the dissolution. Such is the case in linear coreflood experiments in the laboratory. Not so obvious is the dependence of  $\xi$  on the degree of mass-transfer limitations. When dissolution is limited by the transport of reactants to the surface ( $\kappa = K_1$ ),  $\xi$  becomes zero. Physically, this trend is due to the interface concentration of reactants (and, consequently, the concentration of reactants leaking off into the formation) becoming negligible. The leakoff concentration can become negligible even at high rates of fluid loss when the rate of surface reaction is much more rapid than the rate of mass transfer and the rate of fluid loss—i.e., when the dissolution is mass-transfer limited. Thus, for a reactants-transport-limited system such as HCl-limestone, dissolution is dependent on transport and reaction within the wormhole and, hence,  $Da$  dictates the reactant consumption (e.g.,  $Da/(Da + \xi) = 0.999$  for the HCl-limestone system at 200 degF with a high  $v_L$ ). On the other hand, for fluid-mineral systems that are influenced by the kinetics of the surface reaction (e.g., HCl-dolomite and EDTA-limestone at ambient temperature),  $\xi$  and  $Da$  are both significant. Under these conditions, an optimum  $Da + \xi$  may exist. Hence, the dependence of wormhole formation on only  $Da$  is valid for wormhole formation in all fluid-mineral systems when the value of  $\xi$  is low (i.e., in damaged formations with low permeability, when fluid-loss

additives are present or when the wormholes are relatively short) or the dissolution is limited by the transport of reactants to the surface. These conditions are consistent with the assumption used in deriving the analytical solution to this problem.

#### ■ Wormhole competition

During field treatments, many wormholes form and compete for the injected fluid. The longer wormholes, which typically have larger diameters, accept more fluid than the shorter wormholes. As a result, the longer wormholes propagate more rapidly, while the shorter wormholes eventually stop growing as they receive an insufficient amount of reactant (Hoefner and Fogler, 1988; Hung *et al.*, 1989). The number of wormholes that are capable of penetrating to a given depth depends on the length of the competing wormholes and the distance between them. For example, results from simulations in linear geometry have shown that wormhole interactions significantly reduce the flow rate in a wormhole when the distance between neighboring wormholes is less than the wormhole length (Hoefner and Fogler, 1988; Buijse, 1997). In general, the number of dominant wormholes decreases as the depth of penetration increases. In addition, the number of dominant wormholes depends on  $Da$  within each wormhole. At the extremes of high and low  $Da$  values, face dissolution and uniform dissolution result in a single dissolution structure and an infinite number of dissolution channels, respectively. Between these extremes, a gradual increase in the wormhole density is expected as  $Da$  is decreased.

To maintain efficient wormhole formation, the optimum  $Da$  must be maintained in each of the competing wormholes. Therefore, the optimum injection rate required for efficient wormhole formation in laboratory experiments must be scaled by the number of wormholes that will form in the formation. Some investigators have proposed scaling laboratory data by the relative surface areas (i.e., maintaining the same superficial injection velocity) (Buijse, 1997; Frick *et al.*, 1994b). However, this scaling inherently assumes that the same number of wormholes will form per unit surface area in the field as in the laboratory. In general, this assumption overestimates the number of wormholes that will form and, correspondingly, overpredicts the effect of wormhole competition on the optimum injection rate. The importance of maintaining an optimum injection rate per wormhole (i.e., the optimum  $Da$  in each wormhole) is demonstrated by results from laboratory studies. Different wormhole structures were observed during linear coreflood experiments when the cross-sectional area for flow was varied and the superficial

velocity was held constant (Buijse, 1997). In contrast, similar wormhole structures were observed when the cross-sectional area was changed and the injection rate was held constant (C. N. Fredd, unpubl. data, 1989).

### Application of the optimum Damköhler number

The previous section demonstrates the conditions at which wormhole formation is dominated by the dependence on  $Da$ . Because those conditions are typical of conditions often experienced during field treatments, it is reasonable to assume that effective wormhole formation will occur if  $Da$  is maintained near its optimum value. Therefore, an optimum  $Da$  of 0.29 was used as the basis for predicting optimum injection conditions during field treatments. To scale the laboratory observations to the field, additional information about the fluid loss and wormhole competition is required. Although the effects of fluid loss and wormhole competition have not been rigorously investigated, this information can be estimated from the literature. These estimates, along with the method of calculating the optimum injection conditions, are discussed here.

The predictions of the optimum injection conditions are based on determining the injection rate required to maintain an optimum  $Da$  of 0.29. It was assumed necessary to maintain the optimum  $Da$  in only the dominant wormhole channels (i.e., the longer wormholes that carry most of the injected fluid, as shown in Appendix Fig. 7). Therefore, the calculations depend on the number of dominant wormholes that can penetrate to a depth  $l$ . Because the number of wormholes, diameter of the wormholes, growth rate and fluid-loss rate change as the depth of penetration increases, the wormhole properties are evaluated for discrete increases in the depth of penetration. The fluid-mineral system and temperature are specified, and the relevant parameters are evaluated (i.e., diffusion coefficients, surface reaction rates and effective equilibrium constants). The optimum injection rate in a single wormhole of length  $l$  is then determined from Appendix Eq. 9. The change in wormhole diameter is determined from the volume of reactant consumed within the wormhole channel, which is a function of  $Da$  and the wormhole growth rate. The growth rate is calculated by assuming all reactant transported to the tip of the wormhole propagates the wormhole channel by dissolving the tip over the same cross-sectional area as the existing wormhole. The growth rate is

$$\frac{dl}{dt} = r_{At} \frac{MW_A}{\rho_A} X_t, \quad (15)$$

where  $r_{At}$  is the rate of reactant consumption at the tip,  $MW_A$  and  $\rho_A$  are the molecular weight and density of the reactant, respectively, and  $X_t$  is the volumetric

dissolving power (i.e., volume of mineral dissolved by a given volume of reactant) at the tip. The rate of reactant consumption at the tip is given by Appendix Eqs. 4 and 5 with the mass-transfer coefficients replaced by the superficial velocity in the wormhole at the tip, which is a function of the wormhole diameter. Appendix Eq. 15 is similar to the growth rate expression introduced by Hung *et al.* (1989). These calculations require an iterative solution because  $Da$  and the growth rate are functions of the wormhole diameter. (If the system is mass-transfer limited,  $Da$  is independent of the wormhole diameter.) The injection rate determined in this manner represents an average injection rate along the length of the dominant wormhole that is required to maintain the optimum  $Da$  in that wormhole. To achieve that average injection rate, the injection rate into the wormhole must be larger to compensate for fluid loss from the walls of the wormhole. The required injection rate  $q_i$  is approximated as

$$q_i = q + q_L, \quad (16)$$

where  $q$  is the average optimum flow rate within the wormhole (such that the optimum  $Da$  is maintained) and  $q_L$  is the rate of fluid loss. The rate of fluid loss was estimated from predictions for fluid loss from a single wormhole (Wang *et al.*, 1993).

Once the optimum flow rate in a single wormhole has been calculated, the optimum injection rate in the field is calculated by scaling by the number of dominant wormholes that will penetrate to the given depth. Although no study has reported wormhole density as a function of injection conditions, two studies have provided a basis for estimating the parameter. The results of network model simulations indicate that the number of wormholes should scale roughly with the ratio of the inlet area to the depth of penetration (Hoefner and Fogler, 1988). A similar observation was made from a capillary tube model (Buijse, 1997). Both of these studies are based on wormhole structures consistent with the dominant wormhole channels. Because the goal of this extension is to predict the growth and competition of dominant wormhole channels, the wormhole density was estimated on the basis of the scaling observed by Hoefner and Fogler (1988).

### Optimum injection strategies

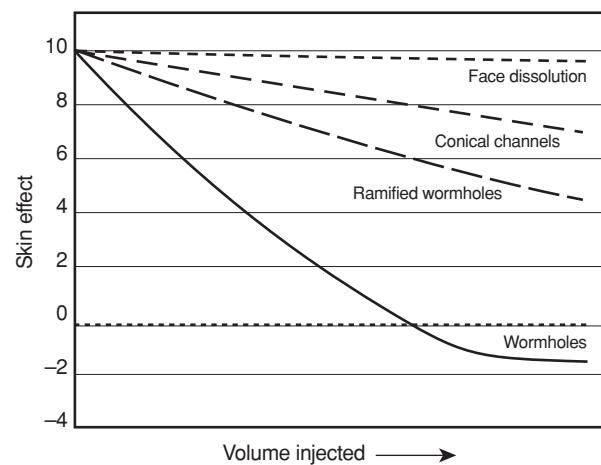
Optimum injection strategies for field treatments were predicted for an optimum  $Da$  of 0.29. The predictions are based on three main assumptions: the value of the optimum  $Da$  is not affected by fluid loss or wormhole competition, the rate of fluid loss is consistent with that predicted for a single wormhole, and wormhole density in the near-wellbore region is consistent with that predicted

by network models. Because these assumptions must be verified experimentally, the optimum injection strategies presented in this section are considered qualitative trends.

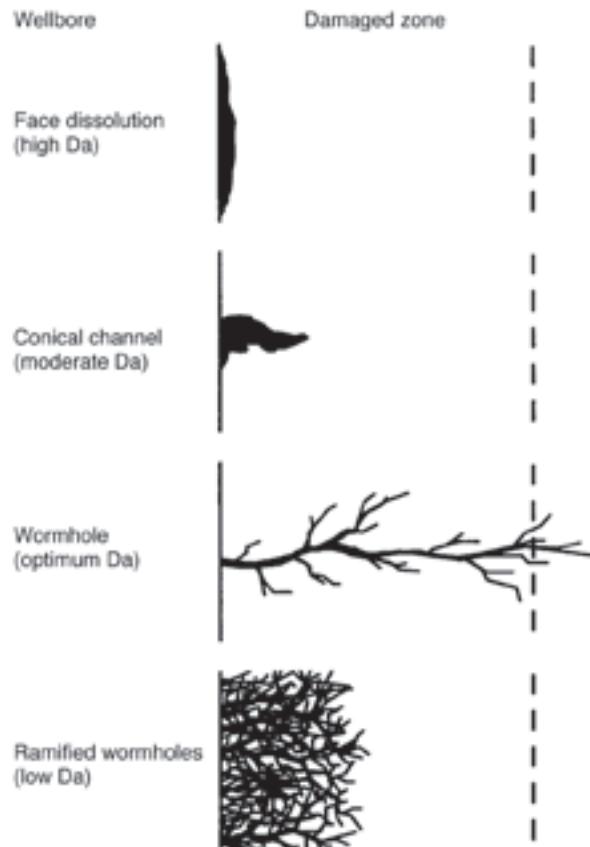
Before optimum injection strategies for field treatments can be presented, it is first necessary to understand how the various dissolution structures, and hence  $Da$ , influence the effectiveness of matrix stimulation treatments. Typical skin effect evolution curves are shown in Appendix Fig. 8 for various dissolution structures. The skin effect was calculated using the three-zone model described by Frick *et al.* (1994a) and the depth of stimulation as determined from the dependence on  $Da$ . The results demonstrate that no significant skin effect evolution is observed when face dissolution occurs. As the value of  $Da$  decreases, the dissolution structure changes to conical channels and a slight decrease in skin effect is observed. Near the optimum  $Da$ , wormhole formation results in effective stimulation as evidenced by the negative skin effect. Additional decreases in  $Da$  result in more ramified wormholes and a less effective evolution of skin effect. This later trend of decreasing effectiveness with decreasing  $Da$  (below the optimum value) is consistent with that predicted by Frick *et al.* for an increasing injection rate.

Appendix Fig. 8 demonstrates that the formation of dominant wormhole channels represents the most effective mode of stimulation for a given volume of fluid injected. This effectiveness is due to the dominant wormhole channels providing the greatest depth of penetration, as shown in Appendix Fig. 9. Obviously the other types of dissolution structures are also capable of stimulation beyond the damaged zone if a sufficient volume of fluid is injected. The trade-off is the cost of the additional fluid injected and possible loss of integrity of the near-wellbore matrix as a result of excessive dissolution.

The influence of the dissolution structure on the effectiveness of the matrix stimulation treatment demonstrates the importance of maintaining the optimum  $Da$ . The question that now must be addressed is how to maintain that optimum injection condition when dissolution is influenced by fluid loss and wormhole competition. The optimum condition can be maintained by increasing the injection rate as the depth of penetration increases. This approach is demonstrated in Appendix Fig. 10, which shows the normalized optimum injection rate required to maintain the optimum  $Da$  as a function of the depth of penetration. The optimum injection rate is normalized by the optimum injection rate for HCl at 200°F with zero fluid loss. The curve represents injection rates at which efficient wormhole formation occurs. At injection rates above and below the optimum curve, ramified wormholes and face dissolution form, respectively. The curves reveal that the injection rate must be increased significantly as the depth of penetration

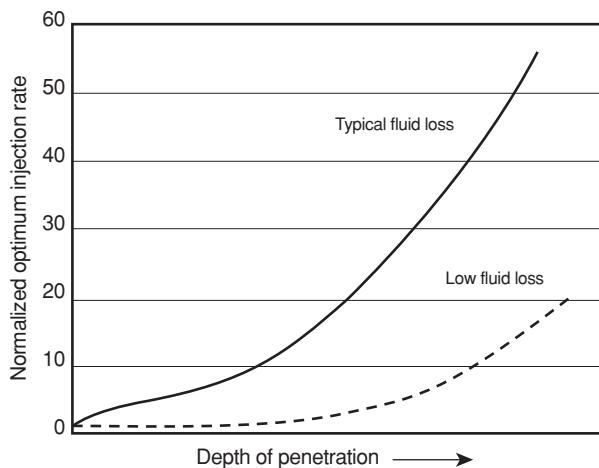


**Appendix Figure 8.** Dependence of skin effect evolution on the dissolution structure.



**Appendix Figure 9.** Schematic of dissolution structures and relative depth of penetration obtained by injecting the same volume of fluid at different  $Da$  values.

increases. This increase in injection rate is necessary to offset the effects of fluid loss from the wormhole channels. The amount of fluid diverted to the dominant wormholes as a result of wormhole competition is not

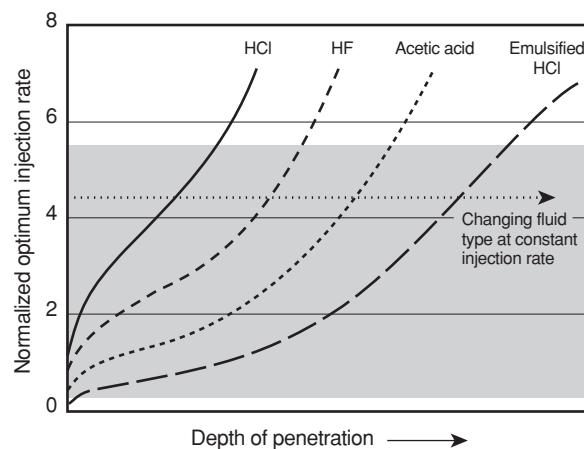


**Appendix Figure 10.** Effect of fluid loss on optimum injection strategies for effective wormhole formation with HCl at 200°F.

sufficient to overcome the effects of fluid loss. When  $v_L$  is low (such as in low-permeability damaged zones), the rate at which the injection rate must be increased is less significant. This effect of fluid loss is consistent with experimental data that demonstrate a decrease in stimulation efficiency when the permeability is increased and the injection rate held constant (Frick *et al.*, 1994b; Mostofizadeh and Economides, 1994).

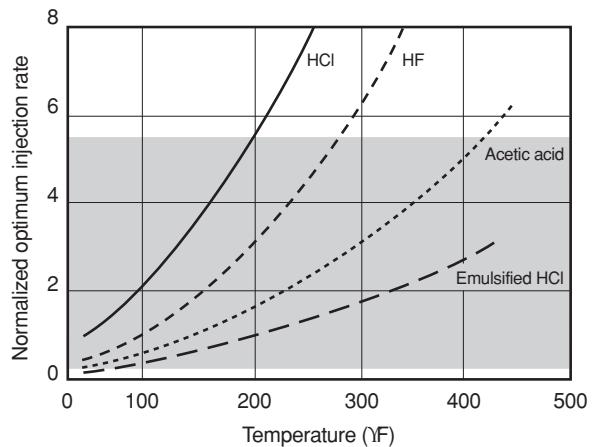
The effect of fluid type on the injection strategy in limestone formations at 200°F is shown in Appendix Fig. 11. The shaded area represents typical injection rates used in conventional matrix stimulation treatments (Paccaloni, 1995). The results show that HCl is unable to achieve significant penetration without requiring excessive injection rates that would fracture the formation. In contrast, alternative fluids such as weak acids and emulsified HCl can stimulate to increasingly deeper depths without exceeding the same maximum injection rate. Under these conditions, emulsified HCl would be the most effective stimulation fluid. Results for EDTA are similar to those of emulsified HCl. The data also demonstrate that weak acids and emulsified HCl are more effective than aqueous HCl when the treatments are limited to low injection rates. This effectiveness at low injection rates is consistent with results reported by previous investigators (Hoefner and Fogler, 1985; Fredd and Fogler, 1998a; Takulpakdee, 1998).

Appendix Fig. 11 reveals an alternative injection strategy, as indicated by the dashed arrow. This strategy involves maintaining a constant injection rate and gradually changing the reactant type (thereby changing the overall rate of dissolution). For example, a more effective stimulation could be achieved by injecting an HCl–acetic acid blend that is gradually changed from HCl to acetic acid as the depth of penetration increases.



**Appendix Figure 11.** Optimum injection strategies for various acid systems at 200°F. The shaded area (Paccaloni, 1995) represents typical injection rates used in matrix acidizing treatments.

The optimum injection rate is a strong function of temperature, as shown in Appendix Fig. 12. To obtain a particular depth of penetration, the optimum injection rate must be increased as the temperature increases. This trend is consistent with experimental results with HCl where increasing the temperature resulted in an increase in the optimum injection rate (Wang *et al.*, 1993; Fredd, 1998). A much more significant dependence of the optimum injection rate on temperature was predicted by Huang *et al.* (1997) because of the emphasis they placed on the kinetics of the surface reaction. Appendix Fig. 12 demonstrates that optimal stimulation with HCl is limited to low temperatures if excessive injection rates and, consequently, fracturing the formation are to be avoided. The figure also reveals that weak acids and emulsified HCl are more effective than aqueous HCl for stimulating high-temperature limestone formations.



**Appendix Figure 12.** Effect of temperature on the optimum injection rate required to achieve a given depth of penetration with various acid systems. The shaded area represents typical injection rates used in matrix acidizing treatments.

This section has provided a means of predicting optimum injection strategies based on laboratory data. With the effective strategies demonstrated, it must be emphasized that the effectiveness of a matrix stimulation treatment depends significantly on the depth of penetration, as shown in Appendix Fig. 8. The depth of penetration is typically limited by fluid loss from the wormholes (Nierode and Williams, 1971; Hung *et al.*, 1989). Therefore, limiting fluid loss is critical to obtaining effective penetration depths, whereas maintaining an optimum  $Da$  is critical to maintaining effective wormhole growth. (Fluid loss from wormholes is inhibited when foamed acids are used for matrix acidization; Bernadiner *et al.*, 1992.) These influences are not independent because fluid loss from the main wormhole channel increases with increasing wormhole branching. Fortunately, effective wormhole formation tends to minimize fluid loss by minimizing wormhole branching. Therefore, effective wormhole formation provides the combined benefits of reducing fluid loss from the dominant channels and reducing the volume of fluid required to achieve a given depth of penetration. Thus, maintaining the optimum  $Da$  can result in significant improvements in the effectiveness of matrix stimulation treatments.

## Conclusions

Wormhole formation in carbonate porous media involves complex interplay between a variety of transport and reaction processes. Stimulation fluids, such as strong acids, weak acids and chelating agents, are influenced by the effects of convection, reactants transport, reversible surface reactions and products transport. Thus, to adequately describe the dissolution phenomenon, a generalized description of carbonate dissolution is required. When the combined effects of transport and reaction are accounted for, a common dependence on  $Da$  for flow and

reaction is observed. The value of  $Da$  dictates the type of wormhole structures that is formed by systems with various degrees of transport and reaction limitations. In addition, there exists an optimum  $Da$  at which dominant wormhole channels are formed and the number of pore volumes to breakthrough is minimized. This optimum  $Da$  occurs at approximately 0.29 for a wide range of fluid-mineral systems. The existence of an optimum  $Da$  was substantiated by network model simulations.

The use of laboratory data to predict the optimum injection conditions in the field, such as fluid type and injection strategy, is complicated by the effects of fluid loss and wormhole competition. From estimates of the effects of these processes on wormhole formation, the theory for the optimum  $Da$  has been extended to predict optimum field conditions. Direct extension of the optimum  $Da$  to the field is valid for three cases: low fluid-loss velocity, reaction-rate-limited dissolution and mass-transfer-limited dissolution. Because these conditions often exist in the field, injection strategies required to maintain the optimum  $Da$  can be used to determine optimum injection conditions in the field. Results predict that to maintain efficient wormhole formation, either the injection rate should be increased or the overall dissolution rate decreased (by changing the fluid type) as the depth of penetration increases. At the injection rates commonly used for matrix acidizing, conventional treatments with HCl are optimal only in low-temperature formations. Fluids such as weak acids and emulsified HCl provide effective alternatives to HCl at high temperatures and low injection rates. The results discussed in this Appendix to Chapter 16 provide qualitative predictions of optimum injection strategies that are in agreement with experimental observations. A rigorous investigation of the effects of fluid loss and wormhole competition on wormhole formation will enable more quantitative predictions of the optimum injection conditions.

# 17. Carbonate Acidizing Design

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## 17-1. Introduction

Carbonate rocks, by definition, contain more than 50% carbonate minerals. The most common carbonate minerals are calcite (calcium carbonate,  $\text{CaCO}_3$ ) and dolomite, a single mineral associating 1 mole of  $\text{CaCO}_3$  with 1 mole of  $\text{MgCO}_3$ . Carbonate rocks are typically classified by the calcite:dolomite ratio, and those with a ratio higher than 50% are generally called limestones. Carbonate rocks present singular physical characteristics, such as double porosity or high permeability contrasts, which are inherited from their process of formation.

Hydrochloric acid (HCl) is usually selected for carbonate acidizing. It reacts readily with carbonate minerals and is available in large quantities at a relatively low price. Whereas the purpose of sandstone acidizing is to dissolve the damage, acid is used in carbonate formations to dissolve the matrix and bypass the damage. For this reason, both damage and rock characteristics must be taken into account when designing the treatment.

## 17-2. Rock and damage characteristics in carbonate formations

### 17-2.1. Rock characteristics

Carbonate rocks are sedimentary rocks resulting mostly from organic activity. The vast majority of these sediments is composed of skeletons of marine organisms that vary in size from a few microns to several centimeters. Some carbonate sediments are formed by the chemical precipitation of  $\text{CaCO}_3$ .

Because they consist of noneroded, homogeneous materials, carbonate sediments usually have a high initial porosity. Conversely, because the permeability of sediments depends mainly on grain size, carbonate rocks present a wide range of permeabilities. For example, chalks formed from sediments of microscopic fossils have low permeabilities in comparison with those of oolithic limestones, although they can have similar porosities.

After deposition, carbonate sediments are subject to chemical and physical transformation (diagenesis). Chemical modifications consist primarily of the evolution of the sediments to stable forms such as calcite and dolomite. This process is called neomorphism. Dolomites result from evolution under long-term contact with fluids with a high magnesium content. Dolomitization usually increases porosity but impairs permeability by precipitating dolomite crystals. When dolomites are in contact with rainwater, the inverse process of dedolomitization can occur.

Modifications of permeability and porosity can also result from other chemical transformations such as dissolution, reprecipitation and cementation while in contact with subterranean water or molecular diffusion during severe subsurface conditions. Stress and pressure modifications occurring upon burial

of the sediments may also entail a lithologic change, with porosity and permeability reductions. High in-situ pressures result in grain compaction, with loss of most of the interstitial water. Higher pressures trigger physical dissolution with immediate reprecipitation causing pore lining. If the interstitial water can be expelled, grain joints are also dissolved and reprecipitated, decreasing the rock porosity to nearly zero and creating fissures of residual circulation. Carbonate sediments are much more sensitive to these phenomena than sandstones are. For example, a chalky mud becomes a compact calcitic rock at depths greater than 6,500 ft if all the interstitial water escapes. Mechanical stress modifications also induce fractures, which are important for the economic viability of carbonate reservoirs.

Carbonate reservoirs present a wide range of porosities and permeabilities, depending on the degree of reprecipitation and cementation. Many carbonate reservoirs are fissured under the action of tectonic stresses and behave like homogeneous, primary porosity reservoirs, with an apparent permeability several orders of magnitude higher than the rock permeability.

## 17-2.2. Damage characteristics

Damage identification is a prerequisite to the proper design of a carbonate acidizing treatment. In formations that are highly sensitive to acid, nonacidic formulations should be used, and the choice of the treating fluid is usually determined by the type of damage. Furthermore, the volume of treating fluid depends on the extent and location of the damage.

All the types of damage that occur in sandstone formations (see Chapter 14) can occur in carbonate formations, except those related to the presence of clay particles in the matrix. In addition, poorly cemented chalks can be permanently impaired by acidic water-base fluids, which can easily dissolve the calcitic cement material, resulting in formation compaction from a loss of mechanical strength.

Problems related to fluid surface tension (i.e., water blocks) are not expected in fissured reservoirs with low matrix permeabilities. In this type of formation, induced damage is concentrated in the fissures, and a greater invasion depth is expected than in a homogeneous reservoir. Pressure variation in the fissures can also result in the precipitation of mineral (scales) and hydrocarbon (asphaltenes) deposits.

## 17-3. Carbonate acidizing with hydrochloric acid

### 17-3.1. Introduction

HCl is generally selected for carbonate acidizing. It can be replaced by organic acids, mainly to minimize corrosion problems at temperatures greater than 400 degF [205 degC]. The purpose of acidizing with HCl is either to bypass the damage by creating high-conductivity channels (also called wormholes) or to etch partially plugged fissures in low-permeability fissured formations. Although mere permeability restoration is usually targeted for sandstone formations (zero damage skin effect), carbonate acidizing commonly results in negative skin effects. This is due to the reopening of natural fissures and creation of high-permeability wormholes in the near-wellbore area.

HCl can be retarded through the use of emulsions or microemulsions to prevent rock deconsolidation. In this case the wormholes are replaced by a more uniform increase of pore size throughout the stimulated zone. Deep penetration of live acid is obtained by reducing the contact area between the acid and the rock.

### 17-3.2. Historical background

Acidizing was one of the earliest methods developed for increasing well productivity, along with nitro shooting. The technique was first used in 1895, with patents issued in 1896. The original Frasch (1896) patent describes a technique in which HCl is injected into a limestone formation, where it reacts to create channels within the rock. Frasch did not envision the use of corrosion inhibitors, and his process required pipe lined with rubber or some other corrosion-resistant coating.

Although the early acidizing treatments produced some impressive results, their actual use declined within a few years, possibly because of corrosion problems resulting from the uninhibited acid. About 30 years later, the Gypsy Oil Company performed a number of well treatments in sandstone formations in which inhibited HCl was used in an attempt to remove "gyp" deposits (calcium sulfate). The inhibitor used had been developed earlier in the steel industry for the acid pickling of metals. The treatment results were mostly unimpressive, and no patents were filed on the process.

The modern era of acidizing began on February 11, 1932, when the Dow Chemical Company siphoned 500 gal of HCl containing 2 gal of an arsenic inhibitor into a well owned by the Pure Oil Company and displaced it with an oil flush. This was the first use of an inhibited acid on a limestone formation. The previously dead well responded by producing 16 BOPD.

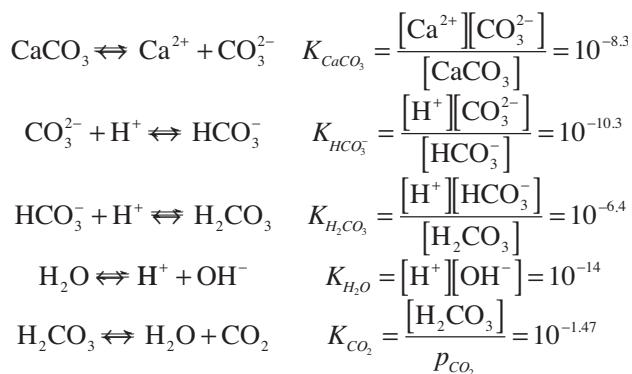
The first treatments were apparently done in an attempt to dispose of surplus HCl. However, it was soon noted that these acid disposal wells accepted fluid at an increasing rate. Treatments performed later on brine-producing wells at the Dow plant in Midland, Michigan, resulted in increased brine flow, prompting the idea that the process might also have application for oil wells.

The use of inhibited acid to treat oil wells spread quickly, and the Dow Well Service Group was formed to exploit this new process. The first two words of the company's name were combined, becoming Dowell, Inc., in November 1932. Other service companies soon followed. Within 3 years, acidizing was practiced widely.

The first hydraulic fracturing treatments were probably performed with acid, although they were not recognized at the time. Wells in tight carbonate formations would usually not accept acid until a critical pressure was reached. However, after this pressure was reached, acid could be easily injected at high rates. It was later recognized that these wells had been hydraulically fractured. For this reason, later hydraulic fracturing patents were never enforced against acid fracturing treatments.

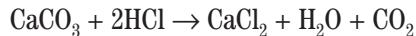
### 17-3.3. Reactivity of carbonate minerals with hydrochloric acid

Calcium carbonate reacts with HCl to produce carbon dioxide, water and calcium chloride. This system is governed by several chemical reactions (Garrels and Christ, 1965), listed as follows with their values of the equilibrium constant  $K$ :



where the use of square brackets indicates the concentration in mol/L and  $p_{\text{CO}_2}$  is the pressure of carbon dioxide.

Because  $\text{H}_2\text{CO}_3$  is a weak acid, and the concentrations of  $\text{HCO}_3^-$  and  $\text{CO}_3^{2-}$  are negligible in presence of HCl, the reaction of  $\text{CaCO}_3$  with HCl can be written as



For dolomite, the reaction equation becomes



This solid-liquid reaction takes place at the rock surface. In excess of HCl, it is complete and irreversible. Table 17-1 lists the quantities of different by-products of the reaction of 15% HCl with calcite. Calcium chloride ( $\text{CaCl}_2$ ) and magnesium chloride ( $\text{MgCl}_2$ ) are highly soluble in spent acid and present no risk of reprecipitation.

**Table 17-1. Quantities of by-products created by the reaction of 15% HCl and limestone.**

HCl	$\text{CaCO}_3$	$\text{CO}_2$	$\text{H}_2\text{O}$	$\text{CaCl}_2$
1000 gal	1846 lbm	6616 scf	343 lbm [41 gal]	2121 lbm

The reaction rate  $K_r$ , expressing the moles of acid reacting per square meter of wetted surface area per second, depends primarily on the temperature and acid concentration:

$$K_r = k_r C^n, \quad (17-1)$$

where  $k_r$  is the reaction rate constant,  $C$  is the HCl concentration in mol/m<sup>3</sup>, and  $n$  is the reaction order. The terms  $k_r$  and  $n$  have been determined experimentally (Lund *et al.*, 1973, 1975; Li *et al.*, 1993). The constant  $k_r$  varies with temperature according to Arrhenius' law, and the coefficient  $n$  varies with temperature for dolomite. The reaction of limestone with HCl is fast and cannot be measured at room temperature. Lund *et al.* (1975) measured limestone reactivity with a rotating disk apparatus at a maximum temperature of 28.4 degF [-12 degC]. Dolomite is less reactive, and reaction rates can be measured at much higher temperatures (212 degF [100 degC]).

The reaction rates obtained by Lund *et al.* are given in Chapter 16. The following example provides the order of magnitude of the reactivity of limestone and dolomite: assuming a reaction-rate-limited process (see Section 17-3.4) and using data from Lund *et al.* (1973, 1975), it can be calculated that at 75 degF [25 degC], the thickness of a rotating disk of calcite reacting with excess 5% HCl decreases by 1.2 um/min. This value drops to 1.4 um/min for dolomite at the same conditions.

Weak acids such as formic acid or acetic acid also react with carbonate rocks. However, the high concentration of  $\text{CO}_2$  produced by the reaction prevents it from going to completion, even in the presence of excess fresh acid.

### 17-3.4. Acidizing physics

#### ■ Reaction process

A solid-liquid reaction such as HCl with carbonate minerals involves the transport of hydronium ions ( $\text{H}_3\text{O}^+$ ) to the rock surface, reaction of the ions with the rock and transport of the reaction products from the surface to solution. When one of the steps is much slower than the others, it imposes itself on the reaction rate and is said to be the limiting step. Lund *et al.* (1973, 1975) studied the reaction rate of calcite and dolomite with HCl using the rotating disk technique. Theory predicts that for a diffusion-limited process, the rate of dissolution is proportional to the square root of the rotation speed and to the bulk concentration. Lund *et al.* found that the reaction with calcite at room temperature and higher is transport limited, whereas dolomite switches from reaction rate limited to diffusion rate limited between 125 degF and 212 degF [50 degC and 100 degC]. These results were confirmed by de Rozières *et al.* (1994). On the other hand, Wang *et al.* (1993) argued that at the pore level the reaction rate determines the overall rate of acid consumption, thereby implying that the process is reaction rate limited.

Reaction rate limited and diffusion rate limited represent extreme cases in which one phenomenon is much slower than the others. There is also an intermediate case in which different processes have kinetics of the same order of magnitude and influence each other. Both the diffusion rate and the reaction rate depend on ion concentrations at the surface. Therefore, for surface concentrations of the same range as the bulk concentration, transport by diffusion and the reaction rate are interdependent phenomena. This is the case for dolomite and HCl at intermediate temperatures and for calcite and ethylenediaminetetraacetic acid (EDTA) at room temperature (Fredd *et al.*, 1997).

#### ■ Wormholing phenomenon

Limestone cores acidized with HCl show the formation of macroscopic channels, called wormholes. Most of the published experiments were performed with linear cores (radial section, flow parallel to the longitudinal axis). They show that the acid injection rate affects the geometry of the channels and the amount of acid required for breakthrough. Daccord *et al.* (1989) found that wormholing occurs in limestone cores above a critical flow rate and that within the wormholing region the volume required for breakthrough increases with the rate at a power of  $\frac{1}{3}$ . These results were confirmed by Wang (1993) for calcite and dolomite at high temperatures.

Wormholing can be explained by the instability of the acidizing phenomenon: bigger pores tend to receive more acid, which increases both their area and length. This eventually creates a macroscopic channel, or wormhole, that accepts more acid than the surrounding pores and propagates through the core. Wormhole branching depends on the injection rate. Near the wormholing threshold, a single, thick wormhole is formed. As the injection rate is increased, a denser network of thinner channels is created.

Computer network simulations have been used to replicate the wormholing phenomenon (Hoefner and Fogler, 1988; Pichler *et al.*, 1992; Lauritzen *et al.*, 1992). The porous medium is represented by a two-dimensional (2D) network of capillaries. In each pore, the flow obeys Kirchoff's laws, and the growth of each pore is assumed to follow a given function. These 2D models are extensions of the one-dimensional analytical model of Schechter and Gidley (1969) and Guin and Schechter (1971). Similar results are obtained with regard to the development of unstable patterns. The main advantage of the models is that the dissolution function and flow parameters can be changed in a much wider range than experimentally

possible. In these simulations, the occurrence of fractal behavior is bounded by two extreme cases (Fig. 17-1):

- At low velocity, molecular diffusion is predominant, and the solution becomes saturated before any appreciable volume can enter the pore.
- At high velocity, the thickness of the boundary layer becomes so small that the kinetics crosses over to surface reaction rate limited. The velocity is sufficiently high compared with the dissolution rate to allow the invasion of all pores by fresh solution. Uniform etching occurs.

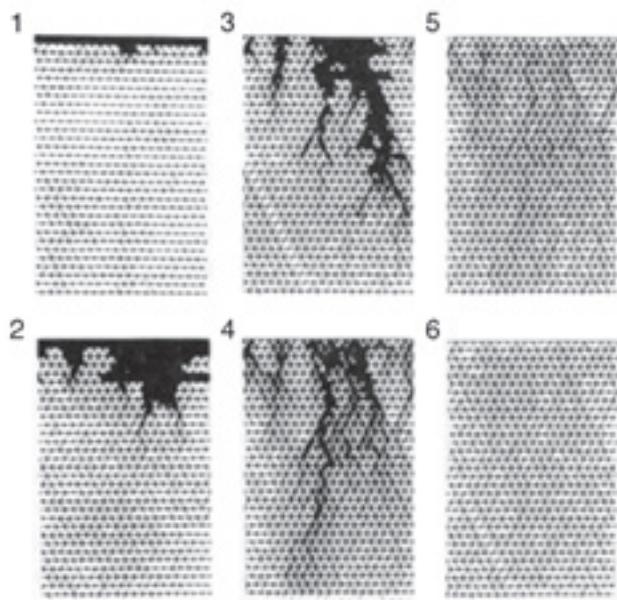
Daccord *et al.* (1993) presented a dimensionless analysis in which the rate of acid diffusion toward the pore walls is compared with the rate of acid convection into the pore. For a wormhole to form, the initial pore radius must be large enough to allow acid transport beyond the pore inlet (see Sidebar 17A). Wang *et al.* (1993) presented a different analysis but came also to the conclusion that a critical initial pore size is required to initiate a wormhole.

According to Daccord *et al.* (1989, 1993), the Peclet number  $Pe$ , which represents the ratio of axial flow to radial transport in the pores, is the dimensionless variable governing the transition between compact dissolution at low rates and wormholing at higher rates for a transport-limited reaction (i.e., calcite and high-temperature dolomite). The Peclet number is

$$Pe = \frac{mq\sqrt{k}}{\phi AD}, \quad (17-2)$$

where  $m$  is a coefficient introduced for consistency with earlier publications,  $q$  is the total injection rate,  $k$  is the matrix permeability,  $\phi$  is the porosity,  $A$  is the area perpendicular to flow, and  $D$  is the diffusion constant. The coefficient  $m$  is equal to 1 for a linear geometry and 2 for radial flow.

Table 17-2 shows the results of linear core tests with various values of acid concentration,  $Pe$  and temperature. The dimensionless volume to breakthrough is the ratio of the pore volumes to breakthrough to the volume required for complete dissolution of the core. The limit for wormholing is between  $Pe = 10^{-3}$  and  $Pe = 10^{-2}$ . The tendency for the critical Peclet number to increase with acid concentration has been explained by the onset of gravity phenomena caused by the difference between the fresh and spent acid densities, which creates additional currents near the pore walls that modify the effective acid diffusivity (Daccord *et al.*, 1989).



**Figure 17-1.** Dissolution patterns observed with a network model (Hoefner and Fogler, 1988). The width of the bonds is proportional to the amount of material removed for 6 orders of magnitude of the Peclet number (1 = lowest, 6 = highest). Flow is from top to bottom.

Fredd *et al.* (1997) used the generalized Damköhler number  $Da$  instead of  $Pe$ :

$$Da = \frac{2\pi r L K}{q_c}, \quad (17-3)$$

where  $r$  is the capillary radius,  $L$  is the capillary length,  $K$  the overall reaction rate taking into account transport by diffusion and reaction, and  $q_c$  is the rate in the capillary. This method enables extending the analysis to systems that are not purely transport limited. Fredd *et al.* reported a series of tests with linear calcite cores and different solvents (EDTA, acetic acid and 1.7% HCl [0.5N]). For all systems the critical Damköhler number is equal to 0.29.

Limestone cores acidized with acetic acid exhibit wormholes with more branching than acidizing with HCl at the same injection rate, and lower live acid penetration is obtained (Hendrickson, 1972; Fredd and Fogler, 1996). Rotating disk measurements indicate that the dissolution of limestone by acetic acid is mass-transport limited (G. Daccord, pers. comm., 1988; Fredd *et al.*, 1997), and the effective diffusivity of acetic acid is lower than that of HCl (Table 17-3). The lower overall reactivity of systems such as EDTA and acetic acid allows fresh acid to penetrate into more pores and causes the more homogeneous dissolution pattern. It also lowers the transition rate between compact dissolution and the wormholing regime (Fredd and Fogler, 1996).

#### ■ Radial geometry

Very few results have been published for acidizing tests using radial geometries. Daccord *et al.* (1989) used a plaster and water system to obtain casts of wormhole patterns (Fig. 17-2). From the experimental data, they derived a formula in Eq. 17-4 linking the apparent stimulation radius  $r_{ac}$  with the injected acid volume  $V_{ac}$ . The apparent stimulation radius is calculated from the pressure differential across the core, assuming that the pressure differential in the wormholes is null:

$$V_{ac} = \frac{\pi r_w^2 h Pe^{1/3}}{A_c} \left[ \left( \frac{r_{ac}}{r_w} \right)^d - 1 \right], \quad (17-4)$$

where  $r_w$  is the wellbore radius,  $h$  is the core height,  $Pe$  is the Peclet number as defined in Eq. 17-2, and  $A_c$  is the acid capacity number:

$$A_c = \frac{CV_M}{\Omega(1-\phi)}, \quad (17-5)$$

where  $C$  is the acid concentration,  $V_M$  is the molar volume, and  $\Omega$  is the stoichiometric coefficient (2 for calcite, 4 for dolomite).

**Table 17-2. Acidizing results for Indiana limestone cores.**

Acid Concentration (N)	Temperature	Pe	Dimensionless Volume to Breakthrough	Reference
0.147	75°F [25°C]	5.5E-3	3.2E-3	Wang (1993) <sup>†</sup>
0.235	125°F [50°C]	8.9E-3	7.5E-3	G. Daccord (pers. comm., 1988)
0.47	75°F	4.6E-3	1.0E-2	G. Daccord (pers. comm., 1988)
0.47	175°F [80°C]	6.7E-3	1.1E-2	G. Daccord (pers. comm., 1988)
1	75°F	9.6E-3	3.11E-3	Wang (1993) <sup>†</sup>
1	125°F	2.2E-2	9.75E-3	Wang (1993) <sup>†</sup>
4.4	75°F	4.9E-2	6.47E-3	Wang (1993) <sup>†</sup>

<sup>†</sup> Data for the near-critical Peclet number

## 17A. Wormhole initiation and propagation

Acid transport inside a pore can be schematically represented by two perpendicular fluxes: axial transport by convection and transport to the pore walls by diffusion.

The diffusion constant  $D$  expresses the ability of ions to migrate when submitted to a concentration gradient:

$$J = D \frac{dC}{dx}, \quad (17A-1)$$

where  $J$  is the acid flux (i.e., the number of moles passing through a unit surface per unit time) and  $dC/dx$  is the concentration gradient. In a pore, because of acid reaction with the rock, the acid concentration at the walls is lower than the bulk concentration. Levich (1962) used boundary layer theory to calculate the rate of diffusion in a capillary:

$$I = 2\pi C_0 D \left( \frac{q_c l^2}{\pi D} \right)^{1/3}, \quad (17A-2)$$

where  $I$  is the diffusion flux in the capillary in mol/s,  $C_0$  is the acid concentration at the capillary inlet,  $q_c$  is the rate in the capillary, and  $l$  is the capillary length.

Under laminar flow conditions, the rate in the capillary  $q_c$  is

$$q_c = \frac{\pi r^4}{8\mu} \frac{\Delta p}{l}, \quad (17A-3)$$

where  $r$  is the capillary radius,  $\Delta p$  is the pressure drop in the capillary, and  $\mu$  is the dynamic viscosity.

Wormholing results from the instability of acid propagation: the rate in a wormhole (or a pore) is proportional to  $r$  to the 4th power (Eq. 17A-3), whereas the rate of acid consumption, equal to the diffusion flux for transport-limited reactions, is proportional to the flow rate to the  $1/3$  power (i.e.,  $r^{4/3}$ , Eq. 17A-2). Therefore, bigger pores accept more and more acid, compared with smaller pores, and the acid is used to increase the

pore length and diameter, which promotes wormhole propagation. Once a wormhole is formed, it tends to capture the whole flow because the pressure drop  $\Delta p$  in a wormhole is negligible compared with  $\Delta p$  in the matrix.

Assuming that a pore is a site for wormhole initiation if only one-half of the fresh acid is spent within a length equal to the pore radius:

$$\frac{q_c C_0}{2} = 2\pi C_0 D \left( \frac{q_c r^2}{\pi D} \right)^{1/3}. \quad (17A-4)$$

Equation 17A-4 leads to

$$\frac{q}{Dr\pi} = \frac{ur}{D} = 8, \quad (17A-5)$$

where  $u$  is the axial velocity in the capillary.

The limit between a transport-limited and a convection-limited regime is therefore defined by the Peclet number  $Pe$  from Eq. 17A-6. For a low value of  $Pe$  (low rate or small radius), all the acid is spent at the pore inlet. For a high value of  $Pe$ , fresh acid is transported beyond the pore inlet and a wormhole is created:

$$Pe = \frac{ur}{D}. \quad (17A-6)$$

If a low injection rate is applied, all pores are below the critical rate for wormhole initiation and all the acid is consumed at the wellbore face. This is compact dissolution. Compact dissolution produces poor stimulation and should be avoided. As the rate increases, the fraction of pores able to initiate wormholing increases, which leads to a denser network of wormholes.

A similar analysis can be performed for a reaction-limited process. In that case, the dimensionless number derived is the Damköhler number  $Da$ , expressing the ratio of axial flow to the rate of consumption at the pore walls (Daccord *et al.*, 1993).

- Rate of wormhole propagation increases with acid strength.
- Rate of wormhole propagation increases as the temperature is increased (acid diffusion increases).
- Within the wormholing regime, the volume for breakthrough increases with the injection rate at  $1/3$  power.

**Table 17-3. Effective diffusivity coefficients ( $m^2/s$ ) for 0.5N acetic acid at different temperatures.**

73°F [23°C]	165°F [75°C]	230°F [110°C]	Reference
$1.14 \times 10^{-9}\dagger$	$2.7 \times 10^{-9}\ddagger$	$4.0 \times 10^{-9}$	Dunn and Stokes (1965)
$0.21 \times 10^{-9}$	$0.51 \times 10^{-9}$	$0.74 \times 10^{-9}$	Nierode and Williams (1970) <sup>§</sup>
$0.08 \times 10^{-9}$	$0.40 \times 10^{-9}$	$0.57 \times 10^{-9}$	G. Daccord (pers. comm., 1988)

Note: For comparison, the diffusivity for 0.5N HCl at 73°F is  $2.4 \times 10^{-9} m^2/s$ .

<sup>†</sup> Value at 75°F [25°C]

<sup>‡</sup> Extrapolated from data at 75°F

<sup>§</sup> Extrapolated from data for 2N acetic acid at 199°F [93°C]



**Figure 17-2.** Cast of a wormhole pattern in radial geometry (Daccord and Lenormand, 1987).

However, the constant  $a$  varies with the system considered. Daccord *et al.* (1993) found that  $a = \frac{1}{84}$  for the plaster and water system. Frick *et al.*'s (1994b) data indicate that the constant  $a$  is approximately  $\frac{1}{18}$  for low-concentration acid (4% HCl) and  $\frac{1}{4}$  for high-strength acid (30% HCl). These different values could be explained by gravity effects or differences in the pores structures of the systems studied. Discrepancies may also be due to different test conditions; i.e., data from Frick *et al.* were obtained with low-permeability rock and low rates (maximum  $Pe$  of  $6E-2$ ), near the compact dissolution/wormholing transition, whereas Daccord *et al.* studied higher  $Pe$  values for which the wormholing regime was fully established.

### 17-3.5. Application to field design

#### ■ Injection rate

To ensure wormhole propagation and successful treatment, the acid velocity near the wellbore should be sufficiently high to reach the wormholing regime. Examples of the rates required to exceed the critical velocity at the wellbore are in Table 17-4. The critical rate is calculated from Eq. 17-2, with the critical  $Pe$  taken as  $5E-2$ .

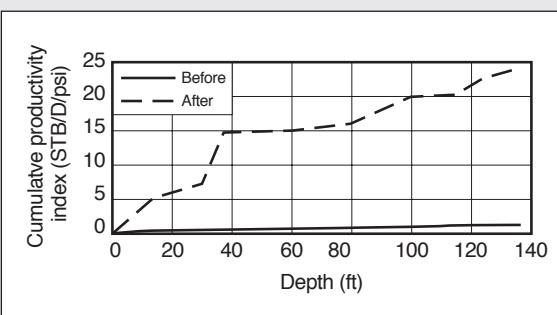
Table 17-4 shows that pump rates applied for matrix acidizing are usually well above the critical rate for wormholing. Field data generally confirm these results and show that good stimulation can be obtained even with moderate pumping rates over large intervals (see the case study in Sidebar 17B).

It is common practice to increase pumping rates as injectivity increases during a treatment. Applying high rates ensures that all portions of the reservoir reach the wormholing regime, even in case of injectivity contrasts between different zones. It also allows sustaining wormhole growth as the stimulation radius increases and the velocity at the acid front decreases. Furthermore, in fissured reservoirs where the purpose of the treatment is to clean up fissures, applying high rates increases the live acid penetration.

### 17B. Acidizing case study

The well was acidized with 60 gal/ft of 20% HCl pumped through coiled tubing over a 135-ft interval. The pumping rate was limited to 2 bbl/min. Permeability varied from 15 to 150 md. Foamed diesel was pumped between the acid stages for diversion.

Figure 17B-1 compares the production profiles before and after stimulation. The new open interval between 31 and 37 ft corresponds to a high-permeability zone. The poorly producing zone between 37 and 79 ft corresponds to a zone of low porosity, according to the results of a log survey. The stimulation increased the well productivity index from 1.1 to 23.9 STB/D/psi. These results indicate that successful stimulation can be achieved at moderate injection rates, provided that coverage of the whole producing interval is ensured.



**Figure 17B-1.** Flow profiles before and after treatment.

## ■ Acid volumes

The results listed in Table 17-2 indicate that at optimum conditions (i.e., the near-critical rate), breakthrough is obtained when less than 1% of the total core has been dissolved. This indicates that designing fluid volumes for 5% to 10% rock dissolution over the stimulated area should provide a conservative design. For a radial geometry, the volume of acid required for a given porosity increase varies with the square of the treatment radius, assuming homogeneous dissolution. Figure 17-3 shows the volume of HCl required to increase porosity by 10% for different values of the treatment radius. For example, 50 gal/ft of 15% HCl is required to increase the porosity by 10% up to 2 ft from the wellbore.

For a more accurate design, use of a numerical simulator is required (Bartko *et al.*, 1997). Using a finite-difference simulator enables tracking acid velocity and mineralogy evolution. The amount of rock dissolved as a function of time and acid location can then be calculated in each grid block using local conditions of mineralogy and acid concentration and velocity. Reaction parameters and the rate of wormhole growth are correlated from experimental data obtained with linear cores for a broad range of flow and acid conditions. Tracking the wormhole propagation front allows calculating a skin effect factor  $s$ , assuming an infinite permeability in the stimulated area:

$$s = -\ln\left(\frac{r_{ac}}{r_w}\right). \quad (17-6)$$

Table 17-5 lists examples of stimulation radii required for different values of skin effect. The completion skin effect resulting from partial completion or well deviation must be added to the stimulation skin effect to obtain the total formation skin effect.

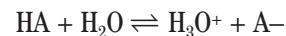
Using a simulator provides a more accurate calculation of skin effect evolution than Eq. 17-6 because factors such as the decrease of velocity as the acid front progresses into the formation and heterogeneities in the reservoir can be taken into account.

## 17-4. Other formulations

### 17-4.1. Organic acids

Organic acids are used instead of HCl when high bottomhole temperatures prevent efficient protection against corrosion (above 400 degF). The two main types of organic acids used are acetic acid and formic acid. Acetic acid is easier to inhibit than formic acid and is used more often. Table 17-6 lists examples of corrosion inhibition with organic acid and HCl.

Organic acids are weak acids, which do not totally dissociate in water. The equilibrium reaction is written as

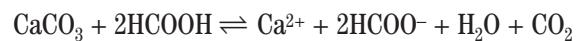
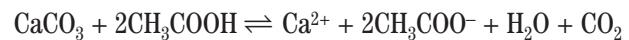


The equilibrium is characterized by the dissociation constant  $k_d$ :

$$k_d = [\text{H}_3\text{O}^+] [\text{A}^-] / [\text{HA}]. \quad (17-7)$$

The dissociation constant  $k_d$  depends on the type of acid and varies with temperature. At 75 degF, acetic acid has a dissociation constant of  $1.76 \times 10^{-5}$  mol/L and formic acid has a dissociation constant of  $1.77 \times 10^{-4}$  mol/L. The value of  $k_d$  increases slightly with temperature up to 175 degF [80 degC] and then decreases as the temperature increases further. This implies that at usual reservoir conditions, organic acids are less reactive than at surface conditions.

Acetic and formic acids react with  $\text{CaCO}_3$  to form calcium acetate and formate, respectively:

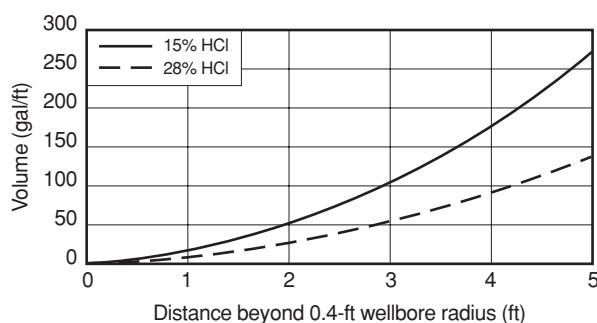


Calcium acetate is highly soluble in spent acid (374 g/L at 75 degF). High concentrations of acid, up to 20% to 25%, can be used without any precipitation problem, although concentrations above 10% are generally not used (Table 17-7). Calcium formate and magnesium formate are much less soluble (162 and 140 g/L at 75 degF, respectively). Formic acid strength should be limited to 9% to 10% to avoid calcium formate reprecipitation.

**Table 17-4. Critical flow rates (bbl/min/10 ft) for transport-limited regimes.**

<b>Critical Flow Rate, at Sandface</b>	<b>15% HCl</b>		<b>28% HCl</b>	
	<b><math>k = 5 \text{ md}</math></b>	<b><math>k = 100 \text{ md}</math></b>	<b><math>k = 5 \text{ md}</math></b>	<b><math>k = 100 \text{ md}</math></b>
Cased completion	0.015	0.003	0.031	0.006
Openhole, 0.8-ft diameter wellbore	0.14	0.03	0.3	0.063

Notes: Diffusivities were computed at 150°F [65°C]. For the perforated case, a density of 4 shots per foot (spf) was assumed, with an 8-in. perforation length and 0.4-in. perforation diameter. Porosity = 15%. These are the critical rates at the wellbore. Higher rates are required to sustain wormhole growth in the matrix.



**Figure 17-3.** Acid volume required to increase porosity 10% (absolute) as a function of the depth of live acid reaction.

**Table 17-5. Stimulation radii for different values of skin effect.**

Skin Effect	Stimulation Radius (ft)
-1	1.1
-2	3
-3	8

Note: Calculated using Eq. 17-6 for a 0.4-ft wellbore radius

**Table 17-6. Maximum protection times for different acids and temperatures.**

Acid	Temperature	Maximum Protection Time (hr)
15% HCl	375°F [190°C]	8
	400°F [205°C]	4
28% HCl	350°F [175°C]	4
10% acetic acid	400°F	24
	500°F [260°C]	16

**Table 17-7. Quantities of calcite and dolomite dissolved per volume of acid, assuming complete spending.**

Acid	Calcite	Dolomite
10% formic	1000 gal	920 lbm [5.4 ft <sup>3</sup> ] 854 lbm [4.8 ft <sup>3</sup> ]
10% acetic	1000 gal	720 lbm [4.3 ft <sup>3</sup> ] 663 lbm [3.7 ft <sup>3</sup> ]

When weak acids attack  $\text{CaCO}_3$ , an equilibrium is established between the chemical species produced by the reaction (see the first five reactions in Section 17-3) and the acid species ( $\text{HA} + \text{H}_2\text{O} \rightleftharpoons \text{H}_3\text{O}^+ + \text{A}^-$ ). In static conditions, the degree of completion of the reaction depends on the concentration of  $\text{CO}_2$  in solution. For instance, at high-pressure conditions (typically above

1,000 psi), only one-half of 10% acetic acid reacts with limestone at 150 degF [65 degC]). In similar conditions, 80% of 10% formic acid reacts. Although some live acid remains once the reaction reaches equilibrium, a low pH is not maintained because of buffering by the reaction products. Acetic acid is also beneficial for preventing ferric hydroxide precipitates, because it creates a weak complex with the iron in solution and thus increases the pH at which hydroxide precipitation occurs (Crowe, 1985). This effect is particularly significant at low temperatures (i.e., below 125 degF). At higher temperatures, some delay of ferric hydroxide precipitation is expected.

Formic and acetic acids can be pumped together, but usually only one acid is selected. Mixtures of organic acid and HCl are also used. The design volume depends on the suspected damage extent around the wellbore. Because organic acids react more homogeneously than HCl, larger volumes are required. Good results have been reported with volumes of the order of 100 gal/ft of 20% acid mixture if proper placement is ensured (Ridwan and Cannan, 1990). Organic acids are much more expensive than HCl per unit volume of rock dissolved. The economics of the treatment must be taken into account for the design.

Acetic acid has other specific applications. Combined either with an aromatic solvent and a mutual solvent to obtain a clear solution or with methanol, it is used to remove water blocks and break emulsions. Combined with a highly concentrated corrosion inhibitor, it can be used as completion fluid to keep the pH low near the wellbore and prevent clay swelling or as a perforating fluid. In the latter case, organic acids are preferred to HCl at temperatures above 200 degF [95 degC] because their reduced reactivity at higher temperatures enables good corrosion protection for several days.

#### 17-4.2. Gelled acids

Gelled acids were developed primarily for fracturing but have found some applications in matrix acidizing. They are used in acid fracturing to increase the viscosity and decrease the leakoff rate. The same principle applies to matrix acidizing conditions in fissured or vugular formations with low primary porosity. In this case, gelled acids are used mainly to clean up the high-permeability channels and minimize fluid loss in the lower permeability matrix. Gelled acids can also be used as a carrier fluid for ball sealers or particulate diverters (flakes).

In the design of gelled acid treatments, the stability of the gelling agent at bottomhole temperatures must be checked carefully. Several types of gelling agents are used. Xantham gums are adequate for moderate conditions (i.e., temperatures up to 230 degF [110 degC]), with the acid strength limited to 15% (Crowe *et al.*,

1981). Under more severe conditions, synthetic polymers are more appropriate for use up to 400 degF to 450 degF [205 degC to 230 degC].

Crowe *et al.* (1990) showed that under dynamic conditions gelled HCl exhibits the same reaction rate with limestones as ungelled acid. In some cases, reaction rates are accelerated. The reaction rate measured is the rate of calcite consumption. It is the overall reaction rate, determined by the limiting step, which is acid transport by diffusion. It is generally agreed (Muhr and Blanshard, 1982) that the rate of diffusion depends on the solvent viscosity and is not modified by the presence of polymers, at least as long as the distance between the polymer chains is large compared with the size of the ions in solution.

The interaction between polymer chains and the rock surface can affect the overall reaction rate and live acid penetration. If the gel exhibits a non-Newtonian behavior, the shear rate at the rock surface can be modified, which may increase the mass transfer and result in a higher reaction rate. Aside from this effect, the polymer can plug the smaller pores, acting as a fluid-loss agent. This effect was studied by Nierode and Kruk (1973), who found that the growth rate of wormholes is maximum for a small concentration of fluid-loss agent.

HCl is usually the acid component of gelled mixtures. Acid strength varies typically from 5% to 28%. The volume of acid depends on the suspected depth of damage in the fissures and vugs and on fluid placement efficiency.

#### 17-4.3. Emulsions

Emulsions are obtained by mixing acid with a refined-oil-base fluid in the presence of a surfactant. The stability of the emulsion depends on the temperature and the ionic strength of the aqueous phase. Some emulsifying agents provide stable emulsions in temperatures up to 300 degF [150 degC]. Depending on the type of surfactant, a water-in-oil or an oil-in-water emulsion can be obtained (see Chapter 15).

In static conditions, emulsions have been found to lower the overall reaction rate of the acid. Acid-in-oil emulsions are more effective for reaction retardation. It is generally agreed that these emulsions build an oil barrier at the rock surface, preventing the acid from reacting readily with the substrate. Acid-external emulsions also provide some retardation, which is generally attributed to physical interaction of the oil with the path of acid transport to the rock surface. Few results have been published on core acidizing with emulsions under dynamic conditions. The initial studies show that oil-external emulsions can treat low-permeability cores more efficiently than plain acid (Horton *et al.*, 1965).

Limestone cores acidized with emulsions display a highly permeable network of microwormholes that reflect significant modification of the process of acid transport and reaction. Emulsions tend to stabilize the acidizing process by reducing the contact area of the acid with the matrix, thereby decreasing the apparent reaction rate. Measurement of diffusion coefficients in acid-in-oil emulsions by de Rozières *et al.* (1994) using the rotating disk technique found that effective diffusion coefficients in these systems are as much as 3 orders of magnitude lower than diffusion coefficients in plain acid at the same temperature conditions. Therefore, good stimulation can be obtained with emulsions at low rates corresponding to the compact dissolution regime with plain acid.

Like gelled acids, emulsions are usually prepared with HCl. Various acid strengths and volumes can be selected for the fractions, with 70:30 acid-in-oil emulsion a commonly used system. The viscosity of the emulsion is an important parameter because the high viscosity of some mixtures used for fracturing limits their application to matrix acidizing.

A recent trend involves adding nitrogen ( $N_2$ ) to the emulsion to obtain a triphase system. Static tests show that this further reduces the reactivity of the acid (Guidry *et al.*, 1989). The exact mechanism of the retardation has not been fully studied. It is generally admitted that  $N_2$  reduces the contact area of acid with the rock. With this type of system, the dissolution pattern is expected to be more homogeneous (in comparison with plain HCl at same pump rate), and relatively large volumes are pumped to obtain large stimulation radii. Liquid volumes as large as 500 gal/ft are usually pumped. This type of treatment is economically advantageous because as much as 50% of the volume pumped consists of nonacid fluids. To increase the matrix injectivity prior to pumping the emulsion, a pretreatment with plain acid is usually performed. Furthermore, to allow injection at higher rates than normally prescribed by the fracturing limit, the wells are generally drawn down as much as possible, and the shut-in time prior to the treatment is reduced to the minimum technically possible. Under these conditions, the near-wellbore pressure is much lower than the average reservoir pressure, and higher matrix rates can be applied. Two- and triphase emulsions are recommended for the treatment of deep damage or if the purpose of the treatment is to stimulate the formation to obtain a highly negative skin effect.

#### 17-4.4. Microemulsions

Microemulsions consist of a fine dispersion of oil and acid, stabilized by proper surfactant and cosurfactant additives. Depending on the concentration of the different

components, an oil-in-acid or acid-in-oil emulsion can be obtained. The main difference from macroemulsions is the size of the droplets, which are reported to be in the range of 0.005 to 0.2  $\mu\text{m}$ .

Oil-external microemulsions may behave as a single-phase fluid in porous media and sweep oil more easily than plain acid, facilitating acid injection and flowback. Acid diffusivity in acid-in-oil microemulsions is also greatly reduced compared with plain acid, by at least 2 orders of magnitude (Hoefner and Fogler, 1985). This results in a more homogeneous attack of the rock, as observed in core experiments (Hoefner *et al.*, 1987), which presents two advantages. First, it should enable acidizing tight carbonate rocks at low rates that correspond to compact dissolution conditions with plain acid. Second, at higher rates it avoids the formation of large wormholes, which can be detrimental to the mechanical properties of soft formations such as chalks.

Despite their advantages, microemulsions are not commonly used in field operations. Because of the high surfactant concentration required, these systems are more expensive and difficult to inhibit. Furthermore, stability problems have been encountered. In most cases similar results can be achieved with macroemulsions. The additional cost of microemulsions is justified only for sensitive formations where mechanical stability is a concern.

#### 17-4.5. Special treatments

HCl can be used in combination with other chemicals for specific treatments. This section briefly reviews the main formulations using HCl. More detailed description is in Chapter 15.

Blends of alcohol (mainly methanol) and HCl are used for gas well treatments. Alcohol lowers the surface tension, but not as much as surfactants. However, because it does not adsorb on the rock, it penetrates into the formation as deeply as the acid. It also increases the vapor pressure of the spent acid. This facilitates cleanup of the spent acid and improves gas permeability by reducing the residual water saturation. The addition of alcohol slightly slows the reaction of acid with the rock and slightly accelerates the corrosion rate. The volume fraction of alcohol can vary widely depending on the application, from 20% to 67%. Mixtures with 67% methanol are stable up to 250 degF [120 degC].

Mixed with an aromatic solvent and a stabilizer, HCl forms a solvent-in-acid emulsion. The volume fraction of the acid varies typically from 50% to 90%. The emulsion stability depends on the solvent concentration and temperature. This formulation is used to remove paraffin and mixed deposits. It is also recommended for removing scale and treating wells being converted from producers to injectors.

HCl can also be used in combination with a surfactant and a chelating agent to remove mud damage in carbonate formations. The combined action of the additives has been found to successfully disperse and remove clays and mud damage. In formations presenting a risk of deconsolidation, HCl can be replaced by a brine or calcium chelant solution such as EDTA. This type of formulation is recommended particularly for naturally fissured reservoirs where completion materials have invaded the fissures (see Sidebar 17C).

For shallow damage caused by cake deposition in natural fissures, such formulations are highly efficient when acid is spotted through coiled tubing and flowed back, possibly several times (Liétard *et al.*, 1995). If an oil-base mud was used, or if damage material has been in contact with oil downhole, the use of a surfactant and mutual solvent is required to water wet the cake surface and facilitate acid flow in the fissures.

#### 17-4.6. Self-diverting acid

Self-diverting acid, originally developed for fracturing, has also been used to improve placement during carbonate acidizing. It consists of HCl mixed with a gelling agent and a pH-sensitive crosslinker. Crosslinking occurs at intermediate values of pH (typically from 1 to 3.5) corresponding to partially spent acid. The lower fresh acid viscosity allows penetration in wormholes and fractures until acid reaction increases the pH and causes crosslinking, thereby diverting the following acid stages to other portions of the reservoir (Fig. 17-4). Because the gel breaks at a pH above 3.5, flowback presents no problem once fresh acid injection is stopped and the acid is allowed to spend completely. Like particulate diverters or foams, self-diverting acids are pumped in several stages, alternating with regular acid stages. Good results are reported in fractured formations and in long, open intervals where benzoic flakes or gelled acid has failed to provide fluid diversion (see Sidebar 17D).

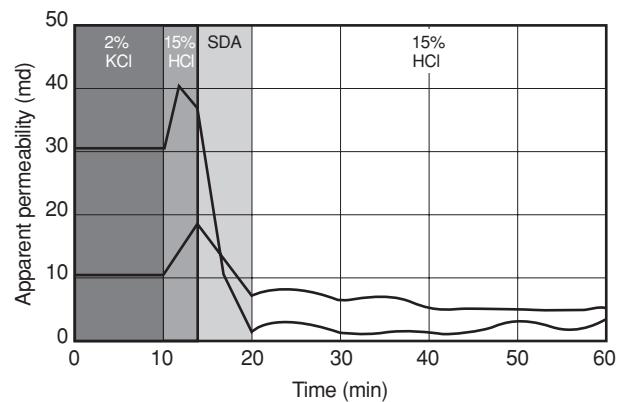


Figure 17-4. Effect of self-diverting acid (SDA) on fluid placement.

## 17C. Examples of special treatments

### Well A

Well A was an oil producer from a fissured dolomitic reservoir with an average matrix permeability of 10 md and a porosity of 3%. Damage by mixed silts and organic deposits was suspected. The well was treated with 130 gal/ft of solvent-in-acid emulsion, with a 90 gal/ft preflush of a mixture of 80% solvent with acetic acid and mutual solvent. The pumping schedule was as follows:

1. Preflush: solvent + acetic acid (42 bbl)
2. Main fluid: solvent-in-acid emulsion (63 bbl)
3. Diverter: benzoic acid flakes (31 bbl)
4. Repeat steps 1, 2 and 3
5. Repeat steps 1 and 2
6. Displacement: nitrogen

Production before the treatment had dropped to 1172 STB/D at a wellhead pressure 455 psi. Postjob production increased to 3580 STB/D at a wellhead pressure of 1179 psi.

### Well B

Well B was an oil producer from a calcitic reservoir containing 5% clays. Reservoir porosity was 2% and the average matrix permeability did not exceed a few millidarcies. The production rate prior to the treatment indicated a damage skin effect of approximately 40. The treatment was executed with 75 gal/ft of 15% HCl laden with suspending and sequestering agents, preceded by a preflush of suspending agent-laden brine. The schedule was as follows:

1. Preflush: suspending agent-laden brine (63 bbl)
2. Main fluid: 15% HCl with suspending agent + nitrogen (107 bbl)
3. Diverter: benzoic acid flakes in gelled acid (31 bbl)
4. Repeat steps 1 and 2
5. Displacement: nitrogen

Production increased from 500 STB/D before the job to 3700 STB/D after the treatment at a wellhead pressure of 5900 psi (i.e., 500 psi below the wellhead shut-in pressure). Striking evidence of the acid effect is provided by the pressure record during the treatment, which shows that the well

head pressure decreased by 1200 psi while the first acid stage was injected into the formation. According to Eq. 17C-1, this pressure falloff is equivalent to a skin effect decrease of more than 40:

$$\Delta s = \frac{2\pi kh\Delta p}{\mu q} \quad (17C-1)$$

### Well C

Well C was converted from an oil producer to a water injector. A well test indicated near-wellbore damage, presumably from the presence of workover material. The average reservoir porosity was 16%, and permeability deduced from a porosity log varied from 5 to 500 md across the 200-ft open interval. The well was treated with 30 gal/ft of 15% HCl laden with suspending agents. The acid was pumped through coiled tubing, and four foam stages were used for diversion. The injection profiles before and after the treatment are shown in Fig. 17C-1. The acid significantly improved injectivity in the middle interval, corresponding to a lower permeability region (less than 25 md). The porosity log indicated that the bottom part of the interval (below 170 ft) corresponded to a very low permeability zone. The total injectivity increased from 30,000 BWPD at a wellhead pressure of 1640 psi to 54,000 BWPD at 1420 psi at the wellhead.

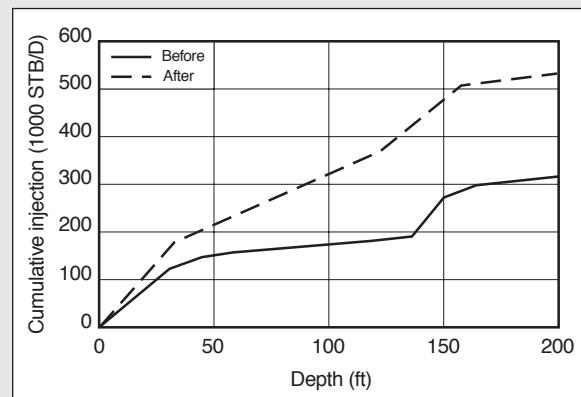


Figure 17C-1. Comparison of injection profiles before and after treatment.

## 17D. Placement using self-diverting acid

Three similar injector wells were treated with different placement techniques. The average reservoir permeability varied from 4 to 10 md. The formation comprised two zones of different injectivities. Treatment for the first well consisted of pumping 15% HCl through coiled tubing. The second well was acidized with gelled acid pumped through tubing. For the third well, three stages of a blend of HCl and suspending agents were pumped through coiled tubing. Two stages of self-diverting acid were used to separate the main stages.

Figure 17D-1 compares the injectivities of the three wells before and after acidizing. Zone A was treated successfully only in the third well with the use of self-diverting acid.

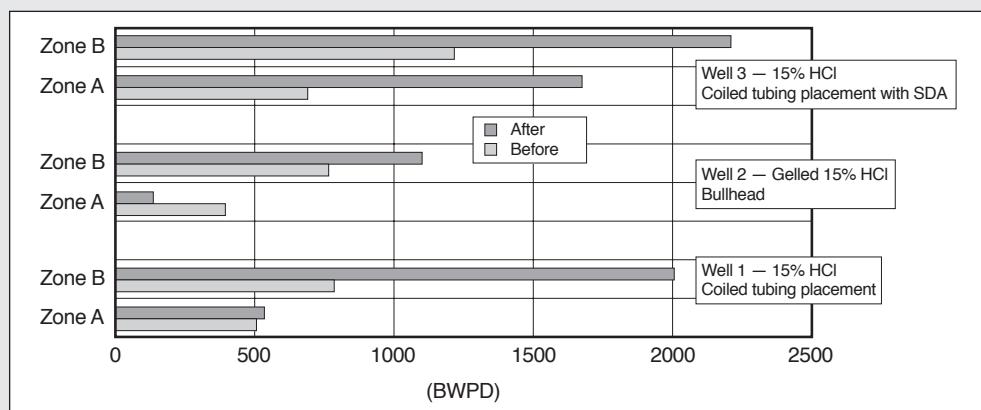


Figure 17D-1. Comparison of acidizing results of three placement techniques.

## 17-5. Treatment design

### 17-5.1. Candidate selection

As explained in Chapter 13, candidate recognition utilizing a systems analysis approach is the first step for the design of carbonate acidizing. Whereas sandstone acidizing is usually limited to damage removal, carbonate acidizing is typically oriented toward reservoir stimulation. Wells exhibiting a slightly negative skin effect prior to the treatment are usually still considered good candidates.

Because of the ability of HCl to create channels, it ensures excellent communication with the reservoir. In higher permeability formations, acidizing can also be used as an alternative to dense perforating. Field experience shows that cased completions with small perforation densities (as low as one perforation every 3 or 5 ft) can exhibit a negative skin effect after stimulation with HCl.

### 17-5.2. Pumping schedule

The second step in the design consists of choosing the right acid formulation, depending on the damage and formation characteristics. Examples of pumping schedules are given in the sidebars to this chapter. Generally, carbonate treatments consist of alternating stages of the main fluid and diverter. A solvent preflush can be used ahead of the main fluid to clean up the formation and increase its receptivity to acid. An overflush of brine or seawater can be used to displace the acid into the formation and ensure complete spending away from the wellbore. N<sub>2</sub> can be used for displacement at the end of the job or added to the treatment fluids to assist the flowback of spent acid that may contain insoluble material or high-viscosity gel residuals remaining in the formation. Generally, N<sub>2</sub> is recommended for low-pressure wells with a pressure gradient below 0.46 psi/ft.

The pumping rate is limited by the fracturing pressure. In tight formations, the rate must be sufficiently high to prevent compact dissolution near the wellbore if plain HCl is used. In naturally fractured formations, good results have been obtained with high flow rates. Such pump rates and high pressures do not correspond to usual matrix conditions and are likely to mechanically enlarge natural fractures and increase their conductivity during the treatment.

### 17-5.3. Additives

Additives must be added to the different stages to protect tubulars and ensure successful treatment of the formation. This topic is fully covered in Chapter 15.

For oil wells, adding a mutual solvent to the preflush or acid stages helps to water wet the formation and provides good contact of the treating fluids with the rock surface.

Acid corrosion inhibitors and inhibitor aids are required to protect tubulars. Organic acids are easier to inhibit than HCl. Stable emulsions are also relatively easy to inhibit. However, in most corrosion tests, emulsion breakage occurs, and the corrosion rate is similar to or greater than that of the nonemulsified acid.

The addition of surfactant and demulsifiers may also be necessary to lower the interfacial tension between treating fluids and the reservoir fluid and to prevent emulsions. Finally, antisludging agents, scale inhibitors and iron control agents can be used to prevent specific problems. When mixing additives, the compatibility of the different components with each other and with the downhole conditions must be checked thoroughly.

### 17-5.4. Placement

Proper placement of acid over the whole pay zone is required for successful treatment. In thick formations or multilayer reservoirs with different values of permeability or damage severity, acid tends to penetrate the more permeable zones and create high-injectivity streaks that prevent injection into the whole interval.

Five main diversion techniques can be used to improve fluid placement in carbonate acidizing: packers, ball sealers, particulate diverters, foam diversion and self-diverting acid. The first four methods are discussed in Chapter 19. The use of self-diverting acid has increased recently (see Section 17-4.6). In large intervals (e.g., horizontal wells) some of these techniques can be combined with the use of coiled tubing (Thomas and Milne, 1995).

## 17-6. Conclusions

Limestone and dolomite formations can easily be stimulated with acid formulations. Unlike sandstone acidizing, the goal of carbonate acidizing is usually to bypass the damage rather than dissolve it. HCl is typically used for carbonate acidizing. In case of incompatibility with the formation or the completion (i.e., risk of corrosion), other formulations are used, such as emulsions or organic acids. Suspending agents or solvents can also be used if required by the type of damage.

The high reactivity of acid with limestones and high-temperature dolomites results in the creation of wormholes, which considerably increase the apparent permeability around the wellbore. When wormholes extend beyond the damaged zone or connect with natural fissures in the formation, a negative skin effect is obtained.

An engineering approach should be adopted to design effective carbonate treatments. As in sandstone acidizing, proper placement of the acid over the whole interval is necessary for successful treatment and usually requires employing placement techniques. Foam diversion and self-diverting acid are two methods that are increasingly used, with good results.

## Acknowledgments

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# 18. Sandstone Acidizing

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## 18-1. Introduction

Sandstone matrix acidizing is distinguished from carbonate acidizing in that it involves the dissolution of damage that is blocking or bridging the pore throats in the formation matrix, thus ideally recovering the original reservoir permeability. Carbonate acidizing dissolves the formation minerals around the damage, creating new permeability. The mineral acids required to dissolve the damage are usually highly reactive with the numerous formation minerals. The resulting chemical complexes can become insoluble in the environment created and can precipitate, yielding gelatinous or solid particles. Because the formation and the damage can have complicated crystalline structures that can yield a variety of reaction products, sandstone acidizing success requires a significantly better understanding of chemistry than does carbonate acidizing. As discussed in Chapter 13, 75% of well-engineered sandstone acid treatments should be successful, resulting in significant production enhancement.

The descriptor “sandstone” is derived from the geologic classification of rocks with a high quartz silica content. Besides the obvious quartz component, they contain other minerals such as aluminosilicates, metallic oxides, sulfates, chlorides, carbonates and noncrystalline (amorphous) siliceous material. The minerals deposited in the original sediment are called detrital species. Most have a high degree of associated water. As fluids are produced through the matrix of the rock, the drag forces can move some of these minerals, clogging the pore throats.

Connate water in a sandstone contains many of the dissolved native mineral species. This is due to equilibrium and partial pressures of gaseous solvents (such as carbon dioxide [CO<sub>2</sub>]) and the presence of other ionic species. As fluids are produced, the associated pressure drop can disturb this equilibrium and the normal ionic content of the formation brines, resulting in precipitation and possible pore-throat restriction. This type of diagenesis yields authigenic species (e.g., scales such as calcium carbonates as well as some clay species such as zeolites, illites, kaolinites and smectites).

Various well operations can result in formation damage (see Chapter 14). For example, drilling mud and completion fluid usually penetrate sandstone formations. This invasion of filtrate can introduce an entirely different chemical environment, which the acid treatment must address. Additional formation damage may occur during perforating, gravel packing, and normal production or injection operations. Acid dissolves a variety of damaging materials along with most formation minerals. An understanding of the chemistry is basic to the selection of the acid type and concentration.

This chapter includes the reaction chemistry of the primary solvent used in sandstone acidizing, hydrofluoric acid (HF). Acid systems that contain mixtures of hydrofluoric and hydrochloric acid (HCl) are commonly called mud acids because they were first used to remove mud damage.

## 18-2. Treating fluids

### 18-2.1. Hydrochloric acid chemistry

HCl reactions are discussed in Chapter 17, and details of the reaction and by-products are omitted in this chapter except for how they relate to sandstone minerals. The compatibility of the HF blends used in this process is twofold; these mixtures must meet both compatibility standards for the formation mineralogy and dissolution of the damage mineralogy. HF mixtures are preceded by HCl to avoid precipitation of the slightly soluble and insoluble reaction products of HF with certain chemical species. The chemistry of HCl with carbonate minerals is discussed in a previous chapter, so the focus here is on the chemistry of the HF systems. Although the chemistry of the reaction of HCl with carbonate or calcite is simple, the chemistry of the reaction of HF and siliceous minerals is complex.

Some complex reactions that occur with certain siliceous minerals have only recently been included in the reactions reported in mineralogy breakdowns. These reactions involve HCl and the mineral family known as

zeolites. Zeolite minerals are crystalline, but hydrated with active, porous channels in the crystalline lattice. Zeolites are known in other industries as “molecular sieves” because their porosity allows the chemical extraction and filtering of selective materials. Zeolite minerals occur in nature as a by-product of volcanic activity and precipitate from water that is rich in silica. It is theorized that as zeolites are exposed to progressively higher pressures and temperatures they metamorphose from extremely loose, hydrated crystalline structures to more dense and compact structures. The results of this process have different mineral names. The hierarchy of their structure and crystalline nature is provided in Table 18-1. Because these minerals are precipitates, they are always authigenic and located in pore spaces.

Zeolite minerals are sensitive to HCl and strong mineral acids. Several core studies have shown that the use of HCl alone causes significant damage, whereas weak organic acid reduces the damage. The problem is that the weak organic acid does not necessarily remove the damaging mineralogy to restore permeability. The solution to the problems associated with zeolites is to recognize the presence of these minerals before a treatment is performed. The use of an organic acid as one of two preflush stages and following the preflushes with a low-concentration HF mixture that conforms with the remaining minerals in the formation has proved to be highly effective in restoring permeability and removing damage. All fluids that are injected should have an

organic acid included to maintain a low-pH environment. Some operators have found the use of an all-organic-acid system followed by an organic acid–HF formulation to be effective in high-temperature environments.

### 18-2.2. Chemistry of hydrofluoric acid systems

HF is the only common, inexpensive mineral acid able to dissolve siliceous minerals. For any acid system to be capable of damage removal, it should contain HF in some form. The most common formulation is simply ammonium bifluoride dissolved in HCl; another is by diluting concentrated HCl-HF formulations. The HCl:HF ratio is varied to accommodate the solubility of the dissolved mineral species present in the formation. This can be augmented by both preflush and overflush acid formulations. Several potential precipitates can be addressed simply by the use of appropriate HCl:HF ratios in the formulations. Numerous mineral species react with HF, and they all generate aluminum silica fluoride complexes (Table 18-2).

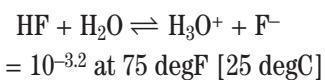
- Reactions of hydrofluoric acid with formation minerals

Details of HF reactions with formation minerals have, for more than 60 years, been known and studied. As early as 1965, it was quantified that 1,000 gal of 2% HF can dissolve as much as 350 lbm of clay (Smith *et al.*, 1965).

An HCl preflush is always injected in sandstones prior to the HF. This is done to avoid the possible precipitation of insoluble or slightly soluble reaction products. Typically, the insoluble species are calcium fluoride ( $\text{CaF}_2$ ), which forms on reaction of HF with calcium carbonate ( $\text{CaCO}_3$ ), or sodium or potassium hexafluosilicates ( $\text{M}_2\text{SiF}_6$ , where M = Na or K), which result from the reaction of cations in formation brines with solubilized species. The dissolution of calcium carbonate or magnesium carbonate by reaction with HCl is discussed in detail in Chapter 17.

- Stoichiometric equations

Reactions of mud acid with the aluminosilicate components of sandstones are those of HF; however, HF is a weak acid and, because of the equilibrated reaction, is only slightly dissociated when mixed with HCl:



where  $K_a$  is the acid equilibrium constant.

HF can also combine and form complexes, but this reaction must be taken into account (Fogler *et al.*, 1976) only when the HF concentration is sufficiently high (less than 10M) to allow numerous collisions to occur between the fluoride species. This occurs

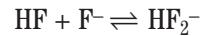
**Table 18-1. The zeolite family.**

Mineral	Description
Stilbite	Hydrous calcium aluminum silicate Dissolves in contact with HCl; no gelatin formed Occurs in shallow environments and may occur inside tubulars in silica-rich connate water formations with high pressure drops
Heulandite	Hydrous calcium/sodium/potassium aluminum silicate Dissolves in contact with HCl; no gelatin formed Occurs in shallow environments
Chabazite	Hydrous calcium/sodium/potassium aluminum silicate Dissolves in contact with HCl; no gelatin formed Occurs in medium-depth environments
Natrolite	Hydrous sodium/potassium aluminum silicate Dissolves in contact with HCl; gelatin formed Occurs in deeper environments
Analcime	Hydrous sodium aluminum silicate Dissolves in contact with HCl; gelatin formed Occurs in deeper environments

**Table 18-2. Chemical composition of typical sandstone minerals.**

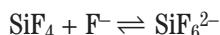
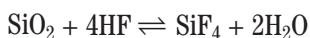
Classification	Mineral	Chemical Composition
Quartz		$\text{SiO}_2$
Feldspar	Microcline	$\text{KAISi}_3\text{O}_8$
	Orthoclase	$\text{KAISi}_3\text{O}_8$
	Albite	$\text{NaAlSi}_3\text{O}_8$
	Plagioclase	$(\text{Na,Ca})\text{Al}(\text{Si,Al})\text{Si}_2\text{O}_8$
Mica	Biotite	$\text{K}(\text{Mg,Fe}^{2+})_3(\text{Al,Fe}^{3+})\text{Si}_3\text{O}_{10}(\text{OH})_2$
	Muscovite	$\text{KAi}_2(\text{AlSi}_3)\text{O}_{10}(\text{OH})_2$
	Chlorite	$(\text{Mg,Fe}^{2+},\text{Fe}^{3+})\text{AlSi}_3\text{O}_{10}(\text{OH})_8$
Clay	Kaolinite	$\text{Al}_2\text{Si}_2\text{O}_5(\text{OH})_4$
	Illite	$(\text{H}_3\text{O,K})_y(\text{Al}_4 \cdot \text{Fe}_4 \cdot \text{Mg}_4 \cdot \text{Mg}_6)(\text{Si}_{8-y} \cdot \text{Al}_y)\text{O}_{20}(\text{OH})_4$
	Smectite	$(\text{Ca}_{0.5}\text{Na})_{0.7}(\text{Al,Mg,Fe})_4(\text{Si,Al})_8\text{O}_{20}(\text{OH})_4 \cdot n\text{H}_2\text{O}$
	Chlorite	$(\text{Mg,Fe}^{2+},\text{Fe}^{3+})\text{AlSi}_3\text{O}_{10}(\text{OH})_8$
Carbonate	Calcite	$\text{CaCO}_3$
	Dolomite	$\text{CaMg}(\text{CO}_3)_2$
	Ankerite	$\text{Ca}(\text{Fe,Mg,Mn})(\text{CO}_3)_2$
	Siderite	$\text{FeCO}_3$
Sulfate	Gypsum	$\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$
	Anhydrite	$\text{CaSO}_4$
Chloride	Halite	$\text{NaCl}$
Metallic oxide	Iron oxides	$\text{FeO}, \text{Fe}_2\text{O}_3, \text{Fe}_3\text{O}_4$

only in the case of ultra mud acid (25% HCl–20% HF) formulations:



$$K = 3.86 \text{ at } 75 \text{ degF}$$

The reaction of HF with quartz grains (pure silica) is expressed in the following two equilibria:



The intermediate silicon complex,  $\text{SiF}_5^-$ , which is not stable in aqueous solution, is not considered. The first step of silica dissolution consists of the chemisorption of the fluoride anion at the silica surface (Iler, 1979). Kline and Fogler (1981b), on the contrary, showed that it is the molecular HF rather than the fluoride anion that adsorbs (see Section 18-4).

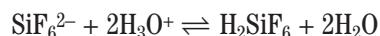
Gaseous silicon tetrafluoride usually remains dissolved in the liquid phase at bottomhole pressure, as  $\text{CO}_2$  does in the case of carbonate acidization, so the equilibrium is shifted toward the formation of silicon hexafluoride anions and the remaining  $\text{SiF}_4$  does not represent more than 1% of the total dissolved silicon (Labrid, 1971).

Silicon hexafluoride anions can be hydrolyzed further into monosilicic acid with the evolution of heat:



$$K = 1.2 \times 10^{-27} \text{ at } 75 \text{ degF}$$

When the silicon concentration increases in the aqueous phase, part of the hexafluorosilicate anions are also transformed into the acidic form of fluosilicic acid according to the reaction



$$K = 6.7 \times 10^{-4} \text{ at } 75 \text{ degF}$$

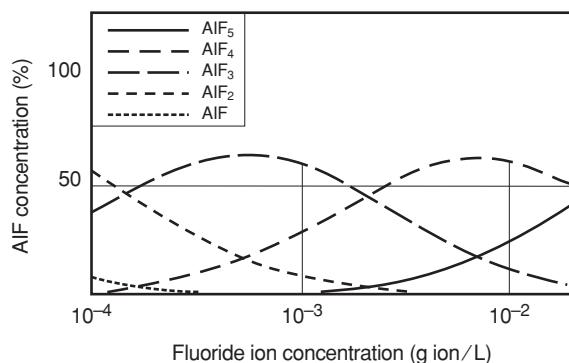
This transformation is usually limited, because fluosilicic acid is a strong acid. Aluminosilicate minerals generally have complex chemical compositions, such as those listed in Table 18-2. Their overall dissolution reactions thus involve many simple equilibria.

The disintegration of aluminosilicate minerals by HF can be considered stoichiometric as a first step; i.e., the Al:Si ratio is the same in the solution as in the mineral. Silicon is solubilized by the same process mentioned for quartz, whereas aluminum is involved in several fluorinated complexes:



where  $0 \leq n \leq 6$ .

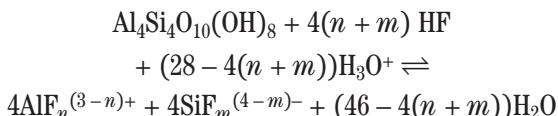
The prominent form of aluminum complexed varies as a function of the free fluoride ion concentration: the average ratio of fluorine to aluminum decreases as the dissolution reaction progresses (fewer fluoride anions are available), as shown in Fig. 18-1 (Labrid, 1971).



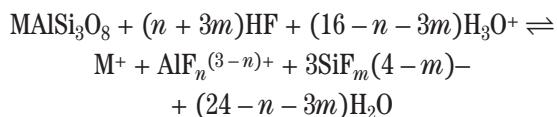
**Figure 18-1.** Domains of existence of aluminum-fluorine complexes (Labrid, 1971).

The dissolution reaction of all aluminosilicate minerals in sandstones follows the previous equations for the basic lattice atoms (Si, Al) concerned. Other metallic ions, such as Na, K, Mg, Ca, and Fe, which are in the minerals constituting the rock as substitution cations in the lattice or as exchangeable (adsorbed) cations, come into solution as free ions during the reaction. In the case of iron, fluorinated complexes ( $\text{FeF}_z^{(3-z)+}$ , where  $1 < z < 3$ ) also are formed through reactions similar to those for aluminum. Thus, different global reactions can be written as a function of the considered mineral:

– Kaolinite clay



– Sodic or potassic feldspar



where  $0 \leq n < 6$  and  $m = 4$  or  $6$ .

### 18-3. Solubility of by-products

When minerals are dissolved by HF, numerous by-products can form. Some potential precipitates are listed in Table 18-3. In many cases, the increase in the liquid-phase pH value resulting from acid mixture spending constitutes the driving force for precipitate formation; therefore, precipitation can be predicted from consideration of the sole liquid phase. The extent of precipitation should always be limited. If this is not possible, the potential precipitation zone that would cause a decrease in permeability should be diluted and displaced from the wellbore (Walsh *et al.*, 1982).

Should precipitation occur, most of the calcium and sodium complexes that precipitate in the field can be redissolved by using boric acid. This is not true, however, for potassium and some of the magnesium complexes. The very low solubility of potassium complexes has been shown both in the laboratory and in the field.

Colloidal silica precipitation cannot be avoided, as it results partly from the greater affinity of fluorine for aluminum than for silicon. This process accelerates the hydrolysis of  $\text{SiF}_6$  because the released  $\text{F}^-$  anions are further involved in aluminum complexes and more monosilicic acid ( $\text{Si}(\text{OH})_4$ ) is generated. Certain authors (Labrid, 1971; Shaughnessy and Kunze, 1981; Walsh *et al.*, 1982) have emphasized the highly damaging potential of the precipitation of colloidal silica in a porous medium; however, this damaging action has never been demonstrated clearly and satisfactorily.

**Table 18-3.** Solubility in water at room temperature of HF reaction by-products.

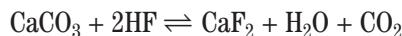
Secondary Product	Solubility (g/100 cm <sup>3</sup> )
Orthosilicic acid ( $\text{H}_4\text{SiO}_4$ )	0.015
Calcium fluoride ( $\text{CaF}_2$ )	0.0016
Sodium fluosilicate ( $\text{Na}_2\text{SiF}_6$ )	0.65
Sodium fluoaluminate ( $\text{Na}_3\text{AlF}_6$ )	Slightly soluble
Potassium fluosilicate ( $\text{K}_2\text{SiF}_6$ )	0.12
Ammonium fluosilicate ( $(\text{NH}_4)_2\text{SiF}_6$ )	18.6
Calcium fluosilicate ( $\text{CaSiF}_6$ )	Slightly soluble
Aluminum fluoride ( $\text{AlF}_3$ )	0.559
Aluminum hydroxide ( $\text{Al}(\text{OH})_3$ )	Insoluble
Ferrous sulfide ( $\text{FeS}$ )	0.00062

On the contrary, other authors (Crowe, 1986) showed that such “precipitation” is actually the result of a topochemical reaction (exchange of fluoride from the hexafluorosilicate anion occurs with aluminum on the surface of the silt and clay), and it does not induce damage.

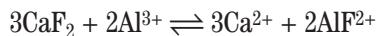
Precipitation begins earlier in the dissolution process at higher temperatures (within 10 min at 200 degF [95 degC]) because of the increased thermal agitation. It also occurs more quickly in montmorillonite-type clays than in kaolinite clays because of the different initial Al:Si ratios in these minerals (molar ratio of 1 for kaolinite and less than 0.5, depending on the substitution extent, for montmorillonite). Finally, aluminum can be totally removed from clays, with a correlated silica deposition at the surface (topochemical reaction).

### 18-3.1. Calcium fluoride

Some carbonates may remain after preflushing, either because of the initial amount of carbonate cementing material in the sandstone or as a result of the carbonates' initial protective siliceous coating. Also, slightly soluble, fine crystalline CaF<sub>2</sub> readily forms when calcite contacts HF. This can lead to substantial damage:



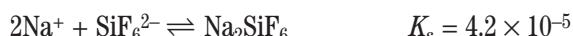
Where this precipitate has formed but has not completely blocked the porosity of the formation, it may partially redissolve when HF is near complete spending toward the end of the job. At this time, the concentration of fluoride anions in solution is so low that aluminum is hardly complexed and appears mainly as free Al<sup>3+</sup> ions (Labrid, 1971). These aluminum ions are then able to extract fluorine from the CaF<sub>2</sub> precipitates, as they did for silicofluorides, and partly redissolve the CaF<sub>2</sub> according to the reaction



This reaction may be followed by subsequent equilibria between the different aluminum and fluorine complexes.

### 18-3.2. Alkali fluosilicates and fluoaluminates

The aluminum or silicon fluorine complexes can react with alkali ions released in the solution from highly substituted clays or alkali feldspars as soon as their concentration becomes sufficiently high to form insoluble alkali fluosilicates and, probably, fluoaluminates:



where  $K_s$  is the solubility constant.

Alkali fluosilicate precipitation is favored by a high level of HF. Fluosilicate precipitates, which form from the attack of mud acid on alkali feldspars or clays, are well crystallized and very damaging (Bertaux, 1989). These damaging precipitates also form when the volume of preflush is insufficient and HF contacts formation brine containing alkali ions.

### 18-3.3. Aluminum fluoride and hydroxide

Aluminum fluoride (AlF<sub>3</sub>) or aluminum hydroxide (Al(OH)<sub>3</sub>) in the gibbsite form can precipitate upon spending of the acid. The precipitation of AlF<sub>3</sub> can be reduced by maintaining a high proportion of HCl to HF (Walsh *et al.*, 1982). These precipitates form according to the reactions



### 18-3.4. Ferric complexes

This mechanism of forming iron fluorine complexes applies only to relatively clean sandstones. In the presence of clays, the dissolved aluminum ions have a greater affinity for fluorine than iron does. Therefore, the iron fluorine complexes do not form and iron hydroxide still precipitates at pH levels greater than 2.2.

The nature of the precipitate (crystalline or amorphous) varies as a function of the anions present (Smith *et al.*, 1969). Ferric hydroxide can be strongly bound to the quartz surface by electrostatic interactions because its point of isolectric charge is above a pH value of 7. In the presence of excess calcite, the dissolved CO<sub>2</sub> can also lead to the precipitation of insoluble ferric carbonates (siderite or ankerite). Chapter 15 provides additional information about iron control and solutions for problems.

## 18-4. Kinetics: factors affecting reaction rates

This section summarizes qualitatively the results described in detail in Chapter 16. Because theoretical aspects are covered in Chapter 16, only the practical implications are discussed here.

Kinetically controlled reactions (surface reaction limited) are effective during the acidization process of sandstones, and factors affecting reaction rates are discussed to complete previous thermodynamic considerations.

### 18-4.1. Hydrofluoric acid concentration

Dissolution reaction rates are proportional to the HF concentration (Fogler *et al.*, 1976; Kline and Fogler, 1981b) for most sandstone minerals, except smectite. This explains why formations with low competence (i.e., weak cementation, potentially mobile fine particles) should be treated with a reduced-strength mud acid (1.5% HF) to avoid crumbling, especially at bottomhole temperatures greater than 200 degF. Fluoboric acid performs similarly because of the low concentration of HF present at any time.

### 18-4.2. Hydrochloric acid concentration

Dissolution reaction rates generally increase in a more acidic medium because the leaching of constitutive surface cations involves their replacement by protons, but the dependence on HCl concentration is not straightforward (Gdanski and Peavy, 1986). The principal role of HCl is to prevent secondary precipitation by maintaining a low pH value. The other main effect of HCl is to catalyze the attack of sandstone minerals by HF. The mechanism and degree of catalysis depend on the type of mineral, as shown in the following.

For example, the reaction rate measured at 95 degF [35 degC] for pure quartz has the following expression (Fogler *et al.*, 1976):

$$r_{quartz} = 9.2 \times 10^{-9} (1 + 0.8[H^+])[HF] \quad (18-1)$$

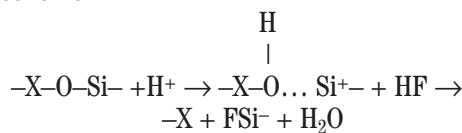
in mol quartz/cm<sup>2</sup>/s.

In the case of a feldspar with the overall formula Na0.72K 0.08Ca 0.2Al 1.2Si 2.808, the following expression has been determined (at 75 degF under 275-kPa pressure) as the reaction rate (Fogler *et al.*, 1976):

$$r_{feldspar} = 1.3 \times 10^{-9} (1 + 0.4[H^+])[HF] \quad (18-2)$$

in mol feldspar/cm<sup>2</sup>/s.

An elemental mechanism proposed to explain the previous variation involves the adsorption of protons on the surface that weakens the siloxane bondings, which is followed by the reaction of HF molecules that creates unstable silicon-fluorine bonds at the surface, according to the scheme



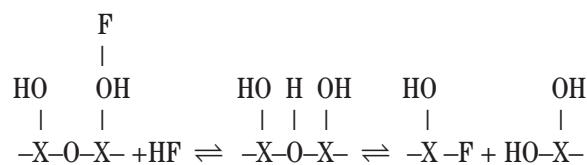
where X = Al or Si.

This is the acid (proton) catalysis mechanism proposed by Kline (1980) for feldspar.

The dissolution reaction is a first-order reaction with respect to the HF concentration for most aluminosilicate minerals. Nevertheless, dissolution kinetics is better represented by a Langmuir-Hinshelwood-type law in the case of sodium montmorillonite (Kline and Fogler, 1981):

$$R = \frac{KK_{ads}[\text{HF}]}{1 + K_{ads}[\text{HF}]}, \quad (18-3)$$

where  $K_{ads}$  is the equilibrium constant of the exothermic adsorption of HF molecules at surface-reactive sites. This adsorption constant is independent of the total acidity, whereas  $K$  increases with proton concentration (acid catalysis).  $K_{ads}$  is especially high for a mineral with a high cation exchange capacity (CEC), such as sodium montmorillonite. For most other clay minerals, the value of this adsorption constant is small. Therefore, when  $1 \gg K_{ads}[\text{HF}]$  the expression can be simplified to the experimentally determined first-order kinetics law. An elemental mechanism different from that mentioned for feldspars can be proposed to explain the kinetics and to take into account solely the HF adsorption:

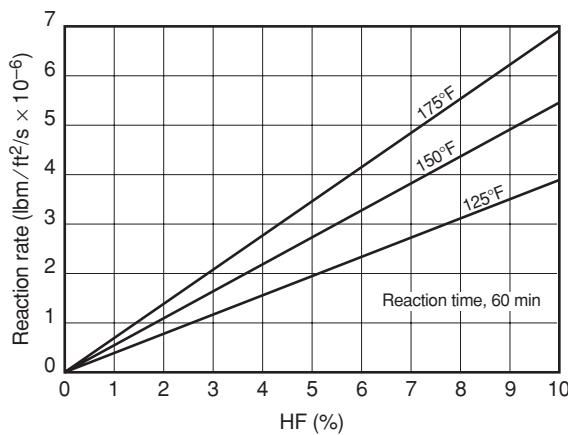


where X = Al or Si.

### 18-4.3. Temperature

The dissolution of minerals is a thermally activated phenomenon; thus, the rates increase greatly as a function of temperature (approximately multiplied by 2 for quartz for a 25 degC increment), and the penetration depths of live acid diminish accordingly. In the case of quartz, the activation energy is about 5.2 kcal/mol, and in the case of the previous feldspar, it is about 8 kcal/mol (Fogler *et al.*, 1976).

Figure 18-2 shows the variation of the reaction rate of mud acid with vitreous silica (more reactive than quartz) as a function of both HF concentration and temperature (Smith and Hendrickson, 1965). Aluminum and iron solubilities also increase slightly with a rise in temperature.



**Figure 18-2.** Reaction rate of HCl-HF on silicate glass (Smith and Hendrickson, 1965).

#### 18-4.4. Mineralogical composition and accessible surface area

The relatively high total specific surface area of sandstone rocks is the primary parameter determining mud acid spending because of the heterogeneous nature of the dissolution reaction. However, if the contribution of each mineral to the total accessible surface area is considered, great discrepancies between the reaction rates of pure phases can be predicted and observed (Table 18-4).

Clays react much faster than feldspars, which react much faster than quartz, especially in the presence of high proton ( $H^+$ ) concentrations. Thus, most of the quartz matrix (about 95%) can be considered inert with respect to the dissolution reaction, and the mineralogical nature of the accessible rock components determines the overall reaction rate. This situation also emphasizes the necessity of HCl preflushes and excess HCl in the HCl-HF mixture. Calcite reacts at the highest rate of all the minerals that can be present in a sandstone, leading to HF microchanneling, but the mechanism of attack is not comparable because protons coming from either HCl or HF can provoke the dissolution.

#### 18-4.5. Pressure

An increase in pressure speeds up the overall dissolution reaction slightly, because dissolved silicon tetrafluoride can be transformed partially into an acidic species ( $H_2SiF_6$ ) and can quickly initiate further reactions. For quartz, a 24% rise in the reaction rate was noticed between the two extreme conditions (Smith *et al.*, 1965).

In a radial injection situation, the mineral pore-space texture that determines flow partition around the wellbore (most live acid flows through the large pores) is also a relevant parameter; clay clasts can be bypassed by the acid flow (Williams, 1975).

**Table 18-4. Relative surface areas of sandstone minerals.**

Mineral	Surface Area
Quartz	<0.1 cm <sup>2</sup> /g
Feldspar	Few m <sup>2</sup> /g
Kaolinite	15–30 m <sup>2</sup> /g
Illite	113 m <sup>2</sup> /g
Smectite	82 m <sup>2</sup> /g

#### 18-5. Hydrofluoric acid reaction modeling

The parameters that affect the reaction rate of HF on sandstone minerals are incorporated in a model that predicts the evolution of formation parameters when acid is injected.

In terms of surface reaction rates, sandstones are typically considered a two-component system:

- slow-reacting pseudocomponent, forming the crystalline quartz fraction
- fast-reacting pseudocomponent, comprising all other species (e.g., clays, feldspars and poorly crystallized silica).

For both pseudocomponents, the overall kinetics, which includes the diffusion of HF-reactant species to the surface, surface reactions and the diffusion of reacted products back to the bulk solution, is governed by the surface reactions because they are the slowest step. Therefore, matrix acidizing of sandstones with HF is called surface reaction limited.

This is the major difference from the matrix acidizing of limestone, where the process is diffusion controlled. In sandstones, the increase in permeability results from damage removal and is correlated with a small increase in rock porosity. Quartz reacts very slowly with HF; reactions with most aluminosilicates provoke a rapid spending of the acid. A pseudostationary state reflects the much faster variation in species concentration (chemical modifications) than the one within the rock porosity (resulting in physical modification). The HF progresses and homogeneously dissolves every pore and never forms conductive channels or wormholes. The flow is stable, and sharp fronts are formed in response to the dissolution of different mineral species as acid injection progresses radially (McCune *et al.*, 1975).

Several authors have tried to model this process. Taha *et al.* (1986) used the reaction model developed by Fogler and various coworkers (see particularly Hekim *et al.*, 1982). Such a simplified, two-pseudocomponent model and macroscopic description can be used because Fogler *et al.* (1976) showed that the order of reaction of HF with

each pseudocomponent is equal to unity relative to the concentrations of HF and of the pseudocomponent. The flow is considered stable.

In this model the mineral dissolution fronts can be computed and the concentration of remaining clays (or fast-reacting materials) can be calculated. Then, the permeability increase can be estimated from the change in porosity (or amount of material dissolved). The velocity of the mineral dissolution front depends on the acid capacity number  $Ac$ , which is a function of the volume of clays (or fast-reacting dissolvable material) and of the acid concentration.

The acid concentration (or spending) front can be modeled similarly. The thickness of the front depends on the Damköhler number  $Da$ , which is a function of the reaction rate and the acid velocity. These simulations show why HF does not penetrate deeply into the reservoir before spending unless unrealistically large volumes are used. (These large volumes would almost dissolve everything around the wellbore and thus leave the reacted formation totally unconsolidated.)

## 18-6. Other acidizing formulations

Problems related to the use of mud acid to remove damage in sandstone formations include the following:

- Rapid spending provides only a short penetration, especially at high temperatures (maximum depth about 12 in).
- Fines, composed of either mostly quartz or mostly clay minerals, can be generated during the acid reaction and can migrate with the fluid flow. The destabilization of fines can lead to a quick production decline after treatment. Gravel-packed gas wells can exhibit a 50% productivity reduction.
- The high dissolving power of mud acid destroys rock integrity at the formation face.

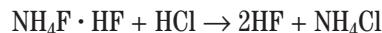
New sandstone acidizing systems are designed to alleviate these shortcomings.

### 18-6.1. Fluoboric acid

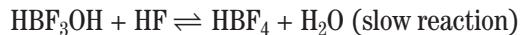
Fluoboric acid is recommended by Thomas and Crowe (1981) as an alternative to mud acids. It does not contain large amounts of HF at any given time and thus has a lower reactivity. However, it generates more HF, as HF is consumed, by its own hydrolysis. Therefore, its total dissolving power is comparable to a 2% mud acid solution. Fluoboric acid solutions are used as a preflush before treating formations sensitive to mud acid; this avoids fines destabilization and subsequent pore clogging. They are also used as a sole treatment to remove damage in a sandstone matrix with carbonate cement

or in fissures that contain many clay particles. Another use is as an overflush after a mud acid treatment that has removed near-wellbore damage (up to 0.5 ft) to allow easier penetration of the fluoboric acid solution (a few feet). Fluoboric acid is recommended when the sandstone contains potassic minerals to avoid damaging precipitates and in the case of fines migration owing to its fines stabilization properties.

In the field, fluoboric acid is easily prepared by mixing boric acid ( $H_3BO_3$ ), ammonium bifluoride ( $NH_4F \cdot HF$ ) and HCl. Ammonium bifluoride, an acidic salt of HF, reacts first with HCl to generate HF:

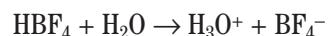


Tetrafluoboric acid is formed as a reaction product of boric acid with HF, according to



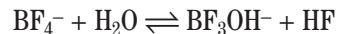
Hydroxyfluoboric acid ( $HBF_3OH$ ) probably does not exist in aqueous solutions unless it is in equilibrium with fluoboric acid (Wamser, 1948). The preceding slow reaction is of an order equal to unity with respect to both HF and  $HBF_3OH$ . For this reaction, equilibrium is attained at room temperature after nearly 40 min for a resulting 1M  $HBF_4$  solution. Because the equilibrium constant at 75 degF is  $K = 2.3 \times 10^{-3}$  (Wamser, 1948), about 6% (molar)  $HBF_4$  is converted into  $HBF_3OH$  at equilibrium for a 1M  $HBF_4$  solution. These equilibrium considerations mean that at any given time and place there is only between 0.1% and 0.2% (weight) of free HF at ambient temperature and 212 degF [100 degC], respectively.

Fluoboric acid is a strong acid with strength comparable to that of HCl (Maya, 1977); thus, the following reaction occurs in solution:



In the following text, reactions are written using  $BF_4^-$  instead of  $HBF_4$ . Acid strength diminishes in the following order: fluoboric, hydroxyfluoboric (the strength of which can be compared to that of trichloroacetic acid; Maya, 1977) and boric acid ( $KH_3BO_3 = 9.2$  at 75 degF).

The dissolving power of fluoboric acid results from the generation of HF through its hydrolysis:



The  $BF_3OH^-$  anions can be further hydrolyzed successively into  $BF_2(OH)_2^-$ ,  $BF(OH)_3^-$ , and  $H_3BO_3$  with correlated HF formation, but these reactions must be taken into account only when the  $BF_3OH^-$  concentration is lower than  $3 \times 10^{-3}$  at 75 degF (Wamser, 1948). In the following text,  $BF_3OH^-$  hydrolysis is neglected at the usual acid concentrations.

The hydrolysis reaction kinetics of fluoborate ions is affected by

- concentration of the fluoborate ions
- medium acidity, which has a catalyzing effect (reaction is proportional to the proton concentration)
- temperature, through the usual activation energy effect.

Thus, the reaction rate, assuming the reverse reaction is negligible, can be expressed after Kunze and Shaughnessy (1983) as

$$r = \frac{d[\text{BF}_4^-]}{dt} = K[\text{H}_3\text{O}^+][\text{BF}_4^-], \quad (18-4)$$

where

$$K = 1.44 \times 10^{17} \exp\left[-\frac{26,183}{1.987T}\right]$$

in  $(\text{mol/L})^{-1}\text{min}^{-1}$  and  $T$  is the temperature in kelvin.

Thus, the reaction rate is increased 300-fold when the mixture is heated from 75 degF to 150 degF [25 degC to 65 degC] and is increased 12,000-fold when heated from 75 degF to 220 degF [105 degC]. Because the hydrolysis reaction kinetics is not affected by clays, fluoboric acid can be considered a retarded acid in normal use (i.e., less than 200 degF). In the presence of excess bentonite, pure 0.1M fluoboric acid is spent within 30 min at 150 degF (Kunze and Shaughnessy, 1983). In a slurry test, which has an infinite surface area (1 L of acid with 20 g of bentonite or 1,600 m<sup>2</sup> of surface area, which is equivalent to several football fields of exposed area), the reaction rate is a function of the rate of hydrolysis. However, in the matrix, where there is a finite amount of clay surface, the reaction rate is a function of the amount of HF present, which in the case of fluoboric acid is low.

The reaction of fluoboric acid in sandstones involves at the same time the hydrolysis reaction of fluoboric acid, standard reactions of the generated HF with minerals and additional slow reactions related to the fluoborate ions in the liquid phase. As expected, the dissolution reaction of clays with fluoboric acid is a first-order reaction with respect to the fluoborate concentration, similar to the relation of the reaction of mud acid to the HF concentration.

The spending rate of fluoboric acid on glass slides at 150 degF is one-tenth that of a mud acid with the same total HF content (Thomas and Crowe, 1981). Amorphous silica reacts faster than quartz, which limits the destruction of cores near the injection face during flow tests with fluoboric acid. Significantly less destruction is noted than during mud acid flow testing. The reduced destruction with fluoboric acid results in 30% to 50% higher compressive strengths than observed for mud acid.

The unique advantage of fluoboric acid is that it provides efficient stabilization of clays and fines through reactions related to borate and fluoborate ions. Swelling clays are desensitized by fluoboric acid, and there is a large decrease in the CEC (e.g., a 93% decrease after 18 h in fluoboric acid at 150 degF for a Wyoming bentonite was observed by Thomas and Crowe).

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After a fluoboric acid treatment, migrating clays and other fines stabilize as a result of the rock's exposure to acid. This is why a long shut-in time is recommended in fluoboric acid treatments. During injection, while the acid spends normally, cores treated only with fluoboric acid exhibit a normal increase in permeability. However, no long-term stabilization occurs after treatment because only a portion of the clay was dissolved; the remainder did not have time to stabilize. Additional shut-in time allows this stabilization.

When treated by fluoboric acid, montmorillonite progressively decreases in aluminum content and then progressively incorporates boron atoms; silicon precipitates from the solution. Cores originally containing 30% silicoaluminates at 150 degF attain maximum static solubilities after only 24 h in the presence of 1M HBF<sub>4</sub> (4 h for mud acid), whereas the maximum increase in permeability is obtained after only 4 h under dynamic conditions (Thomas and Crowe, 1981). These results prove the dissociated effects of mineral dissolution by the generated HF (essentially kinetically controlled)

and of particle stabilization resulting from the slow complex dissolution/reprecipitation mechanisms (toward thermodynamic equilibrium) during the shut-in period.

Examination under a scanning electron microscope (SEM) shows that the original kaolinite clay platelets—pure aluminosilicates—that are not dissolved by fluoboric acid appear welded together and to the quartz grains. A type of chemical fusion of any fines seems to take place slowly onto the silica surface. The formation of borosilicate “glass” has been assumed to account for this reaction.

Bertaux (1989) observed that in silicoaluminates containing potassium, such as illite, potassium fluoborate forms after treatment with fluoboric acid as a non-damaging coating on the clay; potassium hexafluosilicate forms after treatment with mud acid. This shows that nondamaging by-products are formed by fluoboric acid, whereas formation plugging by alkali fluosilicates can occur with mud acid. This is another advantage of using fluoboric acid in some “acid-sensitive” formations.

During the injection period, fluoboric acid behaves like a weak HF solution, but one in which the HF is constantly replenished. The small amount of fluoride ions available at any time limits the danger of precipitating aluminum species. Only the first acidity is used during this step. Hydroxytrifluoboric acid ( $\text{HBF}_3\text{OH}$ ) buffers the solution and prevents other undesirable precipitations.

During shut-in,  $\text{HBF}_4$  and  $\text{HBF}_3\text{OH}$  continue to react, but at a slow pace because the hydrolysis is minimal. The liberated HF reacts further with mineral species. It also reacts by topochemical reactions, in which the aluminum from the undissolved clay structure is put into solution by forming one of the fluoaluminate complex ions (depending on  $\text{F}^-$ ), and the surface of the mineral is therefore enriched in silicon and boron. An amorphous coating

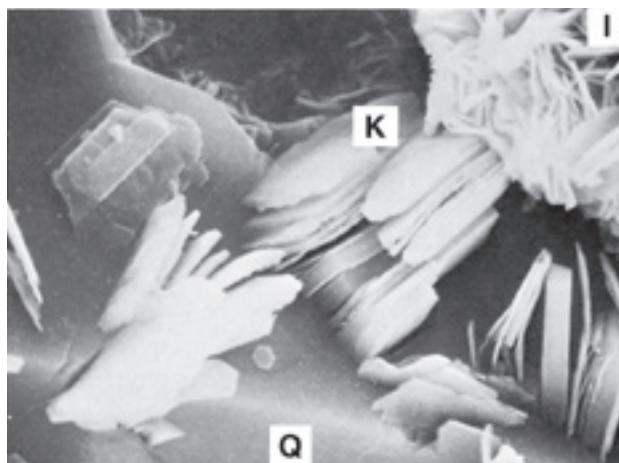
of silica and borosilicate glass is then formed over the remaining silicate and fine silica grains, welding them to the framework and thus preventing their migration.

This effect is clearly seen in Figs. 18-3 and 18-4, where the same pore, containing two different clays (kaolinite and illite), is shown before and after reaction with a fluoboric acid solution. The quartz is barely etched, whereas the high-surface-area, fast-reacting illite is completely dissolved. The kaolinite platelets are about half-dissolved, and an amorphous material is coating the undissolved kaolinite, welding them together and to the underlying quartz grain.

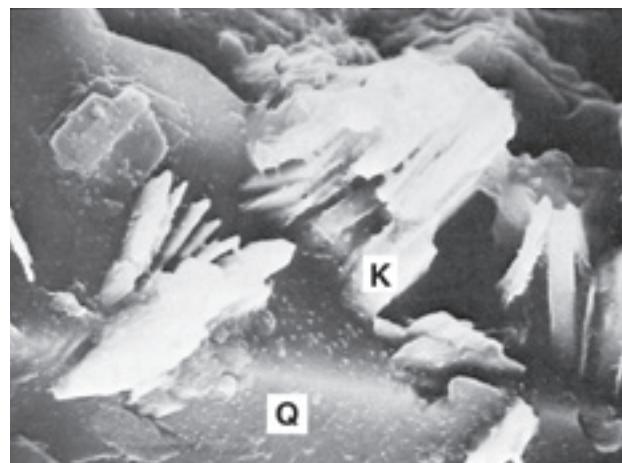
### 18-6.2. Sequential mud acid

The sequential mud acid system involves the in-situ generation of HF, occurring from the alternate injection of HF and ammonium fluoride (Hall *et al.*, 1981). The reactions of HF are thought by some to take place at the rock surface by adsorption followed by ion exchange, but the yield of this heterogeneous process seems highly doubtful for several reasons:

- If HF were generated through such a process, it would be a small quantity, hardly enough to etch the surface of the clay material.
- Because this process is based on the CEC of the clays, migrating kaolinite would hardly be touched.
- This process supposes the initial adsorption of the hydronium ( $\text{H}_3\text{O}^+$ ) ions on the clay surface, followed by their exchange with  $\text{NH}_4^+$ , to generate HF in situ. Exchange and replacement of  $\text{H}_3\text{O}^+$  by  $\text{NH}_4^+$  depends on many parameters and cannot be ascertained. Therefore, even the generation of HF is dubious.



**Figure 18-3.** SEM photograph of kaolinite (K) and illite (I) clays in a pore (Q = quartz), before attack.



**Figure 18-4.** SEM photograph of the same pore after an 8%  $\text{HBF}_4$  treatment.

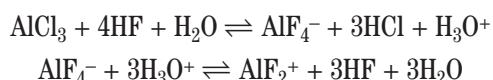
### 18-6.3. Alcoholic mud acid

Alcoholic mud acid formulations are a mixture of mud acid and isopropanol or methanol (up to 50%). The main application is in low-permeability dry gas zones. Dilution with alcohol lowers the acid-mineral reaction rate and provides a retarding effect.

Cleanup is facilitated; acid surface tension is decreased by the alcohols while the vapor pressure of the mixture is increased, which improves gas permeability by reducing water saturation.

### 18-6.4. Mud acid plus aluminum chloride for retardation

An acidizing system to retard HF-mineral reactions has been proposed in which aluminum chloride ( $\text{AlCl}_3$ ) is added to mud acid formulations to complex some of the fluoride ions in the injected mixture, according to the reactions (Gdanski, 1985)



This procedure is tantamount to adding dissolution reaction products to the mixture before the reactions occur (i.e., the injection of spent acid). In theory this should slow the rates. However, the retardation of clay dissolution has not been proved experimentally because of the prime importance of the high surface area on clay reactivity, which is much more important than a slight depletion of acid at high temperatures. The risk of early precipitation of damaging products, such as  $\text{AlF}_3$  or fluoaluminates, is probably increased by the use of an acid that already contains aluminum ions before reaction. Flow tests have shown a smaller effective live acid penetration than in the case of mud acid. In addition, field experience has shown that the addition of aluminum to the system increases the precipitation of amorphous aluminosilicate scale. This white material plugs near-wellbore perforations and gravel packs.

### 18-6.5. Organic mud acid

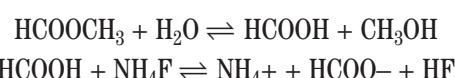
Because total acidity speeds mineral dissolution with mud acid, organic mud acid involves replacement of the 12% HCl component with organic acids (9% formic acid, a weak acid that only partially dissociates), mixed with 3% HF, to retard HF spending. This system is particularly suited for high-temperature wells (200 degF to 300 degF [90 degC to 150 degC]), for which pipe corrosion rates are diminished accordingly. This system also reduces the tendency to form sludge.

### 18-6.6. Self-generating mud acid systems

Self-generating acidizing systems were originally developed by Templeton *et al.* (1975), and their application was widened by Abrams *et al.* (1983). They involve the hydrolysis of organic esters into the corresponding carboxylic acids, followed by the reaction of these acids with ammonium fluoride to yield HF. Because the hydrolysis reaction is activated by temperature and the acidity obtained is not as strong as with mud acid, a low corrosion rate of tubular goods and delayed reaction of the progressively generated HF are expected. The latter would allow deep penetration of live HF.

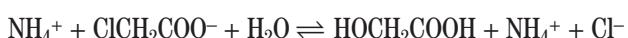
Depending on the bottomhole temperature, different organic esters are used:

- methyl formate between 130 degF and 180 degF [55 degC and 80 degC] with the reactions



(the latter is the slow, rate-controlling reaction).

- ammonium salt of monochloroacetic acid between 180 degF and 215 degF [102 degC]:



- methyl acetate between 190 degF and 280 degF [90 degC and 140 degC].

The reagent choice is intended to limit at 30% (maximum) the generation of HF during pumping of the mixture in the tubing; thus, a minimum of 40 min of spending time seems necessary. However, field tests of these systems have not been conclusive. Many precipitates form in these low acidic systems, such as ralstonite ( $\text{NH}_4\text{MgAlF}_6$ ) and other fluoaluminates (silicates) upon spending of these mixtures on clays; thus, the use of complexing agents or acids, such as citric acid, is suggested. Furthermore, formation sensitivity after treatment has not been tested, and handling problems arise from the high flammability of methyl formate.

Overall, these systems have many drawbacks. Based on the hydrolysis of various organic esters, they are temperature activated. Unlike fluoroboric acid, which generates new HF only upon spending, no equilibrium is reached. This means that more HF is generated as the temperature increases, and the ester can eventually be completely hydrolyzed long before reaching the final depth of damage. The true degree of retardation depends on the temperature and pumping time. These esters are more expensive and more dangerous to handle because of their flammability than HCl or inorganic salts. More precipitates are formed as a result of the poor solubility of the organic by-products. The only advantage over reduced-strength HF is lower corrosion rates.

## 18-6.7 Buffer-regulated hydrofluoric acid systems

Other high-pH acidizing systems proposed for use up to 360 degF [180 degC] involve the buffering effect of an organic acid and its ammonium salt, mixed with ammonium fluoride, as an HF precursor (Abrams *et al.*, 1983). To minimize corrosion, the use of the same uninhibited buffer without ammonium fluoride as a preflush has been recommended up to 350 degF [175 degC]. The ammonium salt of the organic acid is generated from the partial neutralization of the acid with ammonium hydroxide. The proposed buffered systems are

- formic acid/ammonium formate with pH = 3.5 to 4
- acetic acid/ammonium acetate and citric acid/ammonium citrate with pH = 4.5 to 5.

To extend the application to higher temperatures (up to 550 degF [290 degC]), an excess of ammonium salt is formed by using a higher ratio of ammonium hydroxide to organic acid. Because the kinetics of clay dissolution increases with the fluoride ion concentration, more ammonium fluoride is added to compensate for the pH increase (Scheuerman, 1988). Successful in-depth stimulation has been observed with this system only for bottomhole temperatures lower than 129 degF [54 degC]. In most cases using this system, many damaging precipitates are noticed (e.g., fluosilicates, fluoaluminate usually involving ammonium), the formation of which is related to the weak acidity in the near-wellbore area. These systems suffer from the same drawbacks as the self-generated mud acid system.

## 18-7. Damage removal mechanisms

Selection of a chemical as a treatment fluid for any application depends on the contaminants plugging the formation. HCl does not dissolve pipe dope, paraffin or asphaltenes. These solids or plugging agents are organic in nature, and their treatment requires an effective organic solvent (usually an aromatic solvent such as toluene, xylene or orthonitrotoluene). Because different plugging solids require a variety of solvents for their removal, there is no universal solvent for wellbore damage. The proper evaluation of damage and treatment design are illustrated by Clementz *et al.* (1982) for the successful removal of bacterial damage in water injection wells. Solvent or acid should never be pumped into a well until the probable causes of damage and the best chemical to remove the damage have been defined.

Compatibility with formation fluids and mineralogy is extremely important in sandstone acidizing. Thus, determination of the precipitation potential of mud acid mixtures requires close scrutiny of the mineralogy and

connate water present. Acid reaction products are not necessarily soluble in the spent solution or in certain ionic environments.

Formation damage is fully discussed in Chapter 14.

### 18-7.1. Formation response to acid

Incompatibilities may occur even if the damage is identified, an appropriate removal fluid system is available and the probable response of the formation fluids and minerals to the acid and spent acid solution has been determined. These incompatibilities can result in solid or gelatinous precipitates, which can plug pores and offset the improvement the acid was intended to create. Results can range from no harmful effects and complete cleanup of the damage to less than optimum improvement or plugging of the formation with acid-generated precipitates.

When detailed petrographic core analyses are available, geochemical simulators can be used to estimate potential problems. This type of simulation requires detailed definition of the chemistry of the treating fluid, formation damage and matrix mineralogy. The release of fines and undefined spent-acid precipitates still have the potential to damage the formation and are not identified by core testing.

### 18-7.2. Formation properties

Damage prevention and dealing with formation response before acidizing are the goals of proper design. Although it may be easy to dissolve formation damage, success is dependent on dissolving this material without damaging the formation. This is possible, yet it is paramount to define the chemistry of the formation minerals and treating fluids to predict how the spent acid will react as it penetrates the formation. Potential incompatibilities can be prevented by proper log and core evaluation. Because the secondary reactions can be just as damaging, defining the potential problems generated by long-term exposure should also be evaluated.

Two key formation characteristics for fluid selection are mineralogy and permeability. Defining formation mineralogy helps to confirm the types of acid systems and acid concentrations to use. Defining formation permeability provides the information required to estimate the matrix injection rate and the maximum bottomhole pressure allowed before hydraulically fracturing the formation.

Pore pressure, temperature and the mechanical condition of the formation are influential in the design. High-pore-pressure formations fracture at much lower pressure differentials than depleted formations. Depleted formations have a lower fracture pressure than that originally observed. Temperature significantly affects

the selected fluid's reaction rate with different mineral types. Acid concentrations are usually lower for higher temperatures. The mechanical integrity of the formation biases the fluid selection in that the acid concentrations are usually reduced in less consolidated formations.

### 18-7.3. Formation brine compatibility

Compatibility with formation brines must be considered when treating with mud acid. Mud acid mixtures can form  $\text{CaF}_2$  (a solid) when excess  $\text{Ca}^{2+}$  ions are present. Similar solid materials are also created with  $\text{K}^+$  and  $\text{Na}^+$  ions. The use of clear brines as completion and workover fluids has increased the necessity of checking the formation waters for compatibility. This brine usage has also increased the necessity of ensuring that sufficient compatible preflush is used to dilute and remove these ionic species prior to injection of the mud acid system. Several available methods have been tested. The salinity of the connate brine is in equilibrium with the native minerals and their CEC. When possible, the salinity of the preflush and overflush fluids should closely approximate that of the connate brine. Historically, the use of low-salinity brines has rarely presented catastrophic problems when used in conjunction with acid treatments.

Several additives have been demonstrated to positively affect the formation's sensitivity to changes in salinity. Other species in connate water have equal, if not more, influence on the success of the treatments. Each of these species has specialty chemical additives that address them individually. While there is documentation on the benefits of certain types of additives (Gidley, 1971; Hall, 1975), other authors have reported damage caused by a similar system in multiphase-flow environments (Muecke, 1979; Davies *et al.*, 1988). Shaughnessy and Kline (1983) showed the difficulties with high bicarbonate ion content in formation waters. The use of HCl was not sufficient to keep the well from redamaging itself quickly. They used an ingenious treatment with a form of ethylenediaminetetraacetic acid (EDTA) to both remove the calcium carbonate scale that had damaged productivity and prevent recurrence of the scale for long periods of time.

High sulfate ion contents (>1,000 ppm) exist in some formation waters. Spending HCl on calcium carbonates generates a high concentration of calcium ions that will precipitate calcium sulfate when the spent acid mixes with formation water. This can be prevented by preflushing the formation water away from the wellbore. In sandstone formations, water containing ammonium chloride ( $\text{NH}_4\text{Cl}$ ) should be used as a preflush fluid.

### 18-7.4. Crude oil compatibility

Another serious problem with formation fluids is the reaction of crude oil with acid. Removal of the residual hydrocarbon phase improves the effectiveness of aqueous acid systems. Some oils, particularly black heavy oils (less than 30°API gravity), react with acid to form either damaging sludge (precipitated asphaltenes) or a stable emulsion. Moore *et al.* (1965) reported this problem and gave the treatment to prevent it. Sometimes sludge preventers and emulsion breakers cannot prevent the formation of stable emulsions. Houchin and Hudson (1986) discussed similar problems with organic deposits. Recent work shows how dissolved iron creates more stable sludges and emulsions with these crude oils. Some "difficult" crude oils require a hydrocarbon solvent buffer between the crude oil and the acid that is mutually compatible with both the crude oil and the acid. The buffer reduces contact between the acid and the problem oil and prevents or reduces the problems with sludge and emulsion. Using this technique in one Wyoming oil field increased the success rate from 25% to 75%.

Asphaltene particles can precipitate during production as a result of a pressure drop. Solvents can be used to loosen and partially or completely disperse them. This action helps the acid do a better job of dissolving acid-soluble solids. When a well has been completed with oil-base muds, presoaks with an aromatic solvent and producing back before acidizing are helpful. Solvent formulations and surfactant solutions are available as a pretreatment to clean up oil-base mud filtrates and restore the formation to a water-wet condition.

Gidley (1985) reported that the use of  $\text{CO}_2$  as a preflush to acid treatments has many benefits, including reducing the volumes of acid required to generate successful production increases. This type of preflush has worked well in core studies to enhance crude oil displacement and improve mobility.

### 18-7.5. Formation mineral compatibility with fluid systems

An analysis of the formation minerals is important for designing the HCl preflush, mud acid treatment and overflush in sandstone formations. Basic questions that must be answered are listed here.

1. How much of the formation will dissolve in HCl? Where a high HCl solubility exists (20% or more), mud acid should not be used. This statement is based on the assumption that HCl-soluble compounds are carbonate-base minerals. These minerals are the common cementing material of sandstone formations. Dissolution of this cementing material releases particles that can decrease

the permeability. In addition, precipitants exist as small discrete particles that cannot be produced back through the perforations and out of the well. The use of mud acid in sandstones with a high carbonate content produces numerous precipitates.

Calcium carbonate, magnesium carbonate and iron compounds are soluble in HCl. Even feldspars and chlorite clay are slightly soluble (Gdanski and Peavy, 1986). Recent investigations of HCl involvement in the HF reaction with clays show that the HCl is consumed on the clay surfaces, and this should also be accounted for in the preflush volumes and in the HCl:HF ratio of the main fluid stage (Gdanski and Peavy, 1986). Zeolite minerals can produce gelatinous precipitates when exposed to HCl. This can be avoided by the use of organic acid mixtures, as discussed later in this chapter. Sufficient volumes of HCl must be injected ahead of the mud acid to dissolve enough of the HCl-soluble materials before the mud acid or spent mud acid reaches them.

## 2. How much of the formation will dissolve in mud acid? Will acid reaction by-products precipitate?

The volume of mud acid used depends on the concentration of the acid and the amount of damage. Optimizing this volume can be done only by detailing the damage in a valid numerical simulator (Perthuis *et al.*, 1989). The HCl:HF ratio and concentration are selected to prevent or reduce the formation of damaging precipitates (Table 18-5).

Some minerals automatically precipitate fluoride compounds when high concentrations of HF are used, particularly 6% HF. Even 3% HF will precipitate potassium fluosilicate when mud acid reacts with potas-

sium feldspar. HF-dissolved sodium feldspars do not usually precipitate sodium silicate with 3% or less HF.

When HF is used in a formation containing clay, feldspar and micas, hydrous silica always precipitates. Hydrated silica has been reported in a sticky, gelatinous form that if left stagnant can attach to the mineral surfaces. However, Crowe's (1986) work on sandstone cores demonstrates that hydrated silica does not precipitate as a sticky, gelatinous mass. The reaction between the spent mud acid and formation fines is a topochemical reaction, with hydrated silica deposited on the surface of the fines.

It is important to design the overflush to dilute and displace the hydrous silica at least 3 to 5 ft away from the wellbore to reduce the effect of the damage. To avoid silica-creating damage, it is important to limit any static time while the mud acid stage is in the near-wellbore area. If the precipitates are diluted and flushed, the likelihood of permanent damage is reduced. The by-products can be flushed away and sometimes even stabilize formation fines in the process. If the well is then returned to flow quickly, some of the precipitate may be produced back. "Quickly" refers to nonproducing time, not the rate at which flowback is accomplished. The quick return of fluids can help improve cleanup of the formation after acid treatment, regardless of the flow rate. If an inadequate amount of HCl preflush is used in formations with 5% to 15% carbonate, residual carbonate near the wellbore reacts with spent HF (fluosilicic acid or  $\text{AlF}_3$ ), and voluminous precipitates form. The hydrated precipitates occupy a much larger volume than that of the original clays and carbonate dissolved.

## 3. Will iron be a problem?

Where a lot of iron-rich minerals are in the formation, dissolved iron can precipitate in the formation. It is well known that ferric iron precipitates as acid spends to a pH of 2 to 4. The precipitation of iron hydroxide, where concentrations as high as 10,000-ppm iron are present in solution, can be prevented by adequate treatment with a sequestering agent such as nitrilotriacetic acid (NTA), EDTA, citric acid or combinations of acetic and citric acid (Shaughnessy and Kunze, 1981; McLeod *et al.*, 1983; Paccaloni, 1979a, 1979b) (see Chapter 15). Crude oil with a high asphaltene content should be tested for sensitivity to different iron concentrations. Sludge and ridged-film emulsions are common problems for these crude oils.

Damage with iron hydroxides can be compounded by the high iron concentration that comes off the surface of the tubing during acid injection (De Ghetto, 1982). Injecting acid through new tubing can be highly damaging in this respect (Fogler and Crain, 1980; Lybarger

**Table 18-5. Acid use guidelines for sandstone acidizing (McLeod, 1984).**

Condition or Mineralogy	Acid Strength (blend)
HCl solubility > 20%	HCl only
High permeability (>50 md)	
High quartz (>80%), low clay (<5%)	12% HCl–3% HF <sup>†</sup>
High feldspar (>20%)	13.5% HCl–1.5% HF <sup>†</sup>
High clay (>10%)	10% HCl–1% HF <sup>‡</sup>
High iron/chlorite clay (>15%)	10% acetic acid–1% HF <sup>§</sup>
Low permeability ( $\leq$ 10 md)	
Clay (<10%)	6% HCl–1% HF
Clay (>10%)	6% HCl–0.5% HF

<sup>†</sup> Preflush with 15% HCl  
<sup>‡</sup> Preflush with 10% HCl  
<sup>§</sup> Preflush with 10% acetic acid

and Gates, 1978a, 1978b). Newly manufactured tubing has a crust of mill scale, or magnetite, which is a form of ferric and/or ferrous oxide. The mill scale is dissolved and loosened by the acidic fluid, and in the early stages, partially spent, iron-rich weak acid is injected. Particles of mill scale can then be injected into the perforations and trapped there. Injected acid will continue to dissolve the mill scale, creating ferric chloride that enters the formation. If the ferric chloride combines with iron leached out of iron-rich chlorite clay or other iron compounds, a large amount of iron hydroxide precipitates is possible, which can severely damage the formation. This aggravated iron damage can be prevented by pickling (cleaning) new tubing to remove mill scale and then circulating the pickling acid back out of the well, as discussed later.

#### 4. Do the sidewall core samples contain drilling mudcake?

Testing results from samples of sidewall cores with excessive mudcake should be reviewed closely and compared to the log response and other data sources such as a produced water sample analysis. High concentrations of drilling mud solids (e.g., barite, smectite, mica, bentonite or illite minerals) should not be present in clean, high-porosity sandstone formations. The solubility of the samples in mud acid mixtures may be exaggerated.

#### 18-7.6. Acid type and concentration

Permeability and mineralogy determine the compatible concentration of HCl or acetic acid in the preflush stage and HF and HCl in the mud acid stage. Concentration recommendations are provided in Table 18-6 for preflush fluids and Table 18-7 for mud acid fluids. The previously presented acid use guidelines in Table 18-5 were published in 1984 (McLeod, 1984). Lower mud acid concentrations

were first recommended in 1970 by Farley *et al.* (1970) to prevent unconsolidation in California sandstones. U.S. West Coast sandstones are generally rich in potassium feldspars. Holcomb (1975) published work on the first successful acid stimulation of the Morrow formation in West Texas–New Mexico with weak acid (6% HCl–1.0% HF and 3% HCl–0.5% HF). Lybarger and Gates (1978b) subsequently developed the slow-rate, low-pressure injection technique, in which they used 7.5% HCl–1.5% HF for Gulf Coast sandstones.

The guidelines are based on industry practices and the chemistry of sandstone acidizing from limited research studies; however, many case histories have corroborated them with high levels of success.

From 1975 through 1980, poor success in acidizing several formations such as the Frio and Wilcox in Texas led to the concern that spent acid generated damaging precipitates. Quick, qualitative laboratory bench tests confirmed that precipitates occur depending on the solubility of the acid reaction products. These same observations were first pointed out by Smith and Hendrickson (1965), in particular the problem with sodium fluosilicate. Labrid (1971) discussed the precipitation of hydrous silica, which caused some plugging in cores. This damage was later demonstrated by Shaughnessy and Kunze (1981) by leaving spent acid in the core for several hours, a condition that occurs in an actual acid job. This allows the slow reaction rate between the spent mud acid and the clay minerals and feldspars (aluminosilicates) to produce hydrous silica that decreases the permeability.

Crowe (1986) showed that there was little or no plugging during the injection of spent acid (fluosilicic acid) in a Berea core. This reassuring result matches the behavior seen during acid injection; however, plugging conditions are worse during the static conditions of shut-in examined by Shaughnessy and Kunze (1981). Crowe's work does not address shut-in conditions or conditions of inadequate

**Table 18-6. Fluid selection guidelines for preflush fluids.**

Mineralogy	Permeability		
	>100 md	20 to 100 md	<20 md
<10% silt and <10% clay	15% HCl	10% HCl	7.5% HCl
>10% silt and >10% clay	10% HCl	7.5% HCl	5% HCl
>10% silt and <10% clay	10% HCl	7.5% HCl	5% HCl
<10% silt and >10% clay	10% HCl	7.5% HCl	5% HCl

Note: Selection guidelines for all temperatures

For 4% to 6% chlorite/glaucophane, use <20-md guidelines with 5% acetic acid.

For >6% to 8% chlorite/glaucophane, do not use HCl; use 10% acetic acid preflush to mud acid plus 5% acetic acid.

For >8% chlorite/glaucophane, do not use HCl; use 10% acetic acid and organic mud acid.

For <2% zeolite, use 5% acetic acid in all fluids containing HCl and preflush with 10% acetic acid.

For >2% to 5% zeolite, do not use HCl preflush; use 10% acetic acid preflush and overflush to mud acid containing 10% acetic acid.

For >5% zeolite, do not use HCl in any system; use 10% acetic acid preflush and overflush to organic acid prepared from 10% citric acid/HF.

**Table 18-7. Fluid selection guidelines for mud acid fluids.**

Mineralogy	Permeability		
	>100 md	20 to 100 md	<20 md
<10% silt and <10% clay	12% HCl–3% HF	8% HCl–2% HF	6% HCl–1.5% HF
>10% silt and >10% clay	13.5% HCl–1.5% HF	9% HCl–1% HF	4.5% HCl–0.5% HF
>10% silt and <10% clay	12% HCl–2% HF	9% HCl–1.5% HF	6% HCl–1% HF
<10% silt and >10% clay	12% HCl–2% HF	9% HCl–1.5% HF	6% HCl–1% HF

Notes: Selection guidelines for all temperatures  
For 4% to 6% chlorite/glaucosite, use <20-md guidelines with 5% acetic acid.  
For >6% to 8% chlorite/glaucosite, use 10% acetic acid preflush to mud acid plus 5% acetic acid.  
For >8% chlorite/glaucosite, use 10% acetic acid and organic mud acid.  
For <2% zeolite, use 5% acetic acid in all fluids containing HCl.  
For >2% to 5% zeolite, use 10% acetic acid preflush and overflush to mud acid containing 10% acetic acid.  
For >5% zeolite, use 10% acetic acid preflush and overflush to 10% citric acid/HF.

preflush with HCl. Walsh *et al.* (1982) presented theoretical work on the equilibrium of spent acid and showed that plugging precipitates are possible with various acid concentrations and mineral compositions in sandstones.

Research by Bertaux (1986) addresses reprecipitation and plugging problems in acidizing sandstones containing potassium feldspars. The solubility of potassium fluosilicate is less than one-half of the solubility of sodium fluosilicate, which is why lower mud acid concentrations are recommended in the presence of potassic feldspars such as orthoclase or microcline ( $KAlSi_3O_8$ ). The amount of potassium in the mineral orthoclase (potassium feldspar) is enough that the solubility of potassium fluosilicate is exceeded at normal reservoir temperatures (less than 200 degF) by dissolving pure orthoclase in regular mud acid (12% HCl–3% HF). Bryant and Buller (1990) observed the generation of fines by the reaction of HCl with feldspars.

The early work of Smith *et al.* (1965) in acidizing various cores with different permeabilities shows different responses to mud acid. C. F. Smith (pers. comm., 1979) found it more difficult to stimulate wells producing from sandstones with permeabilities of 10 to 60 mD, which are much lower than the usual Berea sandstone permeability (100 to 300 mD) in mud acid experiments. Smith attributed much of the difficulty to the release of fines by the acid.

Long-core tests performed by R. D. Gdanski (pers. comm., 1985) in low-permeability sandstone at high temperatures demonstrate increased permeability with mud acid in the first two 4-in cores in series and decreased permeability in the third 4-in core in a total core length of 16 in. Gdanski and Peavy (1986) also discussed the

depletion of the preflush HCl in sandstone acidizing by ion exchange of  $H^+$  with  $K^+$  or  $Na^+$  ions on the formation clay minerals. This gives new insights into potential problems with sandstones rich in clay minerals with high CECs (smectite and illite).

Simon *et al.* (1979) showed that HCl attacks chlorite clay, extracting the iron and magnesium and leaving an amorphous aluminosilicate residue. J. M. Kullman (pers. comm., 1988) observed plugging problems with these residues as well as with rim coatings of chlorite liberated by HCl in core flow tests. Chlorite is prevalent in the Morrow formation in the same areas where Holcomb (1975) worked and could be the reason why weaker acids worked better in that environment (i.e., they were easier on the chlorite). Thus, weaker acids are recommended for use in sandstones with significant chlorite content and acetic acid is recommended to dissolve the carbonate and not attack chlorite ahead of the mud acid.

A common misunderstanding about the recommended acid concentrations is that they are not absolute. The guidelines are a conservative approach to avoid problems with spent acid precipitates when no previous experience exists in acidizing a particular formation. Significant deviation from these guidelines should not be necessary. Unless evaluated experience exists, the guidelines are the most reliable source of information. Also, acid flow tests with cores are reliable if long cores are used and if the spent acid is left in a portion of the unacidized core for the same period of time and at the same temperature that will occur in the downhole treatment. These tests are expensive and therefore seldom performed.

## 18-8. Methods of controlling precipitates

The methods used to control the precipitates caused by acidizing are proper acid staging, lower acid concentrations, correct usage of preflushes and sufficient overflushing, as illustrated in the following guidelines.

### 18-8.1. Preflush

Preflush with

1. 5% to 15% HCl
2. acetic acid (see Section 18-3).

The preflush displaces formation brine away from the wellbore to prevent it from mixing with reacted mud acid and causing a damaging precipitate. If the formation contains more than 1% to 2% carbonate, an HCl preflush is necessary to dissolve the carbonate, prevent the waste of mud acid and prevent formation of the insoluble precipitate  $\text{CaF}_2$ .

If completion brines such as seawater, potassium chloride (KCl), calcium chloride ( $\text{CaCl}_2$ ) or calcium bromide ( $\text{CaBr}$ ) have been used in the well prior to acidizing, the brines will mix with the mud acid in the formation. Preflushing the mud acid with HCl or brine containing ammonium chloride to dilute the brines and remove them away from the wellbore helps avoid this problem.

Preflushes can also be used to displace and isolate incompatible formation fluids (either brine or crude oil), as previously discussed.

### 18-8.2. Mud acid volume and concentration

#### ■ Volume

Gidley (1985) reported that for the most successful mud acid treatment, more than 125 gal/ft of mud acid is required. Less may be used where only shallow damage exists around new perforations (e.g., 25 to 75 gal/ft is used to remove mud damage or in a spearhead treatment as an aid to perforation breakdown prior to hydraulic fracturing).

When the damage is quantified, a simulator can be used to optimize the volumes of mud acid mixtures to be used. Simulators can be used to aid the modification of volumes if several job stages are used (see Chapter 14).

#### ■ Concentration

Regular mud acid (12% HCl–3% HF) is the normal concentration to use to remove damage in clean quartzose sands. Field experience has shown that weaker concentrations (0.5% to 1.5% HF) can be effective for other sands. Mineral composition from a laboratory analysis can also dictate when less than 3% HF should be used. If the combined percentage of

clay and feldspar is more than 30%, 1.5% HF or less should be used. Field experience with some tight sandstones has shown that concentrations as low as 0.6% HF may be used (e.g., the Morrow formation in Texas and New Mexico; Holcomb, 1975). If the appropriate concentration is in doubt, an acid response test on a typical core should be performed if a core sample is available.

### 18-8.3. Postflush or overflush

The overflush is an important part of a successful sandstone acidizing treatment. An overflush has several purposes:

- to displace nonreacted mud acid into the formation
- to displace mud acid reaction products away from the wellbore
- to remove oil-wet relative permeability problems caused by some corrosion inhibitors.

When overflushing the acid treatment, it is important to remember that miscible fluids are required to perform these listed functions. Aqueous-base liquids should therefore be considered as the first displacing and flushing fluid. Another fluid system can then be used for addressing the other concerns as the conditions dictate. This suggests that multiple fluid types should be used as overflush stages for a given set of circumstances.

Typical overflushes for mud acid treatments are

- water containing 3% to 8% ammonium chloride
- weak acid (3% to 10% HCl)
- diesel oil (oil wells only and only following a water or weak acid overflush)
- nitrogen (gas wells only and only following a water or weak acid overflush).

Studies of displacement fronts indicate that the reactivity and fluid character of the overflush have a major influence on the volume required to displace the spent mud acid. For most overflush fluids (weak HCl and water containing ammonium chloride), volumes less than twice the mud acid stage should be considered inappropriate. The volume of overflush should never provide less than 3 ft of radial penetration. This means that for most situations, the overflush should be at least 200 gal/ft of perforations to push all the spent acid past the critical flow radius of 3 to 5 ft. A large overflush is necessary to prevent the near-wellbore precipitation of amorphous silica, which occurs after spent HF contacts the clay in the formation. At formation temperatures of 200 degF or higher, amorphous silica precipitation occurs while the mud acid is being pumped into the formation. The precipitate is somewhat mobile at first but may set up as

a gel after flow stops. If it is kept moving by overflushing with water containing ammonium chloride or weak acid, it is diluted and dispersed far enough away from the wellbore to where it has a less harmful influence.

Recent experience indicates the advantage of including HCl or acetic acid in the first part of the overflush to maintain a low-pH environment for the displaced spent mud acid stage. This supports the original recommendations of Smith and Hendrickson (1965). As the hydrogen ions adsorb on nonreacted clay deeper in the formation, the pH rises unless it is replaced by fresh acid in the first part of the overflush. Although the most economic overflush of a mud acid treatment is water containing 3% to 8% ammonium chloride with 10% ethylene glycol monobutyl ether (EGMBE) and a polyquaternary amine clay stabilizer, it does not address the pH problem without acetic acid addition. Also, certain chemicals can be added to acids to prevent or reduce the precipitation of some compounds (e.g., iron complexing agents, sulfate scale inhibitors and antisludge agents).

An example of the role of reservoir mineralogy was presented by Boyer and Wu (1983) in evaluating acid treatments in the Kuparuk River formation in Alaska. Their results indicate that fluoboric acid significantly reduces the amount of hydrated silica formed in comparison with conventional HCl-HF systems.

## 18-9. Acid treatment design considerations

Once a well is determined to be a candidate for a matrix acid treatment, the design should account for many different issues. A systematic approach to the estimation and calculation of critical parameters is required. Pressures, rates and volumes must conform to the constraints of the mechanical conditions of the well equipment and the available space for surface and pumping equipment, along with logistical time constraints. The following discussion includes the different types of acid sequences, how and why attempts are made to retard the acid reaction rate, potential contamination from various sources and the resultant damaging precipitation. The basic quality assurance and quality control (QA/QC) checks and the design of treatments from both a formation compatibility and operational standpoint are included.

An acid design technique based on the work of Williams *et al.* (1979) for mud acid injection is in the SPE Monograph *Acidizing Fundamentals*. Although the technique is based on studies of one sandstone, it does show the important effects of temperature and injection rate on live mud acid penetration. Well illustrated is the small depth of invasion of mud acid in sandstone, particularly when formation temperatures are greater

than 200 degF. Live mud acid usually penetrates only about 6 to 12 in into the sandstone before spending. This work was extended by Hill *et al.* (1977), who incorporated the effect of specific mineralogy and added the reaction kinetics of HF to the slower but finite quartz reaction rate. They also discussed the different reactivities of clay minerals and the importance of their morphology in the pore network. McElhiney *et al.* (1979) also reviewed the progress in methods of predicting live mud acid penetration and permeability increases in sandstone. These are worthwhile developments, but a simple guideline of wellbore contact time offers a practical solution to determining acid volumes to remove near-wellbore damage.

### 18-9.1. Selection of fluid sequence stages

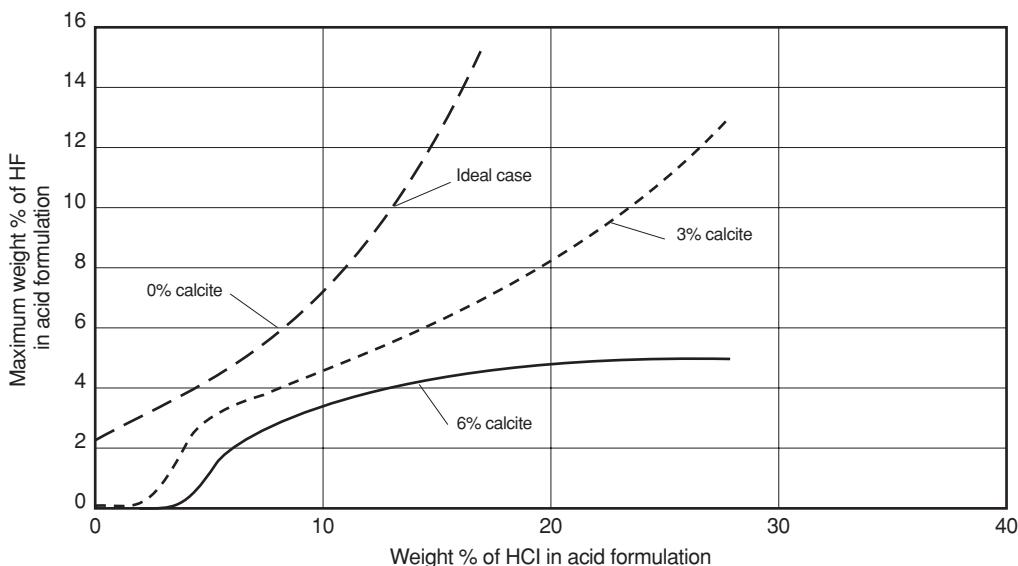
The damage type dictates the sequence of acid systems used for each treatment. The preflushes, main stage and overflush should be matched to the type of damage. Diversion should be matched to formation characteristics and the type of treating fluid. Diversion guidelines are provided in Chapter 19. Each type of diversion technique is addressed as it pertains to sandstone treatments in this section. The sequence of fluids that compose an acid treatment can be the key to making a treatment successful.

### 18-9.2. Typical sandstone acid job stages

A preflush stage should be used ahead of the HCl especially when high sulfate ion or high bicarbonate ion concentrations exist in the formation connate water or seawater or when CaCl<sub>2</sub>, KCl, or CaBr completion fluids have been used and calcium carbonate is a formation mineral. HCl dissolution of the calcite generates high calcium ion concentrations that mix with the incompatible formation water and generate scale (calcium sulfate or calcium carbonate).

### 18-9.3. Tubing pickle

One of the first items to be addressed when matrix treatments are considered should always be a tubing pickle (cleaning). This one step can have a significant impact on the success of treatments. Tubulars, regardless of how new, have scale, rust and other debris that result from handling, installation and production and that can be loosened by the solvents and acid injected into the well. The pickling process may be multiple staged and may involve expensive solvent packages. Typically, a small treatment containing solvent and acid stages will greatly improve, if not completely eliminate, the



**Figure 18-5.** HCl-HF treatment fluid selection based on AlF<sub>3</sub> or CaF<sub>2</sub> precipitation (Walsh *et al.*, 1982).

problems associated with tubular debris. The pickling process should be included in the procedure and time allotted for job execution. The purpose of the pickling process is to

- remove rust, iron oxides and scale
- dissolve oily films and pipe dope that could plug the downhole equipment and perforations
- limit the amount of iron that gets into the formation and contacts the crude oil.

#### 18-9.4. Preflushes

The sequence of fluids in sandstone treatments is dependent largely on the damage type or types. The use of multiple-stage preflushes should functionally address the different types of damage and thereby prepare the surfaces for the main treatment fluids. Hydrocarbon solvents are used to remove oil films and paraffin deposits so the aqueous acid systems can contact the mineral surfaces. These types of preflushes affect treatment success and should not be overlooked or demoted in importance. Acid-compatible brines (e.g., brine containing ammonium chloride) can be used as an excellent preparatory flush to help remove and dilute acid-incompatible species (e.g., potassium or calcium). An example of a preflush sequence is preceding the HCl portion of the preflush with a large quantity of brine containing ammonium chloride followed by a hydrocarbon-base surfactant mixture. The purpose of the brine preflush is to dilute the incompatible species to soluble levels. The hydrocarbon mixture has the same purpose as mentioned previously.

The next consideration for preflushes is compatibility with formation fluids. Certain crude oils have a high sensitivity to acidic mixtures. These situations may require dilution with hydrocarbons or other isolating or buffering fluid systems (e.g., foams). Further compatibility consideration should be given to the iron content of the initial injection fluids that contact the crude or condensate, because even low iron concentrations can cause sludge formation. Displacement of the fluids away from the near-wellbore region reduces the potential of problems that can reduce production success and limit or halt the injection process.

HCl preflushes in sandstone acidizing are extremely important. Their function is to remove as much of the calcareous material as possible prior to injection of the mud acid. Strength and volume guidelines are based on the criteria set in work by Labrid (1971), Fogler *et al.* (1976), Kline (1980), Kline and Fogler (1981) and Walsh *et al.* (1982). Their theoretical work was further investigated and confirmed by field work by Gidley (1985), McLeod (1984), Thomas and Crowe (1981) and others. Table 18-6 provides selection guidelines for the appropriate strength of the HCl preflush. The table is based on the solubility of the formation in HCl and the requirement of minimizing the remaining carbonate or calcite prior to introducing the mud acid.

Figure 18-5 summarizes Walsh *et al.*'s (1982) work on the selection of HCl-HF formulations based on the amount of calcite remaining after the preflush. The figure illustrates the importance of HCl preflushes. The HCl preflush step should never be neglected when using

mud acid mixtures. A few systems containing HF can be injected without an HCl preflush, but these are systems with extremely low HF concentrations, such as fluoboric acid. These systems can be used without an HCl preflush because the HF concentration in fluoboric acid is low enough not to present a precipitation potential.

### 18-9.5. Main fluid stage

The HCl-HF mixture used in each treatment should conform to the guidelines in Table 18-7. Work by Walsh *et al.* (1982) demonstrates that low HF concentrations should be used to avoid the precipitation of  $\text{AlF}_3$  or  $\text{CaF}_2$  if the remaining calcite cannot be quantified. Their work also suggests that 12% HCl-3% HF can be used even in low-calcite environments without a precipitation problem. Some significant problems that may occur in high-clay-content formations include compromised formation integrity and excessive fines generation. These conditions can be the result of too high HF concentrations. The volumes should be determined using a field-validated simulator to sensitize the severity of the damage. Gidley (1985) reported that the percentage of acidizing successes increases as the volume of mud acid increases for gas wells, whereas a maximum of 100 to 125 gal/ft of perforations is required to maximize success for oil wells. This study did not take into account the preflush used or the quantity of overflush. If diversion is maximized and the damage is known or perceived to be shallow, then smaller quantities per foot can be used. The acid strength is important, because precipitation potential and formation matrix collapse are problems that can be irreversible. Table 18-5 provides the original guidelines for HCl-HF mixtures to obtain the appropriate HCl:HF ratio to avoid precipitation and formation collapse. Table 18-7 is derived from this guideline on the basis of further laboratory testing and extensive field experience.

### 18-9.6. Overflush stage

The purpose of the overflush is twofold. First, it should displace the main fluid stage more than 3 to 4 ft away from the wellbore, which is the critical matrix area for radial flow. Second, the portion of the main stage that is not displaced should be diluted. Both of these factors help to eliminate damage in the near-wellbore area caused by the precipitation potential of the spent main fluid stage. Overflush fluids must be chosen carefully to avoid creating damage during the treatment flowback.

Overflush systems should meet the following criteria. The portion of the overflush immediately following the main fluid stage should be aqueous based, have a low pH value and have dilution potential for the spent mud

acid. Smith *et al.* (1965) recommended an HCl overflush to maintain a low-pH environment and match the fluid density of the previous stages. The remainder of the overflush should be miscible and compatible with the previous stages. The total minimum overflush volume must completely displace the main fluid stage at least 4 ft away from the wellbore. Any anisotropy of the formation permeability can warrant doubling or tripling the overflush volume if the energy in the reservoir is sufficient to unload the injected fluid. Although not previously reported, one of the authors of this chapter has achieved notable improvement where larger overflushes were used. This is especially true for wells where heavy bromide brines are used during the completion phase.

### 18-9.7. Diversion techniques

Common practice in sandstone acidizing is for the diverter stage to be applied as merely another stage. This is an excellent way to ensure that the main fluid stages are properly isolated by the preflush and overflush fluids. Some methods described in other chapters (e.g., ball sealers, rock salt) are not suitable for use in sandstone acidizing. The compatibility of the diverting agent with the live and spent acid species requires knowledge of the chemicals. Some forms of benzoic acid solids should not be used because the sodium content in some environments causes precipitation. Rock salt should never, under any circumstances, be used as a diverter with HF mixtures. Other materials can be incompatible with the solvents and surfactants used in the acid systems.

Operational considerations should always be taken into account when designing diversion stage sequences. The use of oil-soluble resins (OSRs) dictates that the method should be slug application. The last stage of preflush can contain a solvent to help dissolve the OSR material, creating uniform injectivity of the last sequence throughout the interval. A few exceptions apply to using certain acid systems. For example, when using fluoboric acid as the overflush to a mud acid treatment for silt and clay control, the fluids should be staged as in Table 18-8.

Other sequences could include brine flushes separating the hydrocarbon preflush from the HCl preflush before the main fluid stage; brine or weaker acid stages could be used to increase the volume of the overflush stage.

### 18-9.8. Typical sandstone acid job stages

The key to successful staging is to address all damage types present and maintain compatibility with formation fluids and formation mineralogy while minimizing the quantities of fluids injected. Table 18-9 provides a listing of typical stage sequences for a sandstone acidizing treatment.

**Table 18-8. Acid treatment sequence and fluid options.**

<b>Stage</b>	<b>Fluid System</b>
1. Preflush	Brine Hydrocarbons HCl
2. Main fluid	HCl-HF formulation
3. Overflush	HCl or NH <sub>4</sub> Cl
4. Diverter	Foam or slug OSR
5. Repeat stages 1–4 as necessary with 1–3 as the last fluid sequence	
6. Fluoboric acid	With diverter solvent for OSR or foam-weakening agent (mutual solvent)
7. Fluoboric acid diverter	Fluoboric acid-based fluid system, either foamed or slug OSR
8. Fluoboric acid	Fluid left at the perforations

**Table 18-9. Typical stage sequence for a sandstone acidizing treatment.**

<b>Stage Number</b>	<b>Stage</b>	<b>Reason for Stage</b>	<b>Information Source</b>	<b>Stage Composition</b>	<b>Stage Volume</b>
1	Crude oil displacement	To prevent oil sludge formation by the acid	Acid-crude oil sludge test	Aromatic solvent	To achieve 3-ft radial displacement
2	Formation water displacement	To prevent scale deposition	HCO <sub>3</sub> and SO <sub>4</sub> contents from formation water analysis	Ammonium chloride (NH <sub>4</sub> Cl) at 3%–8% depending on the salinity of the formation water	To achieve 3-ft radial displacement
3	Acetic acid	Iron compounds in formation (pyrite, siderite, hematite), chlorite, clay, zeolites	X-ray-diffraction (XRD) analysis	3%–10% acetic acid	CaCO <sub>3</sub> (%)      Volume (gal/ft) 0–5                  25 5–10                50 10–15              75 15–20              100
4	Hydrochloric acid	CaCO <sub>3</sub> or other HCl-soluble minerals	HCl solubility test and/or XRD analysis	According to core mineralogy: 3%–15% HCl	Calculated on the basis of HCl solubility and porosity (see Table 18-5) or this schedule:  HCl Solubility of HF (%)      Stage Volume (gal/ft) _____ <5                    50 5–10                100 10–20              200
5	Hydrofluoric acid (not used for carbonates and sandstones where HCl solubility > 20%)	To remove clay, other formation fines and mud damage	XRD analysis, SEM analysis, HCl:HF solubilities	According to formation mineralogy: 3%–13.5% HCl with 0.5%–3% HF	75–100 gal/ft
6	Overflush	To spend acid and flush spent acid away from the near-wellbore area	Always used	3%–8% NH <sub>4</sub> Cl or 3%–5% HCl in all wells followed by nitrogen (gas wells), kerosene (oil wells) or 5% HCl (water injection wells)	One to two volumes of the HCl:HF volume or to achieve 5-ft radial displacement
7	Diversion	To improve injection throughout the interval	Used as required for heterogeneous formation permeability	OSR for oil or low gas/oil ratio wells, foam for either oil or gas wells and water-soluble resins for water injector wells	

## 18-10. Matrix acidizing design guidelines

Matrix acidizing is the process of injecting acid into the formation in radial flow below fracturing pressure to remove damage and restore the permeability to the original reservoir permeability or higher. More detailed procedures are available from McLeod *et al.* (1983), who recommended the following steps for treatment design:

1. Estimate safe injection pressures:
  - a. determine present fracturing gradient
  - b. determine present bottomhole fracturing pressure
  - c. determine allowable safe injection pressure at both the wellbore and at the surface.
2. Estimate safe injection rate into the damage-free formation.
3. Estimate safe injection rate into the damaged formation.
4. Select stages required for fluid compatibility.
5. Calculate volume of each stage required:
  - a. crude oil displacement
  - b. formation brine displacement
  - c. HCl stage or acetic acid stage
  - d. mud acid stage
  - e. overflush stage.
6. Select acid concentrations according to formation mineralogy.

### 18-10.1. Calculations

#### ■ Fracturing pressure

Matrix treatments are defined as fluid injection occurring below fracturing pressure. If the fluid is injected above fracturing pressure, the acid may bypass the damage. It is important to perform some basic calculations to ensure that this pressure is not exceeded, and the exercise also provides the pressure and rates that may occur. Thorough discussions of fracturing pressure and bottomhole injection pressure and how these aspects are derived are provided in Chapters 3<sup>†</sup> and 20, respectively.

An important item to keep in mind with matrix treatments is that fracturing pressure is related to the pore pressure but is not directly proportional. As the pore pressure declines, so does the fracturing pressure. Although this is not a one-to-one relationship, it can be important when treating low-bottom-hole-pressure wells. The hydrostatic pressure exerted by the column of fluid in the tubulars can be sufficient to fracture the formation.

#### ■ Injection rates

The injection rate can be as significant as the injection pressure. The maximum injection rate that does not fracture the formation can be estimated by

$$q_{i,max} = \frac{4.917 \times 10^{-6} kh[(g_f \times H) - \Delta p_{safe} - p]}{\mu B \left( \ln \frac{r_e}{r_w} + s \right)}, \quad (18-5)$$

where  $q_{i,max}$  is the injection rate in bbl/min,  $k$  is the effective permeability of the undamaged formation in mD,  $h$  is the net thickness in ft,  $g_f$  is the fracture gradient in psi/ft,  $H$  is the depth in ft,  $\Delta p_{safe}$  is the safety margin for the pressure in psi (usually 200 to 500 psi),  $p$  is the reservoir pressure in psi,  $\mu$  is the viscosity of the injected fluid in cp,  $r_e$  is the drainage radius in ft,  $r_w$  is the wellbore radius in ft, and  $s$  is the skin effect factor.  $B$  is the formation volume factor and has a value of 1 for noncompressible fluids.

Equation 18-5 is a simple way of estimating the injection rate. However, Eq. 18-5 does not account for several factors, which are detailed in Chapter 20 for accurately modeling the injection rate. Equation 18-5 with zero skin effect and with the estimated value of the skin effect provides respective values for the minimum and a maximum pump rate during the job. These values enable allocating appropriate equipment for the treatment. True transient injection monitoring can be done in real time on location to monitor the progress of the job.

#### ■ Friction pressure estimation

Accurate fluid friction pressure is a difficult parameter to obtain. Because the tubular arrangement can be different in each case, a fairly accurate number is important. The following limited-range equation has been used with relatively good accuracy for estimating friction pressures for Newtonian fluids at rates less than 9 bbl/min:

$$p_{pipe\ friction} = \frac{518\rho^{0.79} q^{1.79} \mu^{0.207}}{D^{4.79}}, \quad (18-6)$$

where  $p_{pipe\ friction}$  is the friction pressure in psi/1,000 ft,  $\rho$  is the density of the fluid (specific gravity) in g/cm<sup>3</sup>,  $q$  is the pump rate in bbl/min, and  $D$  is the diameter of the pipe in in. Coiled tubing friction pressures can also be calculated using Eq. 18-6.

#### ■ Fluid volumes

If it is assumed that acid flows through porous media with a front that is uniform and stable, then the injection is piston-like and the first fluid in should be the

<sup>†</sup>See *Reservoir Stimulation Third Edition* (SMP-7075)  
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last fluid out. To calculate fluid volume, the following equation should be sufficient:

$$V_p = 7.48[\phi(r_s^2 - r_w^2)\pi], \quad (18-7)$$

where  $V_p$  is the pore volume for the distance  $s$  in gal/ft,  $\phi$  is the fractional porosity, and  $r_s$  is the distance it is necessary to penetrate the damaged or displaced section in ft.

Mud acid treatments do not dissolve much of the formation minerals but rather dissolve the materials clogging the pore throats. This means that significant changes in the flow distribution of the injected fluids occur during the treatment as the pore-plugging materials are dissolved (see Chapter 19 on diversion). Because the acid does not follow the ideal mode, adjustments to the injection volumes must be made. Significant changes in the fluid can also occur in the tubulars, before the fluid reaches the formation. The dilution of stage composition and spending are just some of the complications that must be addressed by the designer. The use of smaller tubulars, such as coiled tubing, during acid treatments can contribute to a better acid job by facilitating the maintenance of stage integrity and reducing displacement volumes. Mechanical limitations associated with artificial lift (e.g., gas lift) are more easily overcome by the use of coiled tubing. The risks of leaking valves, undiluted acid remaining in the mandrels and acid leaking into the tubing/casing annulus are avoided. The limited injection rate coincidentally controls the contact time. The pump rate and extraction out of the tanks holding the acid can create a bottleneck during execution. A complete understanding of the operational aspects is necessary for proper execution.

One of the considerations in selecting the stage volumes is the tubulars. The volumes of diverter and their location in the tubulars while injecting must be considered, especially for the use of foam diverters. When using foam diversion techniques, brief shutdowns or momentum changes are called for to maximize diversion. If the foam is in the tubulars when the shutdown occurs, phase separation of the foam can occur, affecting the foam diverter performance.

Another consideration is the preflush activity. If formations do not have much solubility in HCl, operators have tended to lower the volume of acid preflush and use brine. However, Gdanski and Peavy (1986) reported that this is not a good idea because the HCl preflush performs the vital function of cation exchange, which prepares the mineral surfaces for the HF mixture. The cation exchange must otherwise be done by the HCl portion of the HF mixture, which

raises the pH of the acid system and induces the precipitation of silicate complexes. As a minimum, the preflush should penetrate the same distance as the HF mixture (e.g., if the HF blend volume penetrates 2 ft, then the preflush should penetrate a minimum of 2 ft).

Where the HCl solubility is moderate to high, more HCl is necessary. The following equation is used to calculate this volume and address the HCl-soluble materials:

$$V_{HCl} = 7.48 \frac{\pi(1-\phi)X_{HCl}[r_s^2 - r_w^2]}{\beta}, \quad (18-8)$$

where  $V_{HCl}$  is the volume of HCl required in gal/ft,  $X_{HCl}$  is the fraction of the bulk rock dissolved by HCl, and  $\beta$  is the dissolving coefficient expressed as the amount of rock dissolved per gallon of acid and is related to the acid strength.

### 18-10.2. Flowback and cleanup techniques

Selection of the correct flowback procedure is critical. The flowback during multiphase transition periods can cause irreversible damage. The fines loosened during the acid job are invariably produced back into the near-wellbore area. These fines can be removed in diluted concentrations that pass through the completion if small, gradual pressure drops are created. This was demonstrated by Krueger (1986).

The following are key factors to consider for flowback in sandstone formations:

- The fluids flowing back are more viscous than those injected. They are capable of carrying natural formation fines and other partially dissolved solids at lower velocities, which can cause plugging before the well cleans up completely.
- The spent acid usually has a higher density than the formation water. The tubing pressure should be lower than when connate water is produced, owing to the higher hydrostatic pressure of the spent acid.
- Spent acid has an equilibrium established of potential precipitants, held in place by dissolved gases and dissolved salts. Should these gases (e.g., CO<sub>2</sub>) be removed from the spent fluid as a result of creating an excessive pressure drop, precipitation will occur.
- A minimum velocity is necessary for liquid to be voided from the tubing without slippage occurring. The minimum velocity to the unload tubing can be calculated. The flow rate and tubing pressure in this calculation should include the heavier liquid density. The flow rate should be achieved gradually but sufficiently soon to avoid precipitation in the formation. The rate should

then be maintained until all injected fluids are returned and both the tubing pressure and production rate are steady. Plotting the gradual incremental choke changes as pressure and rate stabilize provides insight to the affect of the acid treatments on the formation and completion.

- HF systems should be flowed back immediately after injection of the overflush. The potential damaging precipitates that are generated form when the pH increases as the HCl is spent. If the acid is returned quickly, then the pH change may not reach the range for precipitation. Many iron precipitates also drop out when the pH increases. The exception is fluoboric acid treatments. The shut-in time required for complete HF generation and fines stabilization varies on the basis of temperature.
- The majority of the additives that are injected are produced back. Because the acidizing additives are by design water soluble, they are partitioned into the water phase. This can cause separation and floatation equipment problems. The return fluids are also acidic, which creates problems for chemical-electric detection devices in the separation equipment. Local environmental regulations may dictate water quality standards that are difficult to achieve, and disposal of the returned fluids can be cost prohibitive. Alternatives to disposal of the returns as hazardous waste have been developed, including filtration through inexpensive media (Hebert *et al.*, 1996).

## 18-11. Acid treatment evaluation

Matrix treatment evaluation is the subject of Chapter 20. The following is a partial list of the basic questions that should be answered during the evaluation of an acid treatment to help determine the success or failure of the treatment.

- Was the well damaged? Was there an improvement in the injectivity or transient skin during the treatment? Is there evidence that the well was damaged?
- Which fluid system or stage accomplished the most damage removal? Injectivity values or transient skin values for each of the fluid stages must be evaluated to help identify what damage was causing the most significant production impairment.
- Were emulsions observed during cleanup? During the cleanup of the treatment is when the effectiveness of additives and treatment fluid packages demonstrates value. Cleanup time, emulsion problems and facility upset have an economic impact and can be cause for considering different methods of handling the problems.

- Did any of the treatment fluids or stages create problems during the execution? During the treatment were there mixing or handling problems associated with any of the additives or the fluid system?
- What are the properties of the formation fluids (i.e., hydrocarbons and brine) and are these compatible with the treating fluids? Post-treatment flowback inspection and analysis of fluids identifies emulsions (treating fluid additive formulation), solid debris (proper acid strength) and other telltale signs of precipitation caused by incompatibilities.
- What is the type of completion injected into and was this a consideration during the treatment? When injecting into gravel packs or frac and pack completions, injection rates should be limited if the injected height is limited. Too high an injection rate through the perforations can evacuate them of gravel and create an unstable and unsatisfactory environment where the potential exists for formation sand production. This is especially true for high-solubility zones where a small percentage of the perforations is taking fluid.
- Was the proper diversion technique or sequence chosen and applied? Most acid treatments require diversion. The application of proper diversion techniques with the selected acid system is vital to the ultimate success of the treatment.
- Was the well appropriately prepared before acidizing? When key steps of preparing the wellbore for the acidizing process are left out (e.g., not pickling the tubing, not removing the gas lift valves, not removing the rods or an electrical submersible pump), the prospects for ultimate success are reduced. Wellbore preparation is especially critical for acid treatments. Injection of tubular debris into the formation can be disastrous, and acid in the annulus of a gas lift completion string is corrosive.
- Were the injected fluids checked using quality control steps? Acid strength and certain additives must meet at least threshold ranges for activity and compatibility limits.
- Was the tubing acid cleaned (pickled)? Rust and mill scale must be removed, even with new pipe.
- Were the pumped fluids sampled and checked for cleanliness and concentration? Although samples are routinely taken and checked before the job starts, samples should be taken during the pumping of each stage. Many changes in injection behavior can be explained when these samples are analyzed. Fluctuations in injectivity may be due to a process problem that was innocently incorporated for operational expedience or safety compliance.

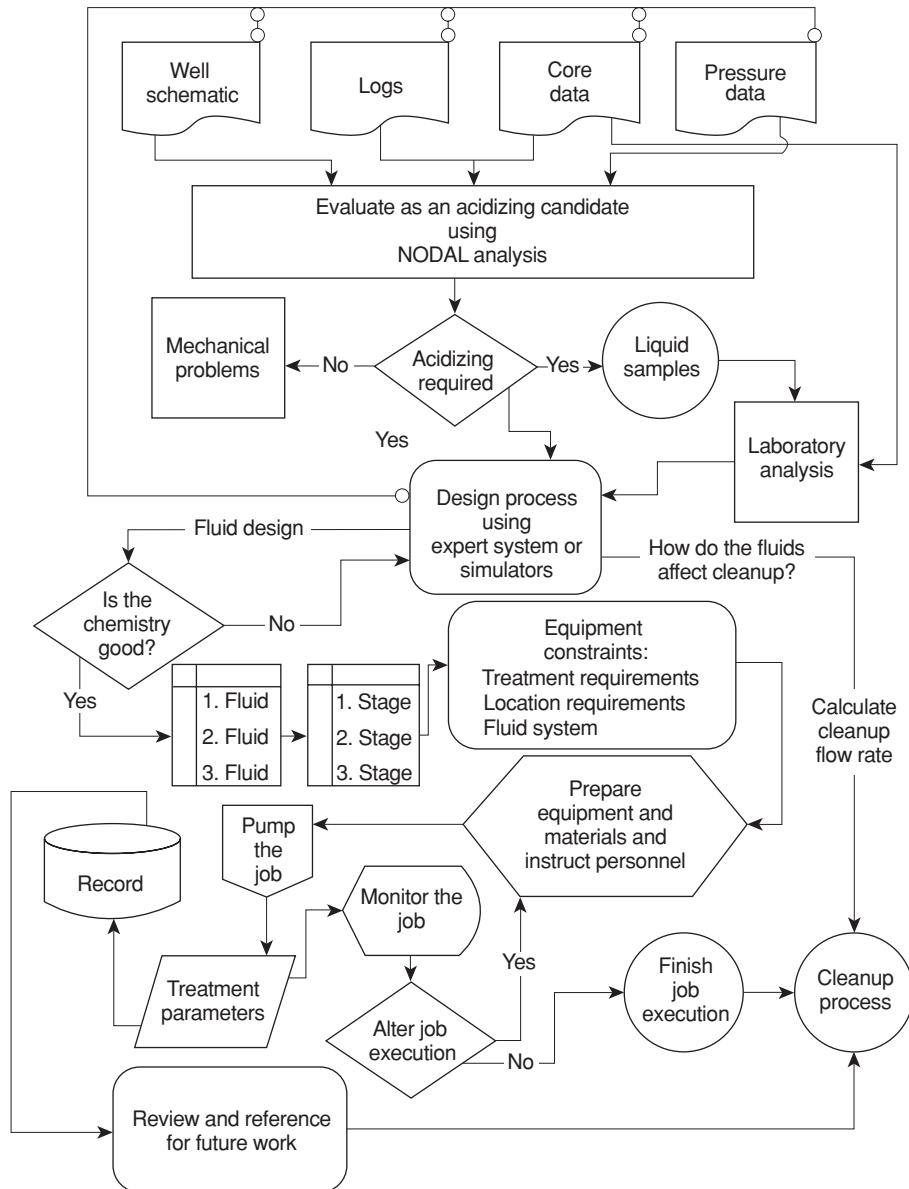
- Was an injection test with the appropriate fluid made before pumping acid to establish a base injectivity before acidizing? Injection testing conducted with platform or field equipment not intended for this purpose can produce misleading results. Contaminated fluids or poorly equipped monitoring can result in bad data.
- Did the acid response during the injection validate the damaging substance identified? HCl-soluble scale may be revealed as the obvious contributor to the injectivity problem when large pressure drops occur when the HCl reaches the formation. If the injection rate is increased, similar pressure drops could also be noted when the HCl-HF mixture reaches the formation.
- Did the pressure response indicate good diversion? Pressure increases may be interpreted as diverter action, but this is not always the case. Diverter response should coincide with the use of a diverter; if not, other parts of the process should be investigated.
- How long was the spent acid left in the well before flowback? Some secondary and tertiary reactions require time to produce precipitates. Quick turnaround for flowback, not high production rates, lessens the potential for these reactions to create damage. Most of these reactions result in damage that is detected only after production is initiated.
- Were spent acid samples recovered and analyzed? Flowback fluid samples should be acquired regardless of the volume of the treatment. These samples should be marked, with the date and time, total volume recovered to that point and other pertinent data, such as choke size, flowing tubing pressure, water cut and produced quantities.
- Were the production results consistent with the acid injection pressure response? If the injection pressure declines too quickly, the acid treatment causes the well to develop a vacuum. Once the well is brought back on line, the production does not improve because of limitations associated with the wellbore construction or production facilities.
- Was a pressure buildup test performed and interpreted? A pressure test analysis is the definitive method to answer whether the treatment is a success or failure.

## 18-12. Conclusions

Acidizing sandstone formations is not an impossible task, but it is not simple either. Success requires a methodical, systematic approach. It can be accomplished without any detrimental effects by analyzing vital information. The flow chart in Fig. 18-6 shows the steps the process encompasses.

The following conclusions can be made about sandstone acidizing:

- Damage identification determines the types of acids and other solvents to use in a sandstone acidizing treatment.
- A knowledge of the chemical reactions involved among acids and formation minerals and connate fluids provides some guidelines for acid types, concentrations and the sequence to prevent or reduce the precipitation of insoluble reaction products.
- The selection of appropriate types and volumes of preflushes and overflushes also helps prevent incompatibilities between formation fluids and acid systems.
- A numerical simulator should be used to quantify acid volumes, although simple guidelines are provided to assist in the selection of treatment volumes. The most important factor in successful acid stimulation is to provide clean, filtered acids at the perforations by filtering all fluids and cleaning (pickling) the tubing before the acid treatment is injected into the formation.
- Evaluating the executed acid treatment provides information to improve subsequent acid treatments in the same or similar formations.



**Figure 18-6.** Sandstone acidizing treatment design process.

# 19. Fluid Placement and Pumping Strategy

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## 19-1. Introduction

Fluid placement is critical to the success of a matrix stimulation treatment (Pye *et al.*, 1970; Cooper and Bolland, 1984). Damage, depending often on fluid-rock interactions, may be unevenly distributed along the net thickness. Also, the natural reservoir permeability may vary considerably, with substantial contrasts. In this environment, matrix stimulation tends to remove or bypass the damage that is easier to reach (i.e., a lower degree of damage or higher permeability) and becomes self-defeating. Each additional volume of stimulation fluid follows the path of least resistance, and more of it invades the layer where it is least required.

Several methods have been developed to improve fluid placement during matrix acidizing. Nonmechanical methods include the use of particles accumulating at the sandface to form a low-permeability cake (i.e., particulate diverters). The size of the particles varies from a few tens of micrometers to a few millimeters. Other methods involve the use of viscous fluid slugs or the use of foam either as staged slugs or combined with the acid stages (i.e., foamed acid). Each of these methods is based on the temporary impairment of the high-injectivity zones accepting most of the diverting material, which results in an increase of the proportion of fluid going into the low-injectivity zones. It is essential, of course, to avoid permanently damaging the higher injectivity zones.

Mechanical techniques consist of ball sealers, which are rubber-lined balls added to treating fluids to plug fluid-taking perforations, and packers, which enable isolating a given zone during a treatment. Mechanical techniques differ from the other diversion methods in that they completely shut off a part of the reservoir to direct all the stimulation fluid to a subsection of the open zone. Another technique is coiled tubing placement in which acid is spotted or injected across the zone of interest. This is especially important in horizontal wells or vertical wells with long producing zones (Thomas and Milne, 1995).

The last method is specific to carbonate formations. It involves pumping gelled acid, with the viscosity varying with the degree of spending. Injectivity is reduced in zones containing large volumes of spent acid, and fresh

acid is directed to lower injectivity zones. This method has been increasingly used recently and has produced good results in terms of placement. It is described in more detail in Chapter 17.

The choice of the pumping strategy must take into account several parameters, such as producing-interval thickness, lithology and permeability profile, damage distribution and the economics of the treatment.

## 19-2. Choice of pumping strategy

### 19-2.1. Importance of proper placement

Matrix stimulation is almost always performed in multilayer reservoirs containing zones with, at times, wide injectivity contrasts caused either by different permeabilities or by uneven severity of damage. Other phenomena causing vertical heterogeneities within a completion interval include permeability gradients in thick reservoirs and selective damage in some perforations. The natural trend of stimulation fluids is to follow the path of least resistance (i.e., to invade the most permeable or least damaged zones). To optimize treatment results, most of the open interval must be treated, and thus, treating fluids must also be injected in significant volumes into the least permeable and most damaged zones.

In many cases, the use of diverting techniques has proved successful in improving fluid placement and treatment results, especially in cases with large variations of initial injectivity throughout the open interval (Brannon *et al.*, 1987).

As an example, consider the three-layer reservoir described in Table 19-1. Middle layer 2 is a high-injectivity zone of limited thickness (10% of the total pay zone) with high permeability and a lower skin effect. A simple calculation, using a steady-state injection relationship, suggests that the high-permeability layer would initially take 51% of the total flow. Assuming that 150 gal/ft of perforated interval is required in each zone to remove the damage, the total volume required to place at least this amount in each zone depends on the placement strategy:

- Total volume is equal to  $150 \text{ gal/ft} \times 100 \text{ ft} = 15,000 \text{ gal}$  in the case of “perfect” placement (i.e., the same injectivity in the three layers).

**Table 19-1. Example three-layer reservoir.**

Layer	Permeability (md)	Net Thickness (ft)	Skin Effect
1	50	50	10
2	500	10	5
3	100	40	10

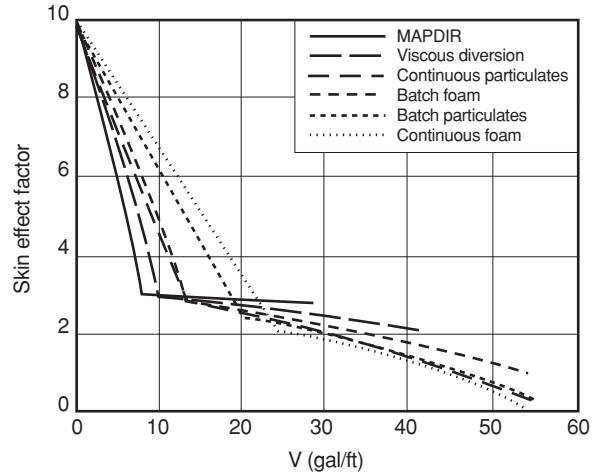
- With no diversion, a volume of about 39,500 gal is necessary to treat the entire interval, including the layer with the lowest injectivity. In this calculation it is assumed that the ratio of the flow rate into each layer remains constant throughout the treatment, but because damage is removed more rapidly in the highest injectivity zone, an even larger volume would be actually required (see also Chapter 13 for numerical simulations).

### 19-2.2. Comparison of diversion methods

A good early review of the development and use of diverting techniques, including mechanical techniques (packers and plugs) and various diverting agents, was presented by Harrison (1972).

Hill and Rossen (1994) presented a comparative study of the efficiency of the existing nonmechanical placement techniques, including the maximum pressure differential and injection rates (MAPDIR) technique introduced by Paccaloni and coworkers (Paccaloni and Tambini, 1990; Paccaloni, 1992). The MAPDIR technique involves pumping at the highest possible rate without fracturing. Hill and Rossen also considered particulate diverters, foams and viscous fluids. In their paper, they compared the evolution of skin effect for a hypothetical two-layer case. For an assumed initial skin effect of 10, the skin effect decrease is proportional to the acid volume injected per layer, and total damage removal is achieved with 50 gal/ft of acid. The permeability and thickness are, respectively, 100 mD and 1 ft for the first layer and 10 mD and 10 ft for the second layer. Simulation results show that the MAPDIR technique allows the fastest total skin effect reduction in terms of pumping time but at the expense of large acid volumes injected into the layer with lower damage. Furthermore, it does not allow treating the low-permeability layer fully.

In terms of the total pumped volume, the continuous injection of particulate diverter appears to be the most efficient technique (Fig. 19-1). The viscous fluid method appears to be far less efficient than the other diversion methods. Moreover, because of the implied reduction in the injection rate, this last technique requires the largest pumping time for treatment completion. However, the study assumed Newtonian fluids. Power law gels may



**Figure 19-1. Total skin effect evolution versus volume for different placement techniques (Hill and Rossen, 1994).**

be more effective. Another simulation with the same permeabilities in each layer, but different initial values of skin effect, led to similar conclusions.

The choice of the best diversion technique depends also on a variety of other parameters. Particulate diversion can be used in most cases, with some restrictions in the case of gravel-pack completions. Materials have been developed for a wide range of reservoir properties, the most important of which are the reservoir permeability and the pore-throat size and distribution. Proper design of particulate diverters requires consideration of the compatibility of the diverting agent with the wellbore and reservoir conditions (e.g., temperature, reservoir fluid) and with other treating fluids (e.g., solubility and flocculation in the carrying fluid or adjacent stages can impair particulate diverter efficiency).

In the case of gravel-pack completions, large-particle-size chemical diverters are not used. Oil-soluble resin (OSR) may be used, but it must be mixed well and injected continuously with the acid to avoid the risk of plugging the screen or gravel pack (McLeod, 1984). Foam diversion is also common for gravel-pack completions and where particulate diverters are not appropriate.

In the case of oil wells with a well-defined water zone, foam has been found to plug the water zone successfully and direct acid to the oil-bearing interval. This is due to the detrimental effect of oil on foam formed by certain surfactants. Acidizing with foam diversion has been reported to improve overall production in some cases without increasing the water cut, but instead reducing it (Zerhboub *et al.*, 1994).

For cemented and perforated completions, buoyant ball sealers have been shown to give good results (Erbstoesser, 1980; Bale, 1983). Conventional ball sealers are generally not recommended for long intervals

or high-shot-density completions, as they require a minimum injection rate per perforation to prevent settling in the rathole (McLeod, 1984).

Packers are the most effective means of selective fluid placement. However, they require the use of coiled tubing or rig operations. They can be used after completion or workover, if a rig is already on site.

Coiled tubing has been increasingly used for matrix acidizing over the past few years. Treatment analysis shows that coiled tubing is especially helpful for acidizing long intervals by allowing spotting successive diverter and acid stages throughout the open interval, thereby ensuring good coverage of the entire producing zone (Economides *et al.*, 1991; Thomas and Milne, 1995).

### 19-2.3. Fluid placement versus injection rate

Selection of the treatment strategy must be based on the trade-off between pump rate and fluid placement. Except for the MAPDIR technique, placement methods result in a reduction in the injection rate, even in low-injectivity zones, with possible loss of treatment efficiency and creation of precipitation damage. Williams *et al.* (1979) mentioned that sandstone acidizing is more efficient at higher rates, both avoiding the creation of precipitates near the wellbore and extending the radius of live-acid penetration. McLeod (1984) and Schechter (1992), however, argued that there exists an optimum rate for sandstone acidizing, based on the reaction rate with damage and acid and/or damage contact time. For carbonate acidizing, it has been shown that the injection rate must be high enough to allow wormholes to form and propagate. Pumping below this rate can cause a considerable reduction in treatment effectiveness.

### 19-2.4. MAPDIR method

The MAPDIR method suggests pumping treating fluids as fast as possible below the fracturing limit without using any diversion technique. It allows a decrease of pumping time and minimizes the risk of treatment failure caused by low pumping rates. However, MAPDIR is not a true diversion technique, as it does not modify the natural flow profile, nor does it necessarily distribute stimulation fluids or remove all damage.

Paccaloni and coworkers analyzed a large series of matrix-acidizing treatments to identify the factors leading to success or failure, including pump rate and the use of diversion (Paccaloni *et al.*, 1988; Paccaloni and Tambini, 1990). Criteria for success or failure were specific to the authors. With development wells, job success involved treating the entire interval. On the basis of the analysis of more than 170 jobs, the authors claimed that the MAPDIR technique is sufficient to obtain full

coverage of the pay zone if the permeability contrast is less than 300 mD and the pay zone does not exceed 200 ft. They concluded that the method actually gives better results than diverting agents.

In the case of carbonate formations, they reported that relatively small volumes of concentrated acid (5 to 10 gal/ft) led to a substantial skin effect reduction, allowing for reasonable injectivity of the zone for further reduction. This could explain why the MAPDIR method can eventually provide full zone coverage: if the treatment is maintained long enough to inject the few gallons required to improve injectivity in the highly damaged zones, then injectivity contrasts are reduced and the entire interval can be treated. However, this method can be applied only for intervals with limited contrasts of permeability, and it does not optimize fluid placement.

For better efficiency, the authors recommended the use of coiled tubing for preacidizing operations such as wellbore cleanup, acid circulation for completion string cleaning and acid spotting in front of the pay zone. Then a T connection can be used to pump acid through both the coiled tubing and tubing string to maximize the pump rate during matrix injection.

## 19-3. Chemical diverter techniques

Chemical diverters, which are materials insoluble in acid but highly soluble in water or hydrocarbons, have been used either to form a low-permeability filter cake at the sandface or to reduce the injectivity of high-permeability zones with the injection of a viscous polymer slug. The first technique has been found to be more effective and can provide faster cleanup.

It has prevailed over the viscous slug technique.

### 19-3.1. Historical background

The first attempts at fluid placement made use of chemical additives. Harrison (1972) reported the injection, as early as 1936, of soap solutions that could react with calcium chloride ( $\text{CaCl}_2$ ) to form water-insoluble, but oil-soluble, calcium soaps. The precipitate acted as a diverting agent for hydrochloric acid (HCl). The generation of solid precipitates in the formation was not, of course, desirable, because they could cause permanent damage. Thus, in the late 1930s, more sophisticated systems were used, such as heavy  $\text{CaCl}_2$  solutions. Diversion effects were possible by impairing injectivity in the zones accepting most of the high-viscosity solution. Other systems utilized cellophane flakes suspended in a water gel with a bacterial breaker. Later, gels were replaced by oil-external emulsions.

In 1954, naphthalenes were first used as a blocking material. Oil-soluble naphthalenes were thought to be ideal diverters because they sublime above 175 degF [80 degC]. Also, crushed limestone, sodium tetraborate, oyster shells, gilsonite, perlite, paraformaldehyde and "chicken feed" were used as diverters with mixed success. These compounds were replaced progressively by rock salt, which is partly soluble in the acid but inexpensive and easy to handle.

A major improvement in diversion techniques was brought about by completely soluble materials, including wax-polymer blends and hydrocarbon resins in production wells and rock salt and benzoic acid in water-injection wells.

### 19-3.2. Diverting agent properties

An effective diverting agent must meet both physical and chemical requirements.

#### ■ Physical requirements

**Cake permeability**—Cakes created on the reservoir walls by agents must be as impermeable as possible to the acid for the maximum diverting effect. If the permeability of the diverter cake is greater than or equal to the permeability of the tightest zone, little or no diversion occurs.

**Invasion**—Deep invasion of the reservoir rock by the diverter particles must be prevented, regardless of the nature of the rock, for maximum diverter effectiveness and minimum problems in cleanup. This and the previous requirement suggest that an optimum particle size must be determined.

**Dispersion**—Diverting agent particles must be properly dispersed in the carrying fluid. If flocculation occurs, the cake will be thicker but with high porosity and permeability.

#### ■ Chemical requirements

**Compatibility**—Diverting agents must be compatible with the bulk treatment fluid and with other additives, such as corrosion inhibitors, surfactants and antifoaming agents. They must be inert toward the carrying fluid at the well treating conditions.

**Cleanup**—Diverting agents must be soluble in either the production or injection fluids. Having acted as diverters, they should undergo a rapid and complete cleanup.

### 19-3.3. Classification of diverting agents

Diverting agents can be classified, according to their particle size, as bridging agents or particulate diverters.

#### ■ Bridging and plugging agents

These diverting agents consist of large-size particles, from 10/20 to 100 mesh. They are used as diverters in carbonate formations, where natural fractures are common. However, their efficiency is limited by the high permeability of the cakes they create. As an example, a cake formed with 10-mesh particles has a permeability between 20,000 and 40,000 mD, whereas a cake created with 100-mesh particles has a permeability between 1,000 and 3,000 mD.

When effective diversion is required in fractured zones, a slug of bridging agent is injected first, followed by the treating fluid containing a diverting agent. The bridging agent fills the fractures, creates a coating in front of high-permeability formations or both. If the plugging agent consists of particles small enough (e.g., 100 mesh), the diverting agent does not penetrate the coating and allows effective diversion through the development of low-permeability cakes.

Bridging agents with various chemical compositions are available:

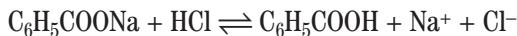
- inert materials, such as silica sand or a mixture of silica, nonswelling clay and starch (Soluble materials reduce the risk of permanently plugging the formation.)
- water-soluble bridging agents, including rock salt and benzoic acid
- oil-soluble bridging agents, including graded oil-soluble resins, naphthalenes flakes and beads made of wax-polymer blends that are soluble in oil, deformable and temperature degradable. (Their composition can be selected according to the bottomhole temperature.)

#### ■ Particulate diverters

Particulate diverters are characterized by very small particle sizes, well below 0.004-in diameter. Both water- and oil-soluble particulate diverters are available.

- Water-soluble, for injection wells—A fine grade of benzoic acid is typically used as a water-soluble diverting agent. Because this product agglomerates during storage, it is difficult to achieve a constant particle-size distribution before injection. For this

reason, salts (i.e., ammonium or sodium benzoate) can be used instead. In HCl, the salts are converted to benzoic acid. For instance, sodium benzoate reacts according to



Benzoic acid is only slightly soluble in HCl but highly soluble in water or alkaline solutions. After acting as a diverter, this compound dissolves in the injection water. Because benzoic acid particles are hydrophobic, surfactants are required to properly disperse the agent in the treating fluid.

- Oil-soluble, for production wells—Oil-soluble agents are blends of hydrocarbon resins. They are totally inert in an acidic medium, yet quickly and completely dissolve in the produced oil after treatment. It is often difficult to disperse these resins in the acid. They are usually injected as dispersions in aqueous solutions.

### 19-3.4. Potential problems during diversion treatment

During a diversion treatment several major problems may occur.

#### ■ Decantation

Bridging agents are subject to gravity effects during injection. They tend to settle in the fluid that fills the well, and the best results are therefore obtained when the solid additives are placed in a water-base gel. Decantation problems rarely occur with diverting agents because of their small particle size and the low density of their constituent materials (1.1 g/cm<sup>3</sup> for resin, 1.3 g/cm<sup>3</sup> for benzoic acid).

#### ■ Solubility

Water-soluble agents are also slightly soluble in acid. Therefore, a portion of these additives dissolves during mixing with the acid. Another portion dissolves during injection because of inter-mixing with wellbore fluids and heating. If the plugging agent is injected in slugs, after it is deposited in the fractures or on the formation walls it undergoes additional dissolution. Thus, the effectiveness of water-soluble products is always low, and large initial concentrations are required. The dissolution rate during the different stages of injection must be considered in the job design.

#### ■ Particle-size distribution

The particle size of the diverting agent must correspond to the petrophysical properties of the treated zones, such as permeability and pore-size distribution. If bridging agents are used in a reservoir with permeability from 100 to 1,000 mD, the resistance

of the diverter cake may not be high enough to avoid fluid penetration in the high-permeability zones. On the other hand, if too fine a diverting agent is used, the solid particles migrate through the porous medium with the treating fluid and diversion will not occur. Where the rock pores have a slightly larger diameter than the diverter particles, an internal cake can be created, and although the diverter will be efficient, cleanup can be difficult.

#### ■ Flocculation

Incompatibility of diverting agents with additives used in the same stage or in adjacent stages can cause diverter flocculation. Carrier fluid composition should follow technical memoranda recommendations or be tested in the laboratory.

#### ■ Compatibility

Rock salt should never be used as a bridging agent in hydrofluoric acid (HF) treatments or before HF treatments because it may increase the risk of sodium fluosilicate precipitation. Such a problem is not anticipated when using sodium benzoate, because this compound is readily converted into benzoic acid in HCl, and the released sodium ions do not contact the subsequent HF flush.

### 19-3.5. Laboratory characterization

Crowe (1971) designed equipment that injects slugs of diverting agent under constant pressure into parallel cores of different permeabilities. By measuring the time required to equalize the flow rates entering each core, he compared the efficiency of different diverters. The best results were obtained using OSRs.

Other investigators (Hill and Galloway, 1984; Houchin *et al.*, 1986) attempted to use a slightly different experimental setup consisting of a well model with three cores of various permeabilities to predict flow distribution at presumed reservoir conditions. This approach, because of differing pressure-drop ratios and slug-volume ratios between laboratory and reservoir conditions, cannot always be extrapolated to field conditions (Doerler and Prouvost, 1987).

Hill and Galloway's original attempt to measure the pressure drop across a diverter cake included the experimental data in a simple numerical reservoir model. However, they assumed the pressure drop to be a linear function of the cumulative volume of diverter and neglected the effect of flow rate and other important parameters, such as diverter concentration and temperature.

Doerler and Prouvost investigated separately the intrinsic properties of the cakes created by diverters and their effects on the flow distribution in heterogeneous reservoirs. Pressure drops through cakes of diverting

agents were measured under various wellbore and fluid conditions, such as temperature, flow rate, concentration of diverting agent and nature

of the carrying fluid. Filtration theory was used to express the experimental results in a more general form:

$$R_{cake} = \frac{\Delta p}{\mu u}, \quad (19-1)$$

where  $R_{cake}$  is the cake resistance in  $\text{m}^{-1}$ ,  $\Delta p$  is the pressure drop across the diverter cake,  $\mu$  is the carrying fluid viscosity, and  $u$  is the superficial velocity across the cake. By analogy with the pressure drop in a porous medium, the cake resistance can be defined as the inverse of the cake permeability divided by the cake thickness. Laboratory testing allows correlation between the cake resistance and the volume of diverter deposited at the sandface per unit area, which can then be used to simulate the diverter effect at reservoir conditions.

Taha *et al.* (1989) and Economides *et al.* (1994) extended the model introduced by Hill and Galloway. They defined a specific cake resistance  $\alpha$  in  $\text{m}/\text{kg}$ :

$$\alpha = \frac{1}{\rho_{div}(1 - \phi_{cake})k_{cake}}, \quad (19-2)$$

which then leads to the pressure drop  $\Delta p$  across the cake:

$$\Delta p = \frac{\alpha \mu u C_{div} \rho_{div} V}{A}. \quad (19-3)$$

In Eqs. 19-2 and 19-3,  $\rho_{div}$  is the density of diverter particles in  $\text{kg}/\text{m}^3$ ,  $\phi_{cake}$  is the cake porosity,  $k_{cake}$  is the cake permeability,  $C_{div}$  is the concentration of diverter particles in  $\text{m}^3$  of particles per  $\text{m}^3$  of solution,  $V$  is the total volume of diverter solution injected, and  $A$  is the surface of cake deposition.

Equation 19-3 is obtained by writing Darcy's law across the cake:

$$\Delta p = \frac{\mu l u}{k_{cake}}. \quad (19-4)$$

The cake thickness  $l$  varies with the diverter volume as

$$l = \frac{C_{div} V}{(1 - \phi_{cake}) A}. \quad (19-5)$$

Combining Eqs. 19-4 and 19-5 and using  $\alpha$  as defined in Eq. 19-2 yields the expression of the pressure drop across the cake as in Eq. 19-3.

The cake resistance  $R_{cake}$  and the specific cake resistance  $\alpha$  are related by

$$R_{cake} = \frac{\alpha C_{div} \rho_{div} V}{A}. \quad (19-6)$$

Either characterization of the diverter cake can be used. However, Doerler and Prouvost took into account the cake compressibility in their correlations for  $R_{cake}$ , whereas the other authors neglected the cake compressibility and assumed  $\alpha$  to be constant.

### 19-3.6. Modeling diverter effects

Presented in this section is a methodology using cake resistance data obtained in the laboratory to predict the efficiency of the treatment in terms of flow distribution between the different layers. The concept of diverter cake pseudoskin effect is introduced.

The diverter cake created at the sandface of a layer induces a pressure drop across a zone of negligible thickness. Figure 19-2 depicts the radial pressure profiles in a formation layer during injection for two different situations:

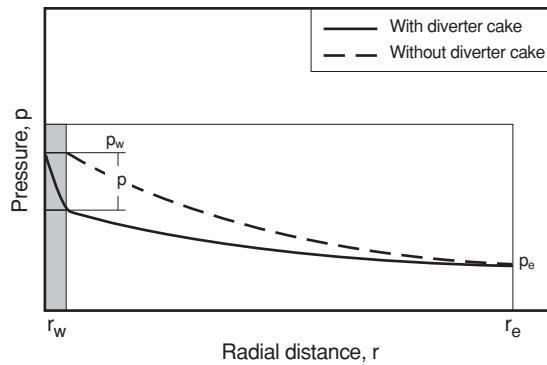
- fluid injection without a diverter (dashed line)
- injection after a diverter cake has been deposited at the sandface (solid line).

The injection and reservoir pressures are identical in both cases, but the injection rates are different. The cake acts as a temporary skin effect. Consequently, a pseudoskin effect factor can be defined by the standard (van Everdingen and Hurst, 1949) with an injection rate  $q_i$ :

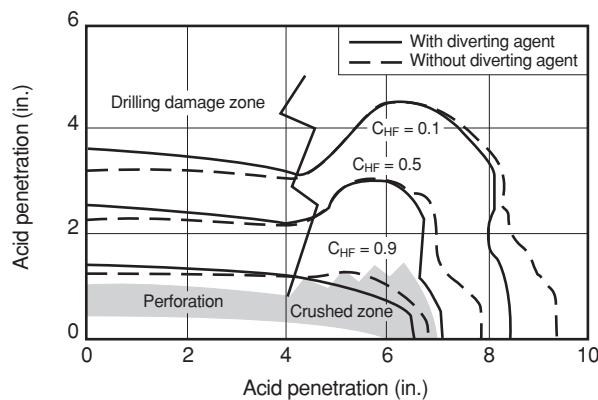
$$s_{cake} = \frac{2\pi kh}{\mu q_i} \Delta p, \quad (19-7)$$

where  $k$  is the permeability and  $h$  is the thickness.

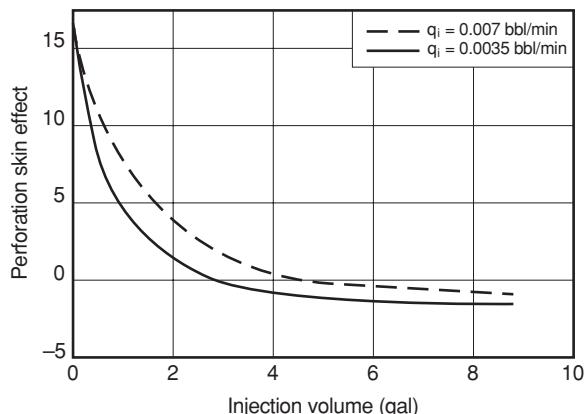
Use of particulate diverters in a perforated completion requires special attention because they can modify the flow pattern in the perforation tunnel itself. Lea *et al.* (1993) showed that a diverting agent tends to equalize the flux entering the formation at the perforation walls. However, the flow profile in the formation is determined mostly by the damage distribution, as acid tends to migrate toward the higher permeability zone. Figure 19-3 shows the acid concentration contours obtained by numerical simulation of a perforation affected by both a crushed zone and shallow drilling mud damage (4-in depth). The figure shows that the diverting agents do not significantly modify the flow patterns around the perforation, and therefore they have little impact on the rate of skin effect reduction for a single perforation (Fig. 19-4). These results indicate that particulate diverters do not provide diversion within the perforations. They provide diversion from one perforated zone to another. The model presented in this section is thus applicable also to a perforated completion.



**Figure 19-2.** Radial pressure profile in the reservoir with and without a diverter cake.



**Figure 19-3.** Hydrofluoric acid concentration  $C_{HF}$  contours around a perforation (Lea et al., 1993).



**Figure 19-4.** Skin effect evolution for different injection rates and diverting agents (Lea et al., 1993).

Using the definition of cake resistance (Eq. 19-1) and expressing the fluid superficial velocity  $u$  through the cake as  $q_i/A$  in Eq. 19-7, then

$$s_{cake} = \frac{2\pi kh}{A} R_{cake}, \quad (19-8)$$

where  $A$  is the sandface area exposed to flow and available for cake deposition.

- For an openhole:  $A = 2\pi r_w h$ , where  $r_w$  is the wellbore radius.
- For a cased hole:  $A = n_{perf} 2\pi r_{perf} l_p$ , where  $n_{perf}$  is the number of perforations in the layer,  $r_{perf}$  is the radius of a perforation, and  $l_p$  is the length of the perforation tunnel.

For the assumptions that the cake thickness is negligible and the fluid velocity across the cake does not vary, the cake resistance obtained under linear flow conditions in the laboratory can be used.

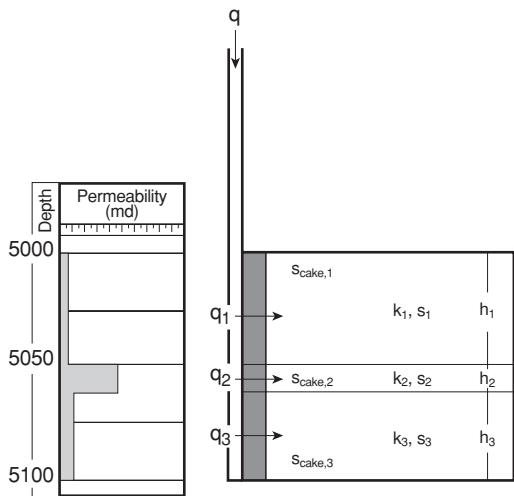
The growth rate of the diverter cake can be related to the injection rate. If  $\rho_a$  is denoted as the mass of cake per unit area of sandface available for deposition, its derivative with respect to time can be expressed for any layer by

$$\frac{d\rho_a}{dt} = \frac{C'_{div} q_i}{A}, \quad (19-9)$$

where  $t$  is the time and  $C'_{div}$  is the net diverter concentration in  $\text{kg}/\text{m}^3$  after dissolution effects are considered. In Eq. 19-9, it is assumed that the injected fluid is evenly distributed on the sandface. If this were not the case, as along a perforation tunnel, a finer modeling involving infinitesimal elements of the surface  $dA$  would be required.

To calculate the evolution of flow and pressure during diverter injection requires expressing the inflow performance relationship (IPR) for a multilayered reservoir and linking the diverter pseudoskin effect to the flow rate entering each layer. Figure 19-5 depicts a cylindrical reservoir made of  $n$  horizontal layers, at the center of which is a vertical well. In the following equations, the wellbore radius is  $r_w$  and the reservoir radius is  $r_e$ . Each layer is characterized by its net thickness  $h_j$ , undamaged permeability  $k_j$ , and skin effect  $s_j$ . The subscript  $j$  denotes the layer number.

For simplicity, a single-phase, radial and horizontal steady-state flow is assumed to prevail. Whenever more complicated geometries exist, such as commingled layers and crossflow, a more sophisticated inflow performance relationship may be used. This would require the results of layered reservoir testing, such as described by Ehlig-Economides and Joseph (1985).



**Figure 19-5.** Flow distribution in a multilayered reservoir: on the left, without a diverter; on the right, with a diverter.

With the simplified assumptions, and assuming steady state, the injection rate entering layer  $j$  is

$$q_j = \frac{2\pi k_j h_j \Delta p}{\mu \left( \ln \left( \frac{r_e}{r_w} \right) + s_j + s_{cake,j} \right)}, \quad (19-10)$$

where  $s$  is the skin effect from damage and  $\Delta p$  is the pressure differential of the wellbore pressure  $p_{w,j}$  minus the outer reservoir pressure  $p_e$ . The skin effect  $s_{cake,j}$  is time dependent because of cake buildup, and  $s_j$  varies with time if the effect of damage removal by acid is considered.

Equations 19-8, 19-9 and 19-10 are coupled because the cake resistance and pseudoskin effect depend on  $\rho_a$ , which is itself dependent on the injection rate. Eliminating  $q_j$  between Eqs. 19-9 and 19-10 and using Eq. 19-8 to replace  $s_{cake,j}$ , an equation governing the rate of growth of the cake in layer  $j$  is obtained:

$$\frac{d\rho_{a,j}}{dt} = \frac{2\pi k_j h_j \Delta p}{\mu \left( \ln \left( \frac{r_e}{r_w} \right) + s_j + 2\pi k_j h_j R_{cake,j} / A_j \right)} \frac{C'_{div}}{A_j}, \quad (19-11)$$

where  $\rho_{a,j}$  is the mass of diverter per unit area in front of layer  $j$ . Equation 19-11 is readily solved for two cases:

- If the injection is performed at constant excess pressure  $\Delta p$ , each differential equation can be solved independently. If the cake resistance varies linearly with the mass of diverter deposited, the system of equations can be solved analytically (Economides *et al.*, 1994; Hill and Rossen, 1994).
- If the injection is performed at a constant total rate  $q_{tot}$ , the differential equations are coupled through the expression of total rate for  $n$  layers:

$$q_{tot} = \sum_j q_j. \quad (19-12)$$

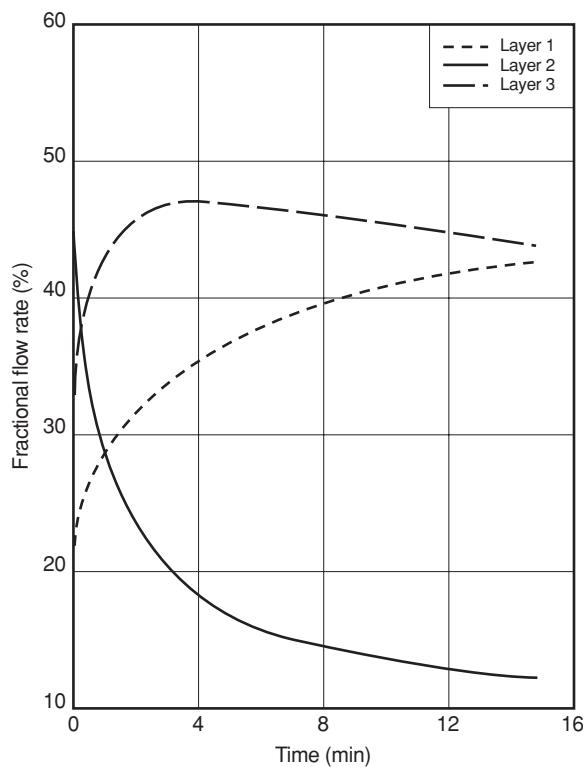
The term  $\Delta p$  derived from Eqs. 19-10 and 19-12 is substituted into Eq. 19-11, which is then solved for each layer. A numerical method is required in this case (Doerler and Prouvost, 1987). Hill and Rossen (1994) presented a simplified numerical method that applies in some cases.

Once Eq. 19-11 is solved for  $\rho_{a,j}(t)$ , the other parameters of interest, such as  $q_j(t)$  or  $\Delta p(t)$  can be derived. The solution shows that the system tends toward equalization of the layer injectivities. Figure 19-6 illustrates the evolution of the fractional flow rate under diverter injection in a three-layer case. At the end of the diverter stage, the rate per layer is roughly proportional to the layer thickness. Table 19-2 details the reservoir geometry corresponding to this case.

For a more accurate calculation of the diverter effect, this model can be included in a finite-difference matrix acidizing simulator. This enables due accounting of other factors such as the effect of damage removal on injectivity and transient effects and the use of more realistic and complicated relations for the cake resistance versus deposited diverter mass.

**Table 19-2. Reservoir data for the example in Fig. 19-6.**

	Layer 1	Layer 2	Layer 3
Wellbore radius	0.35 ft		
Reservoir radius	2000 ft		
Carrying fluid viscosity	1 cp		
Divertor concentration	150 lbm/1000 gal		
Temperature	150°F [65°C]		
Cake resistance function at 150°F	$R_{cake} = 5 \times 10^{12} \rho_a$		
Total injection rate	2 bbl/min		
Layer permeability	50 md	100 md	500 md
Layer thickness	15 m	3 m	12 m
Initial skin effect	10	5	10



**Figure 19-6.** Flow redistribution caused by a diverter slug.

### 19-3.7. Field design

To ensure proper coverage of the zones to be stimulated, the diverter placement design must include the following several steps.

- The chemical nature of the diverter must be selected considering the type of well (injector or producer), formation type (sandstone or carbonate), bottomhole temperature, treating fluid and cleanup procedure.
- The particle-size distribution must be adapted to the pore size of the formation upon which the cake will be deposited. This should prevent any invasion of the porous medium by diverter particles.

In general, the particle size must be adapted to the formation layer with the highest permeability.

- A dispersant must be used to ensure that particles will not flocculate in the carrying fluid. Although not recommended, bridging agents must be mixed in gel pads to prevent sedimentation in some cases.
- Once the proper material has been selected, the volume, concentration and injection rate of the diverter must be determined. Generally, concentrated slugs have been found more effective than continuous

injection at a lower concentration. The pumping parameters, namely bottomhole pressure and injection rate, must then be estimated to ensure their compliance with field operational constraints, such as fracturing pressure. The overall injectivity of the well should not be lowered to the point that only small injection rates are possible.

The method described in this section can be used to optimize diverter slugs if the well and reservoir data are known. Unfortunately, in many cases, critical parameters such as the exact perforation geometry, pore size near the sandface and distributions of permeability and damage are poorly characterized. In the past, this has limited the use of mathematical models for diverter design. Many practical designs are based on local experience (i.e., trial and error). With the use of coiled tubing, which greatly decreases the volume of the injection string, design can be modified on the fly and the pressure response of the well to acid and diverter slugs can help guide diversion optimization. A flat pressure response to acid indicates that a diverter is required, and the efficiency of cake buildup can be assessed from the reservoir response (pressure increase) to diverter injection. This method of design optimization based on real-time well response is more reliable than a priori estimates and is most likely to be effective if facilities are available for on-site stimulation monitoring.

## 19-4. Foam diversion

### 19-4.1. Historical background

Foams have been used for acid diversion since at least the 1960s (Smith *et al.*, 1969). The acid itself can be foamed with the addition of gas and surfactant, or, more commonly, foam can be injected in alternating slugs with acid. Until recently, there was little published information on acid diversion with foam, in contrast to the extensive literature on foam for diverting gas flow in improved oil recovery (IOR) processes (Hirasaki, 1989a, 1989b; Schramm, 1994; Rossen, 1996). The findings of IOR foam research have exerted a strong influence on the understanding of foam acid diversion. More recent research suggests that although the basic mechanisms of the two processes are similar, differences in the flow regime between near-well and reservoir applications cause significant differences in behavior. This section summarizes the current consensus on foam behavior and process design. This is an active area of research, and this consensus may well shift within the next few years.

## 19-4.2. Foam mechanisms

Foams act fundamentally differently as they penetrate and plug the pore space of rock compared with the behavior of foams used for drilling, cementing, fracturing or well cleanout. Therefore, analogies to these other foams can be misleading. For example, foams in pipes are created and maintained by shear forces, and the resulting bubbles are much smaller than the pipe diameter. Within the tiny pores of an oil or gas reservoir, however, foam bubbles larger than the individual pores are squeezed down into elongated shapes, spanning several pores, with a liquid film or lamella between each pair of bubbles (Ettinger and Radke, 1992; Falls *et al.*, 1989). The behavior of foam is dominated by the capillary forces on the lamellae; viscous forces in the conventional sense are relatively unimportant.

Numerous IOR foam studies agree that foam does not directly alter liquid mobility in porous media (Bernard *et al.*, 1965; Friedmann *et al.*, 1991; Huh and Handy, 1989; de Vries and Wit, 1990). In other words, the aqueous-phase relative permeability  $k_{rw}$  is the same function of its saturation  $S_w$  as in the absence of foam. (For the remainder of this section, for simplicity the aqueous phase is referred to as water.) Evidently, upon entering rock most of the water leaves the foam and flows through the same network of narrow pores and pore crevices through which it would flow at that same  $S_w$  in the absence of foam. As a result, overall mobility with foam can be inferred from Darcy's law if the relative permeability function  $k_{rw}(S_w)$  without foam and the water saturation in the presence of foam are known:

$$\Delta p = \frac{(u_g + u_w)}{k\lambda_{rt}} = \frac{u_w}{(k k_{rw}/u_w)} \quad (19-13)$$

$$\lambda_{rt} = \frac{k_{rw}(S_w)}{u_w f_w} \quad (19-14)$$

$$f_w = \frac{100 - \Gamma}{100}, \quad (19-15)$$

where  $u_g$  and  $u_w$  are the volumetric fluxes of gas and water, respectively,  $\lambda_{rt}$  is the total mobility as defined by Eq. 19-14,  $\mu_w$  is the water viscosity,  $f_w$  is the water fractional flow (i.e., water volume fraction of the injected foam), and  $\Gamma$  is the foam quality (i.e., volume percentage of gas in the injected foam). Therefore, the only way to divert acid (i.e., to reduce  $k_{rw}$ ) is to reduce the water saturation  $S_w$  by increasing the gas saturation. During steady foam injection,  $S_w$  is governed by the equation for water fractional flow  $f_w$ :

$$f_w = \frac{u_w}{u_w + u_g} = \frac{1}{\left(1 + \frac{k_{rg}}{\mu_g} \frac{\mu_w}{k_{rw}(S_w)}\right)}, \quad (19-16)$$

where  $k_{rg}$  and  $\mu_g$  are the relative permeability and the viscosity of gas, respectively.

Capillary forces tend to lower the gas mobility ( $k_{rg}/\mu_g$ ) and drive down  $S_w$  (Eq. 19-16). For example, the IOR foam of Persoff *et al.* (1990, 1991) reduced gas mobility by a factor of almost 20,000, which in turn drove down the liquid saturation  $S_w$  and relative permeability  $k_{rw}$  to about 0.37 and 0.001, respectively. During the injection of surfactant solution without gas following foam,  $k_{rw}$  remained at 0.001 during several pore volumes of injection. As discussed subsequently, foams used for acid diversion are neither so strong nor so durable, probably as a result of the higher flow rates used in acid diversion.

The key to the success of foam as a diverter is low gas (and consequently liquid) mobility during foam injection and gas trapping during the subsequent injection of liquid. Foam reduces gas mobility proportionally to the number of liquid films, or lamellae, blocking the flow of gas or, viewed another way, in inverse proportion to the bubble size (Falls *et al.*, 1989; Ettinger and Radke, 1992; Kovscek and Radke, 1994). This reduction is due primarily to the capillary forces resisting movement of the lamellae separating gas bubbles. These forces completely trap gas bubbles in from 70% to 99% of the gas-filled pore space even as injected foam flows through the remaining pores (Radke and Gillis, 1990; Friedmann *et al.*, 1991). The fraction of the pore space completely blocked by foam declines as the pressure gradient increases. Because of these same capillary forces, the effective viscosity of the gas that flows is much higher than that of gas alone.

Both gas trapping and effective viscosity are even more sensitive to bubble size than to flow rates, however. There are many processes that can spontaneously alter bubble size as foam flows through rock (Hirasaki, 1989a; Kovscek and Radke, 1994; Rossen, 1996). For example, if unfoamed gas and water with surfactant are injected into rock under appropriate conditions, foam may be created within the first inch or two of the rock face (Ettinger and Radke, 1992). Although it may be convenient to assume that foam is created instantaneously at the rock face, this entrance region of low  $\Delta p$  in which foam is created can be significant in a well treatment focused on the near-well region. Similarly, if a foam of very small bubbles is injected into rock, there may be an entrance region with  $\Delta p$  higher than that downstream. In addition, if flow rates are suddenly changed, it may take some time for foam to adjust to the changes in conditions.

The various processes that create and destroy lamellae, together with the non-Newtonian mobility of gas at a fixed bubble size, enormously complicate the prediction of foam behavior in rock. Fortunately, two regimes observed experimentally greatly simplify the description of foam mechanisms.

First, under some conditions bubble size is dominated by processes that destroy lamellae, and these processes appear to be sensitive to capillary pressure  $p_c$  in the rock (Khatib *et al.*, 1988): foam properties change greatly upon a small change in  $p_c$ . Because  $p_c$  depends on the water saturation  $S_w$ , the large changes in foam properties upon small changes in  $S_w$ , combined with Eq. 19-13, suggest that  $\Delta p$  is a simple function of the water saturation  $S_w^*$  at which this change occurs (Zhou and Rossen, 1994; Rossen and Zhou, 1995). Under some conditions common in IOR foam processes,  $S_w^*$  appears to be independent of flow rates in a given rock (Persoff *et al.*, 1990). This implies that foam in this regime can be treated simply as a Newtonian fluid of low mobility: the effect of  $p_c$  on bubble size just balances the non-Newtonian mobility of foam at fixed bubble size. The fixed- $p_c^*$  model for foam, discussed subsequently, is based on this mechanism. In conditions where this regime applies, foams are stronger in higher permeability rock (higher  $p_c$ ; i.e., lower  $S_w^*$ ), diverting flow into lower permeability zones (Lee *et al.*, 1991; Zhou and Rossen, 1995).

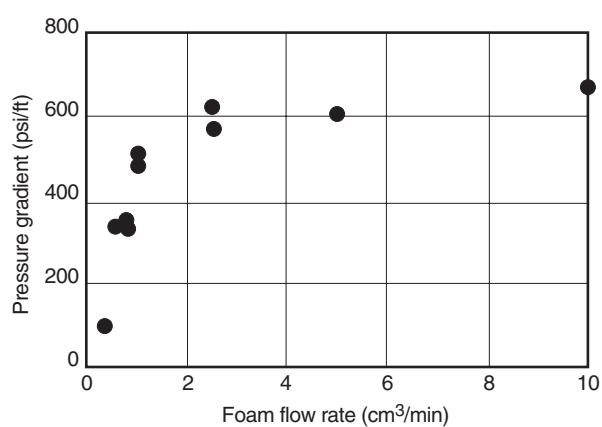
The second regime in which foam behavior appears to be simplified is that in which capillary trapping of the foam bubbles controls overall mobility. In some cases discussed in the following sections,  $\Delta p$  during foam flow or subsequent liquid injection is nearly independent of the foam or liquid flow rate (Parlar *et al.*, 1995). As mentioned, the trapping of foam bubbles in much of the pore space of the rock depends on a balance of capillary forces trapping the bubbles and applied  $\Delta p$  (Rossen, 1990). Evidently, in some cases this balance is highly sensitive to  $\Delta p$ : as the flow rate increases, causing a slight rise in  $\Delta p$ , previously trapped foam bubbles are liberated and allowed to flow, accommodating the increase in flow rate without a further rise in  $\Delta p$ . Whether this conjecture is correct, and its full implications for the design of foam diversion processes, remains to be confirmed.

#### 19-4.3. Foam behavior in porous media

##### ■ Mobility of injected foam

There is a wide body of experimental data on foam behavior in rock for IOR foams and a growing body of data on foams for acid diversion. It appears that there is a substantial difference between foam behavior in the two applications, probably because of the lower quality  $\Gamma$  and much higher flow rates of foams for acid diversion. Observed trends in behavior include the following.

- Foam mobility is at a minimum (i.e., foam is strongest) at qualities between about 70% and 90% (Thompson and Gdanski, 1993). Foams are weaker for qualities greater than 90%. This is probably due to the collapse of foams at high capillary pressures; the reason for weak foams at low quality is not clear.
- Foams are extremely non-Newtonian at high flow rates (Parlar *et al.*, 1995; Zerhboub *et al.*, 1994), as shown in Fig. 19-7. In this case, the pressure gradient responds nearly linearly to the flow rate at low values. At high flow rates  $\Delta p$  becomes independent of flow rate. This suggests that foam mobility is controlled by mobilization and liberation of trapped gas in this high-flow-rate regime. Parlar *et al.* reported that the threshold  $\Delta p$  at which flow becomes independent of flow rate scales roughly as the  $-1/2$  power of permeability values greater than 800 mD.
- During foam injection, foams are stronger (i.e., higher apparent viscosity) in high-permeability rock, implying the diversion of flow from higher permeability to lower permeability or more damaged intervals (see, e.g., Kibodeaux *et al.*, 1994). Whether similar trends apply to diversion between layers differing in the extent of damage rather than permeability per se is not clear. Behenna (1995) used a thin wafer of 0.3-mD sandstone to simulate a damaged zone at the face of a 1-ft sandstone core. Thompson and Gdanski (1993) used the same approach with carbonates. However, most foam studies use relatively high-permeability rock (hundreds of millidarcies). More studies are required to characterize foam behavior in lower permeabilities.



**Figure 19-7.** Example of  $\Delta p$  versus foam flow rate (Robert and Mack, 1995).

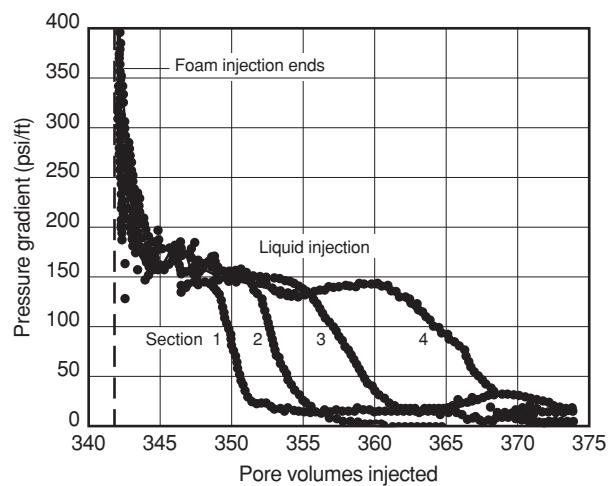
- Oil weakens or destroys most foams (Jensen and Friedmann, 1987; Schramm and Novosad, 1992; Rossen, 1996; Manlowe and Radke, 1990). Oil is extremely detrimental to foam in oil-wet rock. It is possible to tailor a foam formulation to partially withstand the adverse effects of oil, but this weakening can be an advantage, causing foam to collapse in oil-saturated layers and diverting acid to stimulate those productive layers.

#### ■ Mobility of acid injected after foam

Most laboratory studies have used an aqueous slug without acid to simulate acid injection following foam. This is a reasonable simplification if the effects of acid removal of damage and foam diversion are separable. This is clearly not the case for carbonates, as discussed subsequently. The mobility of the liquid injected following foam is the key to processes of alternating slugs of acid and foam; diversion of the foam itself is useless unless the acid following the foam is diverted as well. Observations from laboratory corefloods include the following:

- Trapping of gas by liquid injected following foam is incomplete, and the pressure gradient declines nearly simultaneously throughout the core to a lower, uniform value (Fig. 19-8) (Parlar *et al.*, 1995; Kibodeaux *et al.*, 1994). There is a later decline in  $\Delta p$  that starts near the inlet and proceeds through the core. The second decline is due to the dissolution of trapped gas in injected liquid, which is undersaturated with gas at the high pressure of the core (Robert and Mack, 1995; Zeilinger *et al.*, 1995). The second decline may be unimportant in the field, owing to the large number of pore volumes of liquid required to dissolve the gas. In any event, it can be avoided by including a small amount of gas with the acid.

- The lower, steady pressure gradient observed after liquid follows foam is nearly independent of the foam injection rate preceding liquid injection, the liquid flow rate after foam and whether there is a shut-in period preceding liquid injection (Zeilinger *et al.*, 1995; Parlar *et al.*, 1995). In other words, there is virtually unlimited liquid flow above a threshold  $\Delta p$ . Evidently,  $\Delta p$  during this period is controlled by the mobilization of trapped gas bubbles, as discussed previously (Rossen, 1990). Parlar *et al.* reported that the threshold  $\Delta p$  value scales with the  $-1/2$  power of permeability, which suggests that at any given  $\Delta p$ , high-permeability zones would take large amounts of fluid while low-permeability zones would receive little. This finding considerably affects strategy for foam diversion.



**Figure 19-8.** Pressure evolution during liquid injection following foam (Zeilinger *et al.*, 1995).

- In the field, however, the entire diversion process may occur within the period of decline in  $\Delta p$  to its lower, steady value. The rate of decline depends on the rate of liquid injection. In Fig. 19-8, it takes about 2½ h for  $\Delta p$  to decline to the plateau, with a liquid velocity of about 1 m/d. Parlar and coworkers found that for a velocity of 6 m/d (equivalent to a pump rate of 0.05 bbl/min/10 ft at the wellbore), the plateau value is reached within 10 min. In field application, injection of an entire acid slug may last only 30 min. Thus the rate of decline in  $\Delta p$  may be as important as the lower, steady value. What controls this rate of decline is not yet clear.

#### ■ Foam propagation rate

Foam cannot propagate faster than the surfactant advances into the porous medium, so surfactant adsorption losses to the rock play an important part in foam propagation. The latter can lag behind surfactant propagation, however. Whether controlled by surfactant adsorption or by other factors, foam propagation is faster in high-permeability rock than lower permeability rock and faster with a surfactant preflush than without (Friedmann and Jensen, 1986; Kibodeaux *et al.*, 1994; Parlar *et al.*, 1995). Both effects help the diversion process. Because most preflush enters the higher permeability or less damaged intervals that are to be blocked with foam, a preflush helps to place more foam in the layer to be blocked (Zerhboub *et al.*, 1994; Zhou and Rossen, 1994).

#### ■ Interactions between foam and acid

As noted, most studies of foam diversion do not include acid, on the assumption that the effects of acid and foam are separable. For carbonate rocks,

however, acid dissolves the rock matrix in which foam resides, forming channels or wormholes through the rock (see Chapters 16 and 17). Two effects of foam on the formation of wormholes are crucial to the acid stimulation of carbonates. First, foam causes the formation of longer wormholes with fewer branches, leading to more efficient stimulation of a formation with less acid required (Bernardiner *et al.*, 1992). Second, foam evidently fills and plugs wormholes, diverting acid to layers with fewer or shorter wormholes. This leads to a more even distribution of acid between intervals (Thompson and Gdanski, 1993).

#### 19-4.4. Foam diversion experiments

The first published foam diversion tests in connection with acidizing used high-permeability sandpacks (20/40 and 40/60 mesh) with a permeability ratio of 20 and alternate injection of foaming solution and gas. Smith *et al.* (1969) reported successful plugging of the high-permeability pack, even during the liquid stages following the gas stages. Later, Burman and Hall (1986) used lower permeability cores with permeability ratios between 1.6 and 3.8. They observed durable diversion with core permeabilities of 100 mD and higher: equal flow in both cores was eventually obtained after several foam stages, and diversion was maintained during the liquid stage. For experiments conducted with lower permeability cores (10 to 66 mD), little or no improvement was achieved in the flow profile during liquid stages. However, some diversion was obtained during the foam stages, with better efficiency obtained with lower quality foam.

Zerhboub *et al.* (1994) and Parlar *et al.* (1995) used small preflush volumes of surfactant solution ahead of the foam stage and limited the size of the foam slug to a fraction of the pore volume. They obtained successful diversion, which was maintained during the liquid stages following the foam slugs. Zerhboub *et al.* tested sandpacks from 300 mD to 20 D and reported better efficiency with higher permeability cores. Applying a shut-in after the foam stage and increasing the foam-stage volume resulted in better diversion. A test performed with two cores of the same permeability, one saturated with brine and the other containing residual oil, showed that foam was able to impair temporarily the brine-saturated core and redirect flow into the oil-bearing core. Parlar *et al.* obtained diversion with the slug technique in cores with permeabilities between 100 and 1,200 mD. Behenna (1995) also reported diversion with this technique in two cores with permeabilities of 18 and 126 mD. However, when strong foam was generated in both cores by the injection of larger foam slugs, no diversion or even reverse effects were obtained.

Behenna (1995) also tested the effect of acid on foam diversion. A 5-mm thick wafer of Ohio sandstone was placed at the face of the high-permeability core (322-mD Berea sandstone) to simulate a thin layer of near-wellbore damage. Injection of a small foam slug slightly increased the fraction of flow entering the "damaged" core. The subsequent acid stage, however, directed most of the flow to the damaged core by increasing substantially the permeability of the wafer while the permeability of the foamed undamaged core remained fairly constant. In this case diversion resulted from the combined effect of both foam and acid.

Laboratory experiments show that the keys to foam diversion are placing more foam and (if possible) stronger foam in the higher permeability or less damaged intervals and keeping the gas trapped during subsequent liquid injection. As discussed previously, foam itself is stronger in higher permeability rock, but inefficient trapping of gas during the stages following foam negates some of this effect. Other factors such as slower foam propagation caused by surfactant adsorption in lower permeability zones can help achieve foam diversion during the liquid stages following foam. Furthermore, if partial temporary diversion is achieved, the effect of acid on damaged zones can combine with the foam effect to complete the reversal in flow distribution between the damaged and undamaged zones after the first exposure to a foam slug–acid sequence.

Zeilinger *et al.* (1995) showed, however, that a process that relies primarily on faster foam propagation in higher permeability or undamaged rock may work better in the linear flow geometry of laboratory corefloods than in radial flow in reservoirs. In essence, in radial flow, faster propagation helps only if the slugs are small, because otherwise foam fills the crucial near-well region in all layers.

In carbonate cores, foam diversion is coupled to the formation of wormholes. Thompson and Gdanski (1993) showed that foam can help equalize flow between two cores with wormholes of different lengths; evidently bulk foam fills and blocks the wormhole, diverting acid to the core with shorter or no wormholes.

#### 19-4.5. Modeling and predicting foam diversion

IOR foam researchers use a variety of mathematical models to describe foams (Kular *et al.*, 1989; Fisher *et al.*, 1990). In principle, the most complete, but also highly complex, population balance model (Friedmann *et al.*, 1991; Falls *et al.*, 1989; Kovscek and Radke, 1994) attempts to represent all mechanisms of non-Newtonian mobility and processes altering bubble size. There is no published application of this model to foams for diverting acid.

The much simpler approach of the fixed- $p_c^*$  model (Rossen and Zhou, 1995; Zhou and Rossen, 1994, 1995), focuses on the coalescence of foam as a function of capillary pressure  $p_c$  or water saturation  $S_w$ . Combined with fractional-flow modeling, this foam model predicts some important aspects of foam behavior: the benefits of a surfactant preflush, the importance of compatibility of acid and foam slugs, foam diversion between layers differing in permeability and differences between diversion processes in linear and radial flow. In this approach, laboratory corefloods are used to determine the rates of advance and mobility of foam during the injection of foam and subsequent injection of liquid (Kibodeaux *et al.*, 1994). Mobilities are assumed independent of flow rates. These parameters are then used with equations for radial flow such as Eq. 19-10 to predict diversion in a field application. The model identifies the keys to effective foam diversion as the rate of foam propagation, foam mobility during injection and foam mobility during liquid injection in each layer.

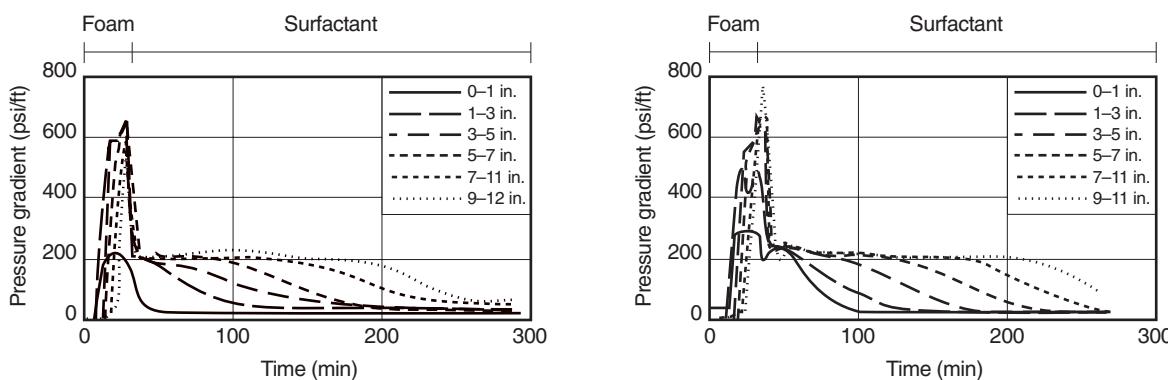
Hill and Rossen (1994) presented an even simpler version that gives essentially equivalent results for many applications. In this model, the foam skin effect  $s_{foam,j}$  replaces  $s_{cake,j}$  in Eq. 19-10. The foam skin effect is

$$s_{foam,j} = \left( \frac{k_j}{k_{foam,j}} - 1 \right) \ln \left( \frac{r_{f,j}}{r_w} \right), \quad (19-17)$$

where  $k_j/k_{foam,j}$  is the mobility reduction resulting from foam (assumed for simplicity to affect only permeability) in layer  $j$  and  $r_{f,j}$  is the radial extent of the foam bank in that layer. Foam advances in each layer at a constant volumetric rate that reflects permeability and the volume of preflush in that layer. Upon switching from foam to acid injection in a slug process, the mobility reduction factor  $k_j/k_{foam,j}$  suddenly takes a new, usually higher, constant value, and  $r_{f,j}$  stays constant during acid injection. An analytical solution is obtained for constant-pressure injection, and other cases, such as injection at a fixed overall injection rate, can be derived easily.

This approach uses many simplifying assumptions, of which two now appear to distort predictions of foam performance in the field: assuming mobility is independent of flow rates and assuming instantaneous attainment of steady-state mobilities upon a change in injection conditions. As noted previously, foams are strongly non-Newtonian in the flow regime relevant to acid diversion, and the period of transition between high  $\Delta p$  with foam and lower  $\Delta p$  during liquid injection (Fig. 19-8) may be crucial to the diversion process. Work to extend this model to account for these effects is ongoing.

The simulator described by Robert and Mack (1995) and Bartko *et al.* (1996) does not make these assumptions and fits their laboratory corefloods well (Fig. 19-9). This approach is closer to full reservoir simulation: the computer solves a partial differential equation for pressure and flow rates as functions of position and time, interpolating mobilities from tables of laboratory data. Local gas and liquid saturations are computed from mobilities and local foam flow conditions using Eqs. 19-14 and 19-15. A mass balance is then used to compute the local flow rates for each phase from the variations of saturation. Both regimes shown in Fig. 19-7—the low-flow-rate regime, in which mobilities are roughly Newtonian at constant quality and the constant-pressure-gradient regime at high flow rates—are included in the simulator foam-mobility model. For liquid injection after a foam stage (i.e., the reimmersion stage), the simulator assumes a sharp transition in gas mobility from complete plugging to high mobility at the threshold pressure gradient. This tends to maintain the actual pressure gradient at the threshold value during liquid injection, as observed experimentally. An empirical correlation is used to account for the delay of gas removal (and the corresponding delay of pressure decrease) observed at low liquid rates. This is the most difficult part of the corefloods to model accurately, and in some cases the simulator tends to overestimate this delay slightly, especially in the downstream section



**Figure 19-9.** Comparison of simulation (right) with laboratory coreflood (actual data, left) (Robert and Mack, 1995).

of the cores. Effects of surfactant adsorption, gas compressibility and gas solubility are also included. In principle, there is no limit to the complexity of mobility behavior that can be incorporated in this approach.

#### 19-4.6. Application to field design

Recent laboratory results have led to the development of guidelines for foam diversion (Gdanski, 1993; Zerhboub *et al.*, 1994). Foam diversion has been used increasingly in recent years, particularly in cases where other diversion techniques are impractical or less efficient such as the application of particulate diverters and ball sealers over large intervals. Foams also help in cleanup and back-production of treating fluids.

##### ■ Choice of surfactant

Traditionally, half-life measurements have been used to rank the foaming performance of surfactants. In these static tests, foam is generated and allowed to decay slowly in a beaker under the action of liquid drainage and gas migration. The time for one-half of the liquid to drain out of the foam is called the foam half-life. These tests are useful for determining chemical compatibility and identifying ineffective foams but not for optimizing surfactant formulation (Rossen, 1996). Foam formation in porous media is a dynamic process in which bubbles (or lamellae) are constantly created and broken. Surfactant adsorption on the rock surface, elasticity of lamellae and kinetics of foam formation are important properties that cannot be measured by static half-life tests. Therefore, only core flow tests can be used to select the most appropriate surfactant formulation for diversion.

Laboratory experiments indicate that diversion requires rapid formation and propagation of strong foam in higher permeability cores, with delayed foam formation in the lower permeability zones. This suggests that surfactant adsorption is a critical parameter for diversion. Oil present in the formation is another parameter to take into account for surfactant selection: the presence of oil can impair significantly the foam strength or delay the onset of effective foam banks, especially in oil-wet formations.

##### ■ Pumping strategy

On the basis of laboratory experiments, Zerhboub *et al.* (1994) proposed a set of guidelines for foam diversion. The principle of the method consists of pretreating the matrix to facilitate the formation of strong foam with a minimum foam volume and adding surfactant to acid stages to preserve the foam bank stability. Experiments on sandstones and carbonates show that effective and durable diversion can be obtained with repetitive slugs of foam and acid.

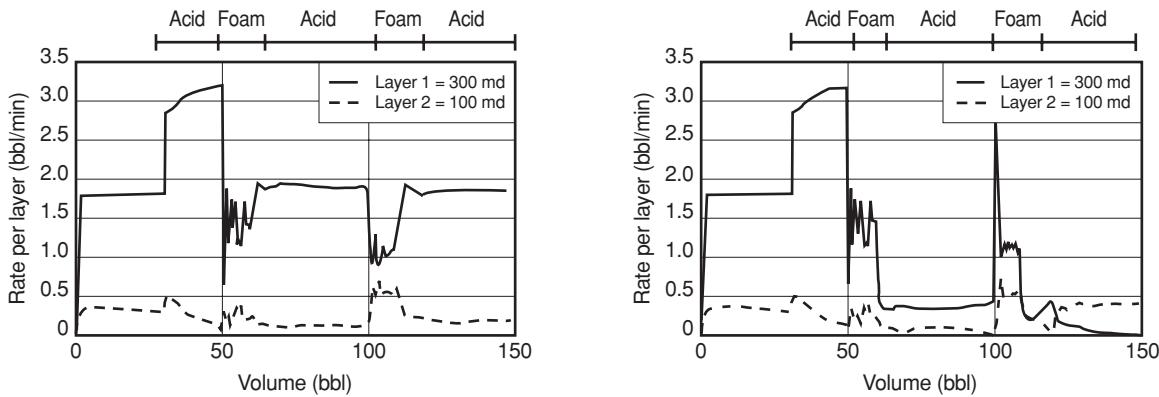
Indeed, once a damaged zone has been acidized, it must be plugged by foam to redirect acid to zones that have not been treated. Furthermore, foam in place tends to undergo slow decay (presumably because of gas dissolution), and periodic regeneration of the foam bank is required.

Use of a mutual solvent is recommended ahead of the treatment to reduce interfacial tension and to help sweep oil from the near-wellbore region. For a well-defined water zone, treatment can be started with a foam slug aimed at selectively plugging the water zone, while the oil prevents strong foam formation in the hydrocarbon-bearing zone. In that case, a mutual-solvent preflush is not beneficial. A gel-based water- or oil-specific diverter can be also used in addition to foam to help plug water zones (Kennedy *et al.*, 1992).

The size of foam slugs can be extrapolated from laboratory studies. As with particulate diverters, the design consists of pumping enough foam to plug higher injectivity zones while keeping the overall injectivity high enough to perform the treatment in a reasonable time and ensure effective acid action. Generally, the volume of the foam stages is gradually increased throughout the treatment to provide diversion over increasing interval lengths and replenish the degenerating foam pumped during prior stages. For carbonate acidizing, increasing the volume of the foam stages accommodates the void space created by rock dissolution during the previous acid stages. Gdanski (1993) recommended also that the volume of the foam slugs be sufficiently large to allow transport in the tubing without excessive mixing with other stages.

Zerhboub *et al.* (1994) found that better diversion is obtained on parallel sandpack cores if moderate acid rates are used. This phenomenon can be explained by the behavior of foam during subsequent liquid injection: mobility in the foam bank appears to be governed by a threshold  $\Delta p$  for foam mobilization and therefore increases strongly with increasing pump rate (Parlar *et al.*, 1995). At high flow rates, foam directs a greater fraction of flow into foam-filled high-permeability intervals. Simulation of field application shows that under certain conditions diversion can depend strongly on the pumping rate (Fig. 19-10).

Foam quality in diverter slugs varies generally from 60% to 80%. Experiments on low-permeability carbonate samples showed better diversion efficiency if higher quality foams (70% to 80%) were used (Thompson and Gdanski, 1993). Single-core tests on Berea sandstones showed that increasing foam quality from 65% to 80% at a constant liquid rate resulted in a slight increase of the pressure gradient in the foam bank (Parlar *et al.*,



**Figure 19-10.** Effect of acid injection rate on diversion efficiency (Robert and Mack, 1995). Left: high injection rate (no diversion). Right: low injection rate (diversion).

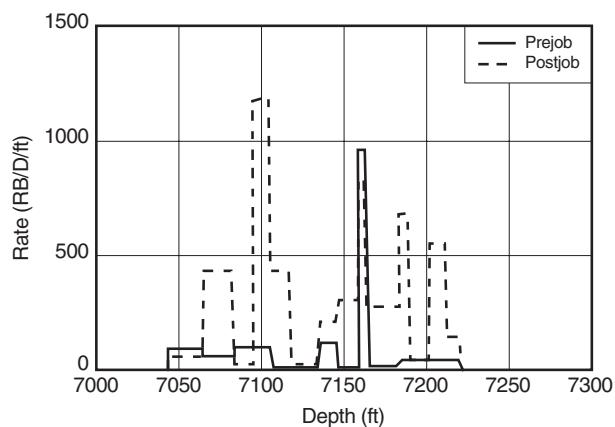
1995). However, little variation of foam behavior was observed during the following liquid stage; therefore, diversion efficiency is not expected to vary.

For long intervals, especially in horizontal wells, coiled tubing is often used to help place treating fluid throughout the interval. Treatment is started at the bottom of the interval, and the coiled tubing is pulled out while pumping. Foam stages are pumped at regular intervals, usually of 30 to 50 ft. This method has been shown to yield better results than simple bullheading (i.e., injection at the top of the interval). Analysis of stimulation results for water injection wells with long openhole intervals (e.g., 300 ft) in a carbonate formation showed that replacing the conventional bull-heading technique (with or without a particulate diverter) with the use of coiled tubing and foam diversion doubled the average post-treatment injectivity index while reducing the required acid volume from 100 to 50 gal/ft (Ginest *et al.*, 1993). Figure 19-11 is an example of a post-treatment flow profile after acidizing with coiled tubing and foam diversion. It shows that acidizing opened the entire interval to flow, which indicates successful damage removal over the entire zone.

Coiled tubing can also help in designing diversion stages on the fly. It allows using downhole sensors to measure pressure or to get an estimate of the bottomhole pressure from the pressure at the wellhead in the annulus between the production tubing and the coiled tubing. An increase of bottomhole pressure when foam is at bottomhole indicates that foam is entering the formation, but this is not a sufficient indication to prove that diversion is taking place. A significant reduction of pressure during the following acid stage can indicate that a new zone is acidized and that diversion was obtained. However, laboratory experiments show that

a drop in injection pressure during the acid stage may also reflect foam displacement and decay (Parlar *et al.*, 1995; Kibodeaux *et al.*, 1994). Therefore, pressure evolution is more difficult to interpret for foam than for particulate diverters.

Foam may be mixed with acid throughout the treatment. Generally, lower qualities are used for foamed acid than for foam slugs. This method was first tried for acidizing gravel-pack formations (Burman and Hall, 1986). Laboratory data indicate that foamed acid provides better coverage than straight acid, even if inversion of the flow profile (i.e., more flow into the damaged or low-permeability zones) cannot be attained. However, this technique requires higher gas volumes and pumping times than the slug method. Thompson and Gdanski (1993) reported that foamed acid does not provide sufficient diversion in high-porosity carbonates.



**Figure 19-11.** Flow profile after acidizing with foam diversion (Ginest *et al.*, 1993). Prejob = 102,000 BWPD at 1,500 psig; postjob = 608,000 BWPD at 1,180 psig.

## 19-5. Ball sealers

Originally introduced in 1956, ball sealers are small spheres intended to seal perforations on the inside of the casing. Added to treating fluids during stimulation, they are carried downhole and seal the perforations accepting the largest quantities of fluid. Although they are widely used, conventional ball sealers often fail to provide diversion. A sufficient rate must be available to maintain a differential pressure across the perforations to keep the balls in place. Their effectiveness is also limited by the roundness and smoothness of the perforation holes. Moreover, ball sealers are not effective in wells with a large number of perforations.

Better efficiency can be gained by using buoyant ball sealers instead of conventional nonbuoyant ones (Erbstoesser, 1980; Gabriel and Erbstoesser, 1984). As shown in Fig. 19-12, when a buoyant ball sealer is transported to the perforations, it either seals an upper perforation or is carried to the lowest one that is accepting fluid. However, because of its buoyancy, it does not remain in the quiescent fluid in the rathole.

Contrary to chemical diverters, ball sealers seated on the perforations facing a high-permeability interval effectively stop fluid entry and direct the entire flow to areas with lower injectivity. Figure 19-13 shows the injected flow distribution resulting from this diversion technique.

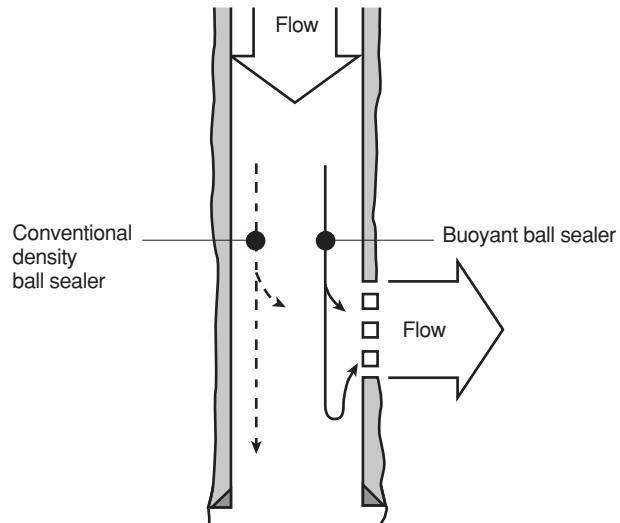
The density of buoyant ball sealers must be compatible with the density of the carrying fluid to allow transport downhole while prohibiting settling in the rathole. Ball sealers are transported downhole as long as the rising velocity does not exceed the fluid velocity in the wellbore. The rising velocity  $u_r$  of spherical particles in a fluid is

$$u_r = \sqrt{\frac{4}{3} \frac{\Delta \rho g d}{\rho_f f_d}}, \quad (19-18)$$

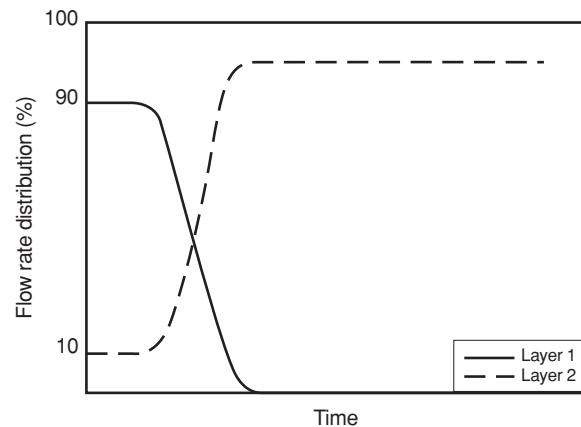
where  $\Delta \rho$  is the difference between the fluid and ball densities,  $d$  is the ball diameter,  $g$  is the acceleration of gravity,  $\rho_f$  is the fluid density, and  $f_d$  is the drag coefficient. The drag coefficient depends on the Reynold's number  $N_{Re}$  and can be obtained from the well-known Moody diagram or from empirical expressions:

$$N_{Re} = \frac{u_r d \rho_f}{\mu}, \quad (19-19)$$

where  $\mu$  is the dynamic viscosity. A trial and error technique is required to solve Eq. 19-18 rigorously



**Figure 19-12.** Two ball sealer seating processes (Erbstoesser, 1980). The dashed trajectory shows the conventional density (nonbuoyant) ball sealer, and the solid trajectory shows the 100%-efficient buoyant ball sealer.



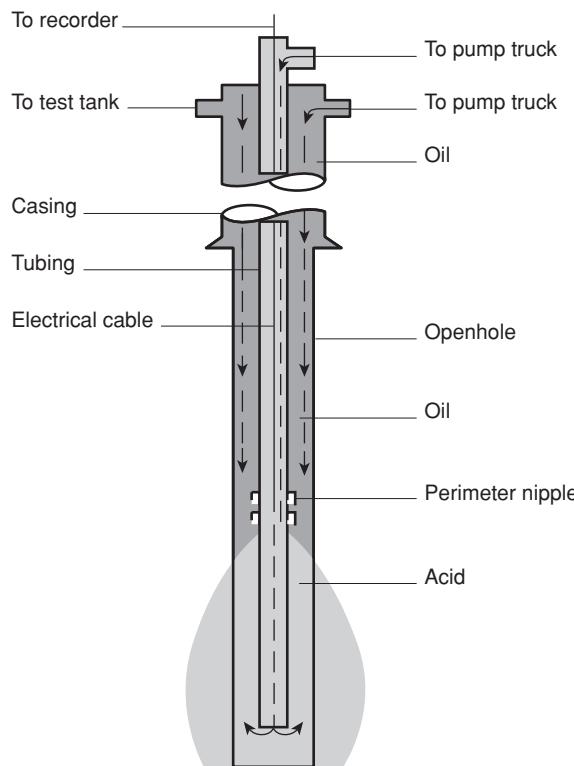
**Figure 19-13.** Flow distribution using ball sealers in a two-layer reservoir ( $h_1/h_2 = 1, k_1/k_2 = 9$ ).

(Brown *et al.*, 1963), because  $N_{Re}$  depends on the calculated velocity. However, in high-flow regimes, and thus at large values of  $N_{Re}$  (between 2,000 and 100,000),  $f_d$  varies slightly about an average value of 0.44. If  $f_d$  is assumed constant over this interval, then the rising velocity can be estimated readily (Gabriel and Erbstoesser, 1984).

## 19-6. Mechanical tools

During the mid-1940s, downhole tools were used to locate the contact between a conductive fluid (acid) and a nonconductive fluid (oil). Both fluids were pumped simultaneously to maintain the interface at a constant level. This allowed treatment of a selected portion of the reservoir. A schematic of this procedure is given in Fig. 19-14. In 1950, the development of hydraulically operated inflatable packers led to improved diverting techniques. When these packers are used as a straddle tool, it is possible to treat three intervals (below, between and above the packers) without moving the completion. Although this is an effective means of obtaining excellent control on coverage, it is expensive and time consuming.

Frac baffles were invented in 1965 to provide economically attractive completions in multilayered reservoirs. In this method, shown in Fig. 19-15, one or more concentric baffle rings of different diameters are designed to accept a "bomb." Bombs of different diameters are dropped to sit on the correct-diameter baffle and thus isolate the zone of treatment. However, this technique limits the treatment to downcasing and requires accurate placement of the baffles when running the casing.

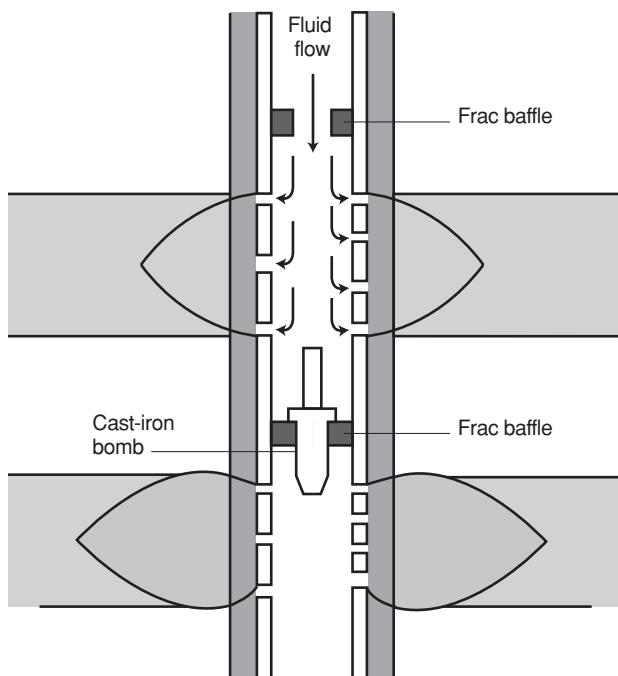


**Figure 19-14.** Diversion in openhole using an "interface locator" tool (Harrison, 1972).

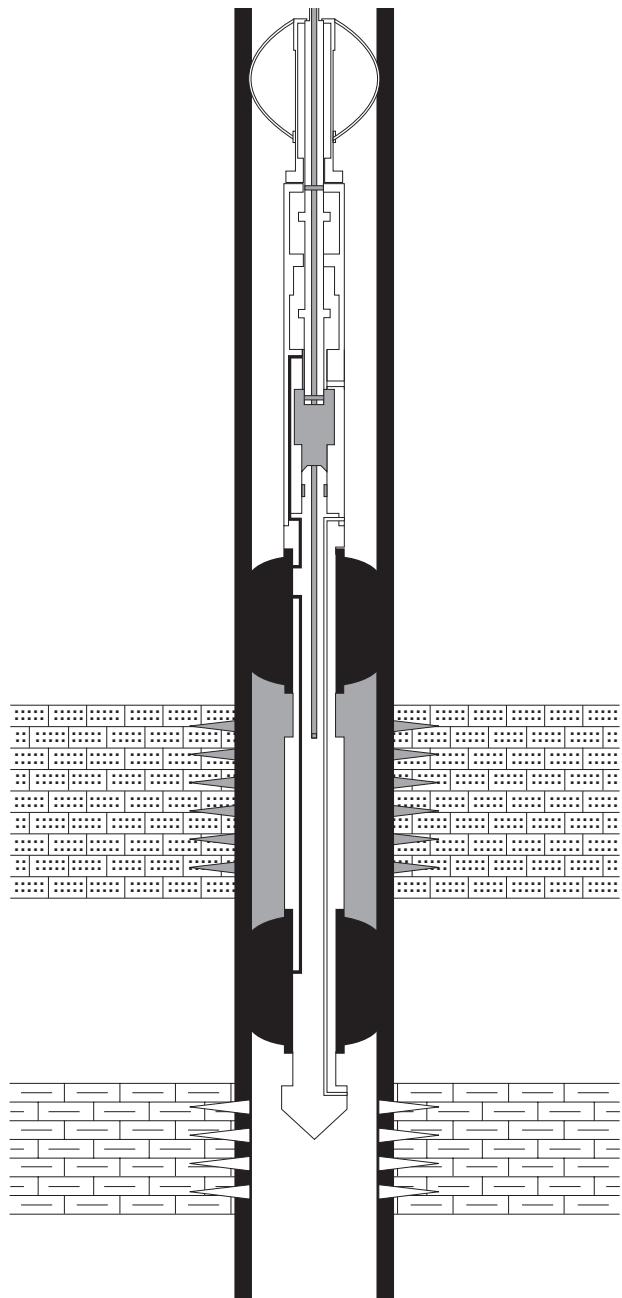
Retrievable packers have also been developed that use various techniques for setting and retrieving. Tension-set packers are particularly suitable for matrix acidizing operations. They are initially set by pulling tension on the tubing and held in place by the pressure differential between the tubing and the annulus above the packer.

Conventional mechanical techniques are efficient at controlling the placement of acid. However, they are cumbersome and generally require a rig on site. They are also expensive and time consuming.

New techniques have been developed to convey packers with coiled tubing. Inflatable straddle packers can provide zonal isolation during matrix treatment. Before packer setting, the treating fluid can be circulated down the coiled tubing above the packers. Setting is obtained by picking up on the coiled tubing and applying pump pressure to inflate the packer elements. Treating fluid can then be directed to the interval between the packers by slackening off weight on the tool string (Fig. 19-16). Picking up over the string weight and then slackening off closes the injection port and reopens the circulating port above the packers. Finally, sustained overpull allows the packer elements to deflate, and the packer can be moved to another zone (Milne, 1991).



**Figure 19-15.** Frac baffle diverting technique (Harrison, 1972).



**Figure 19-16.** Treating between the packers (Milne, 1991).

## 19-7. Horizontal wells

### 19-7.1. Optimal treatment

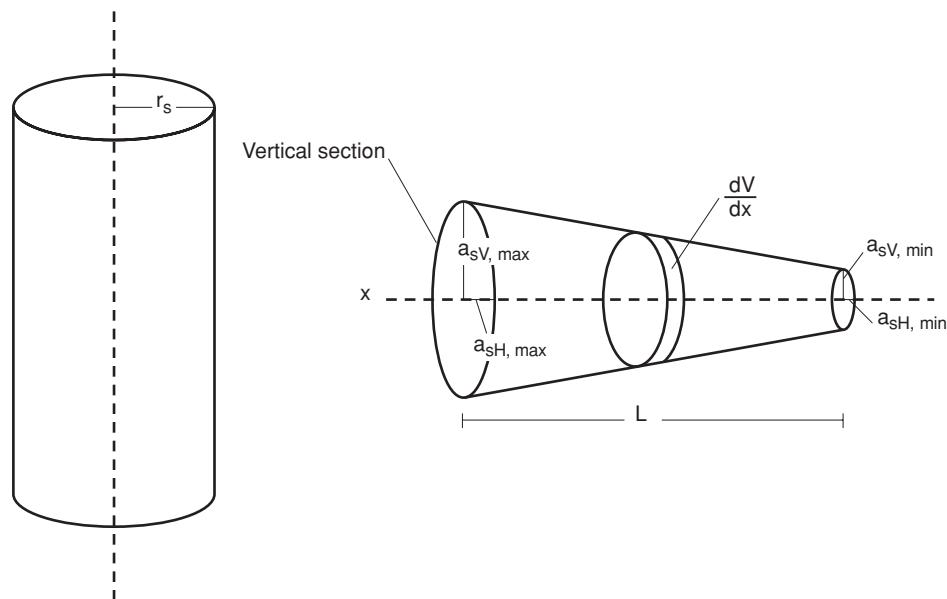
Producing sections in horizontal wells are typically between 1 and 2 orders of magnitude longer than in vertical wells. Therefore, even distribution of treating fluid over the entire open interval is more difficult to achieve. Furthermore, the limits of corrosion-inhibitor efficiency, as well as other practical considerations, restrict the treatment duration and therefore require pumping smaller volumes per length of open interval,

which makes the issue of placement control even more critical. Better results are generally reported when a diversion technique is used than when acid is simply bullheaded via the production tubing. In several cases, production logs performed after acidizing without the use of any diversion technique show that only a small portion of the well was open to flow, generally the area nearest to the vertical section (Frick and Economides, 1991; Thomas and Milne, 1995).

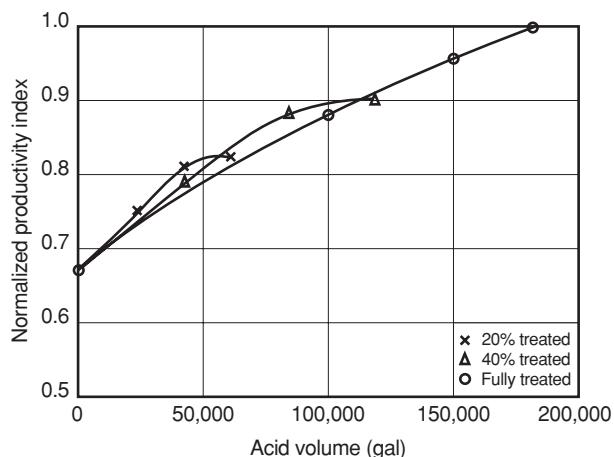
Efforts have been made to determine the optimum treatment design, taking into account the limitation of the total volume that can be pumped. Economides and Frick (1992) recommended adjusting the injection volumes according to the severity of damage. For instance, in the case of completion-induced damage, cone-shaped damage invasion is expected as damage severity increases with the time of exposure to drilling mud, which decreases with increasing measured depth (Fig. 19-17). In that case, a “tapered” injection would be optimal, with more acid pumped near the vertical section of the well. If complete damage removal requires impractical acid volumes, partial damage removal throughout the open interval should be targeted, leaving a uniform damage collar around the wellbore.

Da Motta *et al.* (1994) suggested that in some cases treatment efficiency can be improved by selective acidizing, where some intervals in the horizontal section of the well are intentionally left unperforated or untreated. For example, Fig. 19-18 shows the normalized productivity index (ratio of the productivity index to undamaged productivity index) for three different treatment configurations. Simulations were performed with a 2,000-ft well with 12-in damage penetration and a permeability reduction of 90% in the damaged zone. The original vertical and horizontal permeabilities were 90 and 10 mD, respectively. A total volume of 100,000 gal was pumped, corresponding to 50 gal/ft for full coverage and 125 gal/ft for 40% coverage. For partial coverage, the treated area was divided into five equally spaced intervals. In the particular case shown in Fig. 19-18, optimum treatment would be achieved with partial coverage. However, these simulation results must be interpreted with caution, as they depend on the total volume required for total damage removal. For example, if only 50 gal/ft were required to achieve zero skin effect, then full coverage would obviously become the optimal configuration.

The total volume used in horizontal well treatments is usually limited by practical constraints not directly linked to the acidizing itself, such as pumping time (especially if coiled tubing is used). However, because of the relatively low cost of matrix acidizing compared with the return in terms of a production increase, the highest net present value (NPV, or the difference between revenue from additional production and the treatment cost) is usually obtained when the entire interval is treated, even if this entails large acid volumes (Economides and Frick, 1992).



**Figure 19-17.** Cone-shaped damage (Frick and Economides, 1991).  $r_s$  = radius of the damaged section,  $L$  = length,  $a_s$  = axis of the damaged ellipse with the subscripts V and H denoting vertical and horizontal dimensions and min and max denoting minimum and maximum values, respectively.



**Figure 19-18.** Normalized productivity index for different fractions of the treated interval (da Motta et al., 1994).

### 19-7.2. Placement techniques

Different placement techniques can be used to treat horizontal wells. As most completions are openhole or with slotted liner, ball sealers are generally not applicable. Furthermore, conventional ball sealers are not recommended in horizontal wells, as seating requires a minimum velocity per perforation.

Most recommended techniques include the use of coiled tubing. A standard practice consists of starting the treatment with coiled tubing at bottomhole, then slowly pulling the coiled tubing out while acid is injected, with the rate of coiled tubing retrieval set according to the

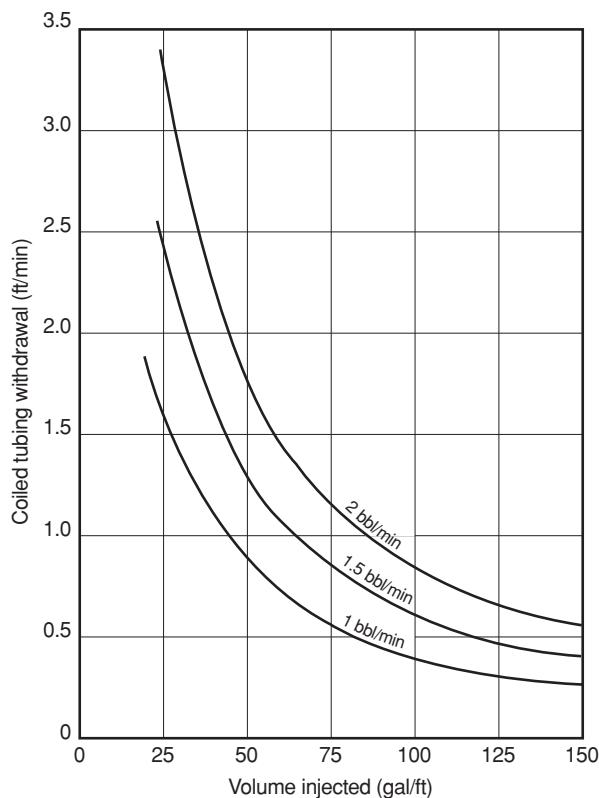
desired volumetric coverage (Fig. 19-19). This technique provides contact of the entire interval with the treating fluid. A diverter stage in the form of foam or particulate agents is usually pumped at regular intervals to avoid the formation of thief zones.

Figure 19-20 shows the rate of skin effect reduction with and without the use of coiled tubing as determined by simulation, assuming a 2,000-ft horizontal section with an initial skin effect of 6, damage penetration of 1.5 ft and damage consisting solely of clays. Clay dissolution with 12% HCl–3% HF was simulated, and the evolution of skin effect with time calculated from the permeability profile around the wellbore. The injection rate was equal to 1.5 bbl/min, corresponding to a total volume of 100 gal/ft over 52 h. Without coiled tubing, it was found that only the first half of the interval could be stimulated, whereas coiled tubing provided good coverage accompanied with better skin effect reduction.

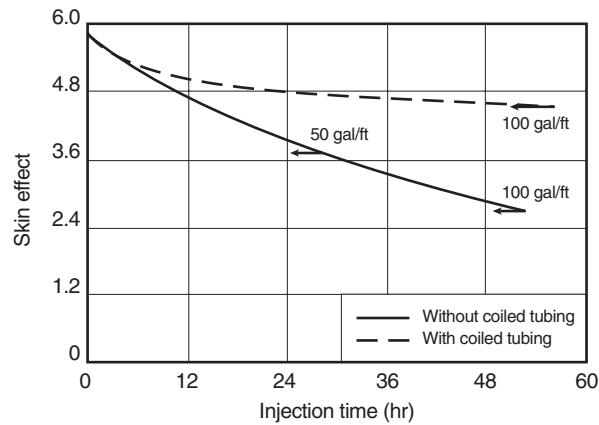
Economides *et al.* (1991) recommended pumping a nonreactive fluid through the annulus between the production tubing and coiled tubing to provide backpressure and force the treating fluid to enter the reservoir next to or below the coiled tubing end. For a tapered treatment, the rate of coiled tubing retrieval should be progressively decreased to follow the pattern of damage severity and gradually increase the volumetric coverage.

Tambini (1992) showed that the method developed by Paccaloni for vertical wells can be adapted to horizontal completions, mainly by adding a friction reducer to allow pumping at the maximum rate under fracturing pressure.

The technique consists of spotting acid (one-third of the total volume) throughout the entire interval by pumping through coiled tubing only (still starting at total depth and pumping while the coiled tubing is retrieved). Then acid



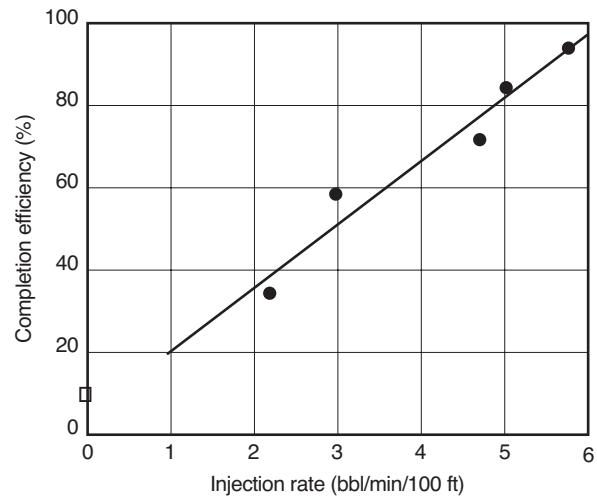
**Figure 19-19.** Coiled tubing withdrawal rate (Economides et al., 1991).



**Figure 19-20.** Skin effect evolution versus time with and without coiled tubing (Economides et al., 1991).

is pumped through both the annulus and coiled tubing at the maximum rate allowed by the surface equipment and reservoir. Good results are reported with this technique for production interval lengths up to 1,500 ft. Pressure analysis during the treatment and production logs run on cemented completions indicate that treatment efficiency depends heavily on the injection rate during the bullheading phase, with the best results reported for rates as high as 5 to 6 bbl/min/100 ft in 15-mD formations (Fig. 19-21). However, this technique requires additional pumping equipment and therefore can be more costly than other methods. Moreover, in some cases the required rates cannot be achieved because of well and surface equipment limitations. Finally, as mentioned earlier, the method does not provide fluid placement optimization, which is critical for long intervals.

Coiled tubing can also be used to convey inflatable straddle packers in cased completions or completions including external casing packers. The drawback of this technique is that the interval between packers is limited to 30 ft, which entails many setting and unset operations. When zonal segmentation is provided by slotted liner with external packers, each segment (500 ft long on average) must be treated with retrievable packers set opposite to the casing packers to prevent treating fluid migration along the wellbore behind the slotted liner (Milne, 1991).



**Figure 19-21.** Completion efficiency versus injection rate (Tambini, 1992).

## 19-8. Conclusions

Pumping strategy is one of the major issues for the success of matrix acidizing. Improving the placement of treating fluids also addresses increasing concerns for environmental protection and cost control.

Four placement techniques are discussed in this chapter: particulate diverter, foam, mechanical tools and ball sealers. The design of particulate diverter or bridging agents requires checking compatibility with the formation and carrying fluids. Particle size must be adapted to the pore-throat distribution of the formation, and the diverter must be soluble in the reservoir fluid to help flowback. Compatibility with the carrying fluid is required to ensure proper dispersion of the particles and prevent dissolution or reaction with other additives.

Foam diversion has been used with success in long intervals. Qualities from 65% to 70% are commonly used. Current practice involves pumping surfactant-laden pre-flush to saturate high-permeability zones and ensure foam stability in these zones. Better foam durability is obtained if surfactant is added to all stages, even at moderate concentrations. Laboratory tests and computer simulations indicate that better diversion is obtained if moderate pump rates are applied.

Contrary to the other techniques, mechanical tools and ball sealers allow complete shut-off of a portion of the wellbore. Mechanical tools provide the best placement control but require additional equipment and costly operations. Ball sealers are normally limited to a single stage in cased completions and cannot be used for long intervals.

One other technique has emerged for carbonate acidizing: self-diverting acid. This technique is presented in Chapter 17. Field and laboratory data indicate that it is highly effective for plugging high-injectivity streaks created by acid.

The application of coiled tubing in matrix stimulation has improved results, especially for the stimulation of long intervals. Combining most of the placement techniques (i.e., particulate diverter, foam, packers) with the use of coiled tubing increases their efficiency. In long intervals, as in horizontal wells, coiled tubing is run to the well bottom and then withdrawn while pumping acid. Diverter stages are pumped between acid stages. This technique allows spotting acid across the entire interval and minimizes the effect of thief zones.

## Acknowledgments

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# 20. Matrix Stimulation Treatment Evaluation

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## 20-1. Introduction

As for any stimulation operation, it is important to evaluate the effectiveness of a matrix treatment. In Chapter 12<sup>†</sup>, the methodology of evaluating hydraulic fracturing through pretreatment and post-treatment well tests is outlined. For matrix stimulation, such a comprehensive approach is rarely justified economically. Usually, the effectiveness is gauged by apparent increases in the productivity index, without the benefits of a post-treatment test. Clearly, increases in the productivity (or injectivity) index, although desirable, may not provide an adequate picture of optimum well conditions.

Estimation of the well skin effect and identification of its individual components are covered in Chapter 1<sup>†</sup>. The total skin effect can be determined from a well test, and test analysis is outlined in Chapter 2<sup>†</sup>. Mechanical skin effects (such as from partial completion and inadequate perforations) may often overwhelm the damage skin component. An appropriate production engineering analysis should enable the identification and separation of these skin effects. Only the portion of the skin effect resulting from damage can be removed by a matrix treatment, which should reduce the total skin effect by that amount. Furthermore, to be cost effective, the injected volume and the pumping time should be minimized.

Several attempts have been made to evaluate the effectiveness of a remedial matrix treatment by monitoring evolution of the skin effect in real time. Monitoring to evaluate whether an adequate fluid volume has been injected indicates whether the treatment requires modification and helps to improve future designs in similar situations.

Techniques for real-time monitoring have been introduced by McLeod and Coulter (1969) and Paccaloni (1979a, 1979b) and further augmented by Prouvost and Economides (1987, 1989), Behenna (1994) and Hill and Zhu (1994). They are described in this chapter.

## 20-2. Derivation of bottomhole parameters from wellhead measurements

In many matrix stimulation treatments, wellhead pressures and injection rates are recorded. Ideally, these variables should be measured bottomhole. However, the hostile nature of the stimulation fluids prevents the use of downhole pressure gauges and flowmeters. Thus, bottomhole parameters are often extrapolated from measurements made at the surface by simple mechanical energy balance applications and estimates of the hydrostatic and friction pressure losses. When stimulation fluids are injected through a conduit such as coiled tubing or rigid tubing, measurement of the bottomhole injection pressure can be done in the "backside" (i.e., at the annulus formed between the injection tubing and other well tubulars). Echometers have also been employed to measure the level of backside fluids if the wellhead pressure is below hydrostatic.

## 20-3. Monitoring skin effect evolution during treatment

Different attempts have been made to interpret recorded wellhead pressures (or derived bottomhole pressures) and injection rates in terms of progress of the remedial treatment. Several techniques have been used to derive the evolution of the skin effect from these records.

### 20-3.1. McLeod and Coulter technique

Each stage of injection or shut-in during the treatment is considered a short, individual well test (McLeod and Coulter, 1969). The transient reservoir pressure response to the injection of fluids is analyzed and interpreted to determine the skin effect and the formation transmissibility. This is accomplished using conventional pressure transient analysis methods, namely the solution to the diffusivity equation and the superposition principle (see Chapters 1<sup>†</sup> and 2<sup>†</sup>).

<sup>†</sup> See *Reservoir Stimulation Third Edition* (SMP-7075)  
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Although the results are presented not in terms of skin effect but in terms of the permeability and the radius of the damaged zone (i.e., the short-term nature of the test has a limited radius of investigation), the objective is essentially the same: the skin effect can be related to the properties of the damaged zone. For example, if the well is initially injected at a constant rate, a graph of the pressure response plotted against the logarithm of elapsed time since injection started yields the permeability in both the damaged and undamaged zones and the radial extent of the damaged zone. With a little modification, the same information can be obtained from pressure falloffs when injection stops.

The technique has several drawbacks:

- The analysis of pressure transients is valid only if the skin effect factor does not change while a set of pressure data for one particular interpretation is collected. This is not the case when reactive fluids are injected into the formation to remove damage. Hence, to be correct, this method requires the injection of a slug of inert fluid each time the damage removal is assessed. This is not usually practical.
- No continuous assessment of the evolution of the treatment is possible. Skin effect measurements are allowed only at discrete times during the course of the treatment, usually before and after the treatment. Thus, real-time analysis is not feasible.

### 20-3.2. Paccaloni technique

A second method, presented by Paccaloni (1979a, 1979b), uses instantaneous pressure and rate values to compute the skin effect at any given time during the treatment. This method is based on the equation for steady-state, single-phase, radial and horizontal flow in the reservoir:

$$p_{iw} - p_e = \frac{141.2 q_i B \mu}{kh} \left( \ln \frac{r_e}{r_w} + s \right), \quad (20-1)$$

where  $p_{iw}$  is the bottomhole injection pressure,  $p_e$  is the reservoir pressure,  $q_i$  is the injection rate,  $B$  is the formation volume factor,  $\mu$  is the viscosity,  $k$  is the permeability,  $h$  is the reservoir thickness,  $r_e$  is the reservoir radius,  $r_w$  is the wellbore radius, and  $s$  is the skin effect.

Paccaloni (1979a) used an arbitrary constant value for an acid bank radius  $r_b$  and the concept of the effective wellbore radius  $r_w' = r_w e^{-s}$  to transform Eq. 20-1 into

$$p_{iw} - p_e = \frac{141.2 q_i B \mu}{kh} \left( \ln \frac{r_b}{r_w'} \right). \quad (20-2)$$

Assuming that the permeability-thickness product  $k_h$  of the reservoir is known, the bottomhole pressures, corresponding to the injection rate, can be predicted for any value of the skin effect. The wellhead injection pressures are then derived from the bottomhole pressures, and at any time, a match of the measured wellhead pressures with the ones corresponding to different values of the skin effect yields the actual skin effect at that time.

Paccaloni used the concept of a damage ratio  $DR$ , which is simply the rewriting of Eq. 20-1 under ideal ( $s = 0$ ) and real ( $s \neq 0$ ) conditions, and obtained the ratio of the productivity indices:

$$DR = \frac{J_{ideal}}{J_{real}} = \frac{\ln(r_e/r_w) + s}{\ln(r_e/r_w)}. \quad (20-3)$$

#### ■ Example application of the Paccaloni method

Figure 20-1 depicts a series of damage ratio curves for a range of injection rates and calculated wellhead pressures. Table 20-1 lists the well and reservoir variables used for this construction.

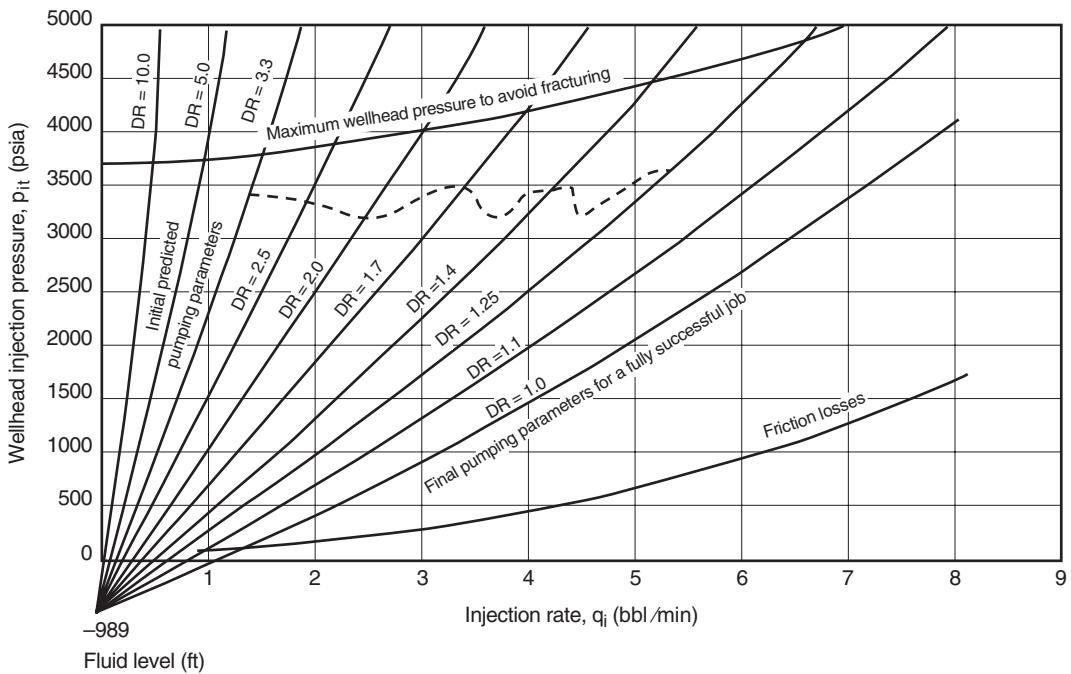
The Paccaloni method (1979a, 1979b) implies that as acid is injected, superimposition of the measured wellhead pressure on the graph indicates the progress of the stimulation. This is shown by the dashed line on the figure.

Among the assumptions listed in the Paccaloni method, the “steady-state” assumption is one that may cause problems and, potentially, errors. Although a steady-state relationship is assumed, transient behavior is in effect for a time duration far exceeding the injection test. For a radial reservoir, for example, the time to a pseudosteady-state condition is

$$t_{pss} \approx \frac{1000 \phi \mu c_t r_e^2}{k}, \quad (20-4)$$

where  $c_t$  is the total compressibility. For a typical oil reservoir (e.g.,  $\phi = 0.25$ ,  $\mu = 1$  cp,  $c_t = 5$  psi<sup>-1</sup>,  $k = 50$  mD and 80-acre spacing or  $r_e \approx 1,000$  ft), the time to pseudosteady state (which may be perceived as a succession of steady states) is more than 50 h, which is significantly longer than the normal pumping times for a typical matrix acidizing job.

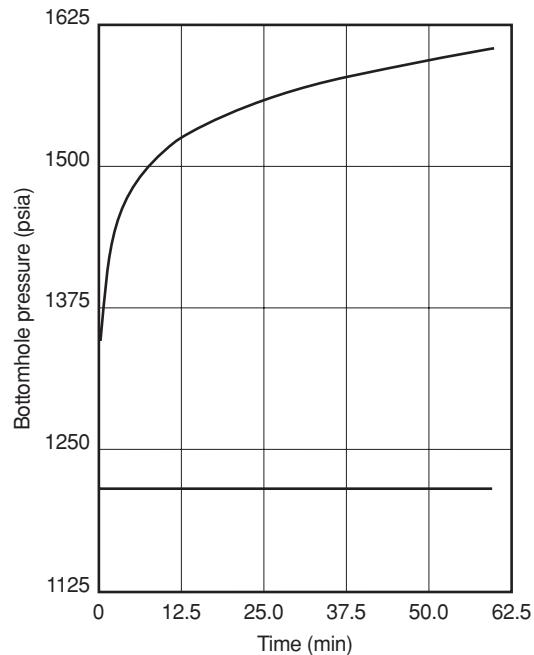
Figure 20-2 is a graph comparing bottomhole pressure evolution using steady-state and transient models. The simulations were generated for  $q_i = 0.5$  bbl/min,  $k_h = 1,000$  mD-ft,  $\phi = 0.2$ ,  $c_t = 1.5 \times 10^{-5}$  psi<sup>-1</sup> and  $r_w = 0.35$  ft. The initial skin effect is equal to 10. For the Paccaloni (1979b) method,  $r_b = 3$  ft was used. It is obvious that the bottomhole transient pressure evolution could lead to errors. The pressure departure between the two curves in



**Figure 20-1.** Job control chart with the damage ratio DR plotted as a parameter. The measured injection rates and injection pressures are recorded on the chart (Paccaloni, 1979b).

**Table 20-1. Well and fluid data used for Fig. 20-1 (Paccaloni, 1979a).**

Depth, $H$	13,540 ft
Density, $\rho$	8.9 lbm/gal [66.6 lbm/ft <sup>3</sup> ]
Viscosity, $\mu$	0.7 cp
Reservoir pressure, $p_e$	5805 psi
Hydrostatic pressure drop, $\Delta p_h$	6262 psi
Reservoir thickness, $h$	30 ft
Permeability, $k$	35 md
Wellbore radius, $r_w$	0.25 ft
Reservoir radius, $r_e$	800 ft
Tubing 1 ID	2.992 in.
Tubing 1 length	12,750 ft
Tubing 2 ID	2.441 in.
Tubing 2 length	750 ft
Acid bank radius, $r_b$	4 ft



**Figure 20-2.** Comparison of calculated steady-state and transient bottomhole pressure responses.

Fig. 20-2 could be identified as the result of an additional skin effect where such a skin effect does not exist. For the example in Fig. 20-2, after about 1 h of injection and a pressure departure  $\Delta p_{\text{departure}}$  equal to 400 psi, this additional false skin effect is equal to

$$\Delta s = \frac{kh\Delta p_{\text{departure}}}{141.2q_iB\mu}, \quad (20-5)$$

a value equal to approximately 4. The practical implication is that more acid may be employed to eradicate this seemingly present skin effect when, in fact, the pressure difference is due to easily explainable transient phenomena.

## 20-4. Prouvost and Economides method

A technique presented by Prouvost and Economides (1987, 1989) enables continuous calculation of the skin effect factor during the course of the treatment and accounts for transient response. The technique is based on a continuous comparison of measured and simulated pressures. The diminishing difference is attributed to the diminishing skin effect. A good reservoir description is presumed, including the type of model and well and reservoir variables. Section 20-4.2 presents an associated methodology to obtain unknown variables just prior to the treatment.

### 20-4.1. Deriving skin effect during treatment

The Prouvost and Economides (1987, 1989) method simulates the reservoir pressure response to the injection of fluids using the sequence of flow rates measured during job execution. Each simulation is performed with a constant skin effect  $s_o$ .

At any time, the difference between the simulated pressure response  $p_{\text{sim}}(t, s_o)$  and the measured value  $p_{\text{meas}}(t)$  is interpreted as the result of the difference between the actual skin effect value and the value used for the simulation ( $s_o$ ). The latter can be zero or some other finite value for a known nondamage skin effect.

Because all other effects that influence the pressure response are accounted for in the simulation, the difference between the simulated and actual pressure responses is attributed to the changing skin effect:

$$s(t) = s_o + \frac{kh}{141.2q(t)B(t)\mu(t)} [p_{\text{meas}}(t) - p_{\text{sim}}(t, s_o)], \quad (20-6)$$

where  $s(t)$  is the skin effect at time  $t$ , and  $q(t)$ ,  $B(t)$  and  $\mu(t)$  are the injection rate, formation volume factor and viscosity of each slug at time  $t$ , respectively.

The method can be executed in real time. The “measured” bottomhole pressure can be calculated from measured wellhead values as shown earlier. Hence, a skin effect evolution with time can be obtained using Eq. 20-6.

### 20-4.2. Determining reservoir characteristics before treatment

Simulation of the pressure response, described in the previous section, requires a good knowledge of the reservoir and the initial value of the skin effect. Even if a well test was performed on the well earlier, the following procedures are recommended to alleviate any changes brought about by time. They apply mainly to oil producers and water injectors and are based on an injection/falloff test, in which native reservoir fluids in the wellbore are displaced and injected into the formation. There are three steps:

1. The reservoir fluid contained in the tubular string before treatment is partly or totally displaced into the reservoir at a matrix rate (i.e., at a rate that no fracture is initiated in the reservoir). To save pumping time, this fluid can be displaced by the first treating fluid.
2. The injection is stopped before any foreign fluid is injected into the formation. The evolution of pressure with time during this period is recorded typically for a duration of 1 hr, depending on the reservoir parameters, until valuable information on the reservoir can be obtained using the appropriate pressure testing methods extensively described in the literature and Chapter 2.<sup>†</sup>
3. Analysis of the pressure falloff data yields a model of reservoir behavior and the associated well and reservoir variables, such as the permeability-thickness product and especially the initial value of the skin effect.

In the case of layered reservoirs and the absence of more detailed downhole measurements, this technique results only in an averaged skin effect factor. Nevertheless, this remains a valuable piece of information, because variation in the average skin effect during treatment can be interpreted as the progress of damage removal by the stimulation fluid. For example, flattening of the  $s$  versus  $t$  curve at a nonzero level could indicate poor fluid placement (or, of course, complete damage removal in a single zone). Knowledge of the type of behavior and parameters enables computing the pressure response at the wellbore to any injection history, as described in Section 20-4.1.

The technique can be generalized by varying the injection rate instead of just stopping the injection, as described in the second step of the procedure. Although

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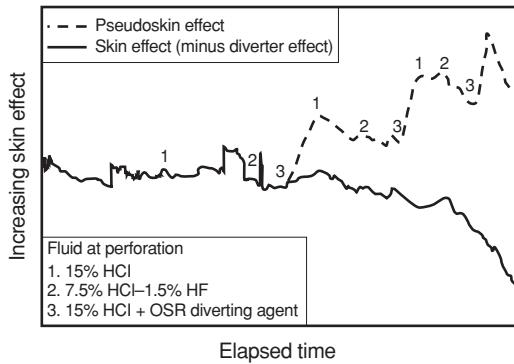
it can introduce some error from computation of the friction pressure drop, this modified procedure is of interest for depleted reservoirs (i.e., when reservoir pressure is not sufficient to balance the head of a column of fluid up to the surface).

An example calculation of the Prouvost and Economides method is presented in Sidebar 20A.

## 20-5. Behenna method

A technique that extends the Prouvost and Economides (1987, 1989) approach was provided by Behenna (1994). He accounted for the effects of diverting agents by subtracting the pressure drop created by the diverting agent from the bottomhole pressure used in the skin effect calculation. The pseudoskin effect caused by the placement of diverting agent slugs corrects the observed pressure response by an amount equal to the pressure increase caused by the diverter placement. Figure 20-3 from Behenna's paper shows an example application. An assumption made with this technique is that all subsequent response is due to removal of damage and not inadvertent removal of diverter.

A second extension that the Behenna method offers is use of the derivative of the skin effect with time as a diagnostic aid. The derivative plot accentuates periods of rapidly changing skin effect and has the effect of smoothing the effects of noisy data. The slope of the derivative is useful in quantifying the rate at which formation damage is removed. The steeper the slope, the faster the rate of change.



**Figure 20-3.** Skin effect evolution with diverters (Behenna, 1994). OSR = oil-soluble resin.

## 20-6. Inverse injectivity diagnostic plot

Hill and Zhu (1994) proposed a technique that is as simple to use as the Paccaloni (1979a, 1979b) method and also takes into account the effects of transient flow as suggested by Prouvost and Economides (1987, 1989). The method utilizes an expression derived from transient analysis methods extensively described in the literature (Earlougher, 1977):

$$\frac{p_i - p_{wf}}{q_N} = m' \sum_{j=1}^N \left[ \frac{(q_j - q_{j-1})}{q_N} \log(t - t_{j-1}) \right] + b', \quad (20-7)$$

where  $p_i$  is the initial reservoir pressure,  $p_{wf}$  is the bottomhole flowing pressure, and

$$m' = \frac{162.6 B \mu}{kh} \quad (20-8)$$

$$b' = m' \left[ \log\left(\frac{k}{\phi \mu c_i r_w^2}\right) - 3.23 + 0.87s \right]. \quad (20-9)$$

From Eq. 20-7, a plot is made of inverse injectivity versus the superposition time function  $\zeta t_{sup}$ , which is defined as

$$\Delta t_{sup} = \sum_{j=1}^N \frac{(q_j - q_{j-1})}{q_N} \log(t - t_{j-1}). \quad (20-10)$$

With all parameters remaining constant, a straight line with a slope  $m'$  and intercept  $b'$  can be produced. To utilize the technique, a series of straight lines with different skin effects at varying rates and times is produced before treatment.

An example application of the Hill and Zhu method is presented in Sidebar 20B.

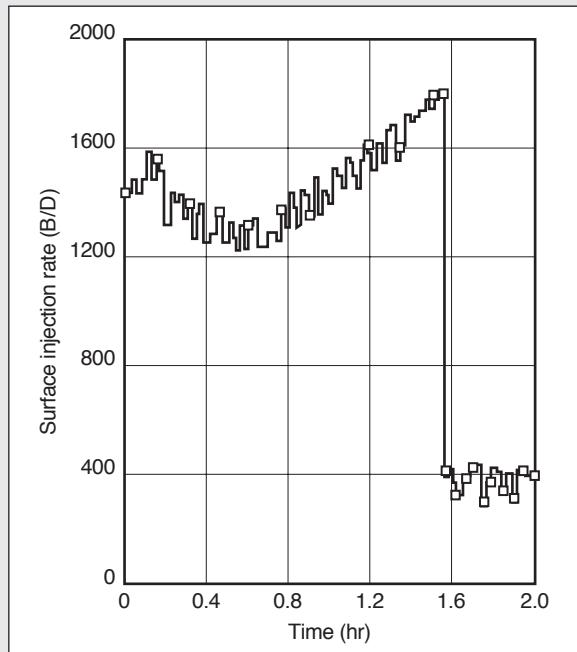
## 20A. Example calculation of the Prouvost and Economides method

In the injection profile in Fig. 20A-1 the rate was maintained at approximately 1 bbl/min and then dropped to 0.25 bbl/min after approximately 1.5 hr of injection. The “measured” bottomhole pressure that appears as the top curve in Fig. 20A-2 is based on the recorded wellhead pressures and the calculated bottomhole pressures using the procedure outlined in Section 20-2.

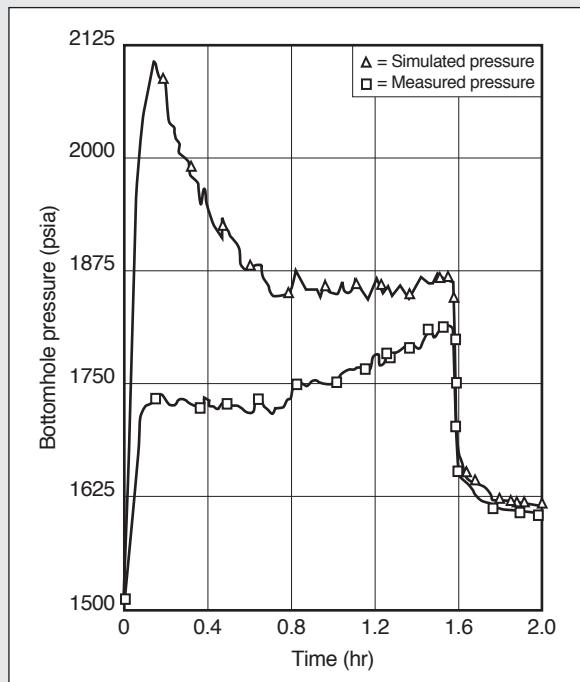
Underneath this curve is the simulated expected pressure response, using the injection profile of Fig. 20A-1 as an input and a skin effect equal to zero. For this well, the permeability-thickness product  $kh = \sim 5000$  md-ft, the wellbore storage constant  $C = 2.6 \times 10^{-3}$  bbl/psi, and the porosity  $\phi = 0.22$ . As usual, both the formation volume factor  $B$  and the viscosity  $\mu$  are taken as equal to unity (water). As outlined earlier, the Prouvost and Economides (1987, 1989) method attributes the departure between the two curves in Fig. 20A-2 to the skin effect. As can be seen, the departure diminishes as injection progresses, and in spite of the reduced rate, after 1.5 hr the two curves coincide and show the effectiveness of the job.

The associated skin effect evolution is shown in Fig. 20A-3. The bottom curve is the predicted skin effect using the Prouvost and Economides technique. The initial value is provided by the injection/falloff test described in Section 20-4.2. The skin effect reduces smoothly during the acid injection and approaches a zero value after approximately 2 hr of operation. Above this curve is the skin effect curve calculated by the Paccaloni (1979a, 1979b) technique. A continuous overestimation is shown, as explained earlier. This is due to the misidentification of a certain amount of pressure transients as caused by an additional skin effect.

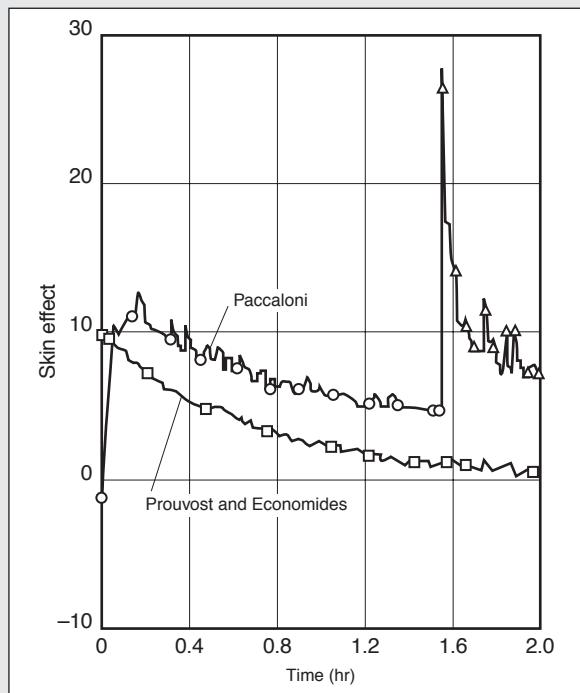
An interesting observation is what happens when the flow rate is reduced. The steady-state relationship of the Paccaloni method requires an analogous reduction in the pressure drop. Because this effect is not forthcoming, a substantial increase (usually unrealistic) in the calculated skin effect is obtained. Such an increase is easy to surmise from Eq. 20-5 and is shown graphically in Fig. 20A-3.



**Figure 20A-1.** Example injection rate profile.



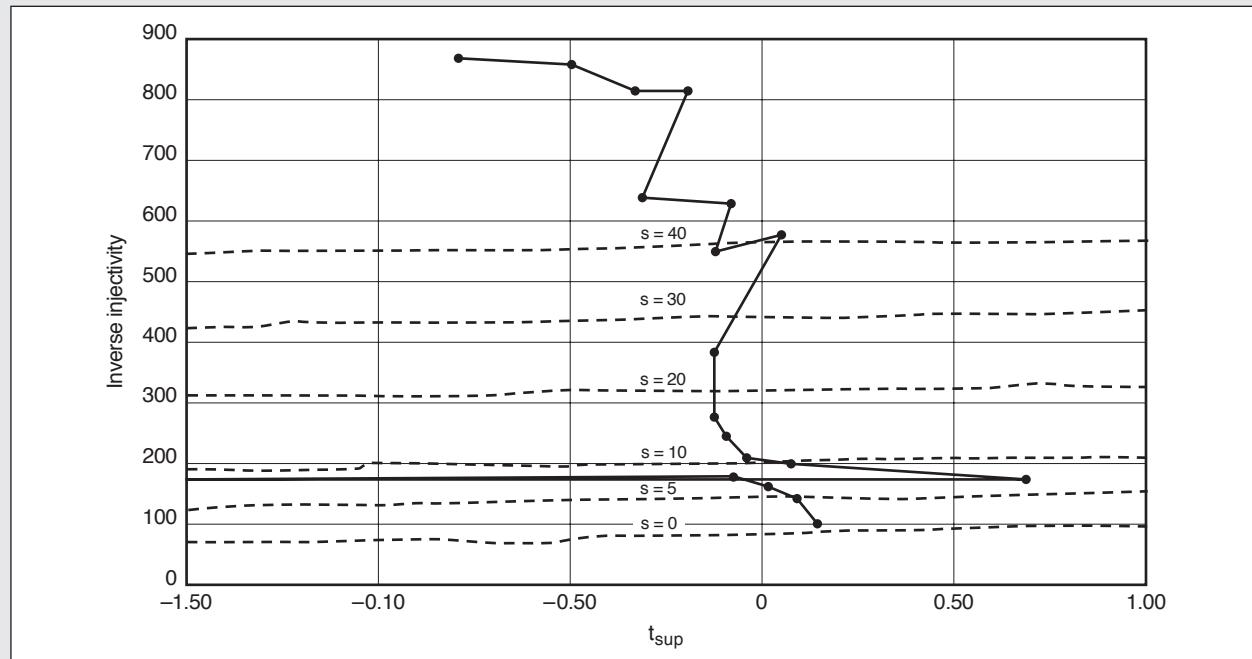
**Figure 20A-2.** Calculated bottomhole pressure (based on measured well pressure) and simulated pressure response with zero skin effect.



**Figure 20A-3.** Example skin effect evolution calculation.

## 20B. Example application of the Hill and Zhu method

An example of the Hill and Zhu (1994) method is shown in Fig. 20B-1 from the data in Tables 20B-1 and 20B-2 (Prouvost and Economides, 1989). As the skin effect changes during an acid treatment,  $\Delta p/q_i$  shifts from one line to another. The changing skin effect is monitored by comparing  $\Delta p/q_i$  versus the  $\Delta t_{sup}$  response. As with the Paccaloni (1979a, 1979b) technique, this job control graph is used in the field to monitor job performance. The advantage of this technique in comparison with the Paccaloni technique is that it includes transient effects caused by injection rate changes.



**Figure 20B-1.** Inverse injectivity plot using the Hill and Zhu (1994) technique and data from Tables 20B-1 and 20B-2.

**Table 20B-1. Well parameters used in example application of the Hill and Zhu (1994) method (Prouvost and Economides, 1989).**

Parameter	Value
$k$	80 md
$h$	253 ft
$\mu$	1 cp
$r_w$	0.51 ft
$\phi$	0.2
$B$	1.2 RB/STB
$c_t$	$10^{-5}$ psi $^{-1}$
$p_i$	2750 psi
$q_i$	2 bbl/min
$s_o$	40

**Table 20B-2. Injection data for example application of the Hill and Zhu (1994) method (Prouvost and Economides, 1989).**

Stage	Fluid	Time (hr)	Time (min)	$q_i$ (bbl/min)	$p_{it}$ (psi)
1	Water	0.15	9	2	4500
2	Water	0.3	18	2	4480
3	Water	0.45	27	2	4400
4	Xylene	0.6	36	2	4390
5	Xylene	0.75	45	2.5	4350
6	Xylene	0.9	54	2.4	4270
7	Xylene	1.05	63	2.7	4250
8	15% HCl	1.2	72	2.5	4200
9	15% HCl	1.35	81	3.2	3970
10	3% HCl-12% HF	1.5	90	3.7	3800
11	3% HCl-12% HF	1.65	99	4.1	3750
12	3% HCl-12% HF	1.8	108	4.4	3670
13	3% HCl-12% HF	1.9	114	4.2	3600
14	3% HCl-12% HF	2.1	126	0.9	2900
15	3% HCl-12% HF	2.25	135	5.6	3730
16	3% HCl-12% HF	2.4	144	5.6	3750
17	3% HCl-12% HF	2.55	153	5.6	3650
18	3% HCl-12% HF	2.7	162	5.7	3600
19	3% HCl-12% HF	2.85	171	5.8	3400

## 20-7. Limitations of matrix treatment evaluation techniques

Coupling the calculated bottomhole pressure (based on measured variables) and the anticipated reservoir response leads to calculation of the reservoir response. However, removal of damage by the stimulation fluid is not the only reason why the bottomhole pressure evolves during the course of a matrix stimulation treatment. It is important that the engineer is aware of the different components that can affect the reservoir pressure response.

- Reservoir response to changing injection rate

When fluid is injected at a constant rate into the reservoir, a pressure transient response develops that at early injection times is dominated by wellbore storage and skin effects. Later, the infinite-acting radial flow regime prevails, and usually for long injection times the effects of the outer reservoir boundaries are not felt. The same series of flow patterns develops when the rate is varied, and the overall response is obtained through the superposition principle. This is described in detail by Earlougher (1977).

- Different viscosities of the various treating fluids

During a typical stimulation treatment, several different fluids are pumped in sequence. Because these fluids have different rheologies and viscosities at reservoir conditions, the pressure response is affected.

- Temporary skin effects created by diverters or ball sealers

When a diversion technique is used, with either chemical diverters or ball sealers, a temporary skin effect is created that reduces the well injectivity and then affects the pressure evolution. Computation of the pseudoskin effect created by diverter cakes is detailed in Section 20-5.

- Other effects

Other effects can obscure the pressure response:

- Two-phase flow can occur when water-base fluid is injected into an oil or gas reservoir. The reduced mobility of the injected foreign fluid can complicate the pressure response.
- The reservoir can be multilayered with commingled flow, or it can be fissured. In the latter case, the fissures may be opened by injection.
- In carbonate reservoirs, the pressure response may be related to reaction kinetics.

- Removal of damage by reactive fluids

As a result of the stimulation and damage removal, the skin effect from damage should decrease during the course of the treatment. This is the component of the pressure response that should be isolated for a proper evaluation of the stimulation treatment.

Compared with this physical analysis, some of the techniques presented in this chapter pose additional limitations:

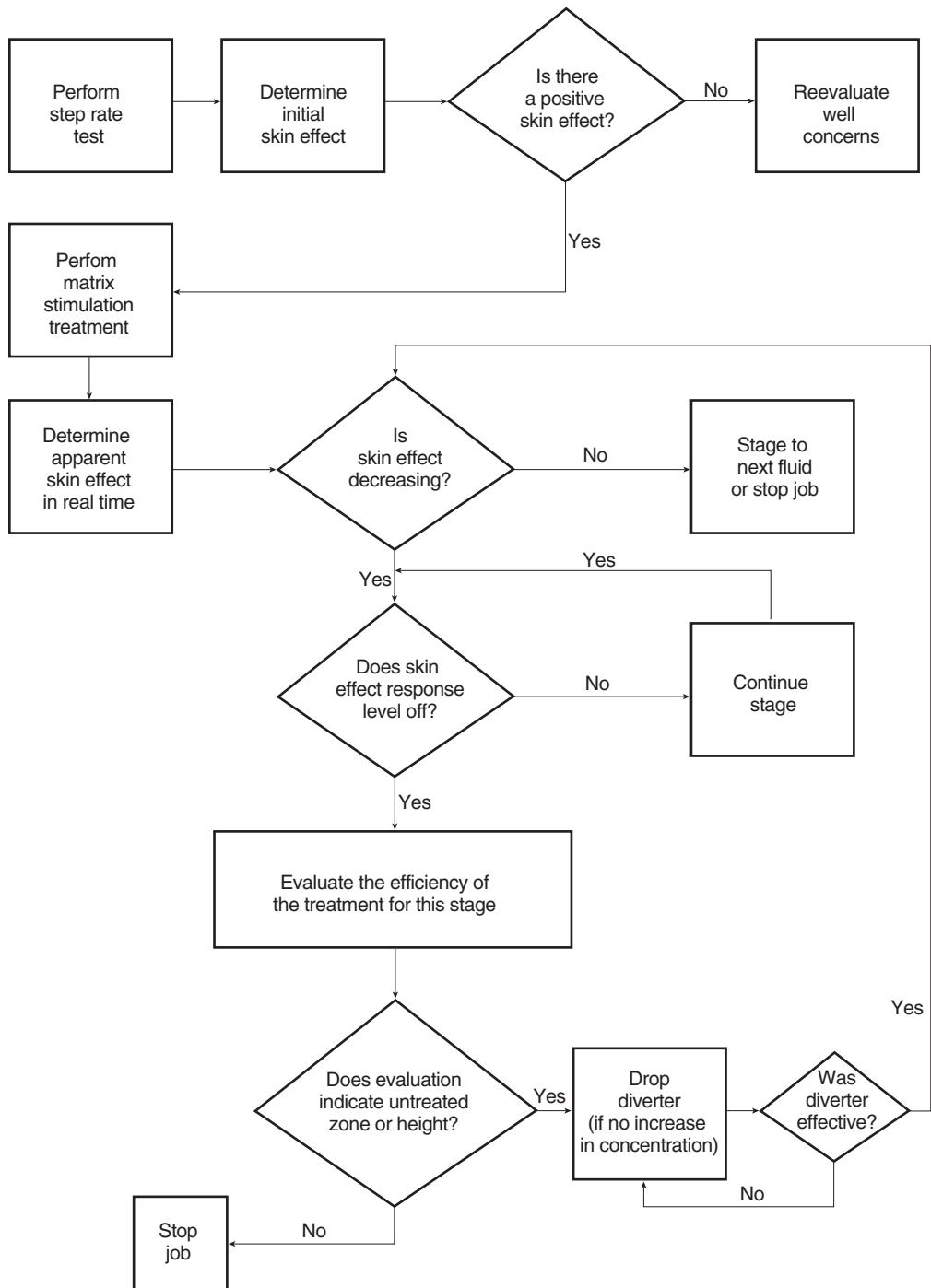
- The McLeod and Coulter (1969) method properly acknowledges the importance of transient reservoir pressure response, but it fails to provide a continuous, real-time measurement of the skin effect. It implicitly assumes that while one measurement is taken the evolution of the skin effect is frozen.
- Although the Paccaloni (1979a, 1979b) method enables continuous, real-time measurement of the skin effect for the duration of the treatment, it is limited by not properly accounting for transient phenomena. As a result, all transient phenomena occurring in the reservoir are interpreted as changes in the skin effect.

## 20-8. Treatment response diagnosis

Montgomery *et al.* (1995) described techniques that can be used during a treatment to provide several levels of diagnostics and interpretation. Figure 20-4 provides an overall schematic of how these diagnostics can be used. An example determination of a well stimulation candidate is provided in Sidebar 20C.

- Well diagnostics

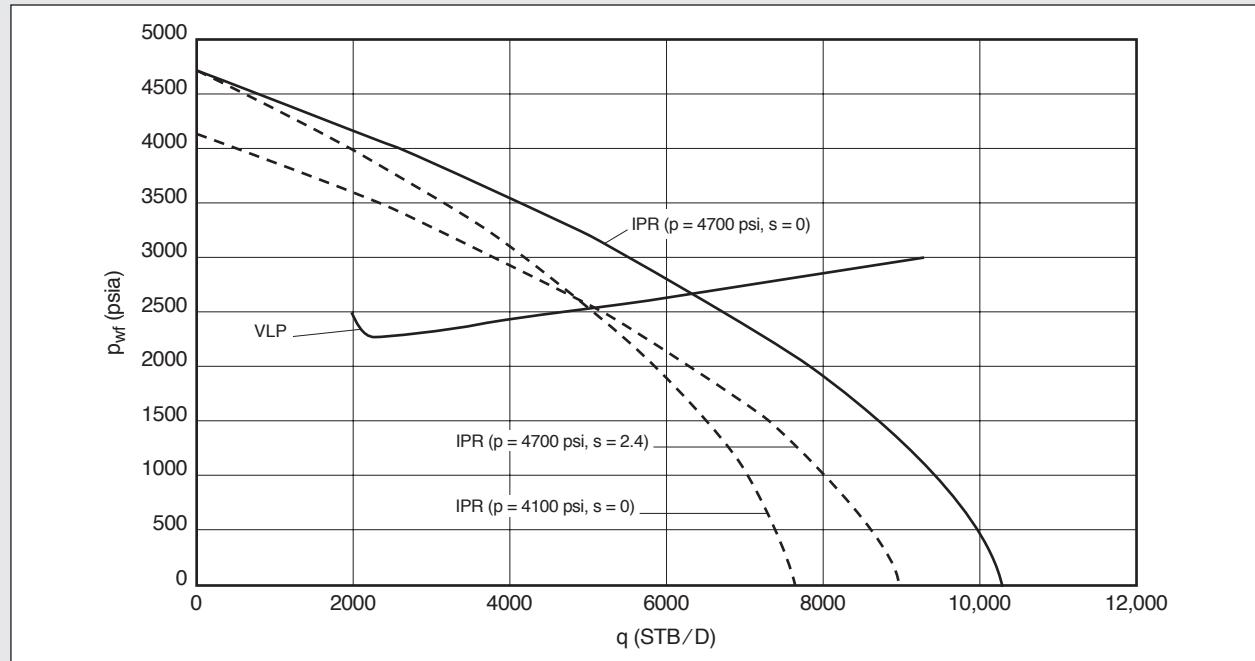
To determine if a well is a candidate for stimulation, a step rate or injectivity test is performed. A nonreactive fluid that is compatible with the formation is injected at various subfracturing rates, with the rate and pressure response carefully monitored. At a constant rate and pressure, a skin effect value can be calculated. When a new constant rate and pressure are achieved, a new skin effect is calculated. At the various rates and pressures the calculated skin effect value should be constant. If a shift is noted in the skin effect value, a new assumption for  $kh$  should be used until a constant value of skin effect is achieved. Although the calculated skin effect is an apparent skin effect, the test gives an indication of  $k_h$  and the skin effect. If the value of the skin effect is zero or less, the need for stimulation should be questioned. An analytical technique for the analysis of this type of step rate test is provided in Earlougher (1977).



**Figure 20-4.** Job treatment diagnosis.

## 20C. Production indications for matrix stimulation requirements

For this example, the well is in a two-phase reservoir with  $k = 50 \text{ md}$ ,  $h = 70 \text{ ft}$ ,  $B = 1.1 \text{ RB/STB}$ ,  $\mu = 0.8 \text{ cp}$ ,  $r_w = 0.328 \text{ ft}$  and  $\bar{p} = 4700 \text{ psi}$ . The drainage radius  $r_e$  is unknown but presumed to be at least 750 ft. A well test 6 months ago suggested zero skin effect. The original inflow performance relationship (IPR) curve (using Eq. 1-17) and the vertical lift performance (VLP) curve are drawn with solid lines on Fig. 20C-1. The original production rate was more than 6600 STB/D, but 6 months later dropped to less than 5150 STB/D. The question is whether this well is a stimulation candidate.



**Figure 20C-1.** Deliverability of the producing system.

### Solution

From the VLP curve, the flowing bottomhole pressure should be about 2550 psi (for  $q = 5150 \text{ STB/D}$ ). Assuming that the average reservoir pressure remains approximately equal to 4700 psi, then from Eq. 1-17 a skin effect equal to 2.4, represented by one of the dashed IPR curves on Fig. 20C-1, would result in this production performance. However, the same performance can be observed with zero skin effect but with the reservoir pressure declining to about 4100 psi. This is shown by the second dashed IPR curve in Fig. 20C-1. Clearly, this example shows the necessity of well management and testing for the appropriate production engineering decision (i.e., deciding whether the well is damaged and requires stimulation or whether the well drainage area is limited).

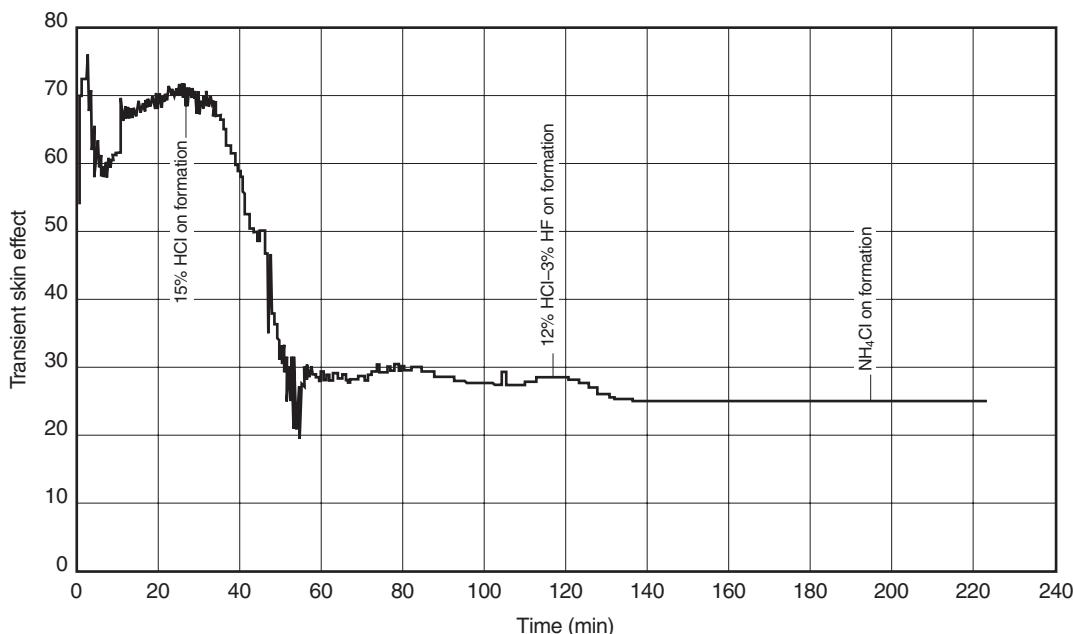
### Treatment optimization

The shape and period of the treatment response curve provide a number of clues about the treatment. Figure 20-5 is an acidizing response curve from a water injection well (Montgomery *et al.*, 1995). The relevant parameters used to interpret this curve are  $\phi = 22\%$ ,  $h = 33 \text{ ft}$  (from a step rate interpretation), average flow rate  $q_{ave} = 1.2 \text{ bbl/min}$  and  $r_w = 0.178 \text{ ft}$ .

From this plot the following conclusions can be drawn:

- Damage mechanism—The damage is clearly removable by hydrochloric acid (HCl). Mud acid does not have an effect. Carbonate scale or iron oxide damage are the most plausible.

- Treatment volume—Most of the damage was removed by the first one-third of the HCl pumped. This is in the time period from 27 to 60 min. The volume used to remove this damage is  $33 \text{ min} \times 1.2 \text{ bbl/min} \approx 40 \text{ bbl}$ . Using the 33-ft height determined from a step rate test, the damage was removed by a treatment of approximately 50 gal/ft.
- Damage radius—Using a porosity equal to 0.22, the radius of formation damage  $r_s$  is 3.26 ft. This ignores residual water saturation and assumes that 100% of the pore volume is displaced.
- Treatment improvement—On the basis of post-treatment spinner surveys, it was determined that only about one-third of the 100-ft perforated interval was treated. To improve effectiveness, the use



**Figure 20-5.** Example matrix acid treatment response curve (Montgomery et al., 1995).

of a diverter is warranted. In addition, the use of hydrofluoric acid (HF) in this well only increases the cost of the treatment, without any measurable stimulation benefit.

## 20-9. Post-treatment evaluation

Several other techniques are available to evaluate the effectiveness of matrix stimulation treatments. In addition to the techniques described in this section, pre- and postbuildup tests and production logging techniques as described in Chapters 1<sup>†</sup> and 2<sup>†</sup> can be used to evaluate acid treatments. It should always be remembered that the primary criterion for a treatment is the economic rather than the technical success.

### 20-9.1. Return fluid analysis

Almond *et al.* (1990) showed that monitoring the ionic content of returned fluids following acidizing treatments can provide insight into the actual chemical acid-spending processes downhole. The mass balance of the injected and returned fluids and the relative percent of silicate reprecipitation allow the determination of relative spending levels of various acids on the formation and well scale. Table 20-2 is an example of the results that can be extracted from this type of analysis. The table shows the concentration of aluminum and silicon contained in the returned fluids from two wells in the same formation.

Comparison of the actual Si and Al concentrations with the theoretical Si and Al concentrations expected from the volume percent of HF indicates that severe secondary clay reaction precipitation occurred. Much less Si and Al were observed in the return samples than expected from the mass-balance equations. On the basis of the tertiary reaction kinetic work of Gdanski (1996) as described in Chapter 15, future jobs should be conducted with higher HCl to HF ratios than the 6.5–0.5 used for these treatments to minimize secondary precipitation problems.

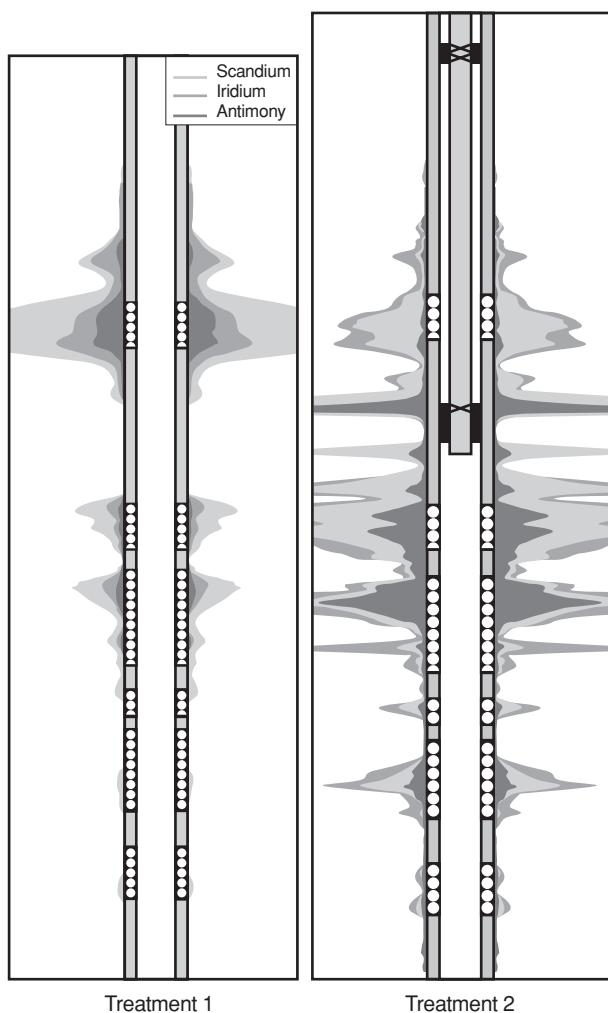
### 20-9.2. Tracer surveys

The use of various radioactive tracers placed strategically in the fluid or with the diverter can provide insight on the effectiveness of matrix treatments. Figure 20-6 shows a log for two treatments placed in the same well. The treatments were into a limestone formation perforated at 4 shots per foot (spf) at a depth of 6,902 to 6,982 ft. The first treatment was a 6,000-gal, three-stage treatment (2,000 gal/stage) diverted with rock salt and pumped at a rate of 7 bbl/min. The acid was traced with liquid <sup>46</sup>scandium. The first 1,000-lbm rock salt diverter stage was tagged with <sup>192</sup>iridium, and the second 1,000 lbm of rock salt was tagged with <sup>124</sup>antimony. The log indicates that the diverter stages were ineffective and that the thief zone at the top took the majority of the treatment.

<sup>†</sup> See *Reservoir Stimulation Third Edition* (SMP-7075)  
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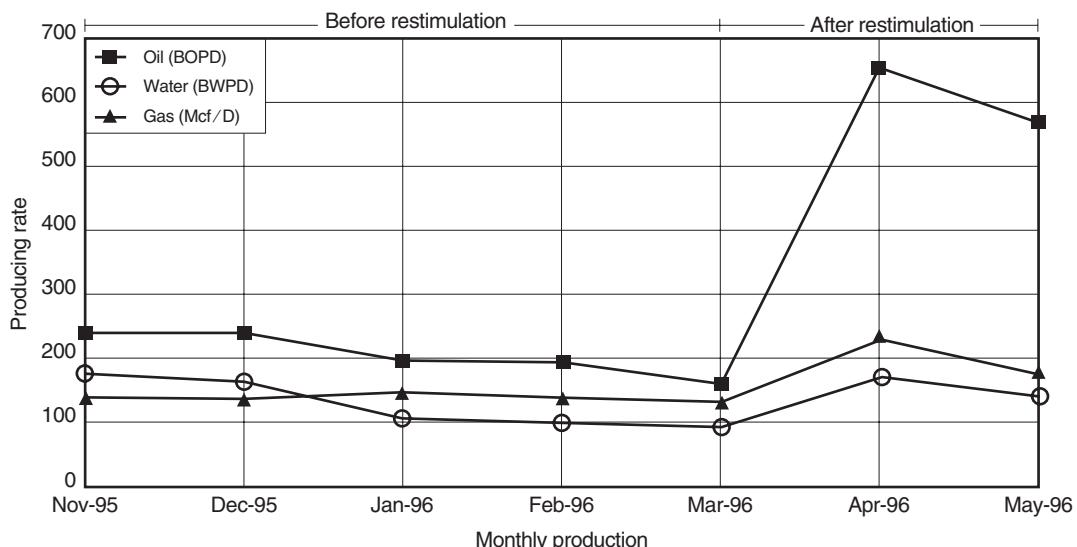
**Table 20-2. Example acid flowback analysis showing aluminum and silicon concentrations in returned fluids (from Almond *et al.*, 1990).**

Well	HF (%)	Flowback Concentration (mg/L)		Theoretical Concentration (mg/L)		Si:Al
		Si	Al	Si	Al	
1	16.5	216	2560	1311	15,543	0.08:1
1	12.1	190	1700	1573	14,070	0.11:1
1	7.5	142	990	1903	13,270	0.14:1
1	3.7	112	312	3060	8,525	0.35:1
1	2.5	102	117	4064	4,661	0.84:1
1	0.4	39	6	9512	1,415	6.5:1
2	7.1	162	675	2270	9,450	0.23:1
2	18.5	60	3810	325	20,630	0.015:1



**Figure 20-6.** Tracer scan comparison of two matrix acid treatments on the same well treatment (courtesy of ProTechnic International, Inc.).

A second three-stage treatment was attempted in which 4,500 gal of acid was staged (1,000, 1,000 and 1,500 gal/stage) by placing rock salt between the stages. In the second treatment the upper thief zone was isolated mechanically by placing tubing and a packer at 6,886 ft. The first 1,000 gal of acid was traced with <sup>192</sup>iridium, the second 1,000 gal with <sup>46</sup>scandium and the third 1,500 gal with <sup>124</sup>antimony. In this case, much better placement of the acid was achieved, indicating that mechanical isolation was much more effective than chemical diversion. The scan also indicates that the rock salt dropped at the end of the second stage was effective in diverting into a lower zone. It would also appear that there was some transfer of acid around the packer into the upper zone. Explanations for this are a poor cement job, poor packer efficiency or a fractured formation. The postproduction curves for the second treatment are shown in Fig. 20-7.



**Figure 20-7.** Results of the second treatment based on use of tracers to evaluate the effectiveness of the primary acid treatment (courtesy of ProTechnic International, Inc.).

## 20-10. Conclusions

Methods to assess the effectiveness of matrix stimulation treatments have been sought over the years. The low overall cost and “low technology” of these treatments usually preclude the justification of comprehensive pretreatment and post-treatment well tests.

Several real-time skin effect evolution techniques are presented in this chapter. The recent ones enable definitive calculation of the initial value of the skin effect and its evolution during injection, taking into account pressure transients and appropriate reservoir models. The efficiency of the stimulation treatment may then be assessed in real time. Changes in the design and optimum termination of the injection are therefore possible.

Several techniques for evaluating the effectiveness of matrix stimulation treatments are also presented. These include the use of pre- and postbuildup tests, production logging, tracer scans, fluid flowback analysis and comparison of inflow performance relationship (IPR) curves.

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# Reservoir Stimulation Nomenclature

$a$	Prats' relative capacity parameter	$b_{fD}$	dimensionless fracture width
$a$	Archie constant	$b_{lf}$	linear flow fracture width
$a$	ellipse axis, ft, m	$b_M$	Mayerhofer <i>et al.</i> (1993) method intercept
$a$	viscosity degradation coefficient	$b_N$	Nolte method intercept
$a$	intermediate area, ft <sup>2</sup> , m <sup>2</sup>	$b_s$	damage extent normal to the fracture plane, ft, m
$a_c$	length scale characteristic	$B$	formation volume factor, RB/STB, res-ft <sup>3</sup> /scf, res-m <sup>3</sup> /m <sup>3</sup>
$a_{sH,max}$	horizontal axis of the maximum damaged ellipse, ft, m	$B$	Skempton pore pressure coefficient
$a_{sH,min}$	horizontal axis of the minimum damaged ellipse, ft, m	$B$	ratio of the inner cup radius to bob radius
$a_{sV,max}$	vertical axis of the maximum damaged ellipse, ft, m	$B_g$	formation volume factor for gas, res-ft <sup>3</sup> /scf, res-m <sup>3</sup> /m <sup>3</sup>
$a_{sV,min}$	vertical axis of the minimum damaged ellipse, ft, m	$B_o$	formation volume factor for oil, RB/STB, res-m <sup>3</sup> /m <sup>3</sup>
$a_X$	chemical activity of species $X$	$B_w$	formation volume factor for water
$A$	area, ft <sup>2</sup> , acre, m <sup>2</sup>	$c_f$	fracture compliance
$A_{BL}$	representative formation property in the boundary layer	$c_f$	pore compressibility, psi <sup>-1</sup> , bar <sup>-1</sup>
$A_c$	acid capacity number	$c_g$	compressibility of gas, psi <sup>-1</sup> , bar <sup>-1</sup>
$A_e$	area at the end of an interval	$c_o$	compressibility of oil, psi <sup>-1</sup> , bar <sup>-1</sup>
$A_{elas}$	elastic area	$c_o$	borate foam viscosity adjustment factor
$A_{etch}$	acid-etched area	$c_t$	total compressibility, psi <sup>-1</sup> , bar <sup>-1</sup>
$A_f$	fracture face surface area, ft <sup>2</sup> , m <sup>2</sup>	$c_{tf}$	fracture compressibility, psi <sup>-1</sup> , bar <sup>-1</sup>
$A_{fso}$	fracture area at screenout, ft <sup>2</sup> , m <sup>2</sup>	$c_w$	compressibility of water, psi <sup>-1</sup> , bar <sup>-1</sup>
$A_{ik}$	influence function	$C$	wellbore storage, bbl/psi, m <sup>3</sup> /bar
$A_L$	leakoff area	$C$	proppant concentration, ft <sup>3</sup> /ft <sup>3</sup> , m <sup>3</sup> /m <sup>3</sup>
$A_{PZ}$	representative formation property in the pay zone	$C$	chemical concentration, mol/L
$A_T$	critical transitional pore size	$C$	constrained modulus, psi, bar, Pa
$b$	y-axis intercept for spurt	$C$	discharge coefficient
$b$	channel width	$C$	rock type and grain size constant
$b$	linear regression constant	$C$	shape factor accounting for wellbore curvature
$b$	slope of log-log plot of net pressure versus time	$C^*$	critical overlap concentration, lbm/1,000 gal, dL/g
		$C_A$	reservoir geometric shape factor
		$C_A$	acid concentration

$C_c$	compressibility control leakoff coefficient, ft/ min <sup>1/2</sup> , m/s <sup>1/2</sup>	$C_w$	wall or filter-cake fluid-loss coefficient, ft/min <sup>1/2</sup> , m/s <sup>1/2</sup>
$C_{ce}$	effective reservoir-controlled fluid-leakoff coefficient, ft/min <sup>1/2</sup> , m/s <sup>1/2</sup>	$C_W$	acid concentration at solid/liquid interface
$C_{CO}$	total interface concentration of carbonate species	$C_{wall}$	surface acid concentration
$C_{cv}$	combined leakoff coefficient, ft/min <sup>1/2</sup> , m/s <sup>1/2</sup>	$C_{wcv}$	total leakoff coefficient, ft/min <sup>1/2</sup> , m/s <sup>1/2</sup>
$C_d$	dimensionless discharge coefficient	$C_0$	acid concentration at capillary inlet
$C_D$	dimensionless wellbore storage coefficient	$C_1$	external phase constant
$C_{div}$	concentration of diverter particles, lbm/gal, kg/ m <sup>3</sup>	$CF$	concentration factor
$C_{div}'$	net concentration of diverter particles after dissolution effects, lbm/gal, kg/m <sup>3</sup>	$d$	diameter, in., m
$C_{drag}$	drag coefficient	$d$	distance, ft, in., m
$C_{dyn}$	dynamic constrained modulus, psi, bar, Pa	$d_{prop}$	proppant particle diameter, in., m
$C_{eqm}$	equilibrium concentration	$d_{sol}$	solid particle diameter, in., m
$C_{fD}$	dimensionless fracture conductivity	$d_{tbg}$	tubing diameter, in., m
$C_{fDapp}$	apparent dimensionless fracture conductivity	$D$	diameter, in., m
$C_{fD,opt}$	optimal dimensionless fracture conductivity	$D$	distance, ft, in., m
$C_{fD,true}$	actual dimensionless fracture conductivity	$D$	turbulence coefficient
$C_{gel}$	gel mass concentration in fluid	$D_A$	diffusion constant, cm <sup>2</sup> /s
$C_H$	shape factor	$D_e$	molecular diffusion coefficient, cm <sup>2</sup> /s
$C_{HF}$	concentration of hydrofluoric acid	$D_{eff}$	effective acid diffusion coefficient, cm <sup>2</sup> /s
$C_i$	reactant concentration at the solid/liquid interface, mol/L	$D_H$	effective acid diffusion coefficient, ft <sup>2</sup> /s, m <sup>2</sup> /s
$C_L$	leakoff or fluid-loss coefficient, ft/min <sup>1/2</sup> , m/s <sup>1/2</sup>	$D_p$	hydraulic diameter, in., m
$C_o$	rock cohesion, psi, bar, Pa	$D_p$	pipe inner diameter, in., m
$C_o$	initial reactant concentration	$D_{pe}$	perforation diameter, in., m
$C_p$	product concentration	$D_w$	effective diffusion coefficient for reaction products, cm <sup>2</sup> /s
$C_{pfl}$	fluid heat capacity	$Da$	wire diameter, in., m
$C_{pi}$	product concentration at the solid/liquid interface, mol/L	$Da_{mt}$	Damköhler number
$C_R$	general reservoir-controlled leakoff coefficient, ft/min <sup>1/2</sup> , m/s <sup>1/2</sup>	$Da_{rxn}$	mass-transfer-limited Damköhler number
$C_{RD}$	dimensionless reservoir conductivity	$De$	reaction-rate-limited Damköhler number
$C_t$	combined fluid-loss coefficient, ft/min <sup>1/2</sup> , m/s <sup>1/2</sup>	$DR$	Deborah number
$C_v$	viscosity-controlled leakoff coefficient, ft/min <sup>1/2</sup> , m/s <sup>1/2</sup>	$E$	Young's modulus, psi, bar, Pa
$C_{ve}$	effective filtrate-controlled leakoff coefficient, ft/ min <sup>1/2</sup> , m/s <sup>1/2</sup>	$E'$	plane strain modulus, psi, bar, Pa
		$E_{av}$	average Young's modulus, psi, bar, Pa
		$E_{dyn}$	dynamic Young's modulus, psi, bar, Pa
		$E_f$	reaction rate constant
		$E_n$	effect of all previous time steps

$E_s$	secant Young's modulus, psi, bar, Pa	$G''$	viscous loss modulus, psi, bar, Pa
$E_t$	tangent Young's modulus, psi, bar, Pa	$G_c$	fluid-loss time function $G(\Delta t_D)$ at fracture closure
$E_t$	Young's modulus of a plastic material, psi, bar, Pa	$G_{dyn}$	dynamic shear modulus, psi, bar, Pa
$f$	friction factor	$G_e$	strain energy release rate
$f$	elastic influence function	$GR_{API}$	gamma ray value
$f_{aL}$	apparent length fraction	$h$	height, ft, m
$f_d$	drag coefficient	$h$	formation or reservoir thickness, ft, m
$f_{fL}$	ratio of fracture to loss volume during injection	$h$	hardening parameter
$f_{LS}$	volume fraction lost to spurt	$h$	heat transfer coefficient
$f_p$	pad volume fraction	$h_{cp}$	height at the center of perforations, ft, m
$f_{pad}$	pad volume fraction	$h_D$	dimensionless height
$f_s$	slurry volume fraction	$h_f$	fracture height, ft, m
$f_v$	volume fraction	$h_{fD}$	ratio of the leakoff area to the characteristic length
$f_w$	water fractional flow	$h_{fo}$	initial fracture height, ft, m
$f_\kappa$	spurt fraction	$h_L$	permeable or fluid-loss height, ft, m
$F$	fill fraction	$h_{pay}$	height of the pay zone, ft, m
$F$	formation factor	$h_s$	penetration into bounding layer, ft, m
$F$	force, lbf, N	$h_{wD}$	dimensionless completion thickness
$F$	fracture development function	$H$	depth, ft, m
$F_b$	ratio of wellbore width or net pressure	$i$	injection rate
$F_c$	critical load	$i$	interest rate
$F_i$	surface flux at the $i$ th time step	$I$	diffusion flux
$F_L$	linear flow function	$I$	influence function
$F_{meas}$	fracture development function for measured data	$I_{ani}$	index of horizontal-to-vertical permeability anisotropy
$F_{sim}$	fracture development function for simulated data	$J$	acid flux
$F_0$	surface flux at time zero	$J$	pseudosteady-state productivity index
$g$	acceleration of gravity, ft/s <sup>2</sup> , m/s <sup>2</sup>	$J_F$	fractured well productivity index
$g(\Delta t_D)$	dimensionless fluid-loss volume function	$J_H$	pseudosteady-state productivity index of horizontal well
$g_f$	fracture gradient, psi/ft, Pa/m	$J_{ideal}$	ideal productivity index
$g_0$	fluid-loss volume function	$J_o$	initial productivity index
$G$	shear modulus, psi, bar, Pa	$J_{real}$	real productivity index
$G(\Delta t_D)$	dimensionless fluid-loss time function	$J_V$	pseudosteady-state productivity index of vertical well
$G^*$	corrected value of $G$ -function at closure	$k$	permeability, mD
$G'$	elastic storage modulus, psi, bar, Pa		

$k_c$	damaged zone permeability, mD	$k_y$	minimum permeability directed perpendicular to the principal permeability axis, mD
$k_{cake}$	filter or diverter cake permeability, mD	$k_y$	permeability in the y direction, mD
$k_d$	dissociation constant	$k_z$	vertical permeability, mD
$k_f$	fracture permeability, mD	$k_0$	reaction rate constant at the reference temperature
$k_{fD}$	dimensionless fracture permeability	$K$	bulk modulus, psi, bar, Pa
$k_{fil}$	relative permeability of the formation to filtrate, mD	$K$	mass-transfer coefficient, cm/s
$k_f$	thermal conductivity of a fluid	$K$	equilibrium constant
$k_{foam}$	foam permeability, mD	$K$	coefficient of earth stress, dimensionless
$k_{fs}$	fracture permeability in the near-well skin effect zone, mD	$K$	empirical kinetic constant
$k_g$	gas effective permeability, mD	$K$	Mark-Houwink coefficient, dL/g
$k_h$	thermal conductivity, BTU/hr ft degF, J/s m degC	$K$	power law fluid rheology consistency coefficient, lbf-s <sup>n</sup> /ft <sup>2</sup>
$k_H$	horizontal permeability, mD	$K'$	power law effective consistency coefficient, lbf-s <sup>n</sup> /ft <sup>2</sup>
$k_{Hs}$	damaged horizontal permeability, mD	$K_a$	equilibrium constant of acid
$k_i$	initial permeability, mD	$K_{ads}$	equilibrium constant of the exothermic adsorption of molecules at surface reactive sites
$k_{near\ wellbore}$	near-wellbore friction proportionality constant	$K_c$	conditional equilibrium constant
$k_o$	oil effective permeability, mD	$K_c$	$G$ -plot slope correction factor for pressure-dependent leakoff
$k_o$	initial permeability, mD	$K_d$	dissociation constant
$k_{pf}$	perforation friction proportionality constant	$K_{dyn}$	dynamic bulk modulus
$k_r$	relative permeability, mD	$K_{eq}$	effective equilibrium constant
$k_r$	reservoir permeability, mD	$K_{foam}$	consistency coefficient for the foam phase
$k_r$	surface reaction rate constant, cm/s	$K_g$	mass-transfer coefficient
$k_{r,app}$	apparent reservoir permeability, mD	$K_I$	stress intensity factor, psi/in. <sup>1/2</sup> , bar/m <sup>1/2</sup>
$k_{rg}$	gas relative permeability, mD	$K_{Ic}$	critical stress intensity factor, psi/in. <sup>1/2</sup> , bar/m <sup>1/2</sup>
$k_{ro}$	oil relative permeability, mD	$K_{Ic}^{eff}$	effective fracture toughness, psi/in. <sup>1/2</sup> , bar/m <sup>1/2</sup>
$k_{rw}$	water relative permeability, mD	$K_{Ic}^{lag}$	critical stress intensity factor in the fluid lag region, psi/in. <sup>1/2</sup> , bar/m <sup>1/2</sup>
$k_s$	damaged permeability, mD	$K_{Ic-apparent}$	apparent fracture toughness, psi/in. <sup>1/2</sup> , bar/m <sup>1/2</sup>
$k_{sph}$	spherical permeability, mD	$K_{II}$	stress intensity factor at bottom fracture tip, psi/in. <sup>1/2</sup> , bar/m <sup>1/2</sup>
$k_V$	vertical permeability, mD		
$k_{Vs}$	damaged vertical permeability, mD		
$k_w$	water effective permeability, mD		
$k_x$	maximum permeability directed parallel to the principal permeability axis, mD		
$k_x$	permeability in the x direction, mD		

$K_{Iu}$	stress intensity factor at top fracture tip, psi/in. <sup>1/2</sup> , bar/m <sup>1/2</sup>	$m_{Gc}$	slope of the $G$ -plot at fracture closure, psi, bar, Pa
$K_o$	coefficient of earth pressure at rest, dimensionless	$m_{hl}$	linear flow slope of a horizontal well
$K_{pipe}$	consistency index for pipe flow, lbf-s <sup>n</sup> /ft <sup>2</sup>	$m_{lf}$	linear flow slope, psi/hr <sup>1/2</sup> , bar/hr <sup>1/2</sup>
$K_r$	reaction rate	$m_M$	Mayerhofer <i>et al.</i> (1993) method slope
$K_r$	temperature-dependent reaction rate constant	$m_n$	straight-line slope
$K_s$	bulk modulus of the solid constituents, psi, bar, Pa	$m_N$	Nolte method slope
$K_s$	solubility constant	$m_p$	match pressure, psi, bar, Pa
$K_{slot}$	consistency index for slot flow, lbf-s <sup>n</sup> /ft <sup>2</sup>	$m_{pp}$	spherical flow slope
$K_v$	consistency index for a concentric cylinder viscometer, lbf-s <sup>n</sup> /ft <sup>2</sup>	$m_{rf}$	radial flow slope, psi, bar, Pa
$l$	length, ft, in., m	$m_{3/4}$	slope of the $G$ -plot at the $\frac{3}{4}$ point, psi, bar, Pa
$l$	diverter cake thickness, ft, m	$M_{acid}$	moles of acid per unit rock face area
$l_d$	length of damaged zone, ft, m	$M_{gel}$	specific density of gel mass in the fluid
$l_p$	perforation channel length, ft, m	$M_v$	viscosity average molecular weight, g/mol
$L$	length, ft, m	$MW$	molecular weight, g/mol
$L$	fracture half-length, ft, m	$n$	number or order
$L$	horizontal well length, ft, m	$n$	index of time step
$L_{app}$	apparent of equivalent fracture penetration, ft, m	$n'$	power law fluid rheology behavior index, dimensionless
$L_e$	length to tip, ft, m	$n_e$	index of time step after shut-in
$L_p$	productive length, ft, m	$n_f$	power law exponent of the filtrate
$L_t$	length of the fracture tip region, ft, m	$n_{perf}$	number of perforations
$L_v$	length of filtrate-invaded zone, ft, m	$N_{DH}$	dimensionless cumulative recovery from a longitudinally fractured horizontal well
$m$	slope on semilogarithmic straight line, psi/cycle (oil), psi <sup>2</sup> /cycle or psi <sup>2</sup> /cp/cycle (gas)	$N_{DV}$	dimensionless cumulative recovery from a fractured vertical well
$m$	Archie constant	$N_p$	oil cumulative production, bbl, m <sup>3</sup>
$m$	linear regression constant	$N_{Re}$	Reynold's number
$m$	reaction rate order	$N_{Sc}$	Schmidt number
$m$	power law turbulence factor	$N_{Sh}$	Sherwood number
$m_{bf}$	bilinear flow slope, psi/hr <sup>1/4</sup> , bar/hr <sup>1/4</sup>	$N_\phi$	coefficient of passive stress
$m_c$	early-time slope used to compute the wellbore storage coefficient $C$	$p$	pressure, psi, bar, Pa
$m_{ef}$	linear flow slope in an elongated reservoir	$p$	reservoir pressure, psi, bar, Pa
$m_{epr}$	early pseudoradial flow slope	$p_b$	bubblepoint pressure, psi, bar, Pa
$m_G$	slope of the $G$ -plot, psi, bar, Pa	$p_{bh}$	borehole pressure, psi, bar, Pa
		$p_c$	constant confining pressure, psi, bar, Pa

$p_c$	closure pressure, psi, bar, Pa	$p_{net,fo}$	net pressure required for fissure opening, psi, bar, Pa
$p_c$	capillary pressure, psi, bar, Pa	$p_{net,max}$	maximum net pressure, psi, bar, Pa
$p_{cf}$	casing friction pressure, psi, bar, Pa	$p_{net,si}$	net pressure at shut-in, psi, bar, Pa
$p_{corr}$	pressure corrected for non-plane-strain contribution, psi, bar, Pa	$p_{net,so}$	net pressure at screenout, psi, bar, Pa
$p_{cp}$	pressure at center of the perforations, psi, bar, Pa	$p_o$	wellbore pressure, psi, bar, Pa
$p_D$	dimensionless pressure	$p_p$	far-field reservoir pressure, psi, bar, Pa
$p_D'$	dimensionless pressure derivative	$p_{pf}$	perforation friction, psi, bar, Pa
$p_{DLs}$	dimensionless pressure difference for pressure-dependent leakoff	$p_{pipe,friction}$	pipe friction pressure, psi, bar, Pa
$p_{dr}$	downstream restriction pressure, psi, bar, Pa	$p_{pwD}$	dimensionless pseudopressure
$p_{dsc}$	pressure downstream of the surface choke, psi, bar, Pa	$p_r$	reservoir pressure, psi, bar, Pa
$p_{dsv}$	pressure downstream of the safety valve, psi, bar, Pa	$p_s$	pressure at the outer bound of the damaged zone, psi, bar, Pa
$p_{D,up}$	dimensionless pressure for a uniform-pressure, fixed-length fracture	$p_{sc}$	standard condition pressure, psi, bar, Pa
$p_e$	constant outer reservoir pressure, psi, bar, Pa	$p_{sep}$	separator pressure, psi, bar, Pa
$p_f$	fissure or fracture pressure, psi, bar, Pa	$p_{sim}$	simulated pressure, psi, bar, Pa
$p_f$	fracturing fluid pressure, psi, bar, Pa	$p_{surf}$	surface pressure, psi, bar, Pa
$p_f$	far-field pore pressure, psi, bar, Pa	$p_{tf}$	tubing flowing pressure, psi, bar, Pa
$p_{fc}$	formation capacity	$p_{tip}$	net pressure at fracture tip for extension, psi, bar, Pa
$p_{fo}$	fissure opening pressure, psi, bar, Pa	$p_{ur}$	upstream restriction pressure, psi, bar, Pa
$p_h$	hydrostatic pressure, psi, bar, Pa	$p_{usv}$	pressure upstream of the safety valve, psi, bar, Pa
$p_{head}$	hydrostatic head of wellbore fluid, psi, bar, Pa	$p_{vapor}$	fluid vapor pressure, psi, bar, Pa
$p_i$	initial reservoir pressure, psi, bar, Pa	$p_w$	wellbore pressure, psi, bar, Pa
$p_{if}$	breakdown pressure for fracture initiation, psi, bar, Pa	$p_{wD}$	dimensionless wellbore pressure
$p_{inj}$	injection pressure, psi, bar, Pa	$p_{wf}$	bottomhole flowing pressure, psi, bar, Pa
$p_{ISI}$	instantaneous shut-in pressure, psi, bar, Pa	$p_{wf,ideal}$	ideal bottomhole flowing pressure, psi, bar, Pa
$p_{it}$	wellhead injection pressure, psi, bar, Pa	$p_{wf,real}$	real bottomhole flowing pressure, psi, bar, Pa
$p_{iw}$	bottomhole injection pressure, psi, bar, Pa	$p_{wfs}$	wellbore sandface flowing pressure, psi, bar, Pa
$p_m$	microannulus pressure, psi, bar, Pa	$p_{wh}$	wellhead flowing pressure, psi, bar, Pa
$p_m$	mud pressure in the wellbore, psi, bar, Pa	$p_{ws}$	bottomhole shut-in pressure, psi, bar, Pa
$p_{meas}$	measured pressure, psi, bar, Pa	$p_{1\ hr}$	pressure on extension of semilogarithmic straight line at $t = 1$ hr, psi, bar, Pa
$p_{net}$	net pressure, psi, bar, Pa	$p_{3/4}$	pressure at the $G$ -plot $\frac{3}{4}$ point, psi, bar, Pa
$p_{net,crit}$	critical net pressure, psi, bar, Pa	$Pe$	Peclet number

$PI$	productivity index, B/D/psi (oil), Mscf/D/psi (gas), m <sup>3</sup> /d/bar	$r_A$	rate of reactant consumption, mol/cm <sup>2</sup> /s
$PI_s$	damaged productivity index, B/D/psi (oil), Mscf/D/psi (gas), m <sup>3</sup> /d/bar	$r_{ac}$	stimulation radius, ft, m
$PV_{BT}$	number of pore volumes to breakthrough	$r_b$	acid bank radius, ft, m
$PV_{inj}$	number of pore volumes injected	$r_{bob}$	bob radius
$q$	flow rate, B/D (oil), Mscf/D (gas), m <sup>3</sup> /d	$r_{cup}$	cup radius
$q_{app}$	apparent flow rate, B/D, bbl/min, m <sup>3</sup> /d, m <sup>3</sup> /s	$r_D$	rate of surface reaction, mol/cm <sup>2</sup> /s
$q_{ave}$	average flow rate, B/D, bbl/min, m <sup>3</sup> /d, m <sup>3</sup> /s	$r_e$	reservoir radius, ft, m
$q_c$	flow rate in capillary pores	$r_{eH}$	radius of horizontal drainage ellipse formed around a horizontal well, ft, m
$q_c$	injection rate into core face	$r_f$	radial extent of foam bank, ft, m
$q_D$	dimensionless flow rate	$r_{feldspar}$	reaction rate of feldspar, mol feldspar/cm <sup>2</sup> /s
$q_{DND}$	dimensionless non-Darcy flow rate	$r_{HF}$	radial penetration of hydrofluoric acid, ft, m
$q_e$	flow at tip	$r_{hyd}$	hydraulic radius
$q_f$	volume rate of storage in a fracture	$r_i$	specific reaction rate of mineral $i$
$q_g$	gas production rate, Mscf/D, m <sup>3</sup> /d	$r_i$	inner radius
$q_i$	injection rate, B/D, bbl/min, m <sup>3</sup> /d, m <sup>3</sup> /s	$r_o$	outer radius
$q_{i,max}$	maximum injection rate, B/D, bbl/min, m <sup>3</sup> /d, m <sup>3</sup> /s	$r_p$	ratio of permeable area to fracture area
$q_L$	rate of fluid loss, B/D, bbl/min, m <sup>3</sup> /d, m <sup>3</sup> /s	$r_p$	probe radius
$q_{last}$	last flow rate, B/D, bbl/min, m <sup>3</sup> /d, m <sup>3</sup> /s	$r_{pD}$	dimensionless ratio of permeable area to fracture area
$q_{L,C}$	rate of fluid loss for reservoir-controlled leakoff, B/D, bbl/min, m <sup>3</sup> /d, m <sup>3</sup> /s	$r_{perf}$	perforation radius, in., m
$q_n$	leakoff rate from one wing through two faces, B/D, m <sup>3</sup> /s	$r_{quartz}$	reaction rate of quartz, mol quartz/cm <sup>2</sup> /s
$q_o$	initial flow rate, B/D, m <sup>3</sup> /s	$r_s$	radius of damaged or displaced section, ft, m
$q_o$	oil production rate, B/D, m <sup>3</sup> /s	$r_v$	fraction of well drainage volume occupied by the crest at water breakthrough
$q_{o,max}$	maximum oil production rate at two-phase flow, B/D, m <sup>3</sup> /s	$r_w$	wellbore radius, ft, m
$q_{perf}$	flow entering a perforation	$r_w'$	effective or apparent wellbore radius, ft, m
$q_{RT}$	total reservoir production rate, B/D, m <sup>3</sup> /d	$r_{wD}'$	dimensionless effective wellbore radius
$q_s$	damaged flow rate	$r_{wh}$	wormhole radius
$q_T$	total injection rate	$R$	pore radius
$q_{tot}$	constant total injection rate	$R$	reaction rate
$q_w$	water production rate, B/D, m <sup>3</sup> /d	$R$	universal gas constant, psi ft <sup>3</sup> /mol °R, bar m <sup>3</sup> /mol K
$Q_p$	cumulative production, B/D, m <sup>3</sup> /d	$R$	fracture radius, ft, m
$r$	radial distance, ft, m	$R_A$	rate of appearance of reactant
$r$	reaction rate	$R_{At}$	rate of reactant consumption at the tip
		$R_B$	rate of mineral dissolution

$R_{cake}$	diverter cake resistance, $\text{m}^{-1}$	$s_p$	skin effect due to perforations, dimensionless
$R_{eff}$	effective radius, ft, m	$s_t$	total skin effect, dimensionless
$R_f$	radial fracture radius, ft, m	$s_V$	vertical skin effect, dimensionless
$R_i$	overall reaction rate of mineral $i$	$s_{wb}$	wellbore skin effect, dimensionless
$R_{mf}$	resistivity of the mud filtrate, ohm-m	$s_x$	vertical effects skin effect, dimensionless
$R_o$	resistivity of 100% water-saturated formation, ohm-m	$s_\theta$	skin effect due to slant, dimensionless
$R_p$	pressure-difference curve, dimensionless	$S$	surface area
$R_{so}$	solution-gas/oil ratio	$S_F$	surface area per unit volume of solids for fast-reacting minerals
$R_{sw}$	solution-gas/water ratio	$S_g$	gas-phase fluid saturation, fraction
$R_t$	true formation resistivity, ohm-m	$S_i$	reactive surface area of mineral $i$
$R_w$	resistivity of formation water, ohm-m	$S_o$	oil-phase fluid saturation, fraction
$R_{xo}$	resistivity of the flushed zone, ohm-m	$S_{oi}$	initial oil saturation, fraction
$R_0$	filter-cake resistance, $\text{s}\cdot\text{m}^{-1}$	$S_{or}$	residual oil saturation, fraction
$R_{0,app}$	apparent filter-cake resistance, $\text{s}\cdot\text{m}^{-1}$	$S_p$	spurt-loss coefficient, $\text{gal}/\text{ft}^2, \text{m}^3/\text{m}^2$
$s$	skin effect, dimensionless	$S_{RE}$	rock embedment strength
$s$	reactive surface area	$S_S$	surface area per unit volume of solids for slow-reacting minerals
$s_c$	skin effect from partial penetration, dimensionless	$S_w$	water saturation, fraction
$s_{c+\theta}$	skin effect due to partial penetration and slant, dimensionless	$S_{wc}$	connate water saturation, fraction
$s_{cake}$	temporary skin effect due to diverter cake, dimensionless	$S_{wi}$	irreducible water saturation, fraction
$s_d$	skin effect due to damage, dimensionless	$t$	time, day, hr, min, s
$(s_d)_o$	perforation skin effect in openhole, dimensionless	$t^*$	reduced time
$(s_d)_p$	perforation skin effect due to perforations terminating outside the damaged zone, dimensionless	$t_a$	pseudotime
$s_e$	vertical eccentricity skin effect, dimensionless	$t_{aD}$	dimensionless pseudotime
$s_f$	skin effect while flowing at pseudoradial conditions, dimensionless	$t_{BT}$	time of water breakthrough, hr
$s_f$	fracture stiffness, ft/psi/m	$t_c$	closure time, min
$s_f$	skin effect due to a fracture, dimensionless	$t_{cD}$	dimensionless closure time
$s_{foam}$	foam skin effect, dimensionless	$t_D$	dimensionless time
$s_{fs}$	fracture face damage skin effect, dimensionless	$t_{DA}$	dimensionless time referenced to reservoir drainage area
$s_H$	plane-flow skin effect, dimensionless	$t_{Dblf}$	dimensionless time at start of formation linear flow regime
$s_o$	initial skin effect, dimensionless	$t_{Debf}$	dimensionless time at end of bilinear flow regime
$s_o$	constant skin effect, dimensionless	$t_{Defl}$	dimensionless time at which fracture linear flow behavior ends
		$t_{Delf}$	dimensionless time at which formation linear flow behavior ends

$t_{dep}$	time of departure from flow regime trend	$T_i$	fluid temperature at the fracture mouth, degF, degC
$t_{D,knee}$	dimensionless knee time for the pressure derivatives	$T_{inlet}$	temperature at inlet, degF, degC
$t_{Dr_w'}$	dimensionless time referenced to the effective wellbore radius $r_w'$	$T_{knee}$	dimensionless knee time for after-closure analysis
$t_{Dx_f}$	dimensionless fracture time	$T_o$	offset temperature, degF, degC
$t_e$	time at end of pumping or injection, min, s	$T_o$	tensile strength, psi, bar, Pa
$t_{end}$	time of the end of dual-porosity behavior	$T_p$	dimensionless time at the end of pumping for after-closure analysis
$t_{exp}$	time of fracture opening and initial fluid exposure	$T_r$	reservoir temperature, degF, degC
$t_i$	injection time	$T_{ref}$	reference temperature, degF, degC
$t_i$	time at the end of the $i$ th step	$T_s$	wire strength, lbf/ft
$t_{knee}$	knee time for the crossing of pressure derivatives	$T_{sc}$	standard condition temperature, degF, degC, K
$t_{min}$	minimum time	$TR$	tool response
$t_n$	time at the end of step $n$ , s	$u$	velocity, ft/s, cm/s
$t_{on}$	time of onset of dual-porosity behavior	$u$	acid flux
$t_p$	producing time, hr	$u_g$	volumetric flux of gas
$t_p$	pumping or injection time, hr	$u_L$	leakoff velocity, ft/s, cm/s
$t_P$	compressional wave arrival time	$u_P$	$P$ -wave velocity, ft/s, m/s
$t_{pss}$	time to pseudosteady state, hr	$u_r$	rising velocity of spherical particles in a fluid, ft/s, cm/s
$t_r$	time at reference point $r$	$u_S$	$S$ -wave velocity, ft/s, m/s
$t_S$	time of tip screenout or injection without screenout	$u_{sol}$	solid particle velocity, ft/s, cm/s
$t_S$	shear wave arrival time	$u_t$	terminal settling velocity, ft/s, m/s
$t_{so}$	time at screenout	$u_{tip}$	fracture tip velocity, ft/s, cm/s
$t_{sp}$	spurt time	$u_w$	volumetric flux of water
$t_0$	reference time	$u_\infty$	terminal proppant settling velocity, ft/s, m/s
$t_{oD}$	dimensionless ratio of time to pumping time	$v$	flow velocity, ft/s, cm/s
$T$	temperature, degF, degC, K	$\hat{v}$	specific volume of foam
$T$	absolute temperature, °R, K	$v_{A,x}$	Fick's law for the velocity of species A
$T$	dimensionless time for after-closure analysis	$v_c$	damaged zone velocity, ft/s, cm/s
$T$	constant for tectonic effects on stress	$v_{fall}$	settling rate, ft/s, cm/s
$T$	wire tension, lbf/ft	$\hat{v}_l$	specific volume of the base liquid
$T_d$	dead weight, lbf	$v_L$	fluid-loss velocity, ft/min
$T_D$	dimensionless temperature	$v_L$	specific fluid-loss volume
$T_f$	flowing temperature, degF, degC	$v_m$	matrix velocity, ft/s, cm/s
$T_{fl}$	fluid temperature, degF, degC	$v_x$	average fluid velocity along the fracture length, ft/s, cm/s

$V$	volume, ft <sup>3</sup> , m <sup>3</sup>	$w_{max}$	maximum width, ft, m
$V_{ac}$	acid volume injected, ft <sup>3</sup> , m <sup>3</sup>	$w_{max,p}$	maximum fracture width at the end of pumping, ft, m
$V_f$	fracture volume, ft <sup>3</sup> , m <sup>3</sup>	$w_{max,si}$	maximum fracture width immediately after shut-in, ft, m
$V_f$	fluid volume	$w_n$	average fracture width at time step $n$ , ft, m
$V_F$	volume of fast-reacting minerals	$w_o$	wellbore width, ft, m
$V_{fp}$	fracture volume at the end of pumping, ft <sup>3</sup> , m <sup>3</sup>	$w_p$	propped width, ft, m
$V_{fso}$	fracture volume at screenout, ft <sup>3</sup> , m <sup>3</sup>	$w_{p-eff}$	effective propped width, ft, m
$V_{HC}$	volume of hydrocarbons, ft <sup>3</sup> , m <sup>3</sup>	$w_{so}$	width at screenout, ft, m
$V_{HCl}$	volume of hydrochloric acid, ft <sup>3</sup> , m <sup>3</sup>	$w_w$	width at the wellbore, ft, m
$V_{HF}$	volume of hydrofluoric acid, ft <sup>3</sup> , m <sup>3</sup>	$W_{elas}$	elastic energy stored in a solid
$V_i$	volume of fluid injected, bbl, gal, m <sup>3</sup>	$W_{ext}$	potential energy of exterior forces
$V_{iso}$	fluid volume injected at screenout, bbl, gal, ft <sup>3</sup> , m <sup>3</sup>	$W_i$	weighting factors
$V_L$	leaked-off fluid volume, bbl, gal, m <sup>3</sup>	$W_{kin}$	kinetic energy
$V_{L,C}$	volume of fluid lost due to filtration, bbl, gal, m <sup>3</sup>	$W_s$	energy dissipated during propagation of a crack
$V_{Lp}$	leaked-off volume during pumping, bbl, m <sup>3</sup>	$x$	linear distance, ft, m
$V_{Lp,C}$	volume of fluid lost due to filtration at the end of pumping, bbl, gal, m <sup>3</sup>	$x_e$	well drainage dimension, ft, m
$V_{Ls}$	volume of fluid lost during shut-in, bbl, gal, m <sup>3</sup>	$x_{e,opt}$	optimal well spacing, ft, m
$V_{L,S}$	fluid-loss component due to spurt, bbl, gal, m <sup>3</sup>	$x_f$	productive fracture half-length, ft, m
$V_{Ls,C}$	volume of fluid lost due to filtration during shut-in, bbl, gal, m <sup>3</sup>	$x_{fa}$	apparent fracture half-length, ft, m
$V_M$	molar volume	$x_{feldspar}$	feldspar volume fraction of a sandstone
$V_{mineral}$	volumetric fraction of a mineral	$x_s$	half-length of the skin effect zone, ft, m
$V_p$	pore volume, ft <sup>3</sup> , m <sup>3</sup>	$X$	volumetric dissolving power
$V_{prop}$	bulk proppant volume injected	$X_C$	dissolving power of acid
$V_{rp}$	relative proppant volume, lbm/md-ft <sup>3</sup>	$X_{HCl}$	bulk rock fraction dissolved by hydrochloric acid
$V_S$	volume of slow-reacting minerals	$y$	vertical linear distance, ft, m
$V_S$	volume of fluid lost to spurt, gal/100 ft <sup>2</sup>	$z$	linear distance, ft, m
$V_{wall}$	volume of fluid leaked off at the fracture wall	$z_{TVD}$	true vertical depth, ft, m
$w$	width, ft, m	$z_w$	elevation from reservoir bottom, ft, m
$w$	fracture width, ft, in., m	$z_w$	standoff from oil-water contact, ft, m
$w_e$	average fracture width at end of pumping, ft, m	$z_w$	elevation of midpoint of perforations from the bottom of the reservoir, ft, m
$w_{etch}$	acid-etched width, ft, m	$z_{wD}$	dimensionless completion elevation
$w_f$	fracture width, ft, m	$Z$	gas deviation factor, dimensionless
$w_L$	leakoff width, ft, m		
$w_{lost}$	proppant volume lost to the fracture width		

## Symbols

$\alpha$	Forscheimer equation coefficient	$\gamma_b$	shear rate at the bob, $s^{-1}$
$\alpha$	Biot poroelastic constant	$\gamma_F$	fracture surface energy
$\alpha$	proportionality constant	$\gamma_{fluid}$	specific gravity of fluid
$\alpha$	specific diverter cake resistance, m/kg	$\gamma_g$	specific gravity of gas
$\alpha$	exponent of fracture area growth, dimensionless	$\gamma_I$	interfacial tension
$\alpha$	order of reaction	$\gamma_{prop}$	specific gravity of proppant
$\alpha_{bf}$	bilinear flow constant	$\gamma_v$	volume-averaged shear rate, $s^{-1}$
$\alpha_c$	wellbore storage constant	$\Gamma$	foam quality, fraction
$\alpha_{cf}$	elongated reservoir constant	$\Gamma(d)$	Euler gamma function
$\alpha_f$	sealing fault constant	$\Gamma(x)$	gamma function
$\alpha_g$	geometry coefficient	$\delta$	dip of the formation (angle with the horizontal), degree
$\alpha_{hl}$	linear flow to a horizontal well constant	$\Delta$	rate of deformation tensor
$\alpha_{lf}$	linear flow constant	$\Delta C$	change in concentration
$\alpha_p$	dimensionless pressure constant	$\Delta E$	activation energy, kcal/mol
$\alpha_{pp}$	partial penetration constant	$\Delta H$	heat of reaction
$\alpha_t$	dimensionless time constant	$\Delta MD$	change in measured depth, ft, m
$\alpha_T$	linear thermal expansion coefficient	$\Delta p$	pressure difference or gradient, psi, bar, Pa
$\alpha_0$	lower bound of area exponent, dimensionless	$\Delta p_c$	pressure drop between filtrate/reservoir interface and far-field reservoir, psi, bar, Pa
$\alpha_1$	upper bound of area exponent, dimensionless	$\Delta p_{cake}$	pressure drop across the filter cake, psi, bar, Pa
$\alpha_\theta$	perforation-phase-dependent variable	$\Delta p_{ct}$	total pressure drop, psi, bar, Pa
$\beta$	dissolving power coefficient related to acid strength	$\Delta p_{departure}$	pressure departure, psi, bar, Pa
$\beta$	stiffness	$\Delta p_{entry}$	fracture entry pressure, psi, bar, Pa
$\beta$	ratio of average to wellbore net pressure or width	$\Delta p_{face}$	pressure drop across fracture face dominated by filter cake, psi, bar, Pa
$\beta$	Forscheimer equation coefficient	$\Delta p_{friction}$	friction pressure ratio with and without solids
$\beta$	non-Darcy flow rate coefficient	$\Delta p_h$	hydrostatic pressure drop, psi, bar, Pa
$\beta_p$	net pressure or width ratio during injection	$\Delta p_{int}$	difference in the pressure intercept, psi, bar, Pa
$\beta_s$	net pressure or width ratio during shut-in	$\Delta p_{misalign}$	perforation misalignment friction, psi, bar, Pa
$\gamma$	shear strain	$\Delta p_{near wellbore}$	near-wellbore pressure loss, psi, bar, Pa
$\gamma$	channel factor	$\Delta p_{nf}$	pressure difference due to near-face leakoff effects, psi, bar, Pa
$\gamma$	<i>G</i> -plot slope correction factor for pressure-dependent leakoff		
$\gamma$	specific gravity		
$\gamma$	shear rate, $s^{-1}$		
$\gamma_{ab}$	interaction energy per unit surface area between liquids a and b		

$\Delta p_{pf}$	friction through the perforation, psi, bar, Pa	$\Delta TBT$	change in true bed thickness, ft, m
$\Delta p_{piz}$	pressure drop across a polymer-invaded zone, psi, bar, Pa	$\Delta TVD$	change in true vertical depth, ft, m
$\Delta p_r$	pressure drop in the reservoir, psi, bar, Pa	$\Delta V$	change in volume
$\Delta p_R$	total pressure increase in the reservoir beyond the filtrate invasion region, psi, bar, Pa	$\Delta \rho$	density difference, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\Delta p_{RC}$	pressure increase in the reservoir beyond the filtrate region due to Carter-based leakoff, psi, bar, Pa	$\Delta \phi_{max}$	difference in maximum porosity
$\Delta p_{RS}$	pressure increase in the reservoir beyond the filtrate region due to spurt, psi, bar, Pa	$\Delta \sigma$	stress difference, psi, bar, Pa
$\Delta p_{safe}$	pressure safety margin, psi, bar, Pa	$\Delta \$_n$	incremental revenue
$\Delta p_T$	total pressure difference between the fracture pressure and initial reservoir pressure, psi, bar, Pa	$\varepsilon$	introduced error
$\Delta p_{tort}$	tortuosity component of pressure, psi, bar, Pa	$\varepsilon$	ratio of closure time to the time interval
$\Delta p_{total}$	difference between fracture pressure and far-field reservoir pressure, psi, bar, Pa	$\varepsilon$	longitudinal strain
$\Delta p_v$	pressure drop across the filtrate-invaded zone, psi, bar, Pa	$\varepsilon_a$	axial strain
$\Delta p_w$	difference in wellbore pressure, psi, bar, Pa	$\varepsilon_e$	elastic strain
$\Delta p_\mu$	viscous pressure contribution, psi, bar, Pa	$\varepsilon_f$	acid front position divided by the linear flow core length
$\Delta t$	time difference, hr	$\varepsilon_h$	minimum tectonic strain
$\Delta t$	sonic transit time in the formation	$\varepsilon_H$	maximum tectonic strain
$\Delta t$	shut-in time, hr, min, s	$\varepsilon_p$	plastic strain
$\Delta t_{ae}$	effective pseudotime	$\varepsilon_r$	radial strain
$\Delta t_c$	closure time	$\varepsilon_S$	specific volume expansion ratio
$\Delta t_C$	compressional wave traveltime	$\varepsilon_V$	volumetric strain
$\Delta t_{eD}$	dimensionless closure time	$\eta$	poroelastic stress coefficient
$\Delta t_D$	dimensionless time difference	$\eta$	efficiency
$\Delta t_D$	dimensionless shut-in time	$\eta_C$	diffusivity constant
$\Delta t_{Dso}$	dimensionless time after a screenout	$\eta_f$	efficiency including spurt loss
$\Delta t_e$	effective time	$\eta_{fD}$	fracture hydraulic diffusivity
$\Delta t_{ma}$	sonic transit time in the rock matrix	$\eta_p$	dimensionless fracture hydraulic diffusivity
$\Delta t_S$	shear wave travelttime	$\eta_{so}$	efficiency at end of pumping
$\Delta t_{so}$	time following screenout	$\theta$	efficiency at screenout
$\Delta t_{sup}$	superposition time function	$\theta$	angle, degree
$\Delta T_{surf}$	temperature change at the surface, degF, degC	$\theta$	fluid-loss exponent
		$\kappa$	dimensionless time
		$\kappa$	opening-time distribution factor
		$\kappa$	ratio of fracture-opening stress to minimum stress
		$\kappa$	spurt effect factor
		$\kappa$	thermal diffusivity
		$\kappa$	overall dissolution rate constant, cm/s

$\kappa_{so}$	spurt correction at screenout	$\xi$	dimensionless area or position
$\lambda$	interporosity constant	$\xi_f$	forward rate constant
$\lambda$	experimental coefficient for the tortuosity reorientation of a fracture path	$\xi_r$	reverse rate constant
$\lambda$	apparent time multiplier	$\rho$	density, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\lambda$	characteristic relaxation time	$\rho_a$	mass of diverter cake per unit area of available sandface, g/cm <sup>3</sup>
$\lambda_{rt}$	total mobility	$\rho_A$	density of reactant, g/cm <sup>3</sup>
$\lambda_t$	multiphase mobility	$\rho_b$	bulk density, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\Lambda$	length scale corresponding to pore size	$\rho_{brine}$	brine density, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\mu$	viscosity, cp	$\rho_C$	density of acid solution
$\mu_a$	apparent viscosity, cp	$\rho_{CaCO_3}$	density of calcium carbonate, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\mu_{base}$	viscosity of base fracturing fluid, cp	$\rho_{div}$	density of diverter particles, kg/m <sup>3</sup>
$\mu_{eff}$	effective viscosity, cp	$\rho_f$	fluid density, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\mu_{fil}$	viscosity of fracturing fluid filtrate, cp	$\rho_l$	liquid density, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\mu_{fluid}$	fluid viscosity, cp	$\rho_{ma}$	density of matrix components, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\mu_g$	gas viscosity, cp	$\rho_o$	oil density, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\mu_{gi}$	gas viscosity at initial reservoir pressure and temperature, cp	$\rho_p$	proppant or particle density, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\mu_i$	intrinsic viscosity, cp	$\rho_r$	ratio of slurry density to fluid density
$\mu_{inh}$	inherent viscosity, cp	$\rho_{rock}$	rock density, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\mu_o$	oil viscosity, cp	$\rho_s$	slurry density, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\mu_r$	viscosity ratio	$\rho_{sol}$	solid particle density, lbm/ft <sup>3</sup> , g/cm <sup>3</sup>
$\mu_r$	viscosity of reservoir fluid, cp	$\sigma$	stress, psi, bar, Pa
$\mu_r$	relative viscosity, cp	$\sigma'$	effective stress, psi, bar, Pa
$\mu_{slurry}$	slurry viscosity, cp	$\sigma_a$	axial stress, psi, bar, Pa
$\mu_{sp}$	specific viscosity, cp	$\sigma_{BL}$	stress acting on a bounding layer, psi, bar, Pa
$\mu_w$	water viscosity, cp	$\sigma_c$	uniaxial compressive strength, psi, bar, Pa
$\mu_0$	zero-shear viscosity, cp	$\sigma_c$	closure pressure or stress, psi, bar, Pa
$\mu_{100}$	viscosity at 100degF [40degC], cp	$\sigma_c'$	effective confining stress, psi, bar, Pa
$\mu_\infty$	high-shear-limiting viscosity, cp	$\sigma_f$	normal stress across a fissure, psi, bar, Pa
$\nu$	Poisson's ratio	$\sigma_{failure}'$	effective ultimate strength, psi, bar, Pa
$\nu$	stoichiometric ratio of reactants to products	$\sigma_h$	minimum horizontal stress, psi, bar, Pa
$\nu_{CaCO_3}$	stoichiometric coefficient of CaCO <sub>3</sub>	$\sigma_h'$	minimum effective horizontal stress, psi, bar, Pa
$\nu_{dyn}$	dynamic Poisson's ratio	$\sigma_H$	maximum horizontal stress, psi, bar, Pa
$\nu_{HCl}$	stoichiometric coefficient of hydrochloric acid	$\sigma_{H,max}$	maximum horizontal stress, psi, bar, Pa
$\nu_u$	undrained Poisson's ratio	$\sigma_{h,min}$	minimum horizontal stress, psi, bar, Pa
$\xi$	fluid-loss term	$\sigma_m$	mean stress, psi, bar, Pa

$\sigma_{min}$	minimum stress or minimum principal stress, psi, bar, Pa	$\tau_o$	foam yield stress, lbf/ft <sup>2</sup> , bar, Pa
$\sigma_n$	normal stress component, psi, bar, Pa	$\tau_{oct}$	octahedral shear stress, psi, bar, Pa
$\sigma'_n$	effective normal stress, psi, bar, Pa	$\tau_w$	wall shear stress, lbf/ft <sup>2</sup> , bar, Pa
$\sigma_o$	equal-stress constant, psi, bar, Pa	$\tau_{yp}$	yield point, lbf/ft <sup>2</sup> , bar, Pa
$\sigma_{pay}$	stress of the pay zone, psi, bar, Pa	$\phi$	porosity, fraction
$\sigma_{PZ}$	stress acting on the pay zone, psi, bar, Pa	$\phi$	angle of internal friction, degree
$\sigma_r$	radial stress, psi, bar, Pa	$\phi_{cake}$	diverter cake porosity, fraction
$\sigma_{ref}$	constant state of stress, psi, bar, Pa	$\phi_D$	porosity from density, fraction
$\sigma_{r\theta}$	shear stress, psi, bar, Pa	$\phi_{eff}$	effective porosity, fraction
$\sigma_v$	vertical stress, psi, bar, Pa	$\phi_f$	fracture porosity, fraction
$\sigma'_v$	effective vertical stress, psi, bar, Pa	$\phi_i$	initial porosity, fraction
$\sigma_1$	maximum principal stress, psi, bar, Pa	$\phi_N$	porosity from neutron, fraction
$\sigma'_1$	maximum principal effective stress, psi, bar, Pa	$\phi_p$	proppant pack porosity, fraction
$\sigma_2$	intermediate principal stress, psi, bar, Pa	$\phi_S$	porosity from sonic, fraction
$\sigma'_2$	intermediate principal effective stress, psi, bar, Pa	$\phi_{total}$	total porosity, fraction
$\sigma_3$	minimum principal stress, psi, bar, Pa	$\varphi$	angle, degree
$\sigma'_3$	minimum principal effective stress, psi, bar, Pa	$\Phi$	channel flow function
$\sigma_\theta$	tangential stress, psi, bar, Pa	$\Psi$	change of angle, degree
$\sigma_{\theta\theta}$	circumferential stress, psi, bar, Pa	$\Psi$	dimensionless hydrofluoric acid concentration
$\tau$	shear stress, psi, bar, Pa	$\Psi$	dimensionless rock dissolution rate
$\tau$	time of fracture opening	$\omega$	angular velocity, rad/s, rpm
$\tau$	dimensionless slurry time	$\omega$	storativity ratio
$\tau_c$	characteristic time for fracture propagation, dimensionless	$\Omega$	stoichiometric coefficient

# Matrix Stimulation

## Introduction

Matrix stimulation is the process of injecting a fluid, either an acid or a solvent, into an old or newly completed well at a pressure below the fracturing pressure to remove or bypass damage. This technique has been used extensively since the 1930s to improve production and injection operations.

The goal of matrix stimulation in sandstones is to restore the natural permeability; i.e., to obtain the undamaged flow capacity in the pay zone by removing formation damage. In carbonates, the objective is to create a highly conductive flow system that bypasses damage to yield a higher production rate than that obtained in the natural, or undamaged, state.

Matrix stimulation is preferred to hydraulic fracturing when fracturing may result in excessive water production, undesirable gas production, inadequate reservoir drainage (highly fissured formation), and when well performance and reservoir management objectives can be reached by removing or bypassing the damage. Worldwide, matrix treatments constitute 75 to 80 percent of all stimulation treatments, both matrix and fracture, performed.

Dramatic production and economic results can be achieved by matrix stimulation if treatments are properly engineered. In an engineered treatment design, many tasks are performed within a structured methodology. This methodology, called Matrix Stimulation Engineering (MSE), is defined as the practical application of scientific and mathematical principles to matrix stimulation. The MSE process steps are:

- candidate selection
- formation damage determination
- fluid selection
- treatment design
- execution
- treatment evaluation.

Treatment fluid selection is an important process step involving many parameters. Fluid systems, composed of base fluids and additives, are selected based on lithology, damage mechanism and well conditions. Each fluid in the treating schedule serves a special purpose. Although the process of fluid selection is complex, matrix acidizing can be highly successful and can produce excellent field results.

The objective of this manual is to provide a comprehensive discussion that will help treatment designers select the optimal fluid to solve a given problem. Since the steps in the MSE process are interrelated, a discussion of formation damage is included.

A basic understanding of the chemistry and physics involved in pumping reactive fluids into the rock matrix is also a necessity. Fluid reactions with the formation minerals are just as important as their reactions with the damage.

The fluid selection guidelines presented here are the results of combining expertise in the fields of chemistry, geochemistry and geology. They are the same rules used to determine the treatment fluid sequence recommended by the Fluid Selection Advisor module in the StimCADE\* design program for matrix acidizing. The information provided covers all the background material behind the rules in the program. Current thoughts on clay reactivity as well as on carbonate wormholing are also included.

# Basic Concepts in Fluid Selection

The basic criteria for selecting the treating fluid are formation damage mechanism, mineralogy, reservoir parameters and well conditions.

Since the goal of the matrix treatment is different in sandstones than in carbonates, the approach to fluid selection is also distinct for each formation type. For example, sandstone acidizing focuses on damage removal; carbonate acidizing emphasizes wormhole creation to bypass damage. Therefore, knowledge of the extent and type of damage, its location and its origin is more important when the well is a sandstone reservoir.

In sandstone formations, hydrofluoric (HF) acid is used to dissolve silicates. The chemistry of secondary and tertiary HF reactions with the reservoir minerals is significant because of the potential for precipitation. Precipitated reaction by-products can block the pore throats when the well is returned to production.

Compatibility issues between the treating fluid and the formation rock are more significant in sandstones than in carbonates. In sandstones, compatibility and precipitation issues make knowledge of the reservoir mineralogy very important. Permeability does not decrease when a compatible fluid contacts the formation.

In carbonates, the treating fluid reactivity with the reservoir rock drives the formation of wormholes. Because this reactivity changes with temperature and diffusion to the rock surface, the physical properties of the reservoir become more important in fluid selection.

Formation damage is discussed in a separate section. Mineralogy is relevant to sandstone fluid selection and is discussed in the section on sandstone reservoirs. The chemistry and physics of the acid reactions are discussed in the sections on sandstone reservoirs and carbonate reservoirs within the context of the reservoir rock.

# Fluid Selection and Damage Identification

## Introduction

Damage is anything that obstructs the normal flow of fluids to the surface; it may appear in the formation, perforations, lift system and tubulars or as restrictions along the flow path. Formation damage specifically refers to obstructions in the near-wellbore region of the rock matrix. Correctly identifying an obstruction to the flow is critical to its successful removal.

The type of fluid used in a treatment often depends on the damage being addressed. Acids can be used when plugging is a problem, but solvents are used for organic deposits. In sandstone reservoirs, knowing the damage mechanism is especially important, because the damage must be removed to regain matrix permeability. In carbonate rocks, damage identification is less critical, because new flow channels are created to bypass the damage.

Not all types of damage require a removal treatment. Some types will clean up during production. Some production impairments are misconstrued as damage when they are actually the result of poor well design and can be remedied with operational changes. Although a matrix treatment focuses on treating the rock matrix, the chemicals can also treat damage in the wellbore tubulars or in the gravel pack.

## Hurdles to accurate damage identification

The basics of formation damage are well documented. Both Krueger (1986) and Porter (1989) emphasize the need for understanding the total chemical and physical picture of the reservoir and its fluids. In particular, knowledge of the clay mineralogy and the ion exchange reactions that affect the clay's physical structure is significant for understanding how damage occurs in sandstone formations.

However, correctly classifying damage requires more than understanding the chemistry and the physics of downhole reactions. A thorough knowledge of the well's history and the field operating conditions is essential. The engineer must not only know what occurred during drilling, completion and any workover operations but also must be familiar with the production and reservoir pressure history, including any pressure maintenance operations. Understanding when the damage occurred can often lead to correctly determining the type of damage.

In reality, however, there are many hurdles to formation damage identification. Many wells are poorly documented with little data about past procedures and even less information on fluids. While mud type is usually listed, there may be no record of the mud additives. Although high-pH cement filtrates can be damaging, the well history may not show if, or how much of, this fluid was lost to the formation during casing operations. The source of the water used in well or waterflood operations is often unavailable, and it is unusual to have production or injection profiles or accurate downhole pressure data.

Typically, reservoir characterization is done on a fieldwide basis, and core or fluid analyses for a specific well may not be available. To make good decisions about well treatment, field study reports or offset well files must be examined to find the necessary information about mineralogy, clay characterization, formation fluid analyses and permeability heterogeneities. This is important in both damage identification and fluid selection.

## Damage identification

Damage is described by two important parameters: composition and location. Composition is important because, to some extent, it determines the fluid used for dissolution. Location is important because the treating fluid contacts several other substrates, e.g., rust from tubular goods or carbonate cementing material from the formation, before it reaches the damage. Unspent fluids must reach the damaged rock for the treatment to be effective. Proper diversion techniques may be necessary to ensure that the fluid contacts the entire treatment interval. Figure 3-1 shows typical damage examples and their locations.

A sharper than expected decline in production or injection is often the first sign of a problem with a well. Diagnostic tests, like pressure buildups or drawdowns, can quantify the extent of the damage as a pressure drop resulting from skin. A production system analysis can then determine if the skin is due to mechanical damage or true formation damage. Production logging can determine the physical extent of the problem by showing if, and at what rate, all expected intervals are producing. Such tests provide valuable information for optimizing the treatment and evaluating its results.

## Types of damage

Formation damage is typically categorized as either natural or induced. Natural damages occur primarily as a result of producing the reservoir fluid. Induced damages result from an external operation on the well, such as drilling, well completion, repair, stimulation treatment or injection operation. In addition, some, induced damages, completion operations or design problems can also trigger natural damage mechanisms.

Natural damages include fines migration, swelling clays, water-formed scales, organic deposits, like paraffins or asphaltenes, and mixed organic and inorganic deposits. Induced damages include plugging, caused by entrained particles such as solids or polymers in injected fluids; wettability changes, caused by injected fluids or oil-base drilling fluids; emulsions, precipitates or sludges, caused by acid reactions, bacteria and water blocks.

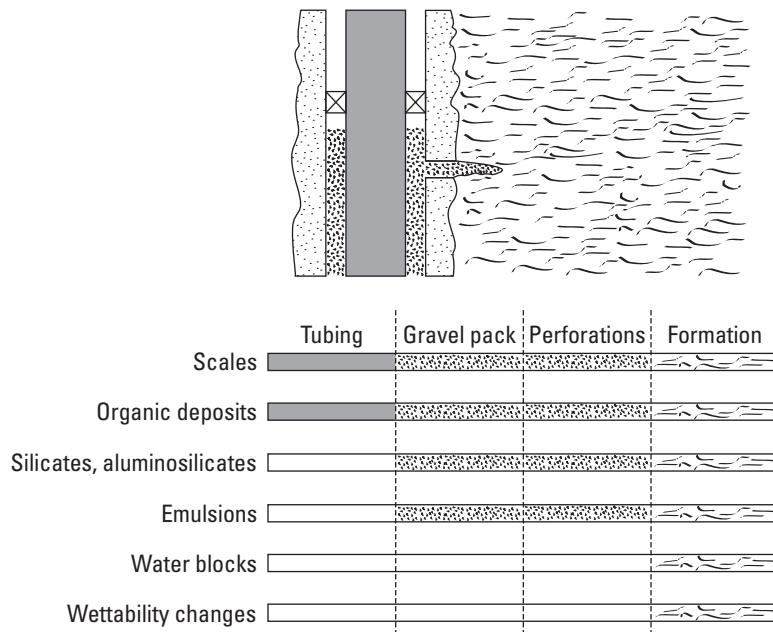


Figure 3-1. Locations of various types of damage.

## Fines migration

Particles suspended in the produced fluid can bridge across the pore throats in the near-wellbore region and reduce the well productivity. When these damaging particles come from the reservoir rock, they are referred to as fines. Migrating fines can be a variety of different materials, including clays (phyllosilicates with a typical size less than 4 mm) and silts (silicates or aluminosilicates with sizes ranging from 4 to 64 mm). Kaolinite and illite are the more common migratory clays. Table 3-1 lists the major components of various clays and fines particles. The table also lists the surface area of the clays, one of the indicators of how quickly the clay can react (Davies, 1978). Damage from fines is located within a 3- to 5-ft radius of the near-wellbore area and can also occur in a gravel pack.

## Clay swelling

Changes in formation permeability resulting from the alteration of clay can be due to dispersion or swelling triggered by ion exchange or salinity dropping below the critical salt concentration. The most common swelling clays are smectite and smectite mixtures. Smectite can increase its volume up to 600% by taking water into its structure. This swelling can significantly reduce permeability. If smectite clay occupies only the smaller pore throats and passages, it will not be a serious problem. However, if it occupies the larger pores, especially the pore throats, then it is capable of creating an almost impermeable barrier to flow.

The total quantity of clay inside the formation does not indicate the potential for formation damage. The structure of the clay, its chemical state at the moment of contact and the location of the clay with respect to the flowing fluids are the factors responsible for changes that can cause damage. This means that predicting the response of in-situ clay to fluid moving in the rock is almost impossible without testing.

Clay swelling sandstones have been well documented in papers by Azari and Leimkuhler, 1988; Jones, 1964; Khilar and Fogler, 1983; Mungan, 1968; Sharma *et al.*, 1985; and Priiscolm *et al.*, 1987. Clay chemistry and reactions not only affect damage mechanisms, but also have a large influence on fluid selection. The chapter on sandstone acidizing provides a more detailed discussion of clays.

## Scales

Scale deposits are among the most common and most troublesome damage problems. Scales are water-soluble chemicals that precipitate out of solution from either a temperature or pressure change or from mixing incompatible waters. The most common oilfield scales are calcium carbonate ( $\text{CaCO}_3$ ) calcium sulfate ( $\text{CaSO}_4$ ) and barium sulfate ( $\text{BaSO}_4$ ). They can be present in the tubing, the perforations or the formation and can occur in both production and injection wells, as long as water is present.

**Table 3-1. Major components of various clay and fines particles**

Particle Mineralogy	Major Components	Specific Area ( $\text{m}^2/\text{g}$ )
Quartz	Si, O	<0.1 $\text{cm}^2/\text{g}$
Feldspar	Si, Al, O, K, Na, Ca	Few
Kaolinite	Al, Si, O, H	15–30
Chlorite	Mg, Fe, Al, Si, O, H	60
Illite	K, Al, Si, O, H	113
Smectite (montmorillonite)	Na, Mg, Ca, Al, Si, O, H	82

Scale forms when the solution equilibrium of the water is upset. Scale deposition is influenced by anything that upsets the solution equilibrium: pressure drop, temperature, dissolved gases, flow viscosity, nucleation sites and metal type. As the fluids move from the reservoir to the surface, temperature changes can upset the equilibrium. In-situ water, which is stable under reservoir conditions, may become supersaturated with an ion when the pressure decreases, which allows carbon dioxide ( $\text{CO}_2$ ) outgassing. The supersaturated solutions react by precipitating a compound from solution.

Scales can also form by mixing incompatible waters. The water used in an injection operation will mix with the reservoir water. The waters are incompatible if precipitation occurs when they are mixed. All water used in well operations can be potential scale sources, not just water injected in secondary waterflood operations. Filtrate from completion or workover fluids, as well as treating fluids, must also be compatible with the formation waters. Seawater, which is sometimes used for injection into offshore wells, typically contains traces of barium that could react with the reservoir water to form detrimental precipitates. The risks associated with water incompatibility should always be considered and accepted before injecting seawater in a well operation.

The Scale Prediction module in the StimCADE design program is one of the computer programs available that model water mixing to show potential precipitates. To prevent scale damage, the program should be used before the fluid is mixed and injected into the well. It can also be used after water injection to help identify scale sources.

When designing a scale removal treatment, contact time is a very important factor because sufficient time must be allowed for the treating fluid to reach and effectively dissolve the bulk of the scale material. When treating some types of slow dissolving scales, shutting in the well to allow the treatment to soak may be required.

Common scales encountered in wells include the following:

- Calcium carbonate, or calcite ( $\text{CaCO}_3$ ), is usually formed when the pressure is reduced on waters that are rich in calcium and bicarbonate ion. The deposition can be affected by  $\text{CO}_2$  outgassing, which raises the pH value and makes high concentrations of calcium unstable.
- Gypsum, or gyp, may be the most common sulfate scale in the oil industry (Cowen and Weintritt, 1976). With a chemical structure of  $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ , it shares a similar composition to the hemihydrate  $\text{CaSO}_4 \cdot \frac{1}{2}\text{H}_2\text{O}$ , commonly called plaster of Paris or bassonite, its mineral name. It also has the same chemical formula as the evaporite mineral anhydrite ( $\text{CaSO}_4$ ).

- Barium sulfate ( $\text{BaSO}_4$ ) is a less common form of sulfate deposit, but it causes extensive problems. Almost any combination of barium and sulfate ions causes a precipitate that is difficult to remove. Normal solvents do not affect it unless it is finely ground, or the structure is interrupted with impurities such as carbonate scale.

Like calcium sulfate, barium sulfate is usually thought to be a product of mixing incompatible waters with precipitation accelerated by pressure drop, outgassing or turbulence. Some barium sulfate is radioactive. It is one of the naturally occurring radioactive material (NORM) scales. The radioactivity results from a concentration of uranium in the lattice of the scale. The buildup of radioactive scale can be monitored using a gamma ray logging tool. When analyzing well debris, care must be exercised to avoid mislabeling barite ( $\text{BaSO}_4$ ) from drilling mud residue as barium sulfate scale.

- Strontium sulfate or celestite ( $\text{SrSO}_4$ ) is a common substitute in the barium sulfate crystal lattice. Strontium scale can also be associated with radioactive scale (NORM). It may be more soluble than barium sulfate in chemical remover systems.
- Iron scales, such as iron carbonate and iron sulfide, are more difficult to remove than calcite scales. They are usually seen in wells that have both a high background iron count and a tendency to precipitate calcium carbonate. Iron sulfide scales react according to their structure. Seven different forms of iron sulfide scale have been identified, and only two of these forms are readily soluble in hydrochloric acid (HCl). The remaining iron sulfide scales are either slowly soluble or not significantly soluble.
- Chloride scales, such as sodium chloride ( $\text{NaCl}$ ) precipitation that is caused by temperature decrease or evaporation of the water, are common. There is no effective prevention for salt precipitation. Salt has a limited solubility in acid ( $\frac{1}{4}$  lbm/gal in 28% HCl), so acid is not generally considered as a treating fluid. Cleanup is typically accomplished using only water. Redesigning the mechanical system to avoid temperature loss and water evaporation can help prevent chloride scales.
- Silica scales generally occur as finely crystallized deposits of chalcedony or as amorphous opal. They are associated with alkaline or steamflood projects and stem from the dissolution of siliceous formation minerals by high-pH fluids (Lieu *et al.*, 1983) or high-temperature steam condensates (Reed, 1980; Amaefule *et al.*, 1984). This dissolution can cause poorly consolidated sandstones to collapse or silica to reprecipitate at a distance from the wellbore where either the flood's alkalinity or temperature or both has decreased.

## Organic deposits

Organic deposits are heavy hydrocarbons (paraffins or asphaltenes) that precipitate as the pressure or temperature is reduced. This is a form of distillation. The deposits are typically located in the tubing, perforations or formation. Although the formation mechanisms of organic deposits are both numerous and complex (Houchin and Hudson, 1986), the main mechanism is a change in either temperature or pressure in the flowing system. Cooling of the wellbore or the injection of cold treating fluids has a pronounced effect on the formation of these deposits.

### Paraffins

Paraffins are straight-chain hydrocarbons composed of only carbon and hydrogen. Solid paraffin deposits consist of molecules with 16 to more than 60 carbon atoms. Paraffin deposition is a crystallization reaction that is triggered by a loss of pressure, temperature or light ends (the short-chain hydrocarbon compounds in the crude).

Although paraffins can form anywhere in the well (Cole and Jessen, 1960; Burger *et al.*, 1981; Newberry, *et al.*, 1986; Thomas, 1988; Sutton and Roberts, 1974), they are usually found in the tubing near the surface, where the temperature and pressure drops are the highest. They can form at the perforations or in the reservoir matrix in cases where the reservoir pressure is nearly depleted, or the formation has experienced dry gas cycling. Paraffins can also be precipitated by the injection of a cool fluid. In many wells, this may contribute to slow cleanup after stimulation.

### Asphaltenes

Asphaltenes are organic materials consisting of aromatic and naphthenic ring compounds containing nitrogen, sulfur and oxygen molecules (Leontaritus, 1989; Leontaritus and Mansoori, 1987; Tuttle, 1983; Newberry and Barker, 1985; Addison, 1989; Thawer, *et al.*, 1990). The asphaltene fraction of crude is defined as the organic part of the oil that is not soluble in a straight-chain solvent, such as pentane or heptane. They exist as a colloidal suspension stabilized by maltene resin molecules in the oil. Maltenes are condensed polynuclear-aromatic ring systems (pyrrole and indoles) with alkyl or naphthenic side chains.

The stability of asphaltic dispersions depends on the ratio of resin to asphaltene molecules. Resin ratios larger than 1:1 (resins to asphaltenes) are more stable, whereas ratios less than 1:1 are unstable and may precipitate during production. Resin ratios of more than 10:1 are known, and they are much less likely to cause significant problems. The actual quantity of asphaltenes

in the oil is less important than the resin ratio in determining if asphaltene damage will be a problem. Although asphaltene contents up to 60% have been found, major problems can occur in oils with asphaltene contents as low as 1% to 3%.

Asphaltene precipitation can be influenced by pressure drop, shear (turbulence), acids, solution CO<sub>2</sub>, which lowers the pH value, injected condensate, gas, commingling with other incompatible oils and charged metal surfaces. Anything that takes away the resins or breaks the stability of the asphaltene micelle can lead to precipitation. During an acid job, iron ions in solution compound and favor the formation of asphaltene deposition.

Organic deposits must not be confused with another type of deposits called sludge. Sludges are viscous emulsions formed by the reaction between certain crude oils and strong inorganic acids, and they cannot be easily dissolved.

### Mixed deposits

Mixed organic and inorganic deposits are a blend of organic compounds and either scales or fines and clays. When migrating, fines, associated with an increase in water production in a sandstone reservoir, become oil wet, and they act as a nucleation site for organic deposits (Houchin and Hudson, 1985). Figure 3-2 shows such a mixed deposit in which crystals of sodium chloride (white) are interspersed with darker organic matter.

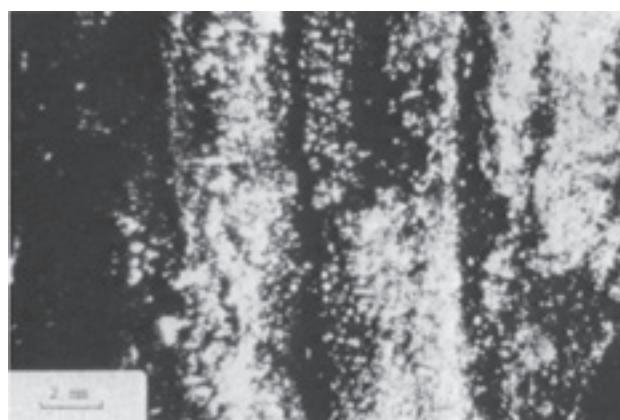


Figure 3-2. Thin section of a layered mixed deposit.

### Induced particle plugging

In addition to the naturally occurring, migrating particles such as clays and fines, many foreign particles are introduced into the formation during normal well operations. Drilling, completion, workover, stimulation and secondary or tertiary production operations can inject extraneous particles into the formation.

Particle damage from injected fluids is caused when injected solids block the near-wellbore formation. Problems include bridging of the pore throats, packing of perforations and losing large amounts of high-solids fluid into natural fractures or propped fracture systems. Potentially damaging particulate materials in drilling fluids include clays, cuttings, weighting agents and fluid-loss control materials (Barna and Patton, 1972; Fischer *et al.*, 1973; Sloan *et al.*, 1975). These components can be a problem independent of mud type (oil, water or polymer base). Workover and stimulation fluids can also contain suspended solids (Rike, 1980; Rike and Pledger, 1981) including bacteria and polymer residues (Tuttle and Barkman, 1974). Kill fluids, in particular, use various polymers either as weighting agents or for fluid loss control. Typical kill-fluid and lost-circulation pill solids include salt pills with polymer, crosslinked polymers, hydroxyethylcellulose (HEC) polymers and  $\text{CaCO}_3$  with polymer. Using a properly controlled range of particle sizes for these materials will help avoid induced particle damage.

Particles can also be introduced in injected fluids as a result of poor water handling practices. Debris from dirty tanks, piping and tubing (e.g., dried mud, scale and pipe dope) can easily plug perforations or matrix pore throats when injected into the rock under pressure. Matrix stimulation fluids, which contain effective cleaners and acids, will disperse and partially dissolve the debris inside of the tanks and piping, exacerbating this problem. Water used in mixing stimulation or circulating fluids of any type should be clean or filtered. The fluids should be stored in clean tanks and pumped through clean piping and tubing.

Particle damage after matrix stimulation may also occur when either partially dissolved parts of the formation or the damage-causing materials are produced back through either the pores or the natural or- propped fracture system. The cleaners and mutual solvents in stimulation treatments can also cause the release of fines from the formation. Partially dehydrated or unbroken polymer gels from fracture or gravel-pack treatments can also leave particles that could cause plugging.

## Wettability change

Wettability and the related relative permeability of a formation are determined by the flowing-phase in the well and by the surfactants and oils in that fluid. Surfactants or other additives in drilling or other injected fluids can cause changes to the wettability of a formation, which can then change the relative permeability of the formation rock. Shifts in relative permeability can reduce the effective permeability of a formation to a particular fluid by as much as 80% to 90%.

In their natural state, formations may be water-wet, oil-wet or neutral. The wetting fluid will coat the surface of the matrix pores, and the nonwetting fluid will flow through these coated pores. In water-wet rock, the bound water, which has a thinner monomolecular layer than oil, occupies less of the pore throat volume leaving more space open to flow than in an oil-wet pore. The relative permeability to oil will also be greater in water-wet rock. Therefore, it is advantageous for oil production to have a water-wet formation.

Preflushing the formation with a wetting surfactant or a solvent that either establishes a new coating on the face of the formation or cleans the current coating from the formation can modify wettability. Regardless of the altered condition of a surface, the wettability is eventually decided by the surfactants in the produced fluid. Thus, the water-wet condition of a formation following an acid job can revert to an oil-wet condition after a sufficient volume of strongly oil-wetting crude is produced. The opposite is also true, and an oil-wet surface caused by surfactants in fluids, such as oil-based mud (OBM), will also revert to a native water-wet state. The question becomes one of economics. If the operator can live with the low productivity while waiting for the wettability to change naturally, then the damage doesn't need treatment. If the low productivity is a problem, then the damage should be treated.

Wettability alteration is one of the damages associated with OBM due to the powerful wetting surfactants necessary to create a stable drilling fluid. When these materials coat or adsorb onto the formation, the wettability of the formation is altered, and permeabilities may be only 10% to 20% of what they were initially. The most severe problems usually occur with muds weighing more than 14 lbm/gal.

## Emulsions

Emulsions are combinations of two or more immiscible fluids (including gas) that will not molecularly disperse into each other. Typically fluids injected into the well or filtrates from fluids used in well operations will mix with the reservoir fluids to form emulsions.

Almost all emulsions found in the field are produced by the addition of some form of energy that produces mixing. In many cases, this is the energy associated with fluid injection or production. Most emulsions break rapidly when the source of energy is removed. If separation of the emulsion does not occur, then there is a stabilizing force acting to keep the fluids emulsified. The most common stabilizing forces modify the surface film strength at the fluid interface. These forces may act singly or in combination.

Surfactants, either naturally occurring or in the injected fluid, help stabilize emulsions by stiffening the film around the droplet or by partially wetting small, solid particles. Natural surfactants are present in many waters and most crude oils. They can be a by-product of bacteria or originate as part of the oil generation process. Surfactants are also commonly used as additives in drilling, completion or stimulation fluids.

Micron-size solids in the liquid may stabilize an emulsion by increasing the toughness of the surface film around the droplets, or by acting as an emulsifier and binding droplets of the dispersed liquid with an electrical charge. The more common solid materials that stabilize oilfield emulsions are iron sulfide, paraffin, sand, silt, clay, asphalt, scale, metal flakes (from pipe dope), cuttings and corrosion products.

Changes in the pH value can also affect emulsion stability. The in-situ pH of a produced fluid will be fairly neutral (6–7). Following an acid treatment, the pH value may drop below 4, and emulsions may be created. Emulsions created in this manner are stable until the pH value rises above 6 or 7. If there is any possibility of fluid loss or mixing with in-situ fluids, the emulsion tendency of the crude oil should always be tested with any fluid to be used in the well.

Most OBM's, and particularly those with densities greater than 14 lbm/gal, contain sufficient solids to create silt-stabilized emulsions when mixed with high-salinity brines or acids. These emulsions are viscous and resist breaking. Some of these emulsions have been shown to be stable for several months, both in the laboratory and in the wellbore. The level of damage caused by these emulsions can be so severe that an entire pay zone can be missed.

### Acid reactions, precipitates and sludges

Under certain circumstances, acid treatments may also cause formation damage. Injected acids and their additives can contribute to induced particle plugging, emulsions, wettability changes and water blocks. There are also certain damage mechanisms unique to acidizing: the precipitation of acid reaction products in sandstone formations and the formation of sludges due to the incompatibility of the native crude and the injected acid system.

In sandstone acidizing, reaction products from HF acids can further react with formation minerals. Hydrated silica may precipitate on clay surfaces and is not necessarily damaging. Compounds, such as borosilicates and fluoborates, can even be beneficial. Some of these reactions, however, produce damaging precipitates. Gelatinous precipitates, such as ferric oxide, can completely plug pores and be particularly

difficult to remove. Another class of by-products consists of species like alkali-fluosilicates, which precipitate in the form of individual crystals that can migrate toward and then bridge in the pore throats. Iron sulfide that precipitates, even at very low-pH values, during the acidization of sour wells also belongs in this category.

As mentioned previously, sludges are viscous emulsions produced by the reactions between certain crude oils and strong inorganic acids (Moore *et al.*, 1965; Houchin *et al.*, 1990). Sludges occur due to reaction between the treating fluid and asphaltene components of the crude. Certain acid additives, such as surfactants or the presence of dissolved iron in the well, can contribute to sludge formation. It is important to test the complete acid formulation with live well crude before injecting the treatment. Sludge testing should always include dissolved iron.

The additives commonly used in acids can also contribute to formation damage. Certain sequestering agents used to prevent iron problems may form precipitates after the acid is spent, if no iron is present. Corrosion inhibitors or the degradation of polymers used for friction reduction can also have residues that could plug formation pore throats.

### Bacteria

Bacteria can be a serious problem in production operations because of what they consume and their by-products. Bacteria can grow in many different environments and conditions: temperatures ranging from 12 degF to greater than 250 degF [-11 degC to greater than 120 degC], pH values ranging from 1 to 11, salinities to 30% and pressures to 25,000 psi. The most troublesome oilfield bacteria are sulfate-reducing bacteria, slime formers, iron-oxidizing bacteria and bacteria that attack polymers in fracture and secondary recovery fluids.

Sulfate-reducing bacteria cause the most problems in a reservoir. Sulfate-reducing bacteria reduce the sulfate or sulfite in the water to sulfide and produce hydrogen sulfide ( $H_2S$ ) as a by-product. The reduction process provides the energy for bacterial growth. Sulfate-reducing bacteria are anaerobic (not requiring oxygen) with slow growth rates when oxygen is present. Sulfate-reducing bacteria occur naturally in surface waters, including seawater. Bacteria accumulation can lead to pitting of the steel under large colonies. The buildup of  $H_2S$  under the colonies increases the corrosivity of the water and creates the possibility of blistering of carbon steels and sulfide cracking.

Iron-oxidizing bacteria are aerobic (requiring oxygen) and convert iron from the ferrous ( $Fe^{2+}$ ) to the ferric ( $Fe^{3+}$ ) state. They produce gelatinous ferric hydroxide, which is highly insoluble and precipitates out

of water. The bacteria metabolize dissolved iron in the water. Ferrous iron is soluble only at low-pH values, i.e., when the water is acidic. Therefore,  $\text{FeOH}_3$  is typically considered an acid-reaction product. The iron bacteria produce some corrosion, but more importantly, they cover sulfate-reducing bacteria colonies and protect them from attack.

Slime-forming bacteria are facultative (can live with or without oxygen) and produce mats of high-density slime that cover surfaces. Their primary detrimental effects are the protection of colonies of sulfate-reducing bacteria and pore plugging.

The bacteria that attack polymers are various aerobic types and a few of the anaerobic bacteria. Most polymers are excellent carbon sources that are readily consumed to support rapid bacterial growth rates. The resulting large quantities of biomass contribute to formation plugging. All these bacteria can be controlled by application of various biocides.

## Water block

Water blocks are caused by an increase in the water saturation near the wellbore. They can form during drilling and completion operations through invasion of water-base filtrate or during production through finger-ing or coning of formation water.

Water blocks are considered to be a special case of relative permeability problem. In a water block, water usually occupies the flowing spaces (either pores or natural fractures) that are typically used by hydrocar-bons to flow to the wellbore. Because of the mobility and viscosity differences, the hydrocarbon fluid may not be capable of displacing the water. The most severe cases of water blocks are usually observed in low-pressure, low-permeability, gas-producing formations after treatment with water that has a high surface tension.

# Sandstone Reservoirs

## Introduction

Treatment fluid selection in sandstone formations is highly dependent on the mineralogy of the rock as well as the damage mechanism. Hydrofluoric (HF) acid is typically used to dissolve the damaging silicate particles. Nonacid systems are sometimes used to disperse whole mud and allow it to be produced with the treating fluid. The criteria for selecting the treating fluid are mineralogy, formation damage mechanism, petrophysics and well conditions.

## Formation mineralogy

### Compatibility and sensitivity

Compatibility of the formation minerals to the various treating fluids and their additives is a significant issue when selecting fluids for acidizing. Compatibility implies that permeability does not decrease when the treating fluid contacts the formation. This concept of compatibility applies especially to sandstones, where potentially damaging reactions may occur.

Compatibility and sensitivity are related concepts. As stated by McLeod (1984), a successful matrix treatment depends on the favorable response of the formation to the treatment fluid. The treating fluid, therefore, must remove existing damage without creating additional damage through interactions with the formation rock or fluids. A formation is sensitive if the reaction between the rock minerals and a given fluid induces damage to the formation.

The sensitivity of a formation to a given fluid includes all the detrimental reactions that can take place when this fluid contacts the rock. These detrimental reactions

include the deconsolidation and collapse of the matrix, the release of fines or the formation of precipitates. The precipitation of some damaging compounds cannot be avoided. Treating and overflush fluid stages are sized; so, there is sufficient volume to push potential precipitates deep enough into the reservoir to minimize their effects because of the logarithmic relationships between pressure drop and distance from the wellbore.

Sandstones can be sensitive to acid depending on temperature and mineralogy. Ions of silicon, aluminum, potassium, sodium, magnesium and calcium react with acid and can form precipitates at downhole temperatures, once their solubility product is exceeded. If these precipitates occur in the near wellbore area, they can damage the formation. Sensitivity depends on the overall reactivity of the formation minerals with the acid. Reactivity depends on the structure of the rock and the distribution of minerals within the rock, i.e., the probability of the acid reaching the soluble minerals.

The sensitivity of sandstone will also depend on the permeability of the formation. Low-permeability sandstones are more sensitive than high-permeability sandstones for a given mineralogy. Acid formulations should be optimized on the basis of a detailed formation evaluation (Davies *et al.*, 1992, Nitters and Hagelaars, 1990).

### Sandstone petrography

From a mineralogical view, two factors affect the reactivity of a given mineral: chemical composition and surface area. The composition and structure, the petrography, of the rock are important factors used to determine potential sensitivity. Figure 4-1 schematically represents the different constituents of a common sandstone.

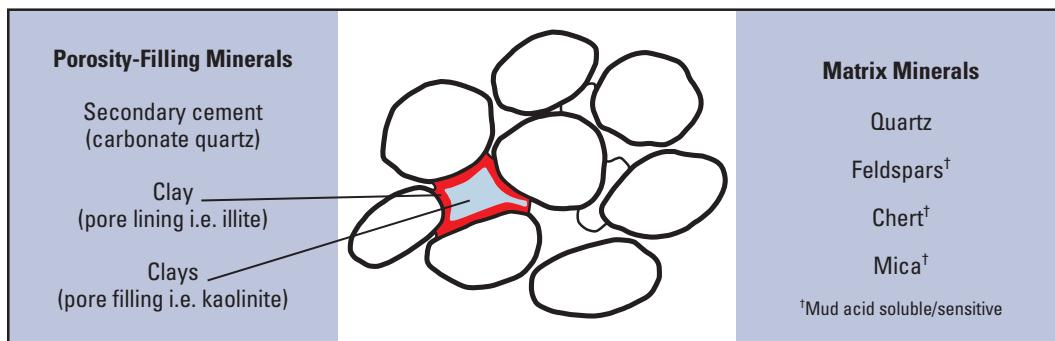


Figure 4-1. Constituents of sandstone.

## Rock structure

Typically, sandstone reservoirs are made of a framework of silicate grains, such as quartz, feldspars, chert and mica. This framework is the originally deposited sand. Secondary minerals, precipitated in the original pore spaces, are the cementing materials for the grains (most frequently secondary quartz overgrowth or carbonates) and the authigenic clays. The main components of clay minerals are silicon and aluminum; hence, they are called aluminosilicates.

The actual solubility of various minerals in a sandstone reservoir depends strongly on their position in the structure of the rock. Only the mineral surfaces that can be contacted by the treating fluid will be dissolved. The total specific surface area of the minerals affects their reactivity with HF acids. The larger the surface area is, the more reactive the minerals are. Because of their greater specific area, clays react much faster than feldspars, and feldspars react much faster than quartz, especially in the presence of high proton ( $H^+$ ) concentrations. Table 3-1 in the chapter on formation damage lists the specific area of some common sandstone minerals.

Since they are usually the most reactive components, it is important to know the amounts of the various clay minerals in the rock. A petrographic study helps in understanding what response will result from pumping an acid and why. Chapter Six<sup>†</sup> discusses petrographic studies in detail.

HCl solubility is commonly used to represent the carbonate content of the sandstone. A petrographic study can verify whether using HCl solubility is an acceptable estimate for carbonate. Other minerals, such as oxides, sulfides and chlorite clay, are also partially soluble in HCl. Overestimation of the amount of carbonate will affect fluid selection because HF acids are not used in sandstones with calcite content greater than 20%. A limit on carbonate content is needed to avoid the precipitation of calcium fluoride from the reaction of HF with calcite. Reservoirs with high calcite content are treated with HCl or organic acids, which are ineffective in dissolving clay and fines particles. If HCl solubility is used for calcite, but is too high because of other HCl soluble minerals, a sub-optimal fluid could be selected because of the assumption that an HF fluid cannot be used.

## Clays

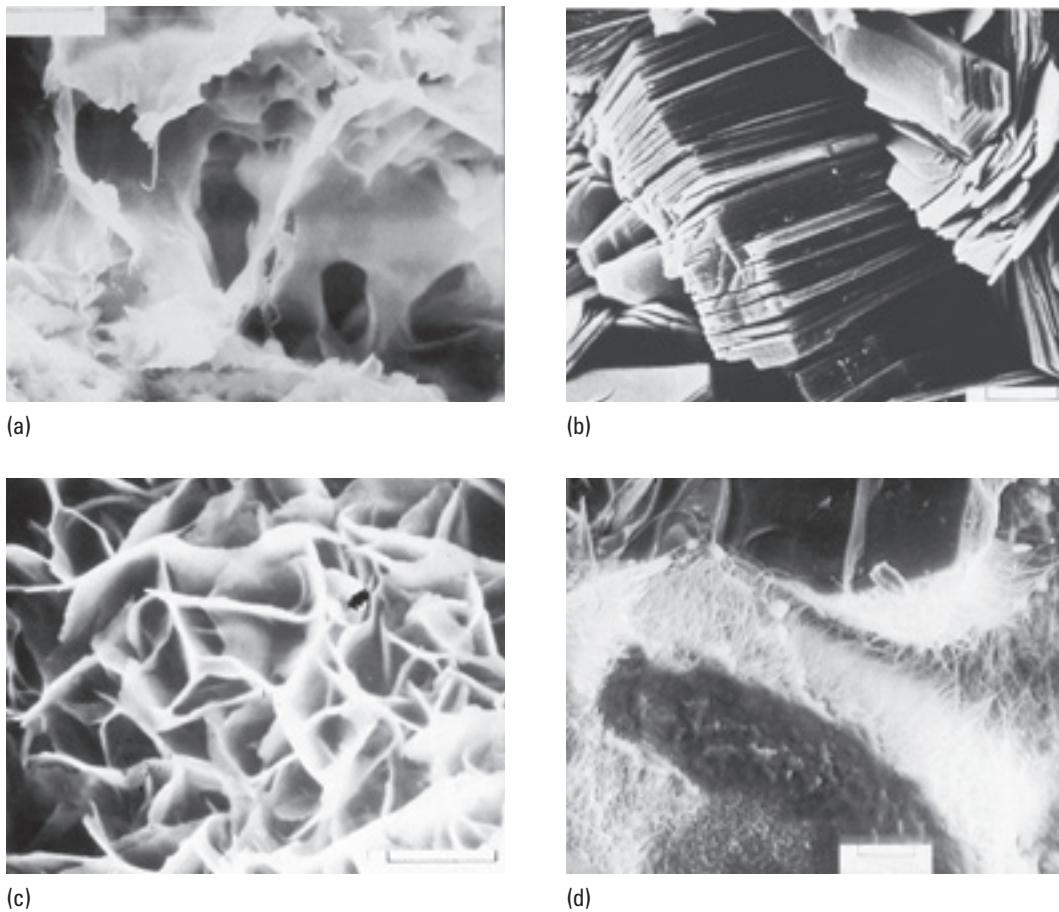
The distinction between clay types depends more on the arrangement of the atoms in their crystalline structure than any major difference in their chemical formula. However, small differences in chemical formula, e.g., the presence of iron, can lead to major problems during treatment. The structures of kaolinite, smectite, illite and chlorite are shown in Fig. 4-2. The structural differences between the clays determine the surface area that is exposed to the reservoir fluids. While clay reactivity is a function of this surface area, the location of the clay in the rock matrix is also critical to its reactivity. Simply because the clay is in the rock does not mean that the clay is reactive.

Authigenic clays, which grow in the pores from minerals in the connate water (Wilson and Pittman, 1977), can be pore filling or pore lining. Authigenic clays have a large amount of surface area exposed in the pore and can be reactive. Detrital clays, part of the building material in the original matrix, are usually less reactive than authigenic clays, because they have less surface area in contact with the fluids in the pore.

Clay may also act as cement holding the matrix grains together. As a binder or cement, clay may react with fluids such as acid and water to deconsolidate the formation. If the clay cement is shielded by a quartz overgrowth, as is common in many sandstone formations, the clay will not be reactive. Only authigenic clays, unprotected clay cements and the few detrital clays on the pore boundary can potentially cause damage. The common clays that account for most of the real and perceived clay problems are kaolinite, smectite (montmorillonite), illite and chlorite. Fortunately, these minerals can be dissolved with HF acid; so, the damage can be treated. If formation collapse is a concern when unprotected clay cement is present, the recommended acid strength would need to be adjusted.

In recent years, clay compatibility with hydrochloric acid (HCl) has become an issue. All clays have a temperature at which they become unstable in HCl (Table 4-1). Unstable clays decompose quickly and consume all available HCl. Silica gel precipitates, which damage the matrix, are products of the decomposition of these clays. Therefore, the presence of these specific clays can have a large influence on the ultimate fluid recommendation.

<sup>†</sup>See *Fluid Selection Guide for Matrix Treatments* (TSL-2069)  
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**Figure 4-2.** Photomicrographs of (a) pore-filling smectite sheets, (b) books of kaolinite platelets in a pore space, (c) honeycomb growth of chlorite on a sand grain (d) hairs of illite extending from a sand grain.

**Table 4-1. Clay instability in HCl acid  
(Simon & Anderson, 1990)**

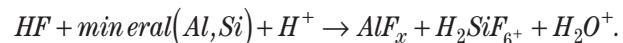
Mineral	Maximum Temperature ( degF [ degC] )
Zeolites	75 [24]
Chlorites	150 [65]
Illite	190 [87]
Mixed layer	200 [93]
Smectite	200 [93]
Kaolinite	250 [121]

## Chemistry of sandstone acidizing

The chemical reactions between sandstone minerals and HF acids have been extensively described in the literature. There are three classes of HF reactions: primary, secondary and tertiary.

### Primary reactions

Primary reactions describe the action of the unspent acid with the various minerals as follows:

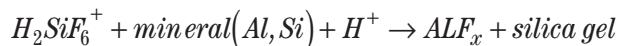


The presence of calcium ( $Ca^{++}$ ) will cause calcium fluoride ( $CaF_2^+$ ) to precipitate. Sodium ( $Na^+$ ) and potassium ( $K^+$ ) can create alkali-fluosilicates and alkali-fluoaluminates when formation minerals, or sodium or potassium brines, react with the hexafluorosilicic acid produced by this reaction. The fluosilicate and fluoaluminate compounds are more likely to form during the

initial phases of the dissolution, since a high concentration of HF relative to the clay enhances the reaction. Precipitation of these compounds will occur when the amount present increases above the solubility limit.

### Secondary reactions

Secondary reactions describe the action of the hexafluorosilicic acid with remaining acid and the rock as follows:

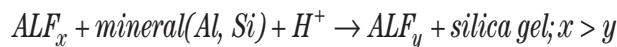


The driving force for this reaction is the greater affinity of fluorine for aluminum than for silicon. Silica gel precipitation is well documented. This precipitation occurs when the initial HF is nearly consumed.

An exchange reaction occurs on the surface of the clays and fines to generate fluoaluminates and silica gel. The silica is deposited on the surface of the mineral particles, and the fluoaluminates remain in solution. This precipitate is more likely to occur when fast-reacting aluminosilicates, such as clays, are present. The damaging effect of silica gel precipitates is still a point of debate; however, it does appear that they are more damaging at higher than lower temperatures.

### Tertiary reactions

Recently there has been much discussion about whether tertiary reaction products are damaging to the reservoir. Tertiary reactions are the reactions of the aluminum fluorides and aluminosilicates.



This reaction is due to the greater stability of  $AlF_y$  over  $AlF_x$ , which leads to continued reduction of the F/Al ratio in spent HF until all remaining HCl is spent. The reaction is insignificant at temperatures below 194 degF [90 degC]. At higher temperature, the reaction can be considerable depending on the stability of the formation clays with HCl. As the reaction drives on, and HF is spent, complex aluminofluorides may be precipitated out deep in the matrix. Gdanski and Shuchart's (1998) recommendations of 9%HCl:1%HF are based on these observations.

### Other reactions

Iron is another potential source of precipitation during sandstone acidizing. Precipitation is due to the formation of colloidal ferric hydroxide as the acid spends ( $pH > 2$ ). Sources of ferric iron ( $Fe^{3+}$ ) include some minerals (chlorite and glauconite clays) and tubing rust (iron oxide). These reactions begin to precipitate gelatinous ferric hydroxide at a pH of 2.2. The nature of the precipitate (crystalline or amorphous) varies as a function of the anions present (Smith *et al.*, 1969). Precipitation of ferric hydroxide during acid injection is normally not a problem, if an adequate HCl tubing wash was used to remove most of the soluble  $FeO_2$ .

All acids used for matrix treatments should also contain iron control additives, either sequestering or reducing agents or both. Ferrous iron ( $Fe^{2+}$ ) is typically not problematic, since ferrous hydroxide precipitates at a pH between 7.7 and 9.

**Table 4-2. Possible precipitates in sandstone acidizing**

Precipitate	Origin
Calcium fluoride ( $CaF_2$ )	Carbonate-HF reaction $CaF_2$ can be caused by an inadequate HCl preflush to remove calcium ions from calcite cementing materials or to flush calcium chloride completion fluids away from the near wellbore.
Amorphous silica	Clay and silicate dissolution in HF. Amorphous silica results from both secondary and tertiary HF acidizing reactions.
Sodium and potassium fluosilicates	Feldspar and illite clay dissolution in HF produce these primary reaction products. They can also form if seawater or sodium or potassium brines are mixed with spent HF.
Sodium and potassium fluoaluminates	Silico-aluminate dissolution in HF. Fluoaluminates, like the fluosilicates, occur when spent mud acid ( $H_2SiF_6$ ) reacts with the formation. They can also form if seawater or sodium or potassium brines are mixed with spent HF.
Aluminum hydroxides and fluorides	Clay and feldspar dissolution in HF can cause these precipitates.
Iron compounds	Iron minerals or iron oxides (rust) can react with HCl-HF to produce these compounds.

The main sources and causes of precipitates formed during sandstone matrix acidizing are summarized in Table 4-2. The formation of these potentially damaging precipitates is affected by the complex mineralogy of many sandstones. The likelihood of damage depends on several factors:

- Chemical—Are the reaction products soluble either in the overflush or the formation fluid?
- Crystallographic—Are the precipitates amorphous or crystalline?
- Morphological—Do they produce grains that can migrate, or do they cover undissolved particles?
- Concentration—Is the concentration high enough to cause plugging in the pore system?
- Physical—Is the damage potential also related to rock properties like permeability, pore size, pore configuration or other reservoir characteristics?

### Reaction front

Sandstone acidizing reactions occur where the fluids meet minerals. As fluid is injected, the position of the zone where reactions take place moves radially outward from the wellbore. Figure 4-3 represents this moving reaction front. The blue line shows the acid concentration relative to the reaction front. As the acid moves through the near wellbore region where all acid soluble minerals have been dissolved, it retains its full strength. Acid spending takes place in the reaction front. The radial width of this zone depends on the minerals present and the temperature of the reservoir at the point of contact, which is affected by any residual cool down effects due to difference between fluid and rock temperature. When the injected fluid is totally spent, it moves through the unreacted minerals.

The primary reactions occur when fresh acid contacts fresh reservoir. This typically happens in the near wellbore region. As spent acid moves through this same

matrix, the secondary and tertiary reactions occur with the reaction products precipitating further away from the wellbore. It is important to keep the injected fluid moving to carry reaction products past the critical matrix region of the well.

### Sandstone treatment design

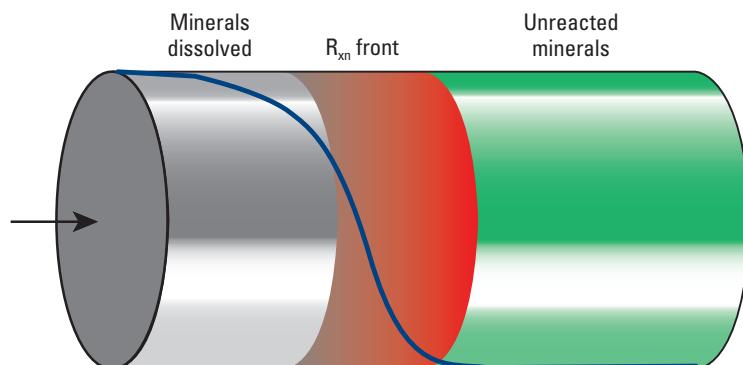
Proper treatment design can be very effective in decreasing the negative effects of pumping acids into sandstone through the use of multiple injection stages and correct fluid selection. A typical matrix treatment in a sandstone will include a preflush, a main fluid and an overflush. When long intervals are treated, diversion stages are pumped after the overflush and before the next stage of preflush.

### Preflush

The sequence of fluids used in a sandstone treatment is largely dependent on the damage type(s) being addressed. A preflush is a fluid stage pumped ahead of the main treating fluid. Multiple preflush stages are sometimes used to address multiple damage mechanisms and prepare the surface for the main treatment fluids.

In sandstone reservoirs, the acid preflush serves two purposes:

- To displace the formation brines, usually containing K, Na, or Ca ions, away from the wellbore so there will be no mixing with HF acids. This decreases the probability of forming alkali-fluosilicates such as potassium hexafluorosilicate.
- To dissolve as much of the calcareous material as possible, prior to injection of the HF acid to minimize calcium fluoride precipitation.



**Figure 4-3. Moving front reaction.**

Due to reservoir heterogeneities, it is unlikely that the acid preflush will remove all of the calcite. However, it has been shown that reducing calcite below 6% is sufficient to avoid precipitation (Fig. 4-4). Strength and volume guidelines are based on the criteria set up in the work done by Labrid (1971), Fogler *et al.* (1976), Kline (1980), Kline and Fogler (1981) and Walsh *et al.* (1982). This theoretical work was further investigated and confirmed by fieldwork done by Gidley (1985), McLeod (1984), Thomas and Crowe (1981) and others.

Using an additional ammonium chloride ( $\text{NH}_4\text{Cl}$ ) brine preflush for sandstone acid treatments is an emerging practice. This preflush conditions the formation clays as it moves formation water away from the near wellbore area. The  $\text{NH}_4^+$  ions in the brine exchange with the alkali (Na, K, or Ca) ions on the clay particles; so, they will be displaced from contact with the mud acid. The effectiveness of this procedure appears to be controlled by the brine concentration at a radial distance of 2.5 ft from the wellbore. This preflush is pumped at the start of the job to establish injectivity before the regular mud acid treatment is pumped. It is only pumped once and is not a part of the regular treating sequence.

Hydrocarbon solvents can be used to remove oil films and paraffin deposits; so, the aqueous acid systems can contact the surfaces of the mineral. These types of preflushes affect treatment success because the acid must contact the damage before it can react with it. A solvent preflush is typically not a part of the normal fluid staging. Like the brine preflush, it is pumped before the normal acid treatment. If a diverter is necessary for better

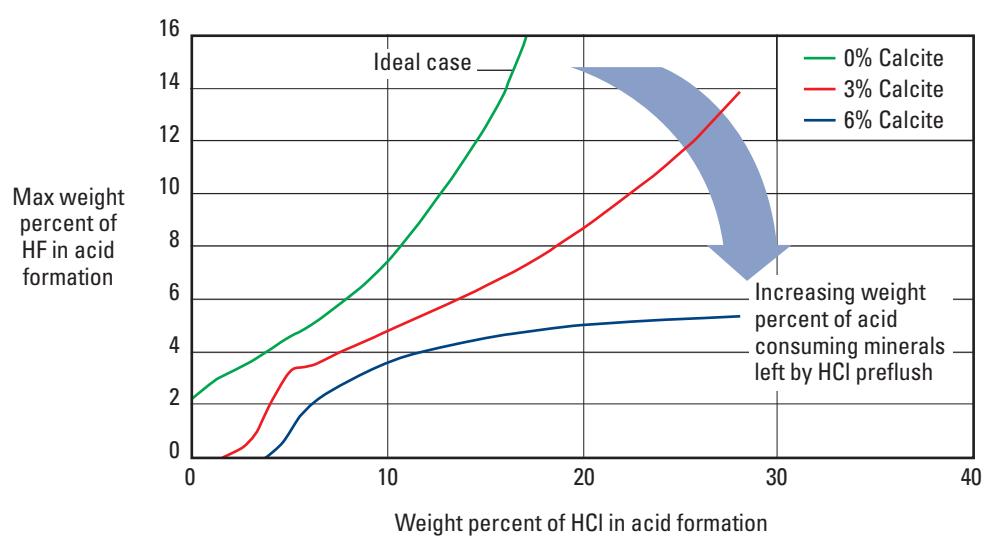
coverage, the diverter is pumped between solvent slugs and before the first acid preflush.

Mutual solvents can also be added to preflush and overflush fluids. However, they must be thoroughly tested for compatibility with the oil in place. Adding mutual solvents to the preflush will help remove oil from the near-wellbore region and leave the rock and damaging materials water-wet. This enhances the rate of acid attack. Mutual solvents can increase inhibitor requirements; so, all formulations must be tested before pumping.

### Main fluid

The main fluid in a sandstone acid treatment is the fluid used to remove the damage. It is typically a mixture of hydrofluoric (HF) and hydrochloric (HCl) or organic acids. HF acid is used because it is the only common, inexpensive mineral acid able to dissolve siliceous minerals. It is mixed with HCl or organic acid to keep the pH low when it spends to aid in prevention of detrimental precipitates. These mixtures are called mud acids because they were originally developed to treat siliceous drilling mud damage.

HF acid should not be used in sandstone formations with high carbonate content. The risk of forming calcium fluoride precipitates is too great, since it is unlikely that a sufficient amount of HCl acid preflush can be pumped. The accepted cutoff point for the use of hydrofluoric acid is 20% calcite + dolomite based on the guidelines developed by McLeod in 1984.



**Figure 4-4 . HCl/HF ratio to avoid precipitation, based on  $\text{AlF}_3$  and  $\text{CaF}_2$  precipitation(Walsh *et al.*,1982).**

## Overflush

The overflush is an important part of a successful sandstone acid treatment. It performs the following functions:

- displacement of the nonreacted mud acid into the formation
- displacement of the mud acid reaction products away from the wellbore
- removal of potential oil-wet relative permeability problems caused by some corrosion inhibitors.

The overflush fluid must be miscible with the acid in order to displace it. Therefore, aqueous-base liquids should be considered as the first displacing and flushing fluid. This may be followed by other fluid systems depending on the concerns and well conditions. Studies of displacement fronts indicate that the reactivity and fluid character of the overflush have a major influence on the volume required to displace the spent mud acid. Recent experience indicates the advantage of including HCl or acetic acid in the first part of the overflush to maintain a low-pH environment for the displaced spent mud acid stage.

The minimum total overflush volume should provide at least 3 ft of radial penetration into the formation to move potential problems past the critical matrix where the greatest pressure drop occurs. Damage effects are minimized beyond the critical matrix because of the logarithmic relationship between pressure drop and distance from the wellbore. Volumes that are less than twice the mud acid stage volume should be considered inappropriate. Formation permeability anisotropy may require doubling or even tripling this volume, if the reservoir pressure is sufficient to unload the injected fluid.

Large overflushes help prevent the near wellbore precipitation of amorphous silica. At formation temperatures of 200 degF [93 degC] or greater, amorphous silica precipitation occurs while the mud acid is being pumped into the formation. The precipitate is somewhat mobile at first, but it can set up as a gel after flow stops. If this potentially damaging material is kept moving by the overflush fluid, it will be diluted and moved beyond the critical matrix.

## Sandstone treatment fluid selection

Fluid selection rules for each stage of the treatment must consider all of the parameters previously discussed: dissolution of damage, compatibility with rock minerals and reservoir fluids and potential damaging reaction products. The rules for the selection of acids are shown below, and they are the same as those in the Fluid Selection Advisor (FSA) of the StimCADE design program. The main selection criteria are the formation mineralogy and permeability. The selection of nonacid fluids for treating damages such as organic deposits,

wettability changes and water block will be discussed at the end of this chapter.

Formation lithology affects the selection of acid strength. Since silts and clays are the component minerals that react with HF acid to cause potentially damaging precipitates, the higher the silt and clay content, the greater risk of precipitation. Increasing the HCl:HF ratio is one way to retard precipitation. HCl increases the dissolving power of the HF and a low-HF content reduces the precipitation of silica. Therefore, as the silt and clay content of the formation increases, the recommended HCl:HF ratio also increases. The presence of HCl sensitive clays will also affect the type of acid chosen.

X-ray diffraction (XRD) analysis is the most common test used to determine formation mineralogy. However, this data is not always available. Formation solubility in both HCl and HCl:HF can be used to approximate the total silt and clay content. The difference in these solubilities correlates well to silt and clay content by XRD analysis as seen in Table 4-3. Solubility information, however, does not indicate the type of clay present.

**Table 4-3. XRD versus Solubility Analysis**

Formation	Silt and Clay from XRD (%)	Difference in solubility between HCl and HCl:HF (%)
Muddy sand	7.0	5.2
Brazos sand	13.6	13.0
Miocene A	25.0	20.7
Miocene B	26.0	22.1
Miocene C	34.0	33.6

Permeability affects acid selection by influencing the amount of damage caused by acid precipitates. A low-permeability formation will be more severely damaged by precipitates than a formation with high permeability. Therefore, weaker acids, which help limit precipitation, are recommended for lower permeability formations.

## Brine preflush or overflush

The NH<sub>4</sub>Cl brine concentration used in a sandstone acid treatment is based on obtaining a 3% NH<sub>4</sub>Cl solution at a distance of 2.5 ft from the well when a volume of 50 gal/ft is pumped. The calculation considers the cation exchange capacity of the various silt and clay components in the formation. The recommended brine concentration is calculated automatically in the StimCADE FSA module, or the following equation can be used:

$$\text{Concentration} = 3 + (\% \text{ smectite} \times 0.3) + (\% \text{ illite} \times 0.12) + (\% \text{ kaolinite} \times 0.08) + (\% \text{ chlorite} \times 0.12) + (\% \text{ feldspar} \times 0.05)$$

(Be sure and add the smectite and illite in mixed layer clays to their respective totals.)

A minimum concentration of 3% NH<sub>4</sub>Cl is used if no clays are present. From the equation, it is obvious that the amount of smectite present in the rock has the most effect. If smectite is present, even if the amount isn't known, use a higher concentration of NH<sub>4</sub>Cl. If the core flow tests exhibit sensitivity to water, smectite should be suspected.

### Acid preflush or overflush

The acid used as a preflush or an overflush to a main treatment containing hydrofluoric acid depends on the silt and clay content of the formation, its permeability and the presence of HCl sensitive minerals, like chlorite, glauconite and zeolites. Table 4-4 lists the acid preflush recommendations. For operational simplicity, the same acid is used for both pre- and overflush.

Organic acids are recommended for use in conjunction with, or instead of, HCl in sensitive formations.

Although they will dissolve the carbonate, they work more slowly. When pumping organic acids as stand-alone fluids, they should be mixed in ammonium chloride rather than fresh water. Organic acids also act as a low-pH buffer and complexing agent that helps minimize the tendency of iron compounds to precipitate as the acid spends. However, they do not dissolve iron scale or prevent clay swelling.

### Main treatment fluid

Determining the proper blend of HCl and HF to use in a mud acid mixture, and whether HCl or organic acid is used, is a complex process. The selection depends on the silt and clay content of the formation, its permeability and the presence of HCl sensitive clays. The criteria are similar to those for choosing the acid preflush or overflush concentration. Table 4-5 lists the recommendations based on these parameters.

**Table 4-4. Acid Preflush and Overflush Selection**

Lithology Criteria (%)			Permeability (mD)	Acid Concentration
Zeolites	Chlorite +	Silt and Clay	Glauconite	
>2	Any	Any	Any	10% Acetic
≤2	>6	Any	Any	10% Acetic
≤2	3–6	>10% silt or >10% clay	Any	5% HCl + 5% Acetic
≤2	3–6	<10% silt and <10% clay	Any	7.5% HCl + 5% Acetic
0–2	≤3	>10% silt or >10% clay	>100	10% HCl + 5% Acetic
0–2	≤3	<10% silt and <10% clay	>100	15% HCl + 5% Acetic
0–2	≤3	>10% silt or >10% clay	20–100	7.5% HCl + 5% Acetic
0–2	≤3	<10% silt and <10% clay	20–100	10% HCl + 5% Acetic
0–2	≤3	>10% silt or >10% clay	≤20	5% HCl + 5% Acetic
0–2	≤3	<10% silt and <10% clay	≤20	7.5% HCl + 5% Acetic
0	≤3	>10% silt or >10% clay	>100	10% HCl
0	≤3	<10% silt and <10% clay	>100	15% HCl
0	≤3	>10% silt or >10% clay	20–100	7.5% HCl
0	≤3	<10% silt and <10% clay	20–100	10% HCl
0	≤3	>10% silt or >10% clay	≤20	5% HCl
0	≤3	<10% silt and <10% clay	≤20	7.5% HCl

**Table 4-5. Mud Acid Selection.**

Lithology Criteria (%)		Permeability (MD)	Acid Concentration
Zeolites	Chlorite + Glaucnrite	Silt and Clay	
>5	Any	>10% silt and >10% clay	>20 OCA HT
>5	Any	>10% silt or >10% clay	>20 OCA HT
>5	Any	<10% silt and <10% clay	>20 OCA HT
>5	Any	>10% silt and >10% clay	≤20 OCA HT
>5	Any	>10% silt or >10% clay	≤20 OCA HT
>5	Any	<10% silt and <10% clay	≤20 OCA HT
2–5	3–6	>10% silt and >10% clay	>20 OCA
2–5	3–6	>10% silt or >10% clay	>20 OCA
2–5	3–6	<10% silt and <10% clay	>20 OCA
2–5	3–6	>10% silt and >10% clay	≤20 OCA
2–5	3–6	>10% silt or >10% clay	≤20 OCA
2–5	3–6	<10% silt and <10% clay	≤20 OCA
≤2	>9	>10% silt and >10% clay	Any OCA HT
≤2	>9	>10% silt or >10% clay	Any OCA HT
≤2	>9	<10% silt and <10% clay	Any OCA HT
≤2	6–9	>10% silt and >10% clay	>20 OCA HT
≤2	6–9	>10% silt or >10% clay	>20 OCA HT
≤2	6–9	<10% silt and <10% clay	>20 OCA HT
≤2	6–9	>10% silt and >10% clay	≤20 OCA HT
≤2	6–9	>10% silt or >10% clay	≤20 OCA HT
≤2	6–9	<10% silt and <10% clay	≤20 OCA HT
≤2	3–6	>10% silt and >10% clay	>20 9 % HCl + 1% HF + 5% Acetic
≤2	3–6	>10% silt or >10% clay	>20 9 % HCl + 1.5% HF + 5% Acetic
≤2	3–6	<10% silt and <10% clay	>20 8 % HCl + 2% HF + 5% Acetic
≤2	3–6	>10% silt and >10% clay	≤20 4.5 % HCl + 0.5% HF + 5% Acetic
≤2	3–6	>10% silt or >10% clay	≤20 6% HCl + 1% HF + 5% Acetic
≤2	3–6	<10% silt and <10% clay	≤20 6% HCl + 1.5% HF + 5% Acetic
0–2	≤3	>10% silt and >10% clay	>100 13.5% HCl + 1.5% HF + 5% Acetic
0–2	≤3	>10% silt or >10% clay	>100 12% HCl + 2% HF + 5% Acetic
0–2	≤3	<10% silt and <10% clay	>100 12% HCl + 3% HF + 5% Acetic
0–2	≤3	>10% silt and >10% clay	20–100 9% HCl + 1% HF + 5% Acetic
0–2	≤3	>10% silt or >10% clay	20–100 9% HCl + 1.5% HF + 5% Acetic
0–2	≤3	<10% silt and <10% clay	20–100 8% HCl + 2% HF + 5% Acetic
0–2	≤3	>10% silt and >10% clay	≤20 4.5% HCl + 0.5% HF + 5% Acetic
0–2	≤3	>10% silt or >10% clay	≤20 6% HCl + 1% HF + 5% Acetic
0–2	≤3	<10% silt and <10% clay	≤20 6% HCl + 1.5% HF + 5% Acetic
0	≤3	>10% silt and >10% clay	>100 13.5% HCl + 1.5% HF
0	≤3	>10% silt or >10% clay	>100 12% HCl + 2% HF
0	≤3	<10% silt and <10% clay	>100 12% HCl + 3% HF
0	≤3	>10% silt and >10% clay	20–100 9% HCl + 1% HF
0	≤3	>10% silt or >10% clay	20–100 9% HCl + 1.5% HF
0	≤3	<10% silt and <10% clay	20–100 8% HCl + 2% HF
0	≤3	>10% silt and >10% clay	≤20 4.5% HCl + 0.5% HF
0	≤3	>10% silt or >10% clay	≤20 6% HCl + 1% HF
0	≤3	<10% silt and <10% clay	≤20 6% HCl + 1.5% HF

The cleaner the sandstone (lower silt and clay content) and the higher the permeability, the lower the HCl:HF ratio, and the more aggressive the treatment can be. Typically, the HCl:HF ratio is either 4:1, 6:1, or 9:1. A higher volume of weak acid must be pumped to attain the same results as a smaller volume of a stronger acid. This is an important consideration when designing treatments for environmentally sensitive areas where disposing spent acids can create problems.

The ratio of HCl:HF should be increased if the formation contains clay rather than calcite cementing materials. Pick the acid concentration recommended in Table 4.5. If the HCl:HF ratio is less than 9:1, change the recommendation to the 9:1 ratio that contains a lower HF content. For example, if a 6:1 HCl:HF fluid is normally used, change to a 4.5:0.5 HCl:HF mixture.

**Table 4-6. Acid Selection for High Calcite Sandstones**

Chlorite + Glauconite	Reservoir Temperature ( degF [ degC ] )	Acid Recommendation
>0	>200 [>93]	10% Acetic
>0	≤200 [≤93]	10% HCl
0	>300 [>148]	10% HCl
0	≤300 [≤148]	15% HCl

Mud acids should only be used in formations with less than 20% carbonate (calcite + dolomite) because of the increased risk of forming damaging calcium fluoride precipitates at higher carbonate content. HCl or acetic acids are used for these formations. The specific acid used is dependent upon reservoir temperature and the presence of HCl sensitive clays as shown in Table 4.6.

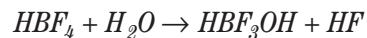
Sandstone treatment fluid recommendations are automatically determined in the FSA of the StimCADE matrix design program. All rules and special cases discussed in this book are part of this computer program, which will also make diverter recommendations.

## Specialty acids

### ClayACID

ClayACID\* treatment is a sandstone acidizing system employing fluoboric acid ( $\text{HBF}_4$ ). ClayACID treatment not only provides good stimulation but also provides permanent stabilization of clays and other fines as

well as eliminating water sensitivity and the mobility of migratory fines (Thomas and Crowe, 1981). The acid slowly releases HF in situ through the hydrolysis of  $\text{HBF}_4$  according to the following reaction:



At any given time, there is only a limited amount of hydrofluoric acid available. The acid is consumed by reaction on clay minerals followed by hydrolysis of fluoboric acid to produce more HF. Therefore, ClayACID fluid is a retarded acid and can penetrate to a much greater distance from the wellbore before spending than mud acid can.

At higher temperatures, >150 degF [65 degC], the kinetics of hydrolysis is rapid. Equilibrium conditions dictate that there is only a limited amount of HF present in solution at any given time. For example, at 212 degF [100 degC] only 0.15% HF is present. Thus, the reaction rate is similar to a very dilute mud acid solution. The result of having such a limited amount of HF available is a decreased probability of forming precipitates of fluosilicates, fluoaluminates or silica.

A major advantage of the ClayACID system is its ability to inhibit the migration of formation fines. Depending on the mineral attacked, partial dissolution takes place, and boron is included in the lattice of the mineral crystal. As a result of this topochemical reaction, borosilicate reaction products coat the mineral surface. The coating does not plug the pores but desensitizes the minerals and stabilizes fines particles by fusing them to the sand grains.

Clay Acid can be used as an alternative to mud acids in formations that show severe sloughing when treated with mud acid. Clay Acid is also recommended for severe fines migration, which is indicated by rapid declines in production that can be as large as 50percent in 6 months. When used for this application, it is pumped as an overflush to a mud acid treatment.

There are two ClayACID formulations. Use ClayACID regular for reservoir temperatures up to 300 degF [148 degC]. Use ClayACID LT for reservoir temperatures to 130 degF [54 degC], but not for temperatures above that. When pumping ClayACID fluids, displace the fluid just into the formation. Do not overflush! To obtain the maximum stabilization effect, the ClayACID feature should react and coat the clays in the critical matrix portion of the reservoir. The well should also be shut in after pumping ClayACID fluid due to its longer reaction time. Table 4-7 lists minimum shut-in times by temperature.

**Table 4-7. Clay Acid Shut-In Time**

BHST ( degF [ degC ])	Min Shut-In Time (hr)	
	Regular Cla ACID	ClayACID LT
100 [37]	96	48
110 [43]	76	38
120 [48]	52	26
130 [54]	35	18
140 [60]	24	Not recommended
150 [65]	16	Not recommended
160 [71]	11	Not recommended
170 [76]	8	Not recommended
180 [82]	5	Not recommended
190 [87]	3	Not recommended
225 [107]	2	Not recommended
250 [121]	1	Not recommended
300 [148]	0.5	Not recommended

### Organic clay acid

In cases where high concentrations of acid sensitive clays, such as zeolite, chlorite or glauconite, are present, specialized acids, like OCA\* Organic Clay Acid) are available. This acid system can also be used when acidizing sandstone formations with very high-bottomhole temperatures or when the total clay content of the formation is greater than 30%. OCA formulations are mixtures of an organic acid and fluoboric acid. When used in matrix acidizing applications, OCA fluid

- removes formation damage caused by clay and other aluminosilicate minerals
- minimizes hydrated silica precipitation, which is known as the secondary reaction
- prevents migration of undissolved fines post acidizing treatments
- treats high-temperature sandstone wells. OCA fluids can be used at temperatures ranging from 80 degF to 400 degF [27 degC to 204 degC].

There are two formulations recommended for different conditions. The first formulation, OCA-Regular, is used for temperatures lower than 350 degF [176 degC] or in formations containing low concentrations of HCl sensitive minerals. The second formulation, OCA-HT, is intended for sandstone formations with temperatures 350 degF [176 degC] and above or in formations containing more than 5% of zeolite or chlorite.

When considering this fluid, crude oil compatibility testing is required. If an incompatibility exists, OCA fluids may form a thick, rigid emulsion that will inhibit cleanup of the formation. This problem appears to be most commonly associated with highly paraffinic crudes.

### Mud and silt remover

MSR\* mud and silt remover, which dissolves, disperses and suspends damaging particles and fines, can be formulated with HCl/HF mixtures. Naturally fractured sandstone is a very hard, compact, low-porosity and low-permeability formation. The reservoir productivity usually comes from the fracture system. These fractures can be plugged with drilling solids. MSR fluids can be used in these types of formations where the plugging particles are located in natural fissures or in hydraulically induced fractures.

MSR formulation is determined using the same criteria as a normal sandstone main treating fluid. However, if organic acids are required due to extreme high temperature or sensitive clays, consult the regional technical specialist or laboratory. MSR is not normally formulated using organic acids.

### Dynamic acid dispersion

DAD\* dynamic acid dispersion, is an acid outside-phase emulsion prepared and stabilized with Dispersing Agent U74. The purpose of the dispersion is to simultaneously dissolve acid-soluble minerals and remove oily paraffinic deposits. Target areas can be tubulars, perforations or the critical matrix. DAD can be used as a preflush ahead of mud acid or ClayACID during matrix treatment procedures. This low-viscosity dispersion allows one-stage cleanup and acidizing of hydrocarbon-coated formations, gravel packs, wellbores and tubulars. Various ratios of acid and hydrocarbon solvent are possible with common dispersions ranging from 90% acid and 10% organic solvent to 50% acid and 50% organic solvent.

### NARS fluid

NARS\* fluids are special treating solutions that contain no acid. These fluids are used as cleanup and breakdown fluids in formations that may be damaged by acid. These solutions are nondamaging to water- or acid-sensitive formations and contain strong chelating and clay suspending agents. They can be used in high-temperature reservoirs (greater than 400 degF [204 degC]) but should not be used if downhole temperatures are below 100 degF [37 degC]. Two solutions, NARS 200 and NARS201, are currently being used.

## Non-acid treatments

Solvents, bleach and other nonacid fluids are used to treat specific damage mechanisms. The damages and recommended fluids are outlined in Table 4-8.

**Table 4-8. Recommendations for Nonacid Fluids**

Damage Mechanism	Recommendation
Asphaltenes or paraffin	Xylene
Bacteria	Formation Cleaning Solution (M91) followed by acid treatment
Emulsion block or injection carryover of emulsion	CLEAN SWEEP*
Injection carryover of oil	CLEAN SWEEP†
Mixed organic and inorganic scale deposits	DAD†
Water block	CLEAN SWEEP†
Wettability alteration	CLEAN SWEEP†

\* Consult *Matrix Materials Manual* for CLEAN SWEEP or DAD recommendation for specific well conditions.

# Carbonate Reservoirs

## Introduction

Treatment fluid selection in carbonate formations is significantly different than in sandstone formations because the damage is by-passed by the creation of new, highly conductive channels called wormholes. The treatment objective is to form the longest and deepest-penetrating wormholes possible. Therefore, wormholing efficiency under expected downhole and surface treating conditions becomes a major criterion in fluid selection.

## Carbonate Rocks

### Origin and Description

Like sandstones, carbonates are sedimentary rocks. The vast majority of these sediments are composed of skeletons of marine organisms. To a lesser extent, carbonate sediment also results from the chemical precipitation of calcium carbonate.

After their deposition, carbonate sediments are subjected to chemical change (diagenesis) and physical transformation (compaction). Chemical modifications mostly consist of the evolution of the sediments to stable forms such as calcite and dolomite.

Limestone, the most abundant carbonate, is rock generally composed of more than 50% of the mineral calcite and/or aragonite. Calcite is relatively stable while aragonite will generally change over time into calcite. Limestone may be white, gray, dark gray, yellowish, greenish, or blue in color; some may even be black. Color variation is due to the admixture of clay particles or organic matter.

Rocks classified as dolomite generally contain more than 50% dolomite. Dolomites are the result of diagenesis under long-term contact with waters of high magnesium content. While dolomitization can generally increase porosity, most often it impairs the permeability by precipitating dolomite crystals. The inverse process, called dedolomitization, can dramatically increase both the rock porosity and permeability.

Modifications of permeability and porosity can also result from other chemical transformations: dissolution, reprecipitation, and cementation under contact with subterranean water, or molecular diffusion under severe

subsurface conditions. Fractures in the limestone often control the movement of water that flows through it. Caves and caverns enlarge as water percolates through the limestone. As the caves become larger, the roof becomes weaker and eventually collapses. Highly dissolved limestone, or karst, has excellent porosity and permeability. While it sometimes has caves, more often it has solution pores up to several inches in diameter called vugs. Both caves and vugs are formed through dissolution by surface water moving through fractures in the sandstone matrix.

Stress and pressure modifications occurring upon burial of the sediments may also cause a lithologic reduction in porosity and a loss of permeability. High in-situ pressures result in grain compaction, with loss of most of the interstitial water. Higher pressures trigger physical dissolution with immediate reprecipitation in the pores causing cementaceous material to line the pore throats. If interstitial water can be expelled, grain joints are also dissolved and reprecipitated, decreasing the rock porosity to near zero and creating fractures.

Carbonate sediments are much more sensitive to these phenomena than sandstones. For instance, chalky mud would become a compact calcitic rock at depths greater than 2,000 m if all the interstitial water was able to escape. Carbonate rocks also tend to have lower permeabilities than sandstone rocks due to these effects. However, the fractures caused by the mechanical and dewatering processes play an important role in the economical viability of the carbonate reservoirs by providing secondary and flow channels so that fluids can be produced.

### Characteristics

The different processes described above have consequences on the characteristics of the carbonate reservoirs. Limestone formations, which are calcitic rocks resulting from complete diagenesis, present a wide range of porosities and permeabilities, depending on the degree of reprecipitation and cementation. Reefs are hard, compact structures that are generally heterogeneous with low permeabilities. Dolomites also often have low matrix permeabilities. Reefs and dolomitic reservoirs are generally fractured under the action of tectonic stresses. These stresses induce a dense network of fissures. Many

of these formations behave like homogeneous, primary porosity reservoirs, with an apparent permeability several orders of magnitude higher than the rock permeability. Consequently, the flow capacity of these rocks is often greater than that of an average sandstone. In the undamaged state, many carbonate rocks will exhibit negative skin values.

While correlations between porosity and permeability have been found to exist in many carbonate reservoirs, they are usually only applicable on a fieldwide rather than a global basis.

Carbonate sediments usually exhibit very high initial porosity since they are formed of noneroded, homogeneous materials. However, the effects of physical stresses that determine the primary and secondary permeability of the resulting carbonate rock tend to vary with the type of sediments. For instance, chalks, issued from high porosity calcitic sediments of microscopic fossils, always present very low permeabilities as compared to oolithic limestones, though they can have similar porosities.

## Chemistry and physics of carbonate acidizing

The greatest distinction between the acid stimulation of carbonate formations and the acid stimulation of sandstone formations is the creation of new porosity.

Carbonate cores acidized with hydrochloric acid show the formation of macroscopic channels, called wormholes. Experiments, performed mainly with linear cores, show that the acid injection rate affects both the channel geometry and the amount of acid required for breakthrough. Daccord *et al.* (1989) found that with limestone cores, wormhole formation occurs above a given critical flow rate and that within the wormholing region, the volume required for breakthrough increases with the rate at the  $\frac{1}{3}$  power. These results were later confirmed by Wang *et al.* (1993) using calcite cores and, at high temperatures, dolomite cores.

Wormhole formation can be explained by the instability of the acidizing phenomenon: Bigger pores tend to receive more acid, which increases both their area and length. This eventually creates a macroscopic channel, or wormhole, which preferentially receives more acid than surrounding pores and propagates through the core. The shape of the wormholes formed depends on the interaction of many parameters including the injection rate, type of fluid, and temperature. If acid is injected at a rate near the wormholing threshold rate, which is the point where the dissolution pattern changes from face dissolution to actual wormholing, a single conical wormhole is formed. Dominant wormholes are more efficient but require higher injection rates.

However, creation of only a few dominant wormholes will exacerbate natural heterogeneities. Any pre-existing high permeability streak or fracture will almost certainly prevent acceptable acid coverage of the wellbore unless good placement techniques are used.

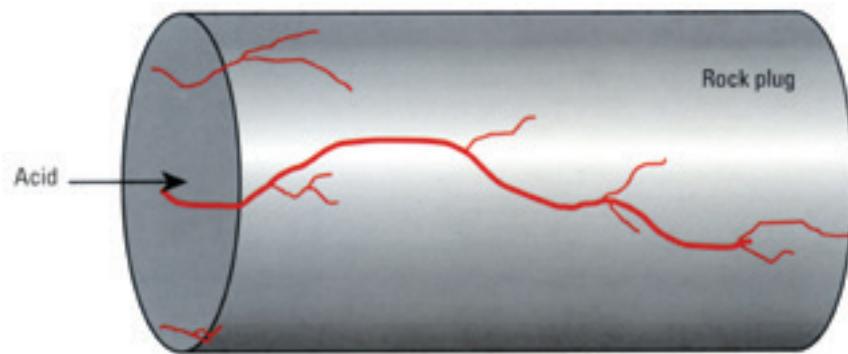
It has been observed that under the right conditions, the wormholes can grow to substantial lengths, resulting in very efficient use of acid to bypass damage. In less favorable situations, the wormhole structure created can utilize a lot of acid to create very short channels. The skin reduction is directly related to the length of the wormholes, because the wormholes act like infinitely conductive flow paths. Wormhole length depends on some operational parameters and physical properties of the formation as well as the acid system.

Figure 5-1 depicts a wormhole that has traversed a cylindrical core plug. There may be more than one wormhole formed. The amount of branching in the wormhole structure depends on factors to be discussed later. The produced structure also depends on the flow geometry, i.e., wormholes in linear experiments will have different structures compared with those in radial or spherical experiments (when conducted under constant injection rate conditions).

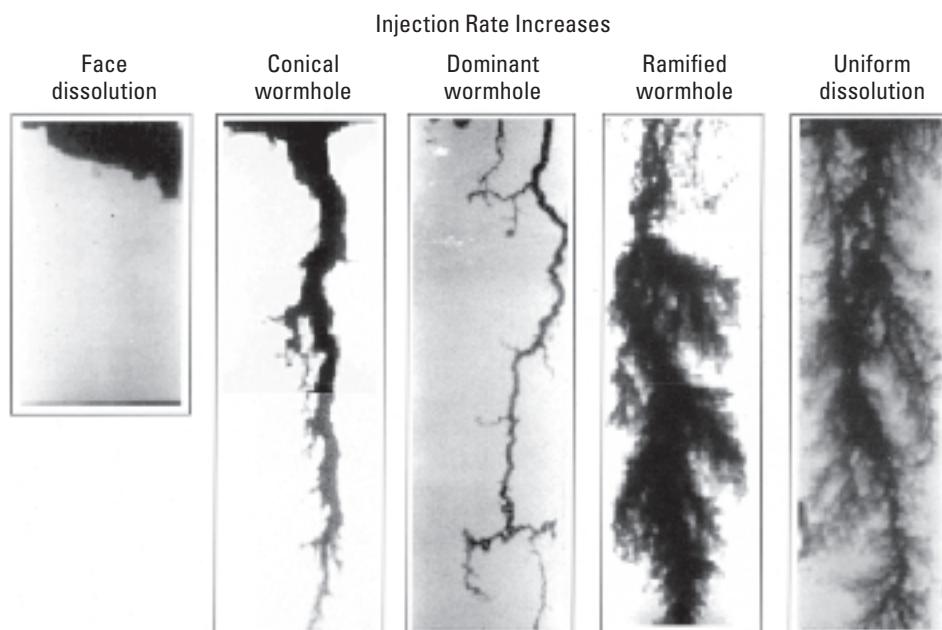
The wormhole structure created during matrix acidizing of carbonates has been studied for 30 years. It is widely recognized that wormhole structure varies from that on the left-hand side of Figure 5-2 to that on the right hand side. In between those two extremes is a continuous range of structures, from relatively straight, thin wormholes to highly branched, ramified wormholes. Among the most highly regarded work is that by D'accord *et al.*, Hoefner and Fogler, Fredd and Fogler, Wang *et al.*, and Frick *et al.*.

The actual structure formed is a strong function of operating parameters: injection rate, temperature, and the type of solvent injected. The type of carbonate mineral studied also affects the final wormhole structure. The following explanation presents one very clear theory that rationalizes the dependence of all wormhole structures on experimental conditions.

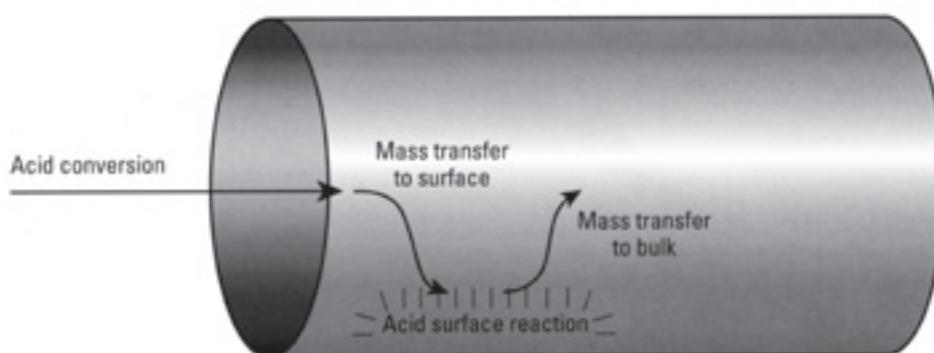
Figure 5-3 represents the pore body as a cylinder. Acid flows by convection into the pore body. Hydrogen ions (in the case of HCl) or acid molecules (in the case of organic acids), undergo mass transfer to the surface of the pore body. This is driven by a concentration gradient between the bulk acid and the concentration at the pore surface. There are three steps in the mass transfer process. Acid first moves to the surface; second, it reacts with the rock; third, the reaction products undergo mass transfer back to the bulk of the flowing acid. This basic process applies for all systems that dissolve carbonate, including chelants, which have a more complicated surface reaction pathway.



**Figure 5-1.** Macroscopic dissolution channels.



**Figure 5-2.** Alternate dissolution patterns (wormhole structures) (Fredd and Fogler, *SPEJ*, 1998, 1999; Helfner and Folger, *AIChEJ*, 1998).



**Figure 5-3.** Pore level model showing competition between acid reaction and transport.

Any one or combination of these steps can control the overall dissolution. There are two extreme conditions that are commonly encountered. When the rate of mass transfer of products is much slower than surface reaction rate, the system is considered to be mass transfer limited. The overall reaction rate can be expressed simply by accounting for mass transfer. The system is considered reaction rate limited when the surface reaction rate is much slower than the mass transfer rate. In this case, the overall rate of reaction can be expressed by accounting for only the reaction kinetics.

Studies performed by Lund *et al.* (1973, 1975) and confirmed by de Rozieres *et al.* (1994) found that the HCl-calcite reaction is mass transfer limited above 32 degF [0 degC]. The HCl-dolomite reaction was found to make a transition between reaction rate limited and mass transfer limited behavior between 122 and 212 degF [50 and 100 degC]. Both the mass transfer and kinetic effects are important to the overall reaction rate at these temperatures.

Equations describing the three steps of the mass transfer process can be combined into one dimensionless group called the Damköhler number (*Da*). The generalized Damköhler number provides a measure of the amount of reactant being consumed on the walls of the wormhole, rather than being transported to the tip, or the end furthest from the wellbore, of the wormhole. *Da* is a function of all three transport and reaction processes. Therefore, it can be applied to a variety of acid/mineral systems including strong acids, weak acids, and chelating agents.

The *Da* number can also be used to relate laboratory experiments and theories to field treatment practices. Through the use of numerical models, reasonable reservoir data can be used to estimate stimulation effectiveness. This is based on the theory relating wormhole efficiency (structure) to the physical properties of the formation, the solvents (acids or chelants) used, and the operating parameters under which the treatments were pumped.

Experiments by Hoefner and Fogler showed that the wormhole structure caused by HCl injected into limestone and chalk core samples does depend on the Damköhler number. More recent work by Fredd and Fogler extended Hoefner's work and showed that the dependence of wormhole structure on the Damköhler number can be generalized to all solvent formation combinations as long as the solvent dissolves the formation and the formation is highly soluble (>50% will dissolve in solvent).

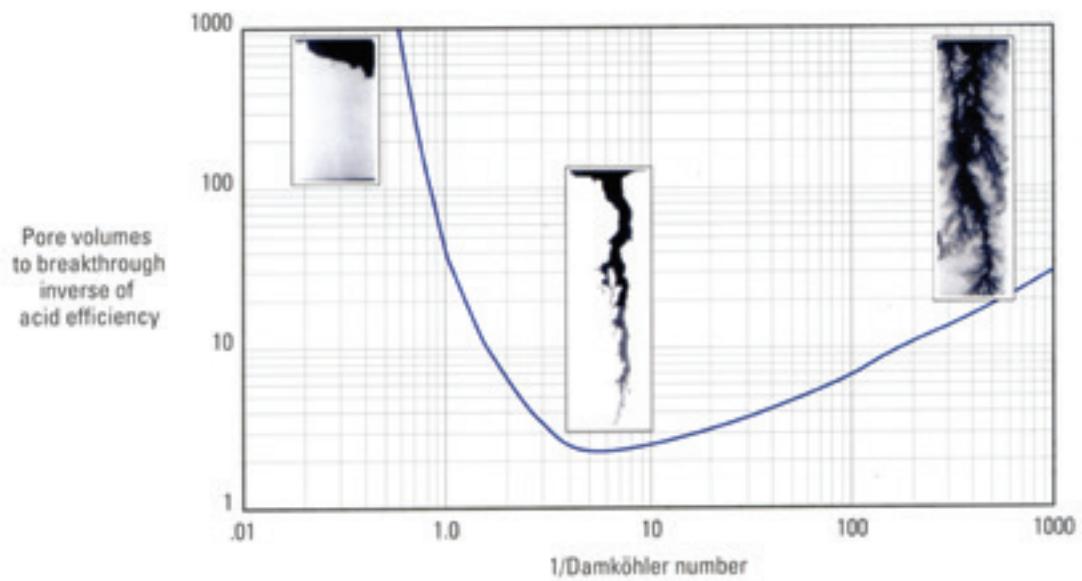
Wormhole structure is related to the efficiency of the acidizing operation. Compact dissolution (see Figure 5-2) is very inefficient, since virtually the entire

matrix must dissolve in order to advance the dissolution front. Uniform dissolution is also relatively inefficient, because all the pore bodies and pore throats must be enlarged to increase the permeability of the sample. In between those two extremes of wormhole structure is an optimum structure that is relatively narrow and unbranched.

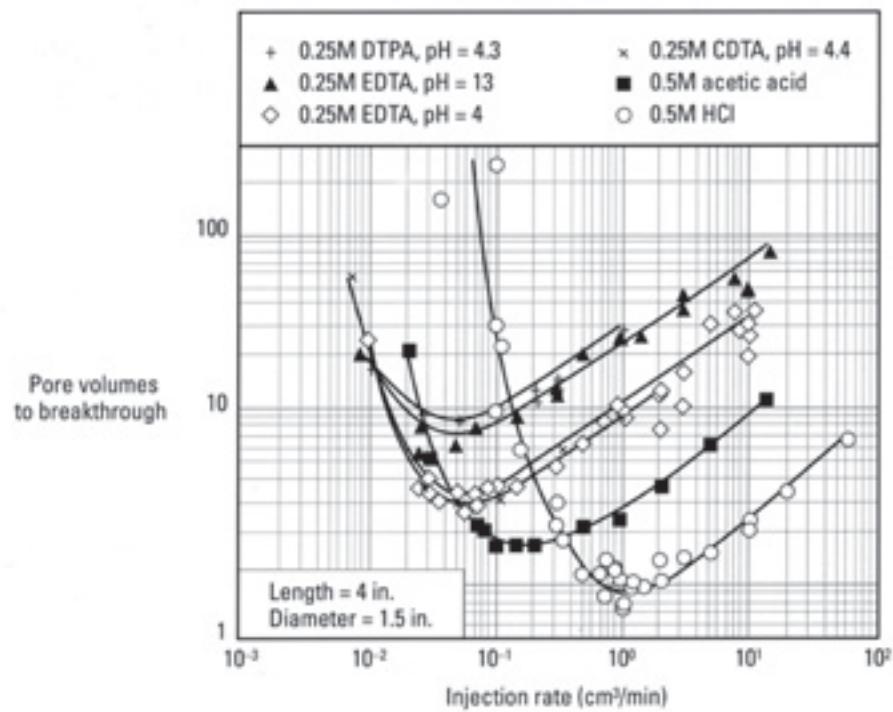
Figure 5-4 depicts the relationship between the acid efficiency, which is indicated by pore volumes of acid required to break through, i.e., the volume of acid required to propagate a wormhole that extends from the inlet to the exit of the core, and the Damköhler number. The x-axis is the reciprocal of the Damköhler number, which is proportional to the flow rate. The y-axis shows pore volumes to break through. The shape of the curve is universal for all fluid/mineral systems. The acid efficiency dependency on Damköhler number brings carbonate acidizing theory one step closer to having a single relationship between acid efficiency, acid properties, operating conditions. The number of pore volumes to breakthrough increases to the left and right of the minimum due to the formation of conical dissolution channels and ramified wormholes, respectively.

The influence of the diffusion coefficient on the optimum injection rate demonstrates the importance of mass transfer on the dissolution phenomenon. As the fluid type varies, the optimum injection rate decreases with decreasing diffusion coefficient in order of HCl > HAc > chelating agents. This is illustrated in Figure 5-5. Because of this influence of diffusion, alternative fluid systems, such as chelating agents and weak acids, are more effective than HCl when injected at rates below about 0.2 cm<sup>3</sup>/min in linear coreflood experiments. Therefore, these alternative fluids may be more effective than HCl for matrix stimulation in shallow or tight formations where low injection rates are required to prevent fracturing the formation or when injection rates are limited due to frictional pressures.

Figure 5-4 also implies that the acidizing treatment should be operated to the right of the minimum (optimum) because the slope of the curve is flatter, making the volume penalty less for pumping at a nonoptimum rate. The standard field practice of injecting at the maximum rate below fracture pressure will normally accomplish this. The real operational problem occurs in heterogeneous formations where high permeability zones will be receiving acid at high rates (efficient acid use) while low permeability zones will probably be receiving acid at low rates (inefficient acid use).



**Figure 5-4.** Effect of Damköhler number ( $Da$ ) on stimulation efficiency.



**Figure 5-5.** Optimized injection rate for various fluids.

## Carbonate Treatment Fluid Selection

The development of mathematical equations describing the complex relationship between fluid pumped, reservoir conditions, and operational parameters allows a more scientific approach to carbonate treatment fluid optimization. This is a giant step forward from the days of pumping the highest strength HCl possible with sufficient corrosion inhibition.

Although the optimization using wormholing efficiency (Damköhler number) is more complicated than just choosing acid strength, the parameters affecting selection are the same. They include

- temperature
- pumping rate
- fluid type.

## Selection Criteria

### Temperature

Temperature is important to acid selection because it affects the reaction rate and, therefore, the calculation of wormholing efficiency. Acid reaction rate increases as temperature increases, because diffusion and surface kinetics depend on temperature. Under both static and dynamic conditions, reaction rate generally increases as temperature increases.

At 120 degF [48 degC], the acid reaction rate of HCl on limestone is approximately double that at 70 degF [21 degC]. Organic acids exhibit similar increase in reaction rate with increasing temperature; however, this temperature dependency in organic acids is different from other acids because the reaction is reversible and the extent of reaction is limited by equilibrium.

Temperature also strongly influences the corrosion inhibition of acids. At high temperatures, greater than 300 degF [148 degC], 28% HCl cannot be inhibited sufficiently to protect well tubulars. Thus, lower concentration HCl and organic acids, which are less corrosive than HCl, are used.

As discussed in the *Chemistry and Physics* section, the reaction of acid and dolomite rocks will vary from being dominated by mass transfer to reaction kinetic effects depending on the temperature. Below 122 degF [50 degC], the reaction is reaction rate limited. Above 212 degF [100 degC], the reaction is mass transfer limited. When the temperature is between these limits both the mass transfer and kinetic effects are important to overall reaction rate. Since wormholes are only created when the rock and acid reactions see mass transfer effects, wormholing efficiency should not be used as a

fluid selection criterion in low-temperature dolomite reservoirs where reactions are reaction rate limited. However, it is reasonable to look at wormholing when the temperature is in the transition zone.

### Pumping Rate (flow velocity)

Flow velocity also affects wormholing efficiency in cases where the reaction is mass transfer limited. Acid treatments in limestone formations exemplify this. The dissolution pattern and the type of wormhole structure formed during injection are functions of the flow velocity (see Figure 5-2). The most efficient treatment will form dominant wormhole channels rather than conical dissolution channels or ramified wormholes. There is an optimum flow velocity for this pattern for each fluid type (see Figure 5-5). In low-temperature dolomite formations, or other situations where the reaction is surface reaction limited, velocity does not matter since wormholing does not occur.

At zero or extremely low velocity (acid soak), the time for acid to diffuse to the surface is much shorter than the time for the acid to move due to convection (flow). Therefore, the entire rock matrix will be homogeneously and completely dissolved. Without any porous matrix left, the penetration of the acid will be limited for the same initial volume of acid.

### Fluid type

Hydrochloric (HCl) is the most common acid used in carbonate acidizing due to its low cost, availability, and soluble reaction products. Organic acids are preferred for high-temperature applications because of their low corrosiveness, ease of inhibition, and seemingly retarded reaction characteristics.

Blends of HCl with either formic or acetic acids have also been used to take advantage of the cost efficiency of HCl and the reduced corrosion provided by the organic acids. However, in the course of reacting with limestone, HCl will react quickly and produce large amounts of CO<sub>2</sub>. The quantity of CO<sub>2</sub> will almost completely stop the reactivity of the organic acids. The overall result is only the one of a lower quantity or concentration of HCl, with the additional expense of the organic acid.

Retarded acids are used to slow down the reaction rate to obtain deeper live acid penetration. In mass transfer limited reactions, retarding the acid means you have to slow down the rate of mass transfer. There are two factors that affect the mass transfer rate of H<sup>+</sup> to the rock surface: diffusion coefficient and viscosity. Effective diffusion coefficients ( $D_{eff}$ ) measured from rotating disk experiments are shown in Table 5-1.

**Table 5-1 Diffusion coefficients for 15% HCl acid systems (de Rozières, Chang and Sullivan, 1994)**

Acid Type	Temperature, degF	D <sub>eff</sub> , cm <sup>2</sup> /sec
Straight	40	1.27 E-6
Straight	84	2.13 E-5
Gelled	84	7.92 E-6
Gelled	112	7.90 E-6
Emulsion	83	2.64 E-8
Emulsion	109	4.29 E-8
Emulsion	147	4.60 E-8

The effective diffusion coefficient increases in magnitude with temperature. Interestingly, the  $D_{eff}$  for straight acid is very close to that of gelled acid. This is contrary to the notion that gelled acids are retarded. However, this result should be expected because the hydronium ion is very small compared to the size of common gelling agents (polyacrylamides and HEC) and a relatively low concentration of gelling agent in acid (~0.1 wt%) is used.

The  $D_{eff}$  for emulsified acid is substantially lower than for gelled or straight acid and occurs because the external hydrocarbon phase (diesel, kerosene, crude oil, xylene) creates a diffusion barrier. The emulsion micelles must diffuse to the rock surface. However, the micelles do not have to break in order for the acid to react. The rate of mass transfer for emulsified acids is substantially retarded compared to the rate of mass transfer of straight acids. For mass transfer limited systems, this mass transfer retardation is equivalent to a dissolution rate retardation.

The following is an excerpt from SPE 50612 (Navarrete *et al.*, 1998) where field data was matched to calculated retardation factors for various temperatures.

Retardation factors for emulsified acid varied between 14 and 19, showing that mass transfer coefficients of straight acid are more than an order of magnitude lower than those of emulsified acid. Retardation factors also tend to increase with temperature. This trend is due to the higher sensitivity to temperature of the mass transfer coefficients of straight acid vs those of emulsified acid. The retardation factor does not significantly vary with acid strength in the range between 15 and 28%. The retardation factor of the 28% emulsified acid is 1.5 to 2 units lower than that of 15 or 20% emulsified acid. This difference can be attributed to the mass transfer coefficient of the straight acid, which significantly increases in relation to the mass transfer coefficient of emulsified acid from 20 to 28%.

## Selection Guidelines

In general, the fluid that gives the deepest penetration for the expected pumping and reservoir conditions is the fluid that should be used. The FSA module in StimCAFE® V3.1 will show a relative ranking of common carbonate acidizing fluids for the input conditions. The model calculates pore volume to breakthrough (PVBT). Fluids with similar PVBT should be considered technically interchangeable.

Charts for carbonate fluid selection are not shown due to the difficulty of covering all the possible variations. Depending on the actual expected conditions, the recommendation is highly variable. The most efficient fluid may not be the normally considered choice. Therefore, it is recommended that an FSA run be made for each specific treatment because of the complexity of the Damköhler efficiency calculation.

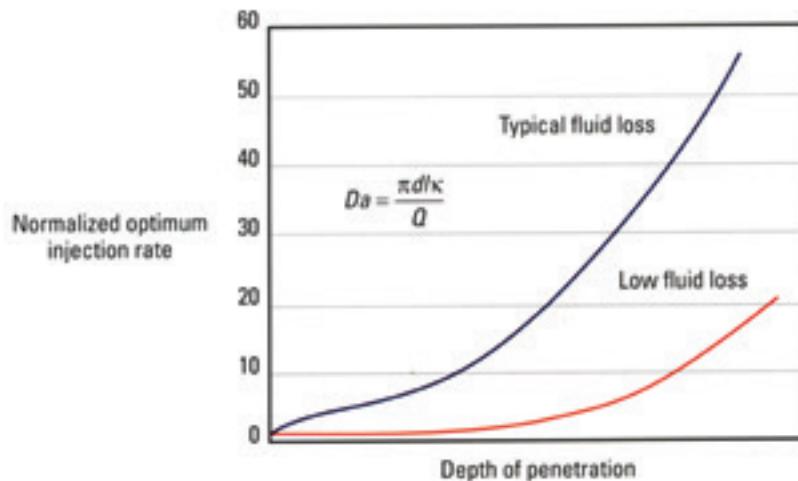
## Injection Strategy

Injection strategies for field treatments can be developed by predicting the rate required to attain the optimum Damköhler number of 0.29 during pumping. Maximum pumping rate is often dictated by reservoir fracture pressure or equipment limitations. Other factors affecting rate selection are fluid loss rate, the type of treating fluid, and temperature.

## Fluid Loss

Figure 5-6 shows the normalized optimum injection rate required to maintain the optimum Damköhler number as a function of the depth of penetration. (The optimum injection rate is normalized by the optimum injection rate for HCl at 200 degF [93 degC] with zero fluid loss.) This optimal condition can be maintained by increasing the injection rate as the depth of penetration increases.

The curves represent injection rates for the formation of efficient wormholes. At injection rates above and below the optimal curve, ramified wormholes and face dissolution, respectively, will form. The curves reveal that the injection rate must be increased significantly as the depth of penetration increases. This increased injection rate is necessary to offset the effects of fluid loss from the wormhole channels. When the fluid loss velocity is low, the rate of the injection rate increase is less significant. The need to increase the injection rate to maintain efficient wormhole formation is consistent with investigators reporting a higher optimum injection rate in radial experiments than in linear experiments.



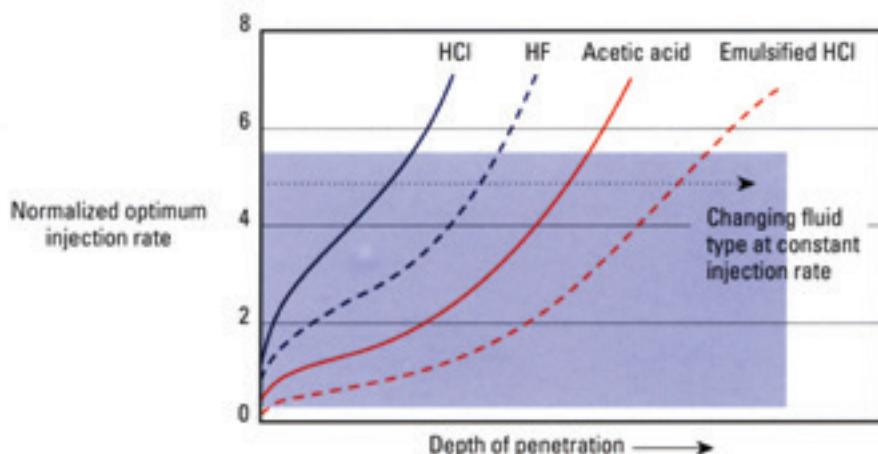
**Figure 5-6.** Injection rate required to maintain a Damköhler number of 0.29.

### Fluid Type

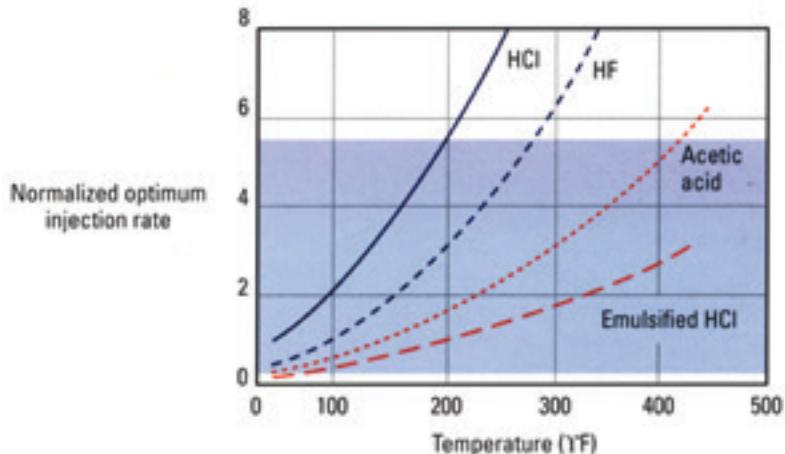
Fluid type should also be considered when determining the injection strategy. Figure 5-7 shows the relative effect of fluid type on optimum injection rate in limestone formations at 200 degF [93 degC], assuming a typical fluid loss profile. The shaded box represents typical injection rates used in conventional matrix stimulation treatments. The results show that HCl is unable to achieve significant penetration without requiring excessive injection rates that may fracture the formation. In contrast, alternative fluids such as weak acids (formic or acetic) and emulsified HCl can stimulate to increasingly deeper penetration without exceeding the same maximum injection rate. Under these conditions, emulsified HCl would be the most effective stimulation fluid. Results for chelant systems are similar to those of emulsified HCl. The data also demonstrate that weak acids and emulsified HCl are more effective than aqueous HCl when stimulating high-temperature limestone formations.

### Temperature

The optimum injection rate is also a strong function of temperature, as shown in Figure 5-8. To obtain a particular depth of penetration, the injection rate must be increased as the temperature increases. This trend is consistent with experimental results with HCl. A much more significant dependence of the optimum injection rate on temperature was predicted by Huang *et al.* (2000) due to the emphasis they placed on the rate of the surface reaction rather than the rate of mass transfer. Fig. 5-8 demonstrates that optimal stimulation with HCl is limited to low temperatures if excessive injection rates that would fracture the formation are to be avoided. The figure also reveals that weak acids and emulsified HCl are more effective than aqueous HCl when stimulating high-temperature limestone formations.



**Figure 5-7.** Effect of acid type on optimum injection rate.



**Figure 5-8.** Optimum injection strategies for various acid systems at 200 degF [93 degC]. The shaded area represents typical injection rates used in matrix acidizing treatments (Paccaloni, 1995).

## Specialty Acids

### MSR

MSR is an acid solution containing a clay suspending agent and a chelating agent. This combination not only provides dispersion of drilling mud solids and formation silts, but also provides unusually effective suspension properties. It is recommended for the removal of drilling mud damage where large quantities (> 5 bbl/ft in the producing interval) of whole mud were lost to the formation. MSR fluid should always be immediately flowed back to take full advantage of the dispersing and suspension capabilities of the fluid.

When treating mud damage in carbonate wells, the amount of iron downhole affects the treatment fluid choice. Iron can be due to iron minerals in the formation, corrosion in the tubing, or poor or no tubing pickling planned. The user should decide whether the downhole iron concentration is high when determining which MSR to use. However, since downhole iron is rarely measured, this is a highly subjective decision. Two formulations of MSR are available: MSR 150 for high downhole iron and MSR 100 for normal downhole conditions.

### SXE Acid

SXE\* superX emulsion is an oil-external emulsion used in formations where a retarded acid would be beneficial. Early studies have shown that oil-external emulsions can efficiently treat low permeability cores that could not be treated as efficiently by plain acid because of their very low injectivity (Horton *et al.*, 1965). Limestone cores acidized with emulsions display a highly permeable

network of microwormholes. Hoefner *et al.* (1987), at the University of Michigan, discussed the uses of micro-emulsions as matrix stimulation fluids. These researchers were able to formulate acid-in-oil emulsions with diffusion coefficients two orders of magnitude lower than aqueous HCl without significant increase in viscosity. More recent papers, Buijse and van Domelen (2000), discuss core tests of wormholing with coarse emulsions where the acid droplets are much larger than the average pore size. These coarser emulsions also showed lower acid diffusion rates, but have higher viscosities.

De Rozieres *et al.* (1994) measured diffusion coefficients in emulsions using the rotating disk technique. They found that effective diffusion coefficients in emulsions are up to three orders of magnitude lower than diffusion coefficients in plain acid at the same temperature. Slow transport of acid to the pore walls also accounts for the slower reaction rate and uniform increase of pore size observed with emulsified acid.

Like gelled acids, emulsions are usually prepared with hydrochloric acid. Various acid strengths and volume portions of acid in the emulsion can be chosen; 70:30 acid-in-oil emulsions are commonly used. The fluid viscosity of the emulsion is an important parameter. Some mixtures used for fracturing can not be applied to matrix acidizing conditions because of their very high viscosities.

Emulsions are obtained by mixing acid with a refined oil-base fluid in presence of a surfactant. The stability of the emulsion depends on the temperature and the ionic strength of the aqueous phase. Some emulsifying agents provide stable emulsions up to 300 degF [148 degC]. Depending on the type of surfactant used, a water-in-oil or an oil-in-water emulsion can be obtained.

## NARS

NARS are special treating solutions that contain no acid. These fluids are used as cleanup and breakdown fluids in formations that may be damaged by acid. These solutions are nondamaging to water or acid sensitive formations and contain strong chelating and clay suspending agents. They can be used in high-temperature reservoirs ( $>400$  degF [204 degC]) but should not be used if downhole temperatures are below 100 degF [37 degC]. Two solutions, NARS 200 and NARS 201, are currently being used.

## DAD

DAD\* dynamic acid dispersion) is an acid outside-phase emulsion prepared and stabilized with Dispersing Agent U74. The purpose of the dispersion is to simultaneously dissolve acid-soluble minerals and remove oily paraffinic deposits. Target areas can be tubulars, perforations, or the critical matrix. Various ratios of acid and hydrocarbon solvent are possible, with common dispersions ranging from 90% acid and 10% organic solvent, to 50% acid and 50% organic solvent.

## Acid plus alcohol (alcoholic acids)

Alcohols are used in acidizing fluids to remove water blocks, enhance fluid recovery, retard acid reactivity, and decrease water content. The most common alcohols used in acidizing are isopropanol and methanol.

Isopropanol is normally used at a maximum of 20% by volume. Methanol is used at various concentrations; a typical concentration may be 30% by volume. In some cases, methanol is used instead of water dilute the concentrated acid to the desired acid treating solution. Alcohol is used mainly in dry gas wells.

Water blocks may form in porous rocks when high capillary forces are present in porous rocks. The most severe water block problems occur in formations with gas permeability less than 120 mD. Adding alcohol to the treating fluid reduces the capillary forces within the reservoir, thus permitting easier removal of the liquid phases.

The addition of alcohol also improves the recovery of treating fluids, especially in gas reservoirs. The high surface tension of water or acid solutions hinders their penetration and recovery. Conventional surfactants help somewhat, although they lose much of their activity by adsorption. The addition of alcohol to acid solutions reduces their surface tension. The concentration of alcohol normally used for this purpose is sufficient that loss by adsorption is not a problem.

## Nonacid Treatments

Solvents, bleach, and other nonacid fluids are used to treat specific damage mechanisms. These treatments are dependent on formation lithology. Table 4-6 in the Sandstone Acidizing chapter outlines recommended nonacid treatments for these damages.

# Additives for Matrix Treatments

## Introduction

Although the proper fluid selection is critical to the success of a matrix treatment, the treatment may be a failure if the proper additives are not used. The main treating fluid is designed to effectively remove, or bypass, the damage. Additives are used to prevent excessive corrosion, sludging or emulsions; they provide uniform fluid distribution, improve cleanup and prevent the precipitation of reaction products. Additives are also used in preflushes and overflushes to stabilize clays, disperse paraffin or asphaltenes and inhibit scale or organic deposition.

Certain additives are used in almost all acid formulations. Corrosion inhibitors, surfactants, mutual solvents and iron control agents address problems caused by corrosion, emulsions and sludging. Other types of additives deal with clay control, friction reduction and scale inhibition. There are also specialty additives available for less frequently occurring problems.

## Major additives

### Acid corrosion inhibitors

Acid corrosion inhibitors reduce the corrosion of well tubulars by acids. They adsorb on the surface of the pipes to form a protective film, thus reducing the reaction rate of acid with steel. Acid corrosion rates increase with temperature, and the ability of the inhibitor to adsorb on steel decreases with temperature. Inhibitor aids are used synergistically with inhibitors to decrease corrosion. The main factors affecting corrosion are metallurgy, acid type and concentration, agitation, temperature, pressure, inhibitor solubility and concentration—the ratio of metal area to acid volume—contact time, presence of inhibitor aids and the influence of other additives.

Table 6-1 shows the inhibitor selection guidelines for the currently available inhibitors and inhibitor aids.

**Table 6-1. SEQ table ARABIC 1 Corrosion Inhibitor Selection Options.**

Acid Category	Metal	Temperature	Inhibitors	Inhibitor Aids
Gas Well Acids				
Gas Well Acid	Carbon Steels (J55, N80, P110, and Coiled Tubing)	Up to 250	A261 or A262	A179
Gas Well Mud Acids	Chrome Steels (9% & 13%Cr)	Up to 250	A261 or A262	A179
Organic Acid Systems				
Acetic Acid (10% L400)Formic Acid (9% L36), Organic Mud Acids, Citric Acid, OCA	Carbon Steels (J55, N80, P110, & Coiled Tubing) Chrome Steels (9% & 13%Cr)	Up to 500	A186 or A272	
	Corrosion Resistant Alloys (2205 Duplex, 25Cr, 25CrW) 13% Cr Steels	Up to 500	A186 or A272	
Titanium Alloys		Any	Cannot be inhibited	
Chelating Agent Systems (CAS)				
U105, U106	Carbon Steels (J55, N80, P110, & Coiled Tubing) Chrome Steels (9% & 13%Cr)	Up to 500	A186 or A272	
	Corrosion Resistant Alloys (2205 Duplex, 25Cr, 25CrW) 13% Cr Steels	Up to 500	A186 or A272	
	Titanium Alloys	Any	Cannot be inhibited	

## Surfactants

Surfactants are chemicals containing both oil- and water-soluble groups with the ability to alter liquid to liquid and gas to liquid interfacial properties. They are used in acidizing to reduce surface or interfacial tension, reduce capillary forces, control wettability, prevent or break emulsions, prevent or break water blocks and disperse or suspend fines. They are also used as foaming agents. The quantity of surfactant used is a function of the application. Surfactants that lower surface or interfacial tension or provide water-wetting are normally used at 0.2% to 0.5%. Other applications require higher concentrations.

Surfactants are classified by the ionic nature of their hydrophilic groups. There are four categories:

- anionic—negatively charged
- cationic—positively charged
- nonionic—not charged
- amphoteric—positive or negative or not charged depending on pH.

Anionic surfactants are balanced with positively charged ions (i.e.,  $\text{Na}^+$ ). Cationic surfactants are balanced with negatively charged ions (i.e.,  $\text{Cl}^-$ ). Anionic and cationic surfactants should not be used together because they may produce insoluble precipitates or neutralize their respective activities. Most surfactants used in well treatments are a combination of anionic and non-ionic surfactants. The Schlumberger *Matrix Materials Manual* should be consulted to determine the correct surfactant to use for a specific application.

## Mutual solvents

Mutual solvents are multifunctional, nonionic agents that are soluble in oil, acid, freshwater and brines. They penetrate deeper than surfactants and increase miscibility by decreasing surface or interfacial tension. Mutual solvents are more effective than most surface-active agents in water-wetting, preventing emulsions and minimizing particle plugging. Additionally, they dissolve oil on the formation pore surfaces and fines, leaving them water-wet. Formation fines that are water-wet have a lower tendency to stabilize emulsions. The net result is that mutual solvents improve the cleanup of spent acid following the treatment. The recommended concentration is a function of the mutual solvent used and the well conditions, but it varies from 0.5% to 35%. Additive incompatibility becomes an issue when mixing different surfactants or mutual solvents.

## Iron control

Iron control is required in acid treatments to control the precipitation of iron compounds from the spent acid. The injected acid dissolves iron from rust, millscale- or iron-containing minerals in the formation. As the acid spends, ferric iron ( $\text{Fe}^{3+}$ ) precipitates as ferric hydroxide resulting in particulate damage. In sour wells, precipitation of elemental sulfur and iron sulfide can also be a problem. Injection of HCl may also cause flocculation and precipitation of asphaltene sludge due to interactions between dissolved ferric iron and asphaltenes present in the crude.

Iron dissolved during an acid treatment can exist in either the  $\text{Fe}^{3+}$  or  $\text{Fe}^{2+}$  oxidation state. Upon spending of the acid, the  $\text{Fe}^{3+}$  will start to precipitate at a pH of approximately 2.2. By the time the spent acid reaches a pH of 3.2, essentially all of the dissolved  $\text{Fe}^{3+}$  will be precipitated as the hydroxide.  $\text{Fe}^{2+}$  hydroxide will not precipitate below a pH of 7.7. Since spent acid usually reaches a maximum pH around 5.2, precipitation of  $\text{Fe}^{2+}$  is rarely a problem.

Previous studies show that most Fe, dissolved by the treating acid, is present in the  $\text{Fe}^{2+}$  oxidation state. An estimate of the average  $\text{Fe}^{2+}$  to  $\text{Fe}^{3+}$  ratio in spent acid is about 5:1 (Smith *et al.*, 1969). However, this varies greatly depending on the well conditions and the type of formation being treated.

Controlling iron during well treatments involves operational practices as well as chemical additives.

- Iron in the tubing should be removed prior to the stimulation by pickling the tubing or using a protected work string.
- The acid must not contain high levels of  $\text{Fe}^{3+}$ . Using clean or lined surface equipment can avoid contamination.
- The use of appropriate chemical additives can control the iron.
- The use of effective corrosion inhibitors will prevent iron from the treating equipment from being added to the well.

There are two types of chemicals used for iron stabilization: chelating agents and reducing agents. Chelating agents associate with iron  $\text{Fe}^{3+}$  or  $\text{Fe}^{2+}$  to form soluble species. Some commonly used chelating agents include citric acid, acetic acid, EDTA and NTA. Schlumberger has a chelating agent, U106, that is very soluble in acid systems and, therefore, has a higher iron control capacity. It can control  $>10,000$  ppm  $\text{Fe}^{3+}$  in acidizing applications up to 300 degF [148 degC]. Reducing agents change, or reduce, the  $\text{Fe}^{3+}$  to  $\text{Fe}^{2+}$  to avoid precipitation. Erythorbic acid (L058) is the main reducing agent used within Schlumberger.

The choice of the iron control agent used for a specific application is a function of the amount of iron, the downhole temperature, the presence of H<sub>2</sub>S and cost. In particular, the presence of H<sub>2</sub>S changes the iron precipitation problem. The reaction of H<sub>2</sub>S and Fe<sup>3+</sup> results in the precipitation of free sulfur and the reduction of Fe<sup>3+</sup> to Fe<sup>2+</sup>. If this occurs at a pH around 2, the Fe<sup>2+</sup> will further react with the sulfide to form ferrous sulfide (FeS), an insoluble precipitate. A combination of chelating and reducing agents can control iron in sour environments. The chelating agent is necessary to prevent the FeS precipitation, while the reducing agent is needed to reduce any Fe<sup>3+</sup> present in the acid and prevent the sulfur precipitation problem. In treating sour wells, iron contained in the treating acid is the only concern. The Fe<sup>3+</sup> must be eliminated to prevent the precipitation of sulfur.

A sulfide-scavenging chemical, M295, is available from Schlumberger. This additive will control precipitation in sour environments with a single chemical that works by reacting with the H<sub>2</sub>S to form soluble byproducts. The main advantage of this system is that less chemical is needed to control the same problem. The M295 additive also enhances the performance of common corrosion inhibitors, and, unlike other commercially available sulfide scavengers, the chemical used in this product does not interfere with the acid dissolution of existing iron sulfide scale.

## Minor additives

### Clay control agents

Formation damage can result from the dispersion, migration or swelling of clay particles. The two main methods of clay control are ionic neutralization and particle fusion.

In order to cause ionic neutralization, the additive is adsorbed on the clay surfaces by either electrostatic attraction or ion exchange. Charge neutralization reduces the ion-exchange capacity of the clays, reducing susceptibility to clay swelling. Brines, such as potassium or ammonium chloride as well as quaternary amine polymers and quaternary surfactants, are used in this clay control method. Typically, brines are used because of their low cost and ready availability.

Polyquaternary amines are organic polymers that are adsorbed on the clay surfaces by ion exchange. Because of the multiple amine units, the molecules adsorb strongly with many points of attachment. These chemicals are relatively expensive, and the treatment will degrade when contacted by brines. Quaternary

surfactants are used as clay stabilizers in dry gas wells. Adsorption occurs due to electrostatic attraction. These materials also tend to oil wet the clay particles, which also minimizes their adsorption of water.

Particle fusion can be chemically caused by the use of ClayACID fluid or organosilanes. ClayACID is an acid system in which fluoboric acid reacts to generate hydrofluoric acid in situ. A topochemical reaction occurs with boron being incorporated into the crystal lattice of the mineral. These reaction byproducts (borosilicates) appear as a coating on the initial rock surfaces. The coating desensitizes the mineral and fuses them to the sand grains. However, ClayACID fluid is not considered an additive, but rather a separate acid system.

Organosilanes are organic compounds containing silica. When added to acid, they hydrolyze to form silanols, compounds with multiple Si-OH sites. These Si-OH sites react with similar sites present on the siliceous mineral surfaces to form siloxane (Si-O-Si) bonds. A nonoil-wetting polysiloxane coating forms on the siliceous mineral surface due to these reactions. The coating stabilizes the fines and clays by blocking ion-exchange sites and increasing interparticle attractive forces.

### Organic dispersants

A relatively new method of removing organic deposits is the use of dispersant surfactants in combination with organic solvents. The surfactants penetrate and loosen organic deposit; so, the solvents can effectively dissolve or remove them. Concentrations of 1% to 10% volume to volume are used depending on the deposit type, the hardness and adhesion of the deposit and the bottomhole temperature. For matrix, wellbore and tubing cleanup treatments, a soaking period of several hours is recommended.

### Friction reducers

Friction reducing additives are used to suppress fluid turbulence when pumping acid treatments through coiled tubing. Some polyacrylamides are excellent friction reducers for acid and can greatly reduce the friction pressure drop in tubulars at concentrations of 1 to 4 lbm to 1,000 gal of acid. For example, at 10 bbl/min, a concentration of 4 lbm of J120 to 1,000 gal of 28% hydrochloric acid (HCl) gives approximately a three-fold reduction in pressure drop. However, the effectiveness of most polymers is limited because they degrade rapidly in acid, particularly at elevated temperatures. Viscoelastic surfactants also have friction-reducing effects.

## Scale inhibitors

Scale prevention involves the use of chemical inhibitors that affect the nucleation growth or adherence of scale crystals. The inhibitor can either be continuously added to production or injection fluids or displaced into the formation as an overflush to an acid treatment. When either overflushed or squeezed into the formation, the chemical is adsorbed onto the rock, or precipitates as widely dispersed, low-solubility particles in the pore spaces. The inhibitor is solubilized into the produced or injected fluid at concentrations of a few parts per million. This small concentration is sufficient to inhibit scale development.

## Specialty additives

### Alcohols

Alcohols, such as isopropanol and methanol, are used in acid or other aqueous fluids to lower surface and interfacial tension, increase vapor pressure and improve cleanup. These attributes make them effective in treating water blocks, enhancing fluid recovery, retarding acid reactivity and decreasing water content. They are commonly used in gas wells to reduce water damage and to decrease surface tension.

There are major disadvantages that decrease the use of this additive. They include the high-concentration requirements, high-cost, low-flash point, increased corrosiveness, as well as incompatibility and acid reaction issues. Concentrations of 20% or higher are needed to provide beneficial effects. The large volume requirements make the treatment more expensive and depress the flash point of the acid-alcohol mixtures. More corrosion inhibitor is required for acid-alcohol mixtures, which also increases the treatment cost. Some crudes are incompatible with these alcohols, and some formation rocks may also be extremely sensitive to aqueous solutions containing high concentrations of alcohols.

### Antifoamer

Antifoamer prevents excess foam from being formed in surface equipment during mixing of fluids containing specific surfactants. Concentrations of 0.05% to 0.1% volume to volume are typically used to avoid operational problems

### Formation cleaner

Formation cleaner M91, a strong oxidizer solution, is used to kill and remove bacteria and polymer residues from the matrix of a productive formation. It is more efficient than bactericides that simply kill the bacteria.

## Emulsifiers

Emulsified treating fluids are mixtures of aqueous and organic phases. Surfactants are the main emulsifying agents. Emulsions can be used to either isolate the internal phase of the emulsion, so it is not as reactive, or to create a fluid with higher viscosity than the base fluids. An example of an emulsified fluid is DAD, a combination of an organic solvent and an acid, which is used to treat mixed organic and scale deposits.

## Diverting agents

Successful matrix treatments depend on the proper placement of the treating fluids. In general, this means uniformly distributing the fluids into the entire producing or injecting interval. In some cases, this may also mean limiting fluid entry into certain parts or the formation, for example, a watered-out zone. Proper fluid placement can be a difficult in any well, but it becomes a real challenge in treating horizontal wells. When acid is pumped into a well, it naturally tends to flow into the highest permeability, or less damaged zone and through open perforations. The proper placement of acid between regions of different injectivities can be accomplished using mechanical or chemical diversion techniques.

### Mechanical

Mechanical diversion methods, such as straddle packers, require good isolation between zones and special equipment. Ball sealers, another mechanical method, are not effective in openholes, gravel packs or in wells with a large number of perforations. Additionally, the slow pump rates frequently used in matrix acidizing are often insufficient to achieve good ball seating.

### Chemical

There are several categories of chemical diverters, including particulates, foam and viscosity forming agents. Particulate diverters form a cake of solid particles in front of high-permeability layers thus directing the flow to less permeable zones. Since the entry of the treating fluid in each zone is limited by the resistance of the cake (Doerler and Prouvost, 1987), diverting agents enable the flow to equalize between zones of different permeabilities. Particulate diverters can be used in sandstone or primary porosity dolomites. Both water- and oil-soluble materials are available for use in either injection or production wells. Coarser materials (flakes), possibly followed by smaller particle-sized diverting agents, are sometimes used as bridging agents in vuggy or fractured formations.

Foams have been used for acid diversion since at least the 1960s. Surfactant foamers are added to fluids that are injected with nitrogen gas during the treatment to create the diversion effect. The acid itself can be foamed with the addition of gas and surfactant, or more commonly, foam can be injected in alternating slugs with acid.

Foam properties that cause diversion are fundamentally different than the properties that are important for foams used in drilling, fracturing or well cleanout. Within the tiny pores of the oil or gas reservoir, foam bubbles, larger than the individual pores, are squeezed down into elongated shapes and span several pores with a liquid film or lamella. Each bubble forms a separate film or lamella; multiple bubbles result in multiple lamellae (Ettinger and Radke, 1992; Falls *et al.*, 1989). The capillary forces on the lamellae dominate the behavior of the foam; viscous forces in the conventional sense are relatively unimportant. It is the viscous forces that are important in other foam applications. Therefore, analogies to these other foams can be misleading.

The key to the success of foam as a diverter is low-gas (and consequently liquid) mobility during foam injection and gas trapping during subsequent injection of liquid. The fraction of the pore space completely blocked by the foam declines as the pressure gradient increases.

Pumping chemicals that cause a temporary increase in viscosity in the matrix can also cause diversion. SDA\* Self-Diverting Acid and other similar materials block the growth of wormholes in carbonate acidizing by temporarily forming a barrier in the wormhole that halts channel growth and loss of fluid from the wormhole. SDA is a temporary, cross-linked fluid that will lose its viscosity as the acid spends.

Viscosity diversion is also possible using viscoelastic surfactant (VES) technology (Chang, *et al.*, 1998). This is the basis of the OilSEEKER® Acid Diverter, which preferentially channels the treatment into the oil zones and away from the water zones. When this viscous material is pumped into the formation, it is broken by residual hydrocarbons. It is more stable in water zones with very little residual hydrocarbon; so, it retains its higher viscosity and diverts the subsequent fluid stage into a different part of the reservoir. A pumping sequence of VES diverter, HCl, VES diverter, HCl, and so on has been shown to effectively divert acid into and stimulate multiple zones of varying permeability in a single wellbore.

Foams, SDA, and OilSEEKER contain no solids. SDA and OilSEEKER have the additional advantage of being a single-phase fluid, so no nitrogen is required. SDA is used specifically in carbonate formations. Foam and OilSEEKER can be used in either sandstones or carbonates.

# Laboratory Studies for Designing a Matrix Treatment

## Objectives of laboratory experiments

Laboratory studies are used to

- identify damage mechanisms
- analyze the rock
- analyze the formation fluids
- select the optimum treating fluid and design.

Formation cores, samples of formation fluids and sometimes samples of the damaging material (organic deposit or scale) are the subject of laboratory studies. Various analyses are performed on these samples to obtain the information necessary for designing a matrix treatment.

## Core analysis

Core analysis, including flow testing, is an integral part of the laboratory study used to help design a matrix treatment. Tests performed on cores can be classified as follows:

- Chemical studies include solubility tests and calculation of iron dissolved in HCl.
- Petrographic studies include X-ray diffraction (XRD), binocular lens observation, thin section examination and scanning electron microscopy (SEM).
- Petrophysic studies determine porosity and permeability.
- Core flow tests monitor the permeability response of the rock when different fluids are injected.

## Solubility tests

Solubility tests are used to determine the amount of any material that is dissolved by a given solvent. The results are given in weight percent. The solubility of a rock sample in a particular solvent (acid) depends on the mineralogy of the rock. The total solubility is the sum of the solubility of the mineral components. Table 7-1 shows the solubility of various common minerals in acid.

Carbonate and clay mineral content of the rock are often estimated from solubility test results. This method is only used if no other information is available. Mineral content is easily skewed by a variety of factors.

- Solubility tests are performed under ideal laboratory conditions. The physical rock structure is destroyed when grinding the sample for the test. Consequently, all the minerals are in contact with a large excess of acid. During acidizing operations in the field, the effective solubility may be completely different because of the structure of the rock and the position of each mineral relative to the pore through which the acid flows.
- Carbonate is assumed to be equal to HCl solubility. However, solubility in 15% HCl includes not only carbonates but also halite and possibly anhydrites and iron compounds.
- The solubility of the sample in regular mud acid (RMA), a mixture of 12% HCl and 3% HF acids, minus the solubility of the sample in HCl is only a rough approximation of the percent of clays in the formation. Silicates and other HF acid-soluble minerals are also included in the RMA solubility test. The percentage of micas, feldspars and quartz soluble in RMA can be many times that of the clays. A large difference between the solubilities in HCl versus RMA (>30%) normally indicates that there is a large amount of clays, micas and feldspars present.
- Negligible solubility in either HCl or RMA normally means that the formation is composed almost entirely of quartz. Acid stimulation may still be viable if the skin damage that is known to be present is composed of acid-soluble material. However, this fact is not apparent from lab studies on clean formation samples.

**Table 7-1. Solubility of Common Minerals in Acid**

Minerals	Chemical Composition	Solubility	
		HCl	HCl + HF
Quartz	SiO <sub>2</sub>	None	Low
Feldspars			
Orthoclase	K(AlSi <sub>3</sub> O <sub>8</sub> )	None	Moderate
Microcline	K(AlSi <sub>3</sub> O <sub>8</sub> )	None	Moderate
Albite	Na(AlSi <sub>3</sub> O <sub>8</sub> )	None	Moderate
Plagioclase	Na, Ca (Al <sub>1-2</sub> Si <sub>2-3</sub> O <sub>8</sub> )	None	Moderate
Micas			
Biotite	K (Mg, Fe) <sub>3</sub> (AlSi <sub>3</sub> O <sub>10</sub> ) (F, OH) <sub>2</sub>	None	Moderate
Muscovite	K Al <sub>2</sub> (AlSi <sub>3</sub> O <sub>10</sub> ) (F, OH) <sub>2</sub>	None	Moderate
Clays			
Kaolinite	Al <sub>4</sub> Si <sub>4</sub> O <sub>10</sub> (OH) <sub>8</sub>	None	High
Illite	(K, H <sub>3</sub> O)(Al, Mg, Fe) <sub>2</sub> (Al <sub>4</sub> Si <sub>4</sub> O <sub>10</sub> ) [(OH) <sub>2</sub> • H <sub>2</sub> O]	Moderate	High
Smectite	(Na, Ca)(Al, Mg) <sub>6</sub> (Si <sub>4</sub> O <sub>10</sub> ) <sub>3</sub> (OH) <sub>6</sub> - nH <sub>2</sub> O	None	High
Mixed layer	Kaolinite, illite or chlorite with smectite	None	High
Chlorite	(Fe, Mg, Al) <sub>6</sub> (Si, Al) <sub>4</sub> O <sub>10</sub> (OH) <sub>8</sub>	Moderate	High
Glaucophane	(K, Na)(Fe, Al, Mg) <sub>2</sub> (Si, Al) <sub>4</sub> O <sub>10</sub> (OH) <sub>2</sub>	Moderate	High
Zeolites	(Ca, Na) AlSiO <sub>6</sub> - H <sub>2</sub> O (general)	High	High
Carbonates			
Calcite	CaCO <sub>3</sub>	High	High
Dolomite	CaMg(CO <sub>3</sub> ) <sub>2</sub>	High	High
Ankerite	CaFe(CO <sub>3</sub> ) <sub>2</sub>	High	High
Scales			
Gypsum	CaSO <sub>4</sub> - 2(H <sub>2</sub> O)	Low	Low
Anhydrite	CaSO <sub>4</sub>	Low	Low
Halite	NaCl	High	High
Iron oxides		Moderate	Moderate

## Petrographic study

Knowledge of the petrography (description and classification) of the formation rock is essential to understanding the rock's response to fluid injection. Understanding rock fluid interactions depends upon

- what minerals are present
- where the minerals are located relative to the path of the injected fluid.

The laboratory techniques described in this chapter are used to determine the answers to these questions and to give insight on how this affects flow through the rocks. Understanding basic concepts on the formation of sedimentary rocks will help in understanding the laboratory procedures.

## Sedimentary rocks

Most petroleum reservoirs are found in sedimentary rocks such as sandstones, carbonates or chalks. Sedimentary rocks form at ,or near, the earth's surface

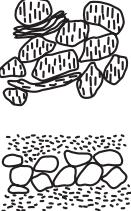
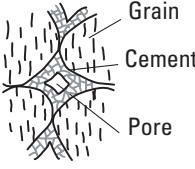
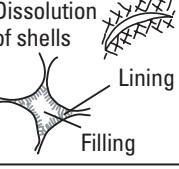
at relatively low temperatures and pressures through the transformation of sediments by diagenesis. Figure 7-1 is a schematic of the main steps of sedimentary rock formation and their consequence on the flow properties.

Sediments are

- deposited by water, wind or ice
- precipitated from solution
- grown in position by organic processes (e.g., carbonate reefs).

These three mechanisms coincide with the three main sediment constituents:

- silicate fragments that are derived from the weathering and erosion of preexisting sedimentary, metamorphic or igneous rocks
- chemical and biochemical precipitates that are formed at the site of deposition, for example, evaporite minerals or cement in sandstones or limestones
- allochems that are skeletal materials, ooliths, faecal pellets, as seen in carbonates.

	Sandstone		Carbonate Rocks
<p>Coarse →</p> <p>Sediment</p> <p>Fine →</p>	<ul style="list-style-type: none"> <li>• Detrial minerals           <ul style="list-style-type: none"> <li>– Quartz</li> <li>– Feldspar</li> <li>– Micas</li> </ul> </li> <li>• Clays           <ul style="list-style-type: none"> <li>Scattered in the framework or as laminae</li> </ul> </li> </ul>		<ul style="list-style-type: none"> <li>• Detrial grain           <ul style="list-style-type: none"> <li>– Fossils</li> <li>– Previously deposited carbonates</li> </ul> </li> <li>• Precipitated mineral           <ul style="list-style-type: none"> <li>– Calcite</li> <li>– Dolomite</li> <li>– Mud</li> </ul> </li> </ul>
<p>Diagenesis</p> <ul style="list-style-type: none"> <li>– Cementation</li> <li>– Compaction</li> </ul> <p>Transformation into a rock</p>	<ul style="list-style-type: none"> <li>• Cement           <ul style="list-style-type: none"> <li>– Quartz</li> <li>– Clays</li> <li>– Calcite</li> <li>– Dolomite</li> <li>– Anhydrite</li> <li>Etc.</li> </ul> </li> </ul>		<ul style="list-style-type: none"> <li>• Cement           <ul style="list-style-type: none"> <li>Calcite</li> <li>Dolomite</li> </ul> </li> </ul>
<p>Flow of brines</p> <ul style="list-style-type: none"> <li>– Dissolution</li> <li>– Recrystallization</li> </ul>	<ul style="list-style-type: none"> <li>– Transformation of clays</li> <li>– Crystallization of authigenic minerals</li> <li>Changes in porosity</li> <li>Permeability</li> </ul>		<ul style="list-style-type: none"> <li>– Transformation of calcite into dolomite</li> <li>– Selective dissolution</li> <li>Changes in porosity</li> <li>Permeability</li> </ul>
Fracturation	Usually minor		Can be very important for reservoir properties

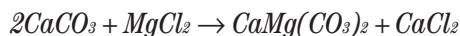
**Figure 7-1.** Formation of sandstone and carbonate rock—consequences for their flow properties.

The coarse particles (0.06 mm–2 mm) form the framework of the sediments. Smaller particles (clays, lime, mud) are also deposited. The original porosity of the sediment depends on the

- size of the particles
- shape (sphericity) of the particles
- packing of the particles
- amount of mixing of coarse and fine grains.

During diagenesis, a cementation process transforms the sediment into rock. Cementation results from the flow of brine through the original sediments. The brines dissolve some components and reprecipitate others between the grains of the framework. Cementation reduces the porosity of the sediments. Dissolution of cementing minerals will increase porosity but cause a decrease in compressive strength in the rock. Diagenesis stops when a nonreacting fluid, such as oil, fills the pore system during the formation of the hydrocarbon trap.

Precipitated minerals are called authigenic, meaning formed in place. Most clays found in the pore network of sandstones are authigenic. In limestones, the transformation of calcite into dolomite by diagenesis results in new porosity. This transformation, called dolomitization, is described by the following mechanism:



Because of this process, dolomites normally have greater porosity than limestones.

## Petrographic techniques

Petrographic techniques include thin section examination, X-ray diffraction and scanning electron microscopy.

### Thin section analysis

Thin section analysis is a method used to study rock structure and quantify minerals. The technique can determine mineralogy, porosity types, grain size, sorting and location of pores, cementing minerals and clay fines.

Rock core samples are impregnated with a colored resin to fill the interconnecting porosity. A thin slice is then cut off, polished to a thickness of about 30 microns and viewed in transmitted light with a polarizing microscope. Characteristic shape and size are used to identify the various minerals. The colored resin identifies interconnected porosity, while the isolated porosity shows up between the mineral crystals.

The location of minerals is important in acidizing, because the injected solvent will only dissolve the minerals that it can contact. Therefore, only minerals available to the interconnected porosity will contact the acid. This

holds true for both the damaging minerals, such as clay particles, or for cementing minerals, such as secondary quartz overgrowth and carbonates in sandstones. The objective is to dissolve as much of the damage as possible to improve flow capacity while dissolving as little of the cementing material as possible to maintain the integrity of the rock.

### X-ray diffraction

X-ray diffraction (XRD) is used to identify rock composition. It is an analytical technique that looks at the scattering pattern of X-rays through crystalline materials. These patterns are unique to individual minerals because they are characteristic of their atomic structure. The XRD patterns from unknown materials are compared to known mineral patterns to determine the composition of the unknown solid. Crystalline scale deposits can also be identified using XRD.

XRD is a very accurate way of qualitatively determining the mineral composition. However, quantitative accuracy is relatively poor. This type of testing requires the use of reservoir core samples. Conventional cores are recommended, because sidewall cores can be contaminated with drilling fluids and may not be representative of the formation. If sidewall cores are used, the analysis should be conducted on duplicate cores.

### Scanning electron microscopy

Scanning electron microscopy (SEM) is another way of looking at solid particles. It provides two major advantages over light microscopy: depth of focus and range of magnification. It is designed for looking directly at the surface of solid objects, and it is particularly useful for the observation of clays. SEM pictures of clay particles show their distinct shapes. For example, illite is spindly and kaolinite has a plate-like structure (Fig. 4-2).

With SEM, electrons, instead of light, are used to produce a reflected image of the sample. The electrons are scanned across the surface and focused with a magnet. They cause the release of energy in the form of X-rays, light and electrons. Detectors record the energy released from the sample and convert it into digital or photographic images.

The types of images of interest to geologists and engineers in the petroleum industry are

- secondary electron images (SEI) generated from the low-energy electrons released from the sample. This type of image emphasizes the topography of the sample.
- Back-scattered electron images (BEI) are produced from the high-energy electrons of the original beam focused on the sample and reflected back from it. This

type of image accentuates the compositional differences of the sample.

Like XRD analysis, SEM testing requires the use of reservoir core samples. Conventional cores are recommended, because sidewall cores can be contaminated with drilling fluids and may not be representative of the formation. If sidewall cores are used, the analysis should be conducted on duplicate cores.

## Computed tomography

Computed tomography (CT) is a method for obtaining cross-sectional images of the internal structure of a solid object. Used extensively in the medical field, this technique is also useful for looking at the internal structure of cores. X-ray images are taken along sequential planes perpendicular to the length of the sample. Computers are used to enhance the visualization of the sample.

The X-rays are focused across an area of the sample and recorded as a pattern of electrical impulses. The radiation absorption figures are used to assess the relative density of the interior of the sample. When plotted, the variation in density is shown as variations of brightness, producing a detailed cross-sectional image of the internal structure.

An example of this technique in oilfield applications is the study of core samples before and after acid response tests. In carbonate cores, this can detail the formation of wormhole structures. In sandstone cores, the dissolution of materials within the pore structure can be visualized.

## Magnetic resonance imaging

Magnetic resonance imaging (MRI) is another diagnostic technique borrowed from the medical field. It can be used to determine fluid distribution in core samples. The method uses the response of magnetic fields to short bursts of radio waves to produce the images. Like CT, MRI images are two-dimensional, cross-sectional, planar views perpendicular to the length of the sample. The images must be viewed sequentially to visualize the whole core. Additional computer enhancement can be used to produce a three-dimensional visualization.

## Petrophysics

The petrophysical characterization of a rock sample includes measurements of its porosity and permeability.

### Porosity

Porosity is the ratio of the void space volume to the bulk volume of a material. It is a measurement of the amount of space occupied by liquid or gas in the reservoir. Total, effective and residual porosities are defined as follows:

$$\text{Total porosity (\%)} = \frac{\text{Pore volume}}{\text{Total bulk volume}} \times 100$$

$$\text{Effective porosity (\%)} = \frac{\text{Volume of interconnected pores}}{\text{Total bulk volume}} \times 100$$

$$\text{Residual porosity} = \text{Total porosity} - \text{effective porosity}$$

$$\text{Pore volume} = \text{Total bulk volume} - \text{grain volume}$$

$$\text{Effective pore volume} = \text{Volume of interconnected pores} = \\ \text{Total bulk volume} - \text{effective grain volume}$$

The porosity of the sample can be determined by several techniques. Typically, only two of the three basic parameters, bulk, grain or pore volume, are measured in the laboratory.

Bulk volume can be determined by either volumetric or gravimetric displacement observations. In either case, fluid penetration into the core sample should be avoided. Direct measurement of fluid displacement is one way of determining bulk volume. Gravimetric techniques measure either

- the weight loss of the sample when it is immersed, or
- the difference in weight of a pycnometer when it is filled with fluid and when it is filled with fluid and the core sample.

Grain volume is the measure of the volume of the rock grains. This value is estimated by dividing the dry weight of the core sample by the sand grain density. Using the density of quartz, 2.65 g/cm<sup>3</sup>, for the sand grain density is sufficient for most applications. However, the sample can also be reduced to grain size, and the actual grain density determined. The Stevens porosimeter can be used to determine the effective grain volume by using gas expansion.

All methods of determining pore volume measure effective pore volume. The measurement methods are based on either extraction of fluid from, or injection of fluid into, the rock matrix. The procedures for determining pore volume by gas expansion are based on Boyle's law and use either nitrogen or helium in a constant volume cell. Pore volume can also be determined by saturating a clean, dry sample with a fluid of known density. The weight gain is used to calculate pore volume.

Porosity obtained from gas expansion methods is consistently higher than porosity obtained from saturation methods. Errors due to gas adsorption would tend to cause higher calculated porosities using the gas expansion method. Conversely, errors due to incomplete saturation would tend to cause lower calculated porosities using the saturation method. However, all methods give acceptably accurate answers if done carefully. (Bradley, 1987 Ch. 26)

## Permeability

Permeability is a measure of the capacity of a porous media to transmit fluids. It can be measured in situ through pressure transient testing and in the lab using cores. Fluid conductivity measurements using cores are made using gas or nonreactive liquids. Core permeabilities to air should not be confused with the effective permeability to the reservoir fluid. Air permeabilities may be an order of magnitude higher than reservoir permeability to fluid.

Absolute permeability is a rock property and should be constant for liquid and gas, since the core is 100% saturated. However, absolute permeability measured by flowing gas through a core must be corrected for gas slippage, also called Klingenbergs corrections. This is because permeability to gas varies with the pressure used for injection. The correction factor is determined by plotting gas permeability versus the reciprocal of the mean pressure. Multiple permeability versus pressure points should fall on a straight line. This line is extrapolated back to infinite mean pressure ( $1/p = 0$ ). The point of intersection with the permeability axis is the equivalent liquid permeability. Klingenbergs and others determined that this equivalent liquid permeability is equal to the liquid permeability through the measured porous media (Bradley, 1987 Ch. 26).

## Core flow test

Core flow tests measure the effects of fluids injected into sandstone formations. Permeability is calculated as a function of time or pore volumes injected. Core flow tests can also determine the water sensitivity of the rock and examine the reaction of the formation to a proposed treating fluid or fluid sequence.

## Acid response curve test

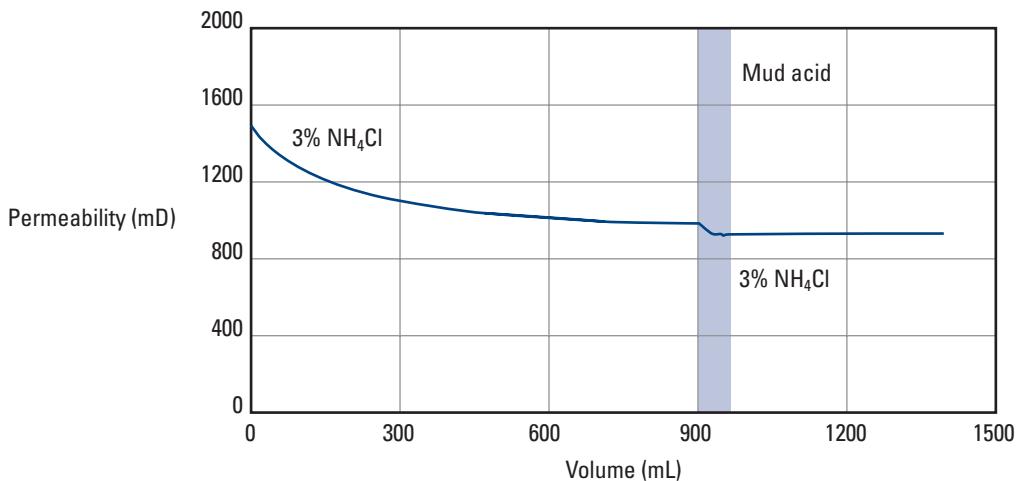
In acid studies, the permeability change depends on the dissolution and precipitation reactions that occur. Observations that indicate what dissolves and what precipitates are extremely useful in selecting the best treatment fluid.

The tests should be run at bottomhole temperature and pressure conditions with backpressure. For tests with acid, a minimum of 1,000-psi backpressure is required to keep the CO<sub>2</sub> produced by the acid dissolution of carbonate components in solution. The flow rates used should ensure that the fluid movement has minimal effect on the movement of fines contained within the pore structure. Typically 17 to 30 pore volumes of test fluid are injected. This approximates a treatment of 125 gal/ft.

The formation cores used are typically 1-in. diameter and 12-in. long. They should be cleaned with aqueous alcohol or ethylene glycol monobutyl ether solutions to remove traces of oil and ensure that they are water-wet. Using core holders with multiple pressure taps, the test can examine the effect of each fluid as it penetrates deeper into the core.

Permeability is calculated based on the changes in pressure and plotted as an acid response curve (ARC). An example of this is shown in Fig. 7-2.

The decrease in permeability seen in Fig. 7-2 indicates probable damage due to mud acid injection. This may be due to calcium fluoride precipitation or fines release. Removal of calcite cementing materials by the HCl stage can result in release of fines. This is more detrimental in low-permeability cores. If large increases in permeability occur during HCl injection, with little response to mud acid, the mud acid stage may not be required. A smooth increase in permeability due to mud or clay acid indicates that the well is a good stimulation candidate.



**Figure 7-2.** Acid response curve of a core treated with HCl and mud acid sequence.

Core flow tests should not be used to estimate treatment fluid volumes. Volumes are based on the amount and type of damage. Since core flow tests are always run on restored-state, cleaned cores, there can be damage due to sample preparation. This unknown damage will skew any attempt to use these tests to estimate treating volumes.

A petrographic study should be done in conjunction with any core flow studies. An accurate lithological breakdown is very helpful when interpreting acid response curves. SEM studies, both before and after fluid injection, can also be a valuable tool when determining the effect of the injected fluid. Sandstone permeability changes, in particular, depend on both dissolution and precipitation reactions. Observations that indicate what dissolves and what precipitates are extremely useful in selecting the best treating fluid sequence. Effluent analysis is another method that can be used to monitor the reactions that occur within the core.

#### Water sensitivity test

Permeability measurements before and after fluid injection, especially brine, can give insights into the sensitivity of the formation clays to both fines migration and clay swelling. The typical procedure calls for sequential injection of the following fluids:

- n-hexane
- isopropanol
- n-hexane
- isopropanol
- 3%  $\text{CaCl}_2$
- distilled water
- 3%  $\text{NaCl}$
- distilled water.

The solvent steps are designed to remove oil and water residues from the core. The calcium chloride followed by distilled water may cause clay swelling or migration. The sodium chloride followed by distilled water will typically cause clay migration in any sandstone core. Table 7-2 explains the permeability effects of each fluid step.

**Table 7-2. Explanation of Permeability Changes in a Water Sensitivity Test**

Fluid Sequence	Change	Meaning
Hexane to isopropanol	Increase	Improved cleaning of core, removal of water and/or alcohol-soluble salts
	Decrease	May indicate incomplete removal of oil residue. In very low-permeability cores, adsorption of alcohol on pore walls may reduce capillary flow. Wettability factors may contribute
Isopropanol to hexane	Increase	In low-permeability cores, differences in adsorption may cause hexane's permeability to be higher than those measured with isopropanol.
	Decrease	May indicate contamination of the hexane or incomplete removal of water by isopropanol.
Isopropanol to 3% CaCl <sub>2</sub> brine	Increase	Seldom noted
	Decrease	Common. The decline may be due to strong adsorption of water molecules on pore surfaces and partial expansion of clay aggregates. Some disintegration may occur in poorly consolidated cores. Severe permeability loss indicates physical movement of clay particles. Failure of core to return to its previous permeability with isopropanol confirms particle movement.
3% CaCl <sub>2</sub> brine to distilled water	Increase	Seldom noted
	Decrease	Uncommon, but extremely sensitive cores may lose some permeability from clay movement
3% NaCl brine to distilled water	Increase	Seldom noted
	Decrease	Fines migration

## Fluid analyses

Analyses of oil and formation brine provide useful information for fluid selection. Most fluid tests are used when determining the damage mechanism affecting the well. These tests are discussed in the "Damage identification" section. Oil compatibility studies should be made with planned treating fluids and formation oil to investigate the possibility of sludge or emulsion formation when the treating fluid, either live or spent, contacts the formation oil. The selection of treating fluid additives is based on the information obtained in compatibility tests.

## Acid and oil compatibility

Before pumping into the well, the compatibility between proposed treating fluids and formation fluids should always be tested. This testing will measure the tendencies to form emulsion or sludge, which can cause major problems if the treating fluid is incompatible with the formation, the rate of separation and the phase condition.

Many types of emulsifying agents occur naturally in crude oils. When formation fluids are contacted by treating fluids, emulsions of varying degrees of stability may result. For example, during treatment of an oil well, as the acid is being forced into the formation, an emulsion of the acid in the crude oil can be formed. These viscous emulsions are slow to return to the wellbore and, often, are never returned, especially in low-pressure wells. When this occurs, the emulsion stays in place in the formation and permanently blocks the flow channels. Therefore, it is better to prevent the emulsion by proper acid plus oil compatibility testing before the treatment. Although emulsions can be broken if they are already in the formation, this is more difficult.

Surfactants and mutual solvents are generally used to treat emulsions. Cationic, anionic or nonionic surfactants may be used depending on the nature of the emulsion being treated. Some mechanically stabilized emulsions may be treated by acidizing the formation to dissolve the stabilizing fines.

The potential for the formation of acid and produced crude oil emulsions and the optimization of the demulsifier treatment are currently evaluated using API *Recommended Procedure RP 42* (1977).

Crude oil sludge is a name given to the black asphalt-like material that precipitates when certain crude oils come in contact with acid. The precipitate is complex consisting of asphaltenes, resins, paraffin waxes and other high-molecular-weight components. This material is present in the crude oil in a colloidal dispersion. Contact with the acid destroys the stability of the dispersed material and results in its precipitation.

Surfactants are generally used as sludge prevention agents. They stabilize the colloidal material to keep the precipitates from forming on contact with the acid. The acid system to be used in treating a formation should be tested with the crude oil to see if sludge will form. Tests to determine whether there is a tendency for a sludge to form, at laboratory conditions, is given in API *Bulletin RP 42*.

## Damage identification

Evaluation of solids or fluids taken out of the well can be useful in determining the damage mechanism affecting well performance. Knowing the damage mechanism is particularly important when treating sandstone reservoirs, since the objective is removal of damage. Testing the formation brine can help determine scaling tendencies and predict incompatibility during mixing with foreign brine. Oil samples can be tested for paraffin and asphalt content to estimate the possibility of damage from heavy hydrocarbon precipitation. Analysis of miscellaneous solid particles from the well can be useful in determining whether the problem is primarily organic or inorganic in nature. These tests can also help narrow down the type of scale.

## Water analysis

Analyses of oilfield waters are used for a variety of reasons. They are helpful when trying to identify the source of downhole water and when planning waterflood operations. The main uses of water analysis data in damage assessment includes examining scaling issues and looking at compatibility with other water that was injected into the reservoir. All water sources associated with the well, either produced or injected, must be tested.

A typical analysis gives the ionic composition of the water. The standard techniques and procedures for oil field water analysis are given in API *RP 45, Recommended Practice for Analysis of Oilfield Waters*.

The following parameters are typically measured:

- major cations—positive ions associated with the minerals dissolved in the water
  - most common cations—sodium (Na), calcium (Ca), and magnesium (Mg) Concentration of these ions can vary from <1,000 mg/L to >30,000 mg/L.
  - fairly typical cations—potassium (K), barium (Ba), strontium (Sr), and lithium (Li) with concentrations in excess of 10 mg/L
  - cations sometimes present—aluminum (Al), ammonium ( $\text{NH}_4$ ), iron (Fe), lead (Pb), manganese (Mn), and zinc (Zn)
- major anions—negative ions associated with minerals dissolved in the water
  - most common anions—chloride (Cl), concentrations can vary from below 10,000 mg/L to over 200,000 mg/L
  - other major anions—bicarbonate ( $\text{HCO}_3$ ) and sulfate ( $\text{SO}_4$ ) found in concentrations up to several thousand mg/L Bicarbonate and sulfate concentrations are important in scaling.
  - fairly typical anions—bromide and iodide with concentrations ranging from less than 50 to more than 6000 mg/L for bromide and less than 10 to more than 1400 mg/L for iodide
- mole fraction of  $\text{CO}_2$ —the amount of this dissolved gas is important in carbonate equilibrium and can affect carbonate scaling tendencies
- pH—usually controlled by the  $\text{CO}_2$  /bicarbonate concentrations—it is used in identifying potential scaling or corrosion tendencies. This measurement should be made in the field at conditions as close to *in situ* as possible. The pH changes over time after sampling because of the formation of carbonate ions due to the decomposition of bicarbonate.

Once the composition is obtained, it can be input into the Scale Prediction module in the StimCADE design program to estimate potential for scale. The program will handle one or two water sources and allows the user to specify the amount of mixing. Analysis of wellhead water samples is sufficient to predict scaling in surface equipment but may not be reliable for estimating downhole scaling. Pressure decreases as water is produced to the surface causing release of  $\text{CO}_2$  and precipitation of scales as the fluid rises. Bottomhole water samples, kept at native pressure and temperature conditions, are necessary for more reliable downhole scaling tendencies.

Proper sampling, transfer and storage procedures are necessary in order to obtain data representative of the well conditions. A good paper, which includes a discussion on sampling, is *Scale Control, Prediction and Treatment or How Companies Evaluate A Scaling Problem and What They Do Wrong* by Oddo and Tomson, presented at the 1992 NACE (National Association of Corrosion Engineers) annual conference.

### Paraffin and asphaltene content

Paraffins are straight- or branched-chain nonpolar alkanes of relatively high-molecular weight. Their chains usually consist of 20 to 60 carbon atoms with a melting range of 98° to 215 degF [36 degC to 101 degC]. The solubility of paraffin waxes in crude oil is limited depending on the molecular weight. Because of the limited solubility, a cooling environment can cause crystallization and precipitation. One standard test method for paraffin content is UOP 46.

Asphaltenes are colloidal aggregates of condensed, polycyclic aromatic hydrocarbons that contain –N, –O, –S, and metal ions. These dispersions are permeated with adsorbed maltene molecules giving the surface a high negative charge. If the negative surface charge comes in contact with a highly charged positive chemical species, an irreversible neutralization occurs. This neutralization destabilizes the micelle and causes precipitation of the asphaltenes. In addition to causing plugging, the precipitated asphaltene molecules can also help stabilize emulsions and sludges. The asphaltene content of a crude oil can be estimated because they are insoluble in certain solvents. The ASTM standard test method for asphaltene is D3279-90 *Standard Test Method for n-Heptane Insolubles*.

### Solids analysis

An analysis of the solids scraped from the tubulars or brought up from the bottom of the well can be useful in determining what type of damage exists. This type of analysis can determine if there is scale, an organic deposit or formation fines.

Common laboratory analysis procedures are shown in Table 7-3.

### Using lab data in fluid selection

The previous section shows how laboratory tests can be used to determine damage mechanisms. This is an important step in selecting the proper fluid to treat the well. Acids would be ineffective in treating paraffins or emulsions. Organic solvents would be recommended in these cases. Likewise, the use of mud acids for treating simple HCl soluble scales, such as calcite, in the wellbore may not be the optimum solution in sandstone formations.

Petrographic and petrophysic studies are particularly important when the reservoir is sandstone. It is highly recommended that the mineralogy be defined since there is the potential for detrimental reaction precipitates when treating with hydrofluoric (HF) acids. The presence of swelling, migrating or HCl sensitive clays should be known when designing the treatment. These parameters will influence the type of fluid chosen and the acid strength recommended.

Finally, compatibility testing is necessary to optimize the acid additive package and to verify that the proposed treating fluid will not cause damage. Proper evaluation before pumping can save time, money and effort afterwards.

**Table 7-3. Solids Analysis Procedure**

Procedure	Result	Indication
Visual inspection of sample	Examination of physical characteristics	Color Texture Friability Organic/inorganic
Heating of sample	Ignition	Oil or organic matter
	Clean flame	Suspect paraffin
	Sooty flame	Suspect asphaltene
	Noisy flame (i.e., pops and sparks)	Contains water
Immersion in water	Sample dissolves	Suspect inorganic salt (typically NaCl)
Immersion in cold HCl	Sample dissolves and gives off odorless gas	CO <sub>2</sub>
	Acid doesn't change color	Suspect calcium or magnesium carbonate
	Acid doesn't change color but sample slowly dissolves	Suspect calcium sulfate
	Acid turns green or yellow and sample is magnetic	Suspect iron carbonate
	Sample dissolves and gives off gas that smells of rotten eggs or lead acetate paper turns brown	Hydrogen sulfide gas suspect iron sulfide
If there is no reaction in cold HCl, immerse the sample in hot HCl	Sample dissolves and turns green or yellow and is magnetic	Suspect iron oxide
If there is no reaction in hot HCl, immerse a portion of the sample in mud acid (HCl/HF)	Sample dissolves	Suspect silica-based compound (e.g., sand or silt particle)
If there is no reaction in mud acid, immerse the sample in U42 or U104.	Sample dissolves (dissolution will be very slow)	Suspect barium or strontium sulfate

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